Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

P.E. Certification Statement

Permittee:
Tampa Electric Company
F.J. Gannon Station

DRAFT Permit No.: 0570040-017-AV

Project type: Title V Revision - Unit Nos. 1, 2, & 4 WDF Modification

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

Scott M. Sheplak, P.E. date
Registration Number: 48866

Permitting Authority:
Department of Environmental Protection
Bureau of Air Regulation
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Telephone: 850/921-9532
Fax: 850/922-6979

SENDER: *COMPLETE THIS SECTION*

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

1. Article Addressed to:

Ms. Karen Sheffield
General Manager - F.J. Gannon
Station and Responsible Official
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* B. Rhind

B. Date of Delivery 10-28-03

C. Signature x B. Rhind ☒ Agent ☐ Addressee

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

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

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

2. Article Number *(Copy from service label)*
7000 0600 0021 6524 2861

PS Form 3811, July 1999 Domestic Return Receipt 102595-00-M-0952

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

7000 0600 0021 6524 2861

Article Sent To:
Ms. Karen Sheffield

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

Postmark Here

Name (Please Print Clearly) (to be completed by mailer)
Ms. Karen Sheffield
Street, Apt. No.; or PO Box No.
P.O. Box 111
City, State, ZIP+4
Tampa, Florida 33601-0111

PS Form 3800, July 1999 See Reverse for Instructions

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

October 17, 2002

Ms. Karen Sheffield
General Manager – F. J. Gannon Station and Responsible Official
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111

Re: Title V Air Operation Permit Revision
DRAFT Permit Project No. **0570040-017-AV**
Revision to Title V Air Operation Permit No. 0570040-002-AV
F. J. Gannon Station

Dear Ms. Sheffield:

One copy of the DRAFT Permit for a Title V Air Operation Permit Revision for the F. J. Gannon Station located at Port Sutton Road, Tampa, Hillsborough County, is enclosed. The permitting authority's "INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION" and the "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION" are also included.

The "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION" must be published as soon as possible. Proof of publication, i.e., newspaper affidavit, must be provided to the permitting authority's office within 7 (seven) days of publication pursuant to Rule 62-110.106(5), F.A.C. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit revision pursuant to Rule 62-110.106(11), F.A.C.

Please submit any written comments you wish to have considered concerning the permitting authority's proposed action to Scott M. Sheplak, P.E., at the above letterhead address. If you have any other questions, please contact Tom Cascio at 850/921-9526.

Sincerely,

A. A. Linero, P.E.
Bureau of Air Regulation

AAL/tbc

Enclosures

In the Matter of an
Application for Permit Revision by:

Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111

DRAFT Permit Project No. **0570040-017-AV**
Revision to Title V Air Operation Permit No. 0570040-002-AV
F. J. Gannon Station
Hillsborough County

______________________________/

INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION

The Department of Environmental Protection (permitting authority) gives notice of its intent to issue a Title V Air Operation Permit Revision (copy of DRAFT Permit attached) for the Title V source detailed in the application specified above, for the reasons stated below. This is a revision to Title V Air Operation Permit No. 0570040-002-AV.

The applicant, the Tampa Electric Company, applied on April 15, 2002, to the permitting authority for a Title V Air Operation Permit Revision for the F. J. Gannon Station, located at Port Sutton Road, Tampa, Hillsborough County.

This permit revision is to change the F. J. Gannon Station Unit Nos. 1, 2, and 4 steam generator operating limitations to allow for the firing of a coal and wood-derived fuel (WDF) blend. WDF can be composed of Paper Pellets, Yard Trash, and Wood/Wood Chips, as defined in the DRAFT permit document. In addition, all references to Tire Derived Fuel (TDF) are removed from the permit, since the facility does not have the authority to burn it.

The permitting authority 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, 62-213, and 62-214. This source is not exempt from Title V permitting procedures. The permitting authority has determined that a Title V Air Operation Permit Revision is required to commence or continue operations at the described facility.

The permitting authority intends to issue this Title V Air Operation Permit Revision based on the belief that reasonable assurances have been provided to indicate that operation of the source will not adversely impact air quality, and the source will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-214, 62-256, 62-257, 62-281, 62-296, and 62-297, F.A.C.

Pursuant to Sections 403.815 and 403.087, F.S., and Rules 62-110.106 and 62-210.350(3), F.A.C., you (the applicant) are required to publish at your own expense the enclosed "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION." The notice shall be published one time only as soon as possible in the legal advertisement section of a newspaper of general circulation in the area affected. 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 permitting authority at the address or telephone number listed below. The applicant shall provide proof of publication to the permitting authority's office, the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114; Fax: 850/922-6979), within 7 (seven) days of publication pursuant to Rule 62-110.106(5), F.A.C. Failure to publish the notice and provide proof of publication may result in the denial of the permit revision pursuant to Rule 62-110.106(11), F.A.C.

The permitting authority will issue the PROPOSED Permit, and subsequent FINAL Permit, in accordance with the conditions of the attached DRAFT Permit unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The permitting authority will accept written comments concerning the proposed permit revision issuance action for a period of 30 (thirty) days from the date of publication of the "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION." Written comments should be provided to the permitting authority office. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in this DRAFT Permit, the permitting authority shall issue a Revised DRAFT Permit and require, if applicable, another Public Notice.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000 (Telephone: 850/245-2242, Fax: 850/245-2303). Petitions filed by the permit revision 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), F.S., 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), F.S., however, any person who asked the permitting authority 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, F.A.C.

A petition that disputes the material facts on which the permitting authority'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 each 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;

(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 permitting authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

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

Mediation will not be available in this proceeding.

In addition to the above, a person subject to regulation has a right to apply to the Department of Environmental Protection 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 of Environmental Protection, 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 United States Environmental Protection Agency 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.

Finally, pursuant to 42 United States Code (U.S.C.) Section 7661d(b)(2), any person may petition the Administrator of the EPA within 60 (sixty) days of the expiration of the Administrator's 45 (forty-five) day review period as established at 42 U.S.C. Section 7661d(b)(1), to object to issuance of any permit revision. Any petition shall be based only on objections to the permit revision that were raised with reasonable specificity during the 30 (thirty) day public comment period provided in this notice, unless the petitioner demonstrates to the Administrator of the EPA that it was impracticable to raise such objections within the comment period or unless the grounds for such objection arose after the comment period. Filing of a petition with the Administrator of the EPA does not stay the effective date of any permit properly issued pursuant to the provisions of Chapter 62-213, F.A.C. Petitions filed with the Administrator of EPA must meet the requirements of 42 U.S.C. Section 7661d(b)(2) and must be filed with the Administrator of the EPA at: U.S. EPA, 401 M Street, S.W., Washington, D.C. 20460.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

A. A. Linero, P.E.
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION (including the PUBLIC NOTICE and the DRAFT Permit) and all copies were sent by certified mail before the close of business on 10/17/02 to the person(s) listed:

Karen Sheffield, Tampa Electric Company

In addition, the undersigned duly designated deputy agency clerk hereby certifies that copies of this INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION (including the PUBLIC NOTICE and Statement of Basis) were sent by U.S. mail on the same date to the person(s) listed or as otherwise noted:

Thomas W. Davis, P.E., Environmental Consulting and Technology, Inc.

In addition, the undersigned duly designated deputy agency clerk hereby certifies that copies of this INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION (including the DRAFT Permit package) were sent by INTERNET E-mail on the same date to the person(s) listed:

Jerry Campbell, Environmental Protection Commission of Hillsborough County
Gerald Kissel, Southwest District Office
U.S. EPA, Region 4

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to Section 120.52(7), Florida Statutes, with the designated agency Clerk, receipt of which is hereby acknowledged.

Barbara J. Friday 10/17/02
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DRAFT Permit Project No. 0570040-017-AV
Revision to Title V Air Operation Permit No. 0570040-002-AV
F. J. Gannon Station
Hillsborough County

The Department of Environmental Protection (permitting authority) gives notice of its intent to issue a Title V Air Operation Permit Revision to the Tampa Electric Company for the F. J. Gannon Station located at Port Sutton Road, Tampa, Hillsborough County. This is a revision to Title V Air Operation Permit No. 0570040-002-AV. The applicant's name and address are: Tampa Electric Company, P. O. Box 111, Tampa, Florida 33601-0111.

This permit revision is to change the F. J. Gannon Station Unit Nos. 1, 2, and 4 steam generator operating limitations to allow for the firing of a coal and wood-derived fuel (WDF) blend. WDF can be composed of Paper Pellets, Yard Trash, and Wood/Wood Chips, as defined in the DRAFT permit document. In addition, all references to Tire Derived Fuel (TDF) are removed from the permit, since the facility does not have the authority to burn it.

The permitting authority will issue the PROPOSED Permit, and subsequent FINAL Permit, in accordance with the conditions of the DRAFT Permit unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

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

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57 of the Florida Statutes (F.S.). The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000 (Telephone: 850/245-2242, Fax: 850/245-2303. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of the notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the permitting authority 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 applicable 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 (F.A.C.).

A petition that disputes the material facts on which the permitting authority'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; 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 petitioner's substantial rights will be affected by the agency determination;

(c) A statement of how and when the 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 state;

(e) A concise statement of the ultimate facts alleged, as well as the rules and statutes which entitle petitioner to relief;

(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 permitting authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the permitting authority's final action may be different from the position taken by it in this notice of intent. Persons whose substantial interests will be affected by any such final decision of the permitting authority 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 for this proceeding.

In addition to the above, pursuant to 42 United States Code (U.S.C.) Section 7661d(b)(2), any person may petition the Administrator of the EPA within 60 (sixty) days of the expiration of the Administrator's 45 (forty-five) day review period as established at 42 U.S.C. Section 7661d(b)(1), to object to issuance of any permit revision. Any petition shall be based only on objections to the permit revision that were raised with reasonable specificity during the 30 (thirty) day public comment period provided in this notice, unless the petitioner demonstrates to the Administrator of the EPA that it was impracticable to raise such objections within the comment period or unless the grounds for such objection arose after the comment period. Filing of a petition with the Administrator of the EPA does not stay the effective date of any permit properly issued pursuant to the provisions of Chapter 62-213, F.A.C. Petitions filed with the Administrator of EPA must meet the requirements of 42 U.S.C. Section 7661d(b)(2) and must be filed with the Administrator of the EPA at: U.S. EPA, 401 M Street, S.W., Washington, D.C. 20460.

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:

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

Affected District/Local Program:
Environmental Protection Commission of Hillsborough County
1410 North 21 Street
Tampa, Florida 33605
Telephone: 813/272-5530
Fax: 813/272-5605

The complete project file includes the DRAFT Permit, the application, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact Scott M. Sheplak, P.E., at the above address, or call 850/921-9532, for additional information.

STATEMENT OF BASIS

Tampa Electric Company
F. J. Gannon Station

Title V Air Operation Permit Revision
Permit No. **0570040-017-AV**

This Title V air operation permit revision 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 drawings, plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

This facility consists of six steam boilers (Units 1 through 6); six steam turbines; one simple-cycle combustion turbine; a once-through cooling water system; solid fuels, fluxing material, fly ash, slag, and storage/handling facilities; fuel storage tanks; and ancillary support equipment. The nominal output is 1317 megawatts (MW). The facility utilizes coal as its primary fuel for Units 1-6. The combustion turbine is allowed to burn new No. 2 fuel oil, with a maximum sulfur content of 0.5%, by weight. Units 1 through 4 are also permitted to burn Wood Derived Fuel (WDF).

Units Nos. 1 and 2 are 1257 MMBTU/hr coal fired steam generators. These "wet" bottom boilers were manufactured by Babcock-Wilcox Corporation and are of the cyclone firing type. The generators have a nameplate capacity of 125 MW each. Particulate matter emissions are controlled by a Combustion Engineering, Inc. electrostatic precipitator. New No. 2 fuel oil is used as an ignition fuel during startup. Units Nos. 1 and 2 began commercial operation in August 1957 and October 1958, respectively. Unit No. 3 is a 1599 MMBTU/hr coal fired steam generator. This "wet" bottom boiler was manufactured by Babcock-Wilcox Corporation and is of the cyclone firing type. The generator has a nameplate capacity of 179.5 MW. Particulate matter emissions are controlled by a Combustion Engineering, Inc. electrostatic precipitator. New No. 2 fuel oil is used as an ignition fuel during startup. Unit No. 3 is also permitted to burn Wood Derived Fuel (WDF). Unit No. 3 began commercial operation in August 1960.

These emissions units are regulated under Acid Rain, Phase I SO_2, as conditional substitution units; Acid Rain, Phase II SO_2; and, Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with more than 250 million Btu per hour heat input. Unit No. 3 is regulated under Acid Rain, Phase II NO_X.

Unit No. 4 is an 1876 MMBTU/hr coal fired steam generator. This "wet" bottom boiler was manufactured by Babcock-Wilcox Corporation and is of the cyclone firing type. The generator has a nameplate capacity of 187.5 MW. Particulate matter emissions are controlled by a Combustion Engineering, Inc. rigid frame electrostatic precipitator, prior to discharge through two (2) 306-foot tall exhaust stacks (designated as East and West Stacks). New No. 2 fuel oil is used as an ignition fuel during startup of the unit. Also, this emissions unit is permitted to burn on-specification used oil in accordance with 40 CFR 279. Unit No. 4 began commercial operation in July 1963.

This emissions unit is regulated under Acid Rain, Phase I SO_2 as a conditional substitution unit; Acid Rain Phase II SO_2 & NO_X; and, Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with more than 250 million Btu per hour heat input.

Unit No. 5 is a 2284 MMBTU/hr coal fired steam generator. This "wet" bottom boiler was manufactured by Riley Stoker Corporation and is of the opposed firing type. The generator has a nameplate capacity of 239.4 MW. Particulate matter emissions are controlled by two Research Cottrell, Inc. electrostatic precipitators operating in series. New No. 2 fuel oil is used as an ignition fuel during startup. Unit No. 5 began commercial operation in September 1965.

Unit No. 6 is a 3798 MMBTU/hr coal fired steam generator. This "wet" bottom boiler was manufactured by Riley Stoker Corporation and is of the opposed firing type. The generator has a nameplate capacity of 414 MW. Particulate matter emissions are controlled by a Research Cottrell, Inc. electrostatic precipitator. Before the flue gas enters the electrostatic precipitator, sulfur trioxide is added to the gas stream to serve as a conditioner to enhance electrostatic precipitator performance. New No. 2 fuel oil is used as an ignition fuel during startup. Unit No. 6 began commercial operation in September 1967.

These emissions units are regulated under Acid Rain, Phase I SO_2 as conditional substitution units; Acid Rain Phase II SO_2 & NOx; and, Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with more than 250 million Btu per hour heat input. The six boilers demonstrate compliance with the sulfur dioxide standard by the use of CEMS.

These units are subject to a steady-state PM emission limit of 0.1 lb/mmBtu and 0.3 lb/mmBtu for soot blowing. The applicant has presented historical PM test results which show that the soot blowing average results are less than half the applicable effective standard. The Department has determined that sources with emissions less than half of the effective standard shall test annually. The average test results from the most recent five years of particulate matter compliance testing under sootblowing conditions (testing under non-sootblowing conditions was not required when the sootblowing result showed compliance with the non-sootblowing limit; therefore, no non-sootblowing tests have been performed in the past five years) are as follows:

Unit 1: 0.03 lb/MMBtu
Unit 2: 0.04 lb/MMBtu
Unit 3: 0.03 lb/MMBtu
Unit 4: 0.04 lb/MMBtu
Unit 5: 0.04 lb/MMBtu
Unit 6: 0.08 lb/MMBtu

Combustion Turbine No. 1 is a simple cycle combustion turbine and is designated as Combustion Turbine No. 1. It is rated at a maximum heat input of 256.5 million Btu per hour (MMBtu/hour) while being fueled by new No. 2 fuel oil. This combustion turbine is used as a peaking unit during peak demand times, during emergencies, and during controls testing, to run a nominal 14 MW generator. Emissions from the combustion turbine are uncontrolled. Commercial operation began in January 1969.

This emissions unit is regulated under Rule 62-210.300, F.A.C., Permits Required. This emissions unit is not subject to 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines. This combustion turbine has its own stack.

For the operation of a fuel yard serving the F. J. Gannon Station boiler Units 1 through 6, yard activities includes barge (clamshell and continuous) and railcar unloading of coal, truck/barge/train unloading of flux, and transfer and storage of these materials.

This emissions unit is regulated under Rule 62-296.711, F.A.C., Materials Handling, Sizing, Screening, Crushing and Grinding Operation; and, Rule 62-296.700, F.A.C., Reasonably Available Control Technology (RACT) Particulate Matter.

For the operation of the F. J. Gannon Station Units 5 and 6 Fly Ash Silo No. 1 with baghouse, pugmill, and truck loading, fly ash that is collected in the hoppers of the electrostatic precipitators of Units 5 and 6 is pneumatically conveyed to a 25 foot diameter, 50 foot high silo. The fly ash in the silo is gravity fed by chute into enclosed tanker trucks or to a pugmill where it is "conditioned" by wetting with water and gravity fed by chute into open bed trucks. In addition, fly ash from F. J. Gannon Station Units I-4 Fly Ash Silo No. 2 may be routed via gravity flow to the pugmill where it is "conditioned" by wetting with water and gravity fed into open bed trucks. The fly ash is then transported to an off-site consumer. Fly ash may also be conveyed from tanker trucks to Fly Ash Silo No. 1 and from Fly Ash Silo No. 1 to Fly Ash Silo No. 2. Particulate matter emissions generated during the filling of the silo are controlled by an 11,300 ACFM United States Filter Corporation Mikro-Pulsaire Model 1F3-24 baghouse.

These emissions units are regulated under Rule 62-296.711, F.A.C., Materials Handling, Sizing, Screening, Crushing and Grinding Operation; and, Rule 62-296.700, F.A.C., Reasonably Available Control Technology (RACT) Particulate Matter.

For the operation of F. J. Gannon Station Units 1-4 Fly Ash Silo No. 2 with baghouse, fly ash that is collected in the hoppers of the electrostatic precipitators of Units 1-4 is pneumatically conveyed to a 30-foot diameter, 45.5-foot high silo. In addition, fly ash from silo No. 2 may be routed to the pugmill at F. J. Gannon Station Silo No. 1 where it is "conditioned" by wetting with water and gravity fed into open bed trucks. The fly ash in the silo is gravity fed by tubing into enclosed tanker trucks for transport to an off-site consumer. Fly ash may also be conveyed from tanker trucks to Fly Ash Silo No. 2 and from Fly Ash Silo No. 2 to Fly Ash Silo No. 1. Particulate matter emissions generated during the filling of the silo are controlled by a 4,690 ACFM Allen-Sherman-Hoff Corporation Flex Kleen 84 WRW C112IIG baghouse system, which is comprised of two (2) bag filters with three (3) common stacks.

This emissions unit is regulated under Rule 62-296.711, F.A.C., Materials Handling, Sizing, Screening, Crushing and Grinding Operation; and, Rule 62-296.700, F.A.C., Reasonably Available Control Technology (RACT) Particulate Matter.

For the operation of the F. J. Gannon Station Units 1-6 fuel bunkers with exhaust fan/cyclone collectors (Roto-Clones) controlling dust emissions from each unit's respective bunker, two moving transfer stations via their respective conveyor belts route fuel through enclosed chutes to each of the six bunkers. Fuel bunkers Nos. 1-4 and 6 are each equipped with a 9,600 ACFM American Air Filter Company Type D Roto-Clone to abate dust emissions during ventilation. Fuel bunker No. 5 is equipped with a 5,400 ACFM Type D Roto-Clone. A number of vent pipes convey air from each bunker to a Roto-Clone during particulate matter removal. Particulate matter removed by the Roto-Clones is returned to a fuel bunker via a hopper and return line. Units 1-6 fuel bunkers are situated in a west to east fashion. Unit 1 fuel bunker is located furthest to the west and Unit No. 6 fuel bunker furthest to the east.

These emissions units are exempt from Rule 62-296.711, F.A.C., Materials Handling, Sizing, Screening, Crushing and Grinding Operation.

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

Based on the Title V permit revision application received on April 15, 2002, this facility *is* a major source of hazardous air pollutants (HAPs).

This permit revision is to change the facility's Unit Nos. 1, 2, and 4 steam generator operating limitations to allow for the firing of a coal and wood-derived fuel (WDF) blend. WDF can be composed of Paper Pellets, Yard Trash, and Wood/Wood Chips, as defined in the DRAFT permit document. In addition, all references to Tire Derived Fuel (TDF) are removed from the permit, since the facility does not have the authority to burn it.

Tampa Electric Company (TECO)
F. J. Gannon Station
Facility ID No. **0570040**
Hillsborough County

Title V Air Operation Permit Revision
DRAFT Permit Revision No. **0570040-017-AV**

Permitting Authority:

State of Florida
Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Title V Section

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

Telephone: 850/488-0114
Fax: 850/922-6979

Compliance Authority:

Environmental Protection Commission of Hillsborough County

1410 North 21st Street
Tampa, Florida 33605
Telephone: 813/272-5530
Fax: 813/272-5605

Title V Air Operation Permit Revision
DRAFT Permit Revision No. **0570040-017-AV**

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Permittee:	DRAFT Permit Revision No. **0570040-017-AV**
Tampa Electric Company	Facility ID No. **0570040**
P.O. Box 111	SIC No.: 49, 4911
Tampa, Florida 33601-0111	Project: Title V Air Operation Permit Revision

This permit revision is for the operation of the F. J. Gannon Station. This facility is located at Port Sutton Road, Tampa, Hillsborough County; UTM Coordinates: Zone 17, 360.1 km East and 3087.5 km North; Latitude: 28° 02' 31" North and Longitude: 82° 25' 31" West.

This Title V air operation permit revision 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 drawings, 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 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).
TABLE 297.310-1, CALIBRATION SCHEDULE (version dated 10/07/96).
Phase II SO_2 Acid Rain Application/Compliance Plan received December 26, 1995.
Consent Final Judgement (DEP vs. TECO) dated December 6, 1999.
Phase II NOx Compliance (Averaging) Plan received December 22, 1999.
Consent Decree (U.S. vs. TECO) dated February 29, 2000.
Attachment 1, PRELIMINARY DETERMINATION POLLUTION CONTROL PROJECT.

Effective Date: January 1, 2001
Revision Effective Date:
Renewal Application Due Date: July 5, 2005
Expiration Date: December 31, 2005

Howard L. Rhodes, Director
Division of Air Resource
Management

HLR/tbc

Section I. Facility Information.

Subsection A. Facility Description.

This facility consists of six steam boilers (Units 1 through 6); six steam turbines; one simple-cycle combustion turbine; a once-through cooling water system; solid fuels, fluxing material, fly ash, slag, and storage/handling facilities; fuel storage tanks; and ancillary support equipment. The nominal output is 1317 megawatts (MW). The facility utilizes coal as its primary fuel for Units 1-6. The combustion turbine is allowed to burn new No. 2 fuel oil, with a maximum sulfur content of 0.5%, by weight. Units 1 through 4 are also permitted to burn Wood Derived Fuel (WDF).

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

Based on the Title V permit revision application received on April 15, 2002, this facility *is* a major source of hazardous air pollutants (HAPs).

Subsection B. Summary of Emissions Unit ID Nos. and Brief Descriptions.

E.U. ID No.	Brief Description
-001	Unit No. 1-Fossil Fuel-Fired Steam Generator
-002	Unit No. 2-Fossil Fuel-Fired Steam Generator
-003	Unit No. 3-Fossil Fuel-Fired Steam Generator
-004	Unit No. 4-Fossil Fuel-Fired Steam Generator
-005	Unit No. 5-Fossil Fuel-Fired Steam Generator
-006	Unit No. 6-Fossil Fuel-Fired Steam Generator
-007	Combustion Turbine No. 1
-008	F. J. Gannon Station Fuel Yard
-009	Unit 4 Economizer Ash Silo with Baghouse
-010	Units 5 and 6 Fly Ash Silo No. 1 with Baghouse
-011	Units 1-4 Fly Ash Silo with Baghouse (Fly Ash Silo No. 2)
-012	Pugmill and Truck Loading
-013	Unit No. 1 Fuel Bunker with Roto-Clone
-014	Unit No. 2 Fuel Bunker with Roto-Clone
-015	Unit No. 3 Fuel Bunker with Roto-Clone
-016	Unit No. 4 Fuel Bunker with Roto-Clone
-017	Unit No. 5 Fuel Bunker with Roto-Clone
-018	Unit No. 6 Fuel Bunker with Roto-Clone

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

<u>These documents are provided to the Permittee for information purposes only:</u>
Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers.
Appendix H-1, Permit History/ID Number Changes.
Statement of Basis.

<u>These documents are on file with permitting authority:</u>
Initial Title V permit application received June 14, 1996.
Phase I SO_2 Acid Rain Permit dated July 14, 1994.
Letter dated October 8, 1996, from Thomas W. Reese.
EPCHC comments dated September 30, 1996.
DEP Additional Information Request dated November 19, 1996.
TECO Additional Information Response received February 21, 1997.
DEP Additional Information Request dated March 20, 1997.
EPCHC comments dated March 21, 1997.
TECO Additional Information Response received June 16, 1997.
TECO letter dated February 21, 1997, changing the Responsible Official.
TECO letter dated June 13, 1997, changing the Responsible Official.
TECO letter dated June 27, 1997, changing the Designated Representative.
Letter dated July 7, 1997, authorizing venting of slag tanks to atmosphere.
1st DRAFT Title V permit clerked on August 26, 1997.
Public notice published on September 3, 1997.
TECO request for an extension of time to file a petition for an administrative hearing dated September 26, 1997.
Phase II NOx Compliance Plan received December 29, 1997.
TECO permit comments dated March 19, 1998.
TECO letter dated July 1, 1998, changing the Designated Representative.
DEP withdrawal of DRAFT permit dated September 30, 1998.
TECO's air pollutant dispersion modeling report dated October 15, 1998.
USEPA's air pollutant dispersion modeling letter dated April 13, 1999.
2nd DRAFT (Revised) Title V permit clerked on September 30, 1999.
Public notice published on October 11, 1999.
TECO request for an extension of time to file a petition for an administrative hearing dated December 15, 1999.
Manatee County Citizens Against Air Pollution comments dated November 9, 1999.
TECO permit comments dated November 10, 1999.
Manatee County comments dated November 12, 1999.
USEPA letter dated November 17, 1999, addressing Phase II NOx Averaging Plans.
TECO request for an extension of time to file a petition for an administrative hearing dated December 15, 1999.
TECO's SO_2 Compliance Plan received April 6, 2000.
TECO letter dated June 2, 2000, requesting removal of periodic monitoring.
3rd DRAFT (Revised) Title V permit clerked on June 6, 2000.
Public notice published on June 7, 2000.
DEP letter to TECO dated June 7, 2000.

TEC request for an extension of time to file a petition for an administrative hearing dated June 30, 2000.
TECO permit comments dated July 7, 2000.
Appendix F, Ambient Air Quality Compliance Plan for SO_2 Emissions.
PROPOSED permit posted for USEPA review on July 26, 2000.
USEPA objection dated September 8, 2000.
TECO comments dated November 3, 2000.
USEPA objection withdrawal letter dated December 19, 2000.
FINAL Title V Permit issued January 1, 2001.
Letter from the Tampa Electric Company requesting a permit revision received April 15, 2002.

Subsection D. Miscellaneous.

The use of 'Permitting Notes' throughout this permit is for informational purposes only; the notes are not permit conditions.

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 one 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 Ringlemann Chart (20 percent opacity). EPA Method 9 is the method of compliance pursuant to Chapter 62-297, F.A.C.
{Permitting Note: Although the permittee is not required to perform a visible emissions compliance test to demonstrate compliance with the facility-wide limitations annually or before renewal, if the Department or EPCHC believes that the general visible emissions standard is being violated, the Department or EPCHC may require that the owner or operator perform a visible emissions compliance test per Chapter 62-297.310(7)(b), Special Compliance Tests. In addition, Department or EPCHC personnel who are certified to perform visible emissions tests may determine compliance with the general visible emissions standard.}
[Rules 62-296.320(4)(b)1. & 4., F.A.C.]

4. Prevention of Accidental Releases (Section 112(r) of CAA).
a. The permittee shall submit its Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center when, and if, such requirement becomes applicable. 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

and,
b. The permittee shall submit to the permitting authority Title V certification forms or a compliance schedule in accordance with Rule 62-213.440(2), F.A.C.
[40 CFR 68]

5. Insignificant Emissions Units and/or Activities. Appendix I-I, List of Insignificant 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.]

6. 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.
[Rule 62-296.320(1)(a), F.A.C.]

{Permitting Note: No vapor emission control devices or systems are deemed necessary nor ordered by the Department as of the issuance date of this permit.}

7. Reasonable precautions to prevent emissions of unconfined particulate matter at this facility include:
(a) Attend to accidental spills (coal and fly ash) promptly and effectively.
(b) Inspect the boiler, the electrostatic precipitators and the ductwork for gas leaks at least once a month. Note any problems and actions taken.
{Note: This condition implements the requirements of Rules 62-296.320(4)(c)1., 3., & 4. F.A.C. (Condition **58.** of APPENDIX TV-3, TITLE V CONDITIONS).}
[Rule 62-296.320(4)(c)2., F.A.C.; and proposed by applicant in the initial Title V permit application received June 14, 1996]

{Permitting Note: Specific Condition **7.** presents the reasonable precautions to be implemented in accordance with Rule 62-296.320(4)(c), F.A.C., in lieu of the requirements of Condition No. **58.** of Appendix TV-3.}

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

9. The Consent Final Judgement (DEP vs. TECO) dated December 6, 1999, and the Consent Decree (U.S. vs. TECO), dated February 29, 2000, are attached hereto and made a part of this permit. The permittee shall comply with the Consent Final Judgement and the Consent Decree. Wherever the Consent Decree conflicts with this permit the terms and conditions of the Consent Decree control. Upon expiration of the Consent Decree the Title V permit shall be modified to incorporate any terms and conditions that are deemed necessary by the permitting authority for the continued operation of the facility.
[Rules 62-4.070(3)&(5) and 62-213.440, F.A.C.]

10. 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.]

11. The permittee shall submit all compliance related notifications and reports required of this permit to the Environmental Protection Commission of Hillsborough County (EPCHC):

Environmental Protection Commission of
Hillsborough County
1410 North 21st Street
Tampa, FL 33605
Telephone: 813/272-5530
Fax: 813/272-5605

12. The permittee shall provide timely notification to the Environmental Protection Commission of Hillsborough County prior to implementing any changes that may result in a modification to this permit. The changes may include, but are not limited to, the following, and may also require prior authorization before implementation:

1. Alteration or replacement of any equipment* or parameter listed in the Facility or Subsection descriptions.
2. Installation or addition of any equipment* which is a source of air pollution.
3. Any changes in the method of operation, raw materials, products or fuels.

*Not applicable to normal maintenance and repairs, and vehicles used for transporting material.
[Rules 62-4.070(3) and 62-210.300, F.A.C.]

13. 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 EPCRA Enforcement Branch, Air Enforcement Section
61 Forsyth Street
Atlanta, Georgia 30303
Telephone: 404/562-9055, Fax: 404/562-9163

14. Certification by Responsible Official (RO). In addition to the professional engineering certification required for applications by Rule 62-4.050(3), F.A.C., any application form, report, compliance statement, compliance plan and compliance schedule submitted pursuant to Chapter 62-213, F.A.C., shall contain a certification signed by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. Any responsible official who fails to submit any required information or who has submitted incorrect information shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary information or correct information.
[Rule 62-213.420(4), F.A.C.]

15. Compliance Plan. Based on the application, (an) emissions unit(s) (was/were) not in compliance. Appendix F, Compliance Plan, is a part of this permit.
[Rule 62-213.440(2), F.A.C.]

Section III. Emissions Units.

Subsection A. This section addresses the following emissions units.

E.U. ID No.	Brief Description
-001	Unit No. 1-Fossil Fuel Fired Steam Generator
-002	Unit No. 2-Fossil Fuel Fired Steam Generator
-003	Unit No. 3-Fossil Fuel Fired Steam Generator

Units Nos. 1 and 2 are 1257 MMBTU/hr coal fired steam generators. These "wet" bottom boilers were manufactured by Babcock-Wilcox Corporation and are of the cyclone firing type. The generators have a nameplate capacity of 125 MW each. Particulate matter emissions are controlled by a Combustion Engineering, Inc., electrostatic precipitator. New No. 2 fuel oil is used as an ignition fuel during startup. Units Nos. 1 and 2 began commercial operation in August 1957 and October 1958, respectively. Unit No. 3 is a 1599 MMBTU/hr coal fired steam generator. This "wet" bottom boiler was manufactured by Babcock-Wilcox Corporation and is of the cyclone firing type. The generator has a nameplate capacity of 179.5 MW. Particulate matter emissions are controlled by a Combustion Engineering, Inc., electrostatic precipitator. New No. 2 fuel oil is used as an ignition fuel during startup. Units No. 1, 2, and 3 are also permitted to burn Wood Derived Fuel (WDF). Unit No. 3 began commercial operation in August 1960.

{Permitting note: These emissions units are regulated under Acid Rain, Phase I SO_2 as conditional substitution units; Acid Rain, Phase II SO_2; and, Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with more than 250 million Btu per hour heat input. Unit No. 3 is regulated under Acid Rain, Phase II NO_X.}

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

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
1 and 2	1257
3	1599

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each emissions unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the emissions 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 emissions unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of 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.}
[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.405, F.A.C.]

A.2. Methods of Operation. Fuels.

a. Normal operation: The only fuels allowed to be burned are coal, on-specification used oil, and wood derived fuel.

b. Startup; shutdown; malfunctions: In addition to the fuels allowed to be burned during normal operations, each unit may also burn new No. 2 fuel oil during startup, shutdown and malfunctions. This includes but is not limited to the emission unit, a new cyclone/mill or flame stabilization.

c. The injection of nonhazardous boiler chemical cleaning waste is allowed in each unit.

{Permitting note: "Flame stabilization" is defined as the use of new No. 2 fuel oil to stabilize a flame during times of unexpected poor coal quality or equipment failure such as coal piping pluggage. Flame stabilization due to poor coal quality occurs when coal is wet or does not provide the necessary heat to maintain a stable flame. In this situation, new No. 2 fuel oil is combusted to provide the additional required heat input to maintain a stable flame. Flame stabilization due to equipment failure occurs when coal piping is plugged or equipment is otherwise damaged that results in an inconsistent amount of coal reaching the burners. Under certain conditions, this may result in the burners intermittently seeing large amounts of fuel at one time, causing a potentially explosive flame 'puff'. In this situation, new No. 2 fuel oil must be used for stabilization to prevent flame 'puffing' and ensure safe operation. Combustion of No. 2 fuel oil is also necessary during periods of load change to initialize and stabilize the flame until coal flow to the burners reaches steady state. As defined in 62-210.700(3), F.A.C., Load change occurs when the operational capacity of a unit is in the 10 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.}
[Rules 62-4.160(2), 62-210.200(272) and 62-213.440(1), F.A.C.; and 0570040-012-AC, Specific condition 3.]

Test Methods and Procedures

{Permitting note: 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.}

A.3. Unit No. 1, Unit No. 2, and Unit No. 3 shall each be individually stack tested for particulate matter and visible emissions, under both sootblowing and non-sootblowing operation conditions, and for sulfur dioxide emissions. Each test shall be conducted annually during each federal fiscal year (October 1 – September 30). The annual calibration RATA associated with the use of SO2 CEMS may be used in lieu of the required annual EPA Reference Method 6, as long as all of the requirements of Rule 62-297.310, F.A.C., are met.

Unit No.	Required Testing
1	Particulate Matter (non-sootblowing)
	Particulate Matter (soot-blowing)
	Visible Emissions (non-sootblowing)
	Visible Emissions (soot-blowing)
	Sulfur Dioxide
2	Particulate Matter (non-sootblowing)
	Particulate Matter (soot-blowing)
	Visible Emissions (non-sootblowing)

Visible Emissions (soot-blowing)
Sulfur Dioxide
3 Particulate Matter (non-sootblowing)
Particulate Matter (soot-blowing)
Visible Emissions (non-sootblowing)
Visible Emissions (soot-blowing)
Sulfur Dioxide

[Rules 62-296.405(1)(e)3., and 62-297.310(7)(a)4., F.A.C.; AO29-204434, AO29-189206, and AO29-172179]

Monitoring of Operations

A.4. Operation and Maintenance for Particulate Matter Control:

A. Process System Performance Parameters:
1. Source Designator: Units Nos. 1, 2 and 3
2. Design Fuel Consumption Rate at Maximum Continuous Rating:

Unit	Tons/hr (fuel)
1	50
2	51
3	65

3. Operating Pressure:

Unit	Psi
1	1575
2	1580
3	1980

4. Operating Temperature: 1000 °F
5. Maximum Design Steam Capacity:

Unit	Pounds/hr
1	910,000
2	950,000
3	1,160,000

B. Particulate Matter Control Equipment Data:
1. Control Equipment Designator: Electrostatic Precipitator
2. Electrostatic Precipitator Manufacturer: Combustion Engineering
3. Design Flow Rate:

Unit	ACFM
1	440,000
2	440,000
3	574,000

4. Primary Voltage: 460 volts
5. Primary Current:

Unit	Amps
1	258
2	258
3	172

6. Secondary Voltage: 56.6 kilovolts

7. Secondary Current:

Unit	milliamps
1	1,500
2	1,500
3	1,000

8. Design Efficiency: 99.09%
9. Pressure Drop: 1.59 in H_2O (avg)
10. Rapper Frequency: 1/1.5 min - 1/4.0 min (avg)
11. Rapper Duration: Impact
12. Gas Temperature: 250 $\pm$ 55° F. (avg)

C. The following observations, checks and operations apply to these emissions units and shall be conducted on the schedule specified:

Continuously Monitored and Recorded:
Opacity
Steam pressure
Steam temperature
Steam flow

Continuously Monitored:
Precipitator Trouble Alarm

Daily Recorded and Monitored:
Primary voltage
Primary current
Secondary voltage
Secondary current
Inspect system controls. Make minor adjustment as needed.

Monthly Recorded or Inspection/Maintenance:
Fuel input
Inspect insulator compartment heaters/blowers. Service as needed.
Observe operation of all rapper and transformer/rectifier controls.

[Rules 62-296.700(6)(b), and 62-296.700(6)(d), F.A.C.]

Miscellaneous Conditions

A.5. Wood Derived Fuel (WDF). Units No. 1, 2, 3, and 4 (see Section III.B. of this permit) are permitted to be fired on coal or a coal/WDF blend with the following restrictions:

a. The maximum amount of WDF fired shall not exceed 10% of the fuel fired in the boiler on a weight basis. The total quantity of WDF fired in Unit Nos. 1, 2, 3, and 4 shall not exceed 56,940 tons per consecutive 12-month period (56,940 TPY is the calculated weight basis from Unit No. 3, allowed by Permit No. 0570040-011-AC).
*(Note: See **c.**, below, for additional restrictions.)*

b. WDF shall be defined only as material falling under one of the following type categories:
*(Note: See **c.**, below, for additional restrictions.)*

i. Paper Pellets - Pellets consisting of paper, cardboard and polymer-impregnated or coated paper, such as disposable drinking cups, paper plates, etc. It shall include no materials coated or treated with hazardous substances including, but not limited to, tar, asphalt, and coatings containing heavy metals. Pellets shall be free of hazardous substances and as free as practicable of metal, hard plastics, textiles, and food products.

ii. Yard Trash - As defined in Rule 62-701.200 (90), F.A.C., and shall contain only vegetative material resulting from landscaping maintenance or land clearing operations and includes materials such as trees and shrub trimmings, grass clippings, palm fronds, trees and tree stumps.

iii. Wood/Wood Chips - Derived from clean wood lumber, pallets, construction debris free of listed hazardous substances including, but not limited to, pentachlorophenol, creosote, tar, asphalt, and paint containing heavy metals.

c. Based upon the operating conditions during the April 18 and 19, 2000, WDF test burn for Unit No. 3, the following additional WDF usage restrictions apply until additional compliance stack testing is done during firing of different WDF blend ratios and WDF types.

i. WDF is limited to a maximum of 4.0% of the fuel fired in the unit on a weight basis.

ii. WDF is limited to paper pellets only.

In order to increase the WDF blend ratio above the level in Specific Condition **A.5.c.i.** (but never to exceed 10% WDF), or allow for the blending of Yard Trash and Wood/Wood Chips as part of the WDF, then additional testing shall be conducted on the applicable unit. To increase the blend % for WDF consisting of paper pellets only, PM and VE testing only will be required. Successful testing showing compliance with the operation permit limitations at a higher blend ratio will allow future operation up to that level + 10% (not to exceed 10% WDF by weight). Successful testing (i.e., testing showing compliance with the permit limitations and demonstrating no increase in emissions due to the inclusion of the additional types of WDF) while firing Yard Trash and Wood/Wood Chips will allow for subsequent use of those categories of WDF as part of the coal/WDF blend. The permittee shall notify the Air Compliance Section of the Southwest District Office of the Department and the Air Management Division of the Environmental Protection Commission of Hillsborough County (EPC), 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. The test notification shall include a proposed test protocol which, upon agreement by the Department, will establish the testing to be done and the conditions under which the test will be conducted and evaluated. A copy of the test report shall be submitted to the Air Management Division of the EPC and the Air Compliance Section of the Southwest District Office of the Department within 45 days after the test is completed.

{Testing Note: As it deems appropriate and applicable, the Department may take into account the results of any WDF blend testing conducted on a unit in approving changes to WDF types and blend ratios in lieu of additional testing.}

d. Paper pellets fired in this unit shall be produced using a waste separation process as described or similar to that described as the "typical waste separation process for Paper Pellets", submitted as Attachment D to the application for Permit No. 0570040-011-AC, including separation of large items, hand sorting, metal extraction/separation, air classification, organic material screening, and large film plastic removal; or equivalent waste separation processing methods (i.e. methods that are designed to result in a target level of approximately 5% or less non-paper materials in the final waste stream). Each time that the permittee receives material from a new paper pellet supplier, or there is a significant change in the waste separation process of a prior supplier, the permittee shall submit a detailed description of the waste separation process used by that supplier (or changes to a previously submitted supplier's process) to the Air Management Division of the Environmental Protection Commission of Hillsborough. The Department reserves the right to request additional information, require additional testing of, or disapprove use of paper pellets from this supplier if it has good reason to believe that this waste separation process will not result in material that meets the above definition of Paper Pellets.

e. Additional Recordkeeping Requirements. In order to document compliance with Specific Conditions **A.5.a.** through **A.5.d.**, the permittee shall maintain daily records for each unit of the quantity (tons) of WDF fired, with a statement as to the type(s) of WDF included (i.e. Paper Pellets, Yard Trash and/or Wood/Wood Chips), and the coal/WDF blend ratio (on a weight basis). The permittee shall also keep records on a monthly basis of the estimated total of WDF fired by type (i.e., Paper Pellets, Yard Trash and/or Wood/Wood Chips). This monthly record shall also include a statement identifying the suppliers of the paper pellets used that month. These records shall be recorded in a permanent form suitable for inspection by the Department upon request, and shall be retained for at least a five (5) year period.

f. Additional Compliance Testing Requirements. Future annual particulate matter and visible emissions testing shall be conducted while firing coal/WDF blend at 90-100% of the maximum permitted WDF blend ratio (or the maximum WDF blend ration for which the permittee wants the unit to be permitted for, not to exceed 10% WDF). This requirement may be waived (and testing done on 100% coal) if coal/WDF blend has been fired for less than 400 hours in the previous 12-month period and it is anticipated that it will not be used for more than 400 hours in the next 12-month period. The test reports shall include a statement and documentation of the coal/WDF blend ratio (weight basis) in use during the test, including a statement as to the types of WDF (i.e., Paper Pellets, Yard Trash and/or Wood/Wood Chips) included in the WDF material fired.

[Rules 62-213.440(1), 62-4.070(3), 62-297.310(7)(a)9, and 62-297.310(2) and (8), F.A.C.; 0570040-011-AC; and 0570040-012-AC, Specific Condition 3.]

A.6. These emissions units are also subject to the conditions contained in **Subsection J. Common Conditions.**

Subsection B. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
-004	Unit No. 4-Fossil Fuel Fired Steam Generator

This emissions unit is an 1876 MMBTU/hr coal fired steam generator. This "wet" bottom boiler was manufactured by Babcock-Wilcox Corporation and is of the cyclone firing type. The generator has a nameplate capacity of 187.5 MW. Particulate matter emissions are controlled by a Combustion Engineering, Inc., rigid frame electrostatic precipitator, prior to discharge through two (2) 306-foot tall exhaust stacks (designated as East and West Stacks). New No. 2 fuel oil is used as an ignition fuel during startup of the unit. Also, this emissions unit is permitted to burn on-specification used oil in accordance with 40 CFR 279. Unit No. 4 is also permitted to burn Wood Derived Fuel (WDF). Unit No. 4 began commercial operation in July 1963.

{Permitting note: This emissions unit is regulated under Acid Rain, Phase I SO_2 as a conditional substitution unit; Acid Rain Phase II SO_2 & NO_X; and, Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with more than 250 million Btu per hour heat input.}

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

Essential Potential to Emit (PTE) Parameters

B.1. Permitted Capacity. The maximum operation heat input rate is as follows:

Unit No.	MMBtu/hr Heat Input
-004	1876

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each emissions unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the emissions 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 emissions unit was tested. Rule 62-297.310(5),F.A.C., included in the permit, requires measurement of 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.}
[Rule 62-4.160(2), 62-210.200 (PTE) and 62-296.405, F.A.C.]

B.2. Methods of Operation - Fuels.

a. Normal operation: The only fuels allowed to be burned are coal, on-specification used oil, and wood derived fuel.
b. Startup; shutdown; malfunctions: In addition to the fuels allowed to be burned during normal operations, each unit may also burn new No. 2 fuel oil during startup, shutdown and malfunctions. This includes but is not limited to the emission unit, a new cyclone/mill or flame stabilization.

c. The injection of nonhazardous boiler chemical cleaning waste is allowed in each unit.

{Permitting note: "Flame stabilization" is defined as the use of new No. 2 fuel oil to stabilize a flame during times of unexpected poor coal quality or equipment failure such as coal piping pluggage. Flame stabilization due to poor coal quality occurs when coal is wet or does not provide the necessary heat to maintain a stable flame. In this situation, new No. 2 fuel oil is combusted to provide the additional required heat input to maintain a stable flame. Flame stabilization due to equipment failure occurs when coal piping is plugged or equipment is otherwise damaged that results in an inconsistent amount of coal reaching the burners. Under certain conditions, this may result in the burners intermittently seeing large amounts of fuel at one time, causing a potentially explosive flame 'puff'. In this situation, new No. 2 fuel oil must be used for stabilization to prevent flame 'puffing' and ensure safe operation. Combustion of No. 2 fuel oil is also necessary during periods of load change to initialize and stabilize the flame until coal flow to the burners reaches steady state. As defined in 62-210.700(3), F.A.C., Load change occurs when the operational capacity of a unit is in the 10 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.}
[Rules 62-4.160(2), 62-210.200(272), and 62-213.440(1), F.A.C.]

Emission Limitations and Standards

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

B.3. [Reserved.]

Test Methods and Procedures

{Permitting note: 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.}

B.4. Unit No. 4 shall be stack tested for particulate matter and visible emissions, under both sootblowing and non-sootblowing operation conditions, and for sulfur dioxide emissions. Each test shall be conducted annually during each federal fiscal year (October 1 – September 30). The annual calibration RATA associated with the use of SO2 CEMS may be used in lieu of the required annual EPA Reference Method 6, as long as all of the requirements of Rule 62-297.310, F.A.C., are met.

Unit No.	Required Stack Testing
4	Particulate Matter (non-sootblowing)
	Particulate Matter (soot-blowing)
	Visible Emissions (non-sootblowing)
	Visible Emissions (soot-blowing)
	Sulfur Dioxide

[Rule 62-297.310, F.A.C.]

Monitoring of Operations

B.5. Operation and Maintenance for Particulate Matter Control:

A. Process System Performance Parameters:

1. Fuel: Coal, new No. 2 fuel oil or on-specification used oil
2. Design Fuel Consumption Rate at Maximum Continuous Rating:
   Coal - 80 tons/hour
   New No. 2 fuel oil - 18 gallons/minute
   On-specification used oil - 48 gallons/minute; max 1,000,000 gals/yr
3. Operating Pressure: 1890 psi.
4. Operating Temperature: 1000 °F
5. Maximum Design Steam Capacity: 1,260,000 pounds per hour

B. Particulate Matter Control Equipment Data:

1. Control Equipment Designator: Electrostatic Precipitator
2. Electrostatic Precipitator Manufacturer: Combustion Engineering, Inc.
3. Design Flow Rate: 631,000 ACFM
4. Primary Voltage: 460 volts
5. Primary Current: 172 amps
6. Secondary Voltage: 56.6 kilovolts
7. Secondary Current: 1,000 milliamps
8. Design Efficiency: 99.05%
9. Pressure Drop: 1.58 in H_2O (avg)
10. Rapper Frequency: 1/1.5 min - 1/3.5 min (avg)
11. Rapper Duration: Impact
12. Gas Temperature: 250 ± 55° F. (avg)

C. The following observations, checks and operations apply to this source and shall be conducted on the schedule specified:

Continuously Monitored and Recorded:
Opacity
Steam pressure
Steam temperature
Steam flow

Continuously Monitored:
Precipitator Trouble Alarm

Daily Recorded and Inspected:
Primary voltage
Primary current
Secondary voltage
Secondary current
Inspect system controls. Make minor adjustment as needed.

Monthly Recorded or Inspection/Maintenance:
Fuel input
Inspect insulator compartment heaters/blowers. Service as needed.

Observe operation of all rapper and transformer/rectifier controls.
[Rules 62-296.700(6)(b) and 62-296.700(6)(d), F.A.C.]

Miscellaneous Conditions

B.6. Wood Derived Fuel (WDF). Units No. 1, 2, 3, and 4 (see Section III.A. of this permit) are permitted to be fired on coal or a coal/WDF blend with the following restrictions:

a. The maximum amount of WDF fired shall not exceed 10% of the fuel fired in the boiler on a weight basis. The total quantity of WDF fired in Unit Nos. 1, 2, 3, and 4 shall not exceed 56,940 tons per consecutive 12-month period (56,940 TPY is the calculated weight basis from Unit No. 3, allowed by Permit No. 0570040-011-AC).
(Note: See ***c.****, below, for additional restrictions.)*

b. WDF shall be defined only as material falling under one of the following type categories:
(Note: See ***c.****, below, for additional restrictions.)*

   i. Paper Pellets - Pellets consisting of paper, cardboard and polymer-impregnated or coated paper, such as disposable drinking cups, paper plates, etc. It shall include no materials coated or treated with hazardous substances including, but not limited to, tar, asphalt, and coatings containing heavy metals. Pellets shall be free of hazardous substances and as free as practicable of metal, hard plastics, textiles, and food products.

   ii. Yard Trash - As defined in Rule 62-701.200 (90), F.A.C., and shall contain only vegetative material resulting from landscaping maintenance or land clearing operations and includes materials such as trees and shrub trimmings, grass clippings, palm fronds, trees and tree stumps.

   iv. Wood/Wood Chips - Derived from clean wood lumber, pallets, construction debris free of listed hazardous substances including, but not limited to, pentachlorophenol, creosote, tar, asphalt, and paint containing heavy metals.

c. Based upon the operating conditions during the April 18 and 19, 2000, WDF test burn for Unit No. 3, the following additional WDF usage restrictions apply until additional compliance stack testing is done during firing of different WDF blend ratios and WDF types.

   i. WDF is limited to a maximum of 4.0% of the fuel fired in the unit on a weight basis.

   ii. WDF is limited to paper pellets only.

   In order to increase the WDF blend ratio above the level in Specific Condition **B.6.c.i.** (but never to exceed 10% WDF), or allow for the blending of Yard Trash and Wood/Wood Chips as part of the WDF, then additional testing shall be conducted on the applicable unit. To increase the blend % for WDF consisting of paper pellets only, PM and VE testing only will be required. Successful testing showing compliance with the operation permit limitations at a higher blend ratio will allow future operation up to that level + 10% (not to exceed 10% WDF by weight). Successful testing (i.e. testing showing compliance with the permit limitations and demonstrating no increase in emissions due to the inclusion of the additional types of WDF) while firing Yard Trash and Wood/Wood Chips will allow for subsequent use of those categories of WDF as part of the coal/WDF blend. The permittee shall notify the Air Compliance Section of the Southwest District Office of the Department and the Air Management Division of the Environmental Protection Commission of Hillsborough County (EPC), 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. The test notification shall include a proposed test protocol which, upon agreement by the Department, will establish the testing to be done and the conditions under which the test will be conducted and evaluated. A copy of the test report shall be submitted to the Air Management Division of the EPC and the Air Compliance Section of the Southwest District Office of the Department within 45 days after the test is completed.

{Testing Note: As it deems appropriate and applicable, the Department may take into account the results of any WDF blend testing conducted on a unit in approving changes to WDF types and blend ratios in lieu of additional testing.}

d. Paper pellets fired in this unit shall be produced using a waste separation process as described or similar to that described as the "typical waste separation process for Paper Pellets", submitted as Attachment D to the application for Permit No. 0570040-011-AC, including separation of large items, hand sorting, metal extraction/separation, air classification, organic material screening, and large film plastic removal; or equivalent waste separation processing methods (i.e., methods that are designed to result in a target level of approximately 5% or less non-paper materials in the final waste stream). Each time that the permittee receives material from a new paper pellet supplier, or there is a significant change in the waste separation process of a prior supplier, the permittee shall submit a detailed description of the waste separation process used by that supplier (or changes to a previously submitted supplier's process) to the Air Management Division of the Environmental Protection Commission of Hillsborough. The Department reserves the right to request additional information, require additional testing of, or disapprove use of paper pellets from this supplier if it has good reason to believe that this waste separation process will not result in material that meets the above definition of Paper Pellets.

e. Additional Recordkeeping Requirements. In order to document compliance with Specific Conditions **B.6.a.** through **B.6.d.**, the permittee shall maintain daily records for each unit of the quantity (tons) of WDF fired, with a statement as to the type(s) of WDF included (i.e. Paper Pellets, Yard Trash and/or Wood/Wood Chips), and the coal/WDF blend ratio (on a weight basis). The permittee shall also keep records on a monthly basis of the estimated total of WDF fired by type (i.e., Paper Pellets, Yard Trash and/or Wood/Wood Chips). This monthly record shall also include a statement identifying the suppliers of the paper pellets used that month. These records shall be recorded in a permanent form suitable for inspection by the Department upon request, and shall be retained for at least a five (5) year period.

f. Additional Compliance Testing Requirements. Future annual particulate matter and visible emissions testing shall be conducted while firing coal/WDF blend at 90-100% of the maximum permitted WDF blend ratio (or the maximum WDF blend ration for which the permittee wants the unit to be permitted for, not to exceed 10% WDF). This requirement may be waived (and testing done on 100% coal) if coal/WDF blend has been fired for less than 400 hours in the previous 12-month period and it is anticipated that it will not be used for more than 400 hours in the next 12-month period. The test reports shall include a statement and documentation of the coal/WDF blend ratio (weight basis) in use during the test, including a statement as to the types of WDF (i.e., Paper Pellets, Yard Trash and/or Wood/Wood Chips) included in the WDF material fired.

[Rules 62-213.440(1), 62-4.070(3), 62-297.310(7)(a)9, and 62-297.310(2) and (8), F.A.C.; 0570040-011-AC; and 0570040-012-AC, Specific Condition 3.]

B.7. This emissions unit is also subject to the conditions contained in **Subsection J. Common Conditions.**

Subsection C. This section addresses the following emissions units.

E.U. ID No.	Brief Description
-005	Unit No. 5-Fossil Fuel Fired Steam Generator
-006	Unit No. 6-Fossil Fuel Fired Steam Generator

Unit No. 5 is a 2284 MMBTU/hr coal fired steam generator. This "wet" bottom boiler was manufactured by Riley Stoker Corporation and is of the opposed firing type. The generator has a nameplate capacity of 239.4 MW. Particulate matter emissions are controlled by two Research Cottrell, Inc. electrostatic precipitators operating in series. New No. 2 fuel oil is used as an ignition fuel during startup. Unit No. 5 began commercial operation in September 1965.

Unit No. 6 is a 3798 MMBTU/hr coal fired steam generator. This "wet" bottom boiler was manufactured by Riley Stoker Corporation and is of the opposed firing type. The generator has a nameplate capacity of 414 MW. Particulate matter emissions are controlled by a Research Cottrell, Inc. electrostatic precipitator. Before the flue gas enters the electrostatic precipitator, sulfur trioxide is added to the gas stream to serve as a conditioner to enhance electrostatic precipitator performance. New No. 2 fuel oil is used as an ignition fuel during startup. Unit No. 6 began commercial operation in September 1967.

{Permitting notes: These emissions units are regulated under Acid Rain, Phase I SO_2 as conditional substitution units; Acid Rain Phase II SO_2 & NOx; and, Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with more than 250 million Btu per hour heat input.}

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

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

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

Unit No.	MMBtu/hr Heat Input
-005	2284
-006	3798

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each emissions unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the emissions 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 emissions unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of 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.}
[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.405, F.A.C.]

C.2. Methods of Operation - Fuels.

a. Normal operation: The only fuels allowed to be burned are coal and on-specification used oil.

b. Startup; shutdown; malfunctions: In addition to the fuels allowed to be burned during normal operations, each unit may also burn new No. 2 fuel oil during startup, shutdown and malfunctions. This includes but is not limited to the emission unit, a new cyclone/mill or flame stabilization.

c. The injection of nonhazardous boiler chemical cleaning waste is allowed in each unit.

{Permitting note: "Flame stabilization" is defined as the use of new No. 2 fuel oil to stabilize a flame during times of unexpected poor coal quality or equipment failure such as coal piping pluggage. Flame stabilization due to poor coal quality occurs when coal is wet or does not provide the necessary heat to maintain a stable flame. In this situation, new No. 2 fuel oil is combusted to provide the additional required heat input to maintain a stable flame. Flame stabilization due to equipment failure occurs when coal piping is plugged or equipment is otherwise damaged that results in an inconsistent amount of coal reaching the burners. Under certain conditions, this may result in the burners intermittently seeing large amounts of fuel at one time, causing a potentially explosive flame 'puff'. In this situation, new No. 2 fuel oil must be used for stabilization to prevent flame 'puffing' and ensure safe operation. Combustion of No. 2 fuel oil is also necessary during periods of load change to initialize and stabilize the flame until coal flow to the burners reaches steady state. As defined in 62-210.700(3), F.A.C., Load change occurs when the operational capacity of a unit is in the 10 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.}
[Rules 62-4.160(2), 62-210.200(272), and 62-213.440(1), F.A.C.]

Test Methods and Procedures

{Permitting note: 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.}

C.3. Units Nos. 5 and 6 shall each be individually stack tested for particulate matter and visible emissions, under both sootblowing and non-sootblowing operation conditions, and for sulfur dioxide emissions. Each test shall be conducted annually during each federal fiscal year (October 1 – September 30). The annual calibration RATA associated with the use of SO2 CEMS may be used in lieu of the required annual EPA Reference Method 6, as long as all of the requirements of Rule 62-297.310, F.A.C., are met.

Unit No.	Required Stack Testing
5	Particulate Matter (non-sootblowing)
	Particulate Matter (soot-blowing)
	Visible Emissions (non-sootblowing)
	Visible Emissions (soot-blowing)
	Sulfur Dioxide
6	Particulate Matter (non-sootblowing)
	Particulate Matter (soot-blowing)
	Visible Emissions (non-sootblowing)
	Visible Emissions (soot-blowing)
	Sulfur Dioxide

[Rule 62-297.310(7)(a)4., F.A.C., AO 29-203511, AO29-203512]

Monitoring of Operations

C.4. Operation and Maintenance for Particulate Matter Control:

A. Process System Performance Parameters:

1. Source Designator: Units Nos. 5 and 6
2. Design Fuel Consumption Rate at Maximum Continuous Rating:

Unit	Tons/hr (coal)
5	93.4
6	151.4

3. Operating Pressure:

Unit	Psi
5	2,250
6	2,600

4. Operating Temperature: 1000 °F
5. Maximum Design Steam Capacity:

Unit	Pounds/hr
5	1,660,000
6	2,700,000

B. Particulate Matter Control Equipment Data:

1. Control Equipment Designator: Two Electrostatic Precipitators Unit No. 5; One Electrostatic Precipitator Unit No. 6
2. Electrostatic Precipitator Manufacturer: Research Cottrell Inc.
3. Model Numbers:
   Unit No. 5: G.O. 3129; G.O. 2791
   Unit No. 6: G.O. 3118
4. Design Flow Rate:

Unit	ACFM
5	820,000; 700,000
6	1,350,000

5. Primary Voltage:

Unit	Volts
5	400; 400
6	430-480

6. Primary Current:

Unit	Amps
5	240; 195
6	241

7. Secondary Voltage:

Unit	Volts
5	53.5; 64.5
6	53.5

8. Secondary Current:

Unit	milliamps
5	1,500; 1,000
6	1,500

9. Design Efficiency:

Unit	Percent
5	99.78; 98.5
6	98.5

10. Pressure Drop: 0.5 in H_2O (avg)
11. Static Pressure: +15 in H_2O (avg)
12. Rapper Frequency: 1/2.0 min (avg)
13. Rapper Duration: Impact
14. Gas Temperature: 293 °F (avg)

C. The following observations, checks and operations apply to this source and shall be conducted on the schedule specified:

Continuously Monitored and Recorded:
Opacity
Steam pressure
Steam temperature
Steam flow

Continuously Monitored:
Precipitator Trouble Alarm

Daily Recorded and Monitored:
Primary voltage
Primary current
Secondary voltage
Secondary current
Inspect system controls. Make minor adjustments as needed.

Monthly Recorded or Inspection/Maintenance:
Fuel input
Inspect penthouse blowers and tub heaters. Replace as necessary.
Observe operation of all rapper and transformer/rectifier controls.

[Rules 62-296.700(6)(b) and 62-296.700(6)(d), F.A.C.]

C.5. These emissions units are also subject to conditions contained in **Subsection J. Common Conditions.**

Subsection D. This section addresses the following emissions unit.

E.U. ID No.	**Brief Description**
-007	Combustion Turbine No. 1

This emissions unit is a simple cycle combustion turbine and is designated as Combustion Turbine No. 1. It is rated at a maximum heat input of 256.5 million Btu per hour (MMBtu/hour) while being fueled by new No. 2 fuel oil. This combustion turbine is used as a peaking unit during peak demand times, during emergencies, and during controls testing, to run a nominal 14 MW generator. Emissions from the combustion turbine are uncontrolled. Commercial operation began in January 1969.

{Permitting notes: This emissions unit is regulated under Rule 62-210.300, F.A.C., Permits Required. This emissions unit is *not* subject to 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines. This combustion turbine has its own stack.}

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

Essential Potential to Emit (PTE) Parameters

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

Unit No.	MMBtu/hr Heat Input
-007	256.5

{Permitting note: The heat input limitations have been placed in the permit to identify the capacity of each emissions unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emissions unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate 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 emissions unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of 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.}
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

D.2. Emissions Unit Operating Rate Limitation After Testing. See **Specific Condition D.13.**
[Rule 62-297.310(2), F.A.C.]

D.3. Methods of Operation - Fuels. Only new No. 2 fuel oil shall be fired in the combustion turbine.
[Rules 62-4.160(2) and 62-213.440(1), F.A.C.]

D.4. Hours of Operation. This emissions unit may operate continuously, i.e., 8,760 hours/year.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and, AO29-252615]

Emission Limitations and Standards

{Permitting Note: The attached 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.}

D.5. Visible Emissions. Visible emissions shall not be equal to or greater than 20 percent opacity.
{Permitting note: The averaging time for this condition is based on the specified averaging time of the applicable test method, unless otherwise specified in this permit.}
[Rule 62-296.320(4)(b)1., F.A.C.]

D.6. Not federally enforceable. Sulfur Dioxide - Sulfur Content. The sulfur content of the new No. 2 fuel oil shall not exceed 0.5 percent, by weight.
[Requested in initial Title V permit application received June 14,1996; and, AO29-252615]

Excess Emissions

D.7. Excess emissions from this emissions units 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.]

D.8. 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

D.9. The permittee shall demonstrate compliance with the liquid fuel sulfur limit by means of a fuel analysis provided by the vendor upon each fuel delivery, or some other comparable method (i.e., composite as-delivered fuel sample analysis).
[Rule 62-213.440, F.A.C.]

D.10. 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.]

Test Methods and Procedures

{Permitting Note: 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.}

D.11. 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, 62-296.320(4)(b)4.a. and 62-297.401, F.A.C.]

D.12. Sulfur Dioxide - sulfur content. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, or both ASTM D4057-88 and ASTM D129-91 or the latest edition of the above ASTM methods.
[Rules 62-213.440 and 62-297.440, F.A.C.]

D.13. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operating 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, 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.
[Rule 62-297.310(2), F.A.C.]

D.14. Applicable Test Procedures.

(a) Required Sampling Time.

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.

[Rule 62-297.310(4)(a)2.c., F.A.C.]

D.15. 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.

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;

8. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.

(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; and, AO29-252615]

D.16. Visible Emissions Testing - Annual. By this permit, annual emissions compliance testing for visible emissions is not required for this emissions unit while burning:

c. only liquid fuels for less than 400 hours per year.

[Rules 62-297.310(7)(a)4. & 8., F.A.C.]

Recordkeeping and Reporting Requirements

D.17. Malfunction Reporting. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Environmental Protection Commission of Hillsborough County 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 Environmental Protection Commission of Hillsborough County.
[Rule 62-210.700(6), F.A.C.]

D.18. The owner or operator shall notify the Environmental Protection Commission of Hillsborough County, 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.
[Rule 62-297.310(7)(a)9., F.A.C.]

D.19. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Environmental Protection Commission of Hillsborough County on the results of each such test.
(b) The required test report shall be filed with the Environmental Protection Commission of Hillsborough County as soon as practical but no later than 45 days after the last sampling run of each test is completed.
[Rule 62-297.310(8), F.A.C.]

Reasonable Assurances

D.20. A statement of the gas turbine new No. 2 fuel oil firing rate (gallons/hour) and corresponding heat input rate (MMBTU/hour) during the test period shall be included with each test report. Failure to submit this information with the test report may fail to provide reasonable assurance of compliance.
[Rule 62-4.070(3), F.A.C.]

D.21. In order to document continuing compliance with Specific Condition **D.6.**, records shall be maintained of the sulfur content, in % by weight, of new No. 2 fuel oil delivered for use in this combustion turbine. On the basis of the requirements of Department of Agriculture and Consumer Services Rule 5F-2001 (which requires that new No. 2 oil sold in Florida have a maximum sulfur content not to exceed 0.5% by weight), reasonable assurance that the sulfur content requirement is being met can also be provided through vendor supplied documentation that the fuel oil delivered for use in the gas turbine meets the above specifications for new No. 2 fuel oil. These records shall be recorded in a permanent form suitable for inspection by the Environmental Protection Commission of Hillsborough County upon request, and shall be retained for at least a five-year period.
[Rules 62-4.070(3) and 62-213.440(1)(b)2.b., F.A.C.]

D.22. In order to document compliance with Specific Condition **D.16.**, the permittee shall maintain a record of the combustion turbine operating hours. These records shall be recorded in a permanent form suitable for inspection by the Environmental Protection Commission of Hillsborough County upon request, and shall be retained for at least a five-year period.
[Rules 62-4.070(3) and 62-213.440(1)(b)2.b., F.A.C.]

Subsection E. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
-008	F. J. Gannon Station Fuel Yard

For the operation of a fuel yard serving the F. J. Gannon Station boiler Units 1 through 6, yard activities includes barge (clamshell and continuous) and railcar unloading of coal, truck/barge/train unloading of flux, and transfer and storage of these materials. Particulate matter control media and other yard activity parameters are listed below:

Emission Point Description	Emission Point ID	Throughput (tph)	Control Method*	Efficiency
Barge to clamshell	FH-002	2,300	DS	95%
Barge to continuous unloader	FH-003	2,300	DS	95%
Clamshell to barge unloading hopper	FH-005	2,300	DS	95%
Continuous unloader to conveyor A	FH-006	2,300	**DS	95%
Conveyor A to continuous feeder	FH-007	2,300	DS/E	95%
Barge unloading hopper to conveyor B	FH-009	2,300	**DS/E	95%
Conveyor B to conveyor C	FH-011	2,300	DS/E	90%
Conveyor C to conveyors D1, D2	FH-012	2,300	**DS/E	90%
Railcar to rail unloading hopper	FH-013	2,300	DS/E	95%
Rail unloading hopper to conveyor L	FH-014	2,300	**DS/E	95%
Conveyor L to conveyors D1, D2	FH-015	2,300	**DS/E	95%
Conveyor D1 to conveyor M1	FH-016	2,300	**DS/E	90%
Conveyor D2 to conveyor M2	FH-017	2,300	**DS/E	90%
Conveyor M1 to conveyor E1	FH-018	2,300	**DS/E	90%
Conveyor M2 to conveyor E2	FH-019	2,300	**DS/E	90%
Conveyor E1 to fuel storage pile	FH-020	2,300	DS	70%
Conveyor E2 to fuel storage pile	FH-021	2,300	DS	70%
Fuel storage pile	FH-022/023		DS	50%
Underground reclaim to conveyor F1	FH-024	1,600	DS/E	85%
Underground reclaim to conveyor F4	FH-025	1,600	DS/E	85%
Underground reclaim to conveyor F3	FH-026	1,600	DS/E	85%
Underground reclaim to conveyor F2	FH-027	1,600	DS/E	85%
Conveyor F1 to conveyors G1, G2	FH-028	1,600	**DS/E	90%
Conveyor F4 to conveyors G1, G2	FH-029	1,600	**DS/E	90%
Conveyor F3 to conveyors G1, G2	FH-030	1,600	**DS/E	90%
Conveyor F2 to conveyors G1, G2	FH-031	1,600	**DS/E	90%
Conveyor G1 to Crusher 3A	FH-032	800	DS/E	90%
Crusher 3A to Conveyor G1	FH-032a	800	DS/E	90%
Conveyor G1 to Crusher 1A1B	FH-032b	800	DS/E	90%

Conveyor G2 to Crusher 3B	FH-033	800	DS/E	90%
Crusher 3B to Conveyor G2	FH-033a	800	DS/E	90%
Conveyor G2 to Crusher 2A2B	FH-033b	800	DS/E	90%
Crushers 1A1B to conveyor H1	FH-034	800	DS/E	90%
Crusher 3A to Conveyor H1	FH-034a	600	DS/E	90%
Crushers 2A2B to conveyor H2	FH-035	800	DS/E	90%
Crusher 3B to Conveyor H2	FH-035a	600	DS/E	90%
Conveyor H1 to bunkering	FH-036/041		Rotoclones	75%
Conveyor H2 to bunkering	FH-036/041		Rotoclones	75%
Conveyor D1 to conveyors G1, G2	FH-042	2,300	**DS/E	90%
Conveyor D2 to conveyors G1, G2	FH-043	2,300	**DS/E	90%
Dozer operations of storage piles	FH-044		DS	50%
Truck unloading - auxiliary	AH-001	400	DS	85%
Storage pile to auxiliary hopper	AH-002	400	DS/E	90%
Auxiliary hopper to conveyor T	AH-003	400	DS/E	90%
Conveyor T to conveyor U	AH-004	400	DS/E	90%
Conveyor U to conveyors G1, G2	AH-005	400	DS/E	90%

**Dust Suppressant Application Point * DS=Dust Suppressant, E=Enclosure

{Permitting note: This emissions unit is regulated under Rule 62-296.711, F.A.C., Materials Handling, Sizing, Screening, Crushing and Grinding Operation; and, Rule 62-296.700, F.A.C., Reasonably Available Control Technology (RACT) Particulate Matter.}

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

Essential Potential to Emit (PTE) Parameters

E.1. Permitted Capacity.
(a) The coal throughput shall not exceed 3,304,646 tons per 12 consecutive month period. The auxiliary fuel, consisting of WDF, throughput shall not exceed 362,025 tons per 12 consecutive month period.
(b) The primary NOx control strategy for the facility is the combustion of high moisture, low BTU coal, and is the basis of the Department's determination that this fuelyard throughout increase qualifies for the PSD exemption as a Pollution Control Project (PCP). If the permittee chooses an alternate NOx control strategy, then this project loses its PCP status and the fuelyard throughput reverts to its previous limitation of 2.85 million tons in any 12 consecutive month period. Use of the two new coal crushers, or any other physical changes made to accommodate this project, would then be prohibited until the permittee submits a construction permit application and receives a Department permit addressing their use.
(c) Attachment 1, PRELIMINARY DETERMINATION POLLUTION CONTROL PROJECT, is a part of this permit.
[Rules 62-4.160(2) and 62-210.200 (PTE), F.A.C.; and, Permit No. 0570040-006-AC.]

E.2. Hours of Operation. This emissions unit is allowed to operate continuously, i.e., 8,760 hours/year.
[Rules 62-4.160(2) and 62-210.200, F.A.C., P.T.E.]

Emission Limitations and Standards

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

E.3. Visible Emissions. Visible emissions generated by fugitive or unconfined particulate matter from fuel handling systems and storage shall not exceed 5% opacity.
{Permitting note: The averaging time for this condition is based on the specified averaging time of the applicable test method, unless otherwise specified in this permit.}
[Rule 62-296.711(2)(a), F.A.C.; and AC29-152987]

E.4. In order to maintain the status of the fuel yard throughput increase modification as a Pollution Control Project, the following limits shall apply on a 12-month rolling average basis:

(a) Starting January 1, 1999 total combined coal heat input to boilers 1 through 6 shall not exceed 69.9×10^6 mmBtu/year.

(b) Starting January 1, 1999, SO_2 total combined emissions from boilers 1 through 6 shall not exceed 66,400 tons per year (tpy).

(c) Starting January 1, 1999, NOx total combined emissions from boilers 1 through 6 shall not exceed 33,100 tons per year, and starting January 1, 2000, NOx total combined emissions from boilers 1 through 6 shall not exceed 31,800 tons per year.

(d) Starting January 1, 1999, and continuing until superceded by the results of the Precipitator Optimization Study (Referenced in Specific Condition **E.11.**) PM total combined emissions from boilers 1 through 6 shall not exceed 1,940 tons per year.

[Rule 62-212.400(2)(a)2., F.A.C.; and, Permit No. 0570040-006-AC.]

Test Methods and Procedures

{Permitting note: 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.}

E.5. A thirty (30) minute visible emissions test shall be performed on the following material transfer operations during each federal fiscal year (October 1 - September 30):

A. The clamshell to the hopper,
B. The railcar to the hopper,
C. Either the conveyor E1 or E2 to their respective stockpiles where the initial free fall is at least 30 feet,
D. The hammermill crusher to either the conveyor H1 and H2,
E. The conveyors D1 or D2 to either conveyor G1 and G2, and
F. Either the conveyor J1 or J2 to their respective bunkers.

[Rule 62-297.310(4)(a)2., F.A.C.]

E.6. The test method for visible emissions shall be determined using 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, 62-297.310(7)(a)4., and 62-297.400, F.A.C.; and, Permit No. 0570040-006-AC]

E.7. Compliance with the limitations in Specific Condition **E.4.** shall be determined on a monthly basis. Heat input shall be determined from the actual fuel input to the boilers and its corresponding heat content, or CEM data, while the SO_2 and the NOx emissions shall be derived from the CEM data. PM emissions shall be based on the most recent stack tests, and TECO shall have the option of conducting additional tests, in addition to those specified in this permit. [Permit No. 0570040-006-AC.]

E.8. Water sprays or chemical wetting agents and stabilizers are acceptable methods to be used on coal storage piles as necessary to maintain an opacity of less than or equal to 5%. Other appropriate methods may be applied to maintain this opacity, after they are approved by the Department.
[Permit Nos. 0570040-006-AC and 0570040-010-AC.]

{Note: Facilities that cause frequent, valid complaints may be required by the Permitting Authority to take these or other reasonable precautions. In determining what constitutes reasonable precautions for a particular source, the Department shall consider the cost of the control technique or work practice, the environmental impacts of the technique or practice, and the degree of reduction of emissions expected from a particular technique or practice.}

Monitoring of Operations

E.9. Operation and Maintenance Plan for Particulate Matter Control:

A. Process Parameters:
1. Operation schedule: 8760 hours per year
2. Equipment Data:
   Conveyor Hoods: corrugated Aluminum
   Transfer Point Enclosures: Carbon Steel
3. Wet Dust Suppression:
   Manufacturer: Benetech

B. Inspection and Maintenance Procedures:

The fuel yard particulate matter control equipment shall receive regular preventative maintenance as follows:

Conveyor Enclosures:
1. Daily random visual inspections of conveyor hoods.
2. Daily random visual inspection of the transfer points chute work

Dust Suppression System:
1. Quarterly inspection of system for water leaks.
2. Quarterly inspection of spray nozzles.

The pumps, tanks, etc., that make-up the dust suppression system undergo normal maintenance including lubrication, flushing, and draining.
[Rule 62-296.700, F.A.C.; and, Application for Renewal, July 16, 1992]

E.10. Dust suppressants shall be applied to the fuel either prior to or at the time of delivery and at all emission points where specified in the table at the beginning of this subsection to control fugitive PM emissions as specified in Specific Condition **E.3.** For the application of dust suppressants prior to delivery, TECO shall keep monthly records of 1) the amount of dust

suppressant applied for each type and amount of coal delivered, and 2) type of dust suppressant used (e.g., MSD sheets, product name).
[Permit No. 0570040-006-AC.]

Recordkeeping and Reporting Requirements

E.11. As part of the PCP, an Electrostatic Precipitator Optimization Study shall be conducted for all six units at the facility within six months of February 9, 1999. A report shall be due at that point and submitted to both the Environmental Protection Commission of Hillsborough County (EPC) and the Department. The study shall be subject to EPC and Department approval and full implementation of the study shall be completed within twelve months of February 5, 1999 (permit issuance date for Permit No. 0570040-006-AC), or within a period mutually agreed to by the permittee and the EPC. The permittee's application to revise their Title V operating permit shall include verifiable and enforceable operating parameters for the ESPs which reflect the results of the optimization study.
[Permit No. 0570040-006-AC.]

E.12. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Environmental Protection Commission of Hillsborough County on the results of each such test.
(b) The required test report shall be filed with the Environmental Protection Commission of Hillsborough County as soon as practical but no later than 45 days after the last sampling run of each test is completed.
[Rule 62-297.310(8), F.A.C.]

E.13. Operation and Maintenance. Records of inspections, maintenance, and performance parameters shall be retained for a minimum of five years and shall be made available to the Environmental Protection Commission of Hillsborough County upon request.
[Rules 62-213.440(1)(b)2.b. and 62-296.700(6)(e), F.A.C.]

E.14. The permittee shall notify the Environmental Protection Commission of Hillsborough County 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.
[Rule 297.310(7)(a)9., F.A.C.; and Permit No. 0570040-006-AC.]

Reasonable Assurances

E.15. All controls associated with the transfer points (i.e., the grab buckets, the windshield, the enclosures and the wet spray systems) shall be maintained to the extent that the capture efficiencies credited will be achieved.
[Rule 62-4.070(3), F.A.C.; and, AO29-216480]

E.16. All compliance testing shall be conducted during normal operation and at the maximum material (including limestone or iron ore where applicable) transfer rate attainable during the test period. Actual material handling rates will be determined using the totalizer readings obtained from scales located on C, L, and H conveyors. The readings from these scales will be recorded at the start and finish of the visible emissions test. The difference between the value recorded divided by the test duration will be the value used to represent the material handling rate.

Alternatively, values from the circular chart recorders located in the coalfield control room will be used in the event a problem with a scale totalizer arises. The test result shall indicate if iron ore has been included in the corresponding material transfer rate. Failure to include the actual process or production rate in the results may invalidate the test.
[Rule 62-4.070(3), F.A.C.; and, AO29-216480]

E.17. 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.; and, Permit No. 0570040-010-AC.]

E.18. 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.
[Rule 62-297.310(7), F.A.C.; and, Permit No. 0570040-010-AC]

E.19. The new crushers (Crushers 3A and 3B) shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions. In addition, the new crushers shall comply with 40CFR60, NSPS for Coal Preparation Plants, Subpart Y.
[Rule 62-204.800, F.A.C., 40CFR60, Subpart Y; and, Permit No. 0570040-010-AC]

Subsection F. This section addresses the following emissions unit.

E.U. ID No.	**Brief Description**
-009	Unit 4 Economizer Ash Silo with Baghouse

For the operation of the F. J. Gannon Station Unit 4 Economizer Ash Handling System and Silo, economizer ash collected in the economizer section of the boiler is either re-injected into the boiler or pneumatically conveyed to a 16 ft diameter, 20 ft high silo at a maximum rate of 1500 lbs./hr. The ash in the silo is gravity fed by tubing into closed tanker trucks for transport to an offsite consumer. Particulate matter emissions generated during the loading of the silo are controlled by an 830 ACFM Mikropul Corporation Model 365-10-30 Baghouse.

{Permitting note: This emissions unit is regulated under Rule 62-296.711, F.A.C., Materials Handling, Sizing, Screening, Crushing and Grinding Operation; and, Rule 62-296.700, F.A.C., Reasonably Available Control Technology (RACT) Particulate Matter.}

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

Essential Potential to Emit (PTE) Parameters

F.1. Permitted Capacity. The maximum permitted operation rate is 1,500 lbs./hr.
{Permitting note: The material loading limitations have been placed in each permit to identify the capacity of each emissions unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the emissions 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 material loading. Instead the owner or operator is expected to determine material loading whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the emissions unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of process variables for emission tests. Material loading determinations may be based on best engineering evaluation of the operating requirements necessary to achieve 90 to 100 percent of the rated loading, unless such operating conditions are otherwise specified by permit condition.}
[Rules 62-4.160(2) and 62-210.200 (PTE), F.A.C.]

Emission Limitations and Standards

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

F.2. Visible Emission. Visible emissions shall not exceed 5% opacity.
{Permitting note: The averaging time for this condition is based on the specified averaging time of the applicable test method, unless otherwise specified in this permit.}
[Rule 62-296.711(2)(a), F.A.C.]

F.3. Particulate matter emissions from this baghouse, based on a design flow of 486 DSCFM (830 ACFM), shall not exceed:

lb/hr	Ton/yr	Standard
0.13	0.56	0.03 grains/dscf

{Permitting note: The averaging time for this condition is based on the specified averaging time of the applicable test method, unless otherwise specified in this permit.}
[Rule 62-296.711(2)(b), F.A.C.]

Test Methods and Procedures

{Permitting note: 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.}

F.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; and
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; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant.

[Rule 62-297.310(7)(a)4., F.A.C.]

Monitoring of Operations

F.5. Operation and Maintenance Plan for Particulate Matter Control:

A. Process Parameters:
1. Source Designators: Economizer Ash Silo
2. Baghouse Manufacturer: Micropul Corporation
3. Model Name and Number: 365-10-30
4. Design Flow Rate: 830 ACFM
5. Efficiency Rating at Design Capacity: 99.9%
6. Pressure Drop: 6 in H_2O max.
7. Air to Cloth Ratio: 2:1
8. Bag Weave: not specified
9. Bag Material: Nomex
10. Bag Cleaning Conditions: Pulse Jet @ 100 psig.
11. Gas Flow Rate: 830 ACFM
12. Gas Temperatures: inlet; 350 °F; outlet; 350 °F
13. Stack Height Above Ground: 72 Ft.
14. Exit Diameter: 8 in
15. Exit Velocity: 21 fps
16. Water vapor Content: 29%
17. Process Controlled by Collection Systems: Fly Ash Handling
18. Material Handling Rate: 1500 lbs./hr

B. The following observations, checks and operations apply to this source and shall be conducted on the schedule specified:

Daily:

1. Check pressure drop and operation of manometer.
2. Observe stack (visual), and change filter bags as necessary. Document date and number of bags replaced.
3. Walk through system listening for proper operation (audible leaks, proper fan and motor functions, bag cleaning systems, etc.).
4. Note any unusual occurrence in the process being ventilated.
5. Observe all indicators on control panel for abnormal operation.
6. Check reverse air pressure.
7. Assure that dust is being removed from system. Unplug hopper if required.

[Rule 62-296.700(6)(c), F.A.C.]

Reasonable Assurances

F.6. Testing of emissions must be accomplished at 90 - 100% of the maximum electrical generating capacity (normally 187 MW) of Unit 4, with 100% of the economizer ash available directed to the silo. The actual MW generation rate shall be specified in each test report. Failure to include the actual generating rate in the report may invalidate the test.
[Rules 62-4.070(3) and 62-297.310(2), F.A.C.]

F.7. This emissions unit is also subject to conditions contained in **Subsection K. Common Conditions.**

Subsection G. This section addresses the following emissions units.

E.U. ID No.	Brief Description
-010	Units 5 and 6 Fly Ash Silo (No. 1) with Baghouse
-012	Pugmill and Truck Loading

For the operation of F. J. Gannon Station Units 5 and 6 Fly Ash Silo No. 1 with baghouse, pugmill, and truck loading, fly ash that is collected in the hoppers of the electrostatic precipitators of Units 5 and 6 is pneumatically conveyed to a 25-foot diameter, 50 foot high silo. The fly ash in the silo is gravity fed by chute into enclosed tanker trucks or to a pugmill where it is "conditioned" by wetting with water and gravity fed by chute into open bed trucks. In addition, fly ash from F. J. Gannon Station Units 1-4 Fly Ash Silo No. 2 may be routed via gravity flow to the pugmill where it is "conditioned" by wetting with water and gravity fed into open bed trucks. The fly ash is then transported to an off-site consumer. Fly ash may also be conveyed from tanker trucks to Fly Ash Silo No. 1 and from Fly Ash Silo No. 1 to Fly Ash Silo No. 2. Particulate matter emissions generated during the filling of the silo are controlled by an 11,300 ACFM United States Filter Corporation Mikro-Pulsaire Model 1F3-24 baghouse.

{Permitting note: These emissions units are regulated under Rule 62-296.711, F.A.C., Materials Handling, Sizing, Screening, Crushing and Grinding Operation; and, Rule 62-296.700, F.A.C., Reasonably Available Control Technology (RACT) Particulate Matter.}

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

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

G.1. <u>Permitted Capacity.</u> The maximum permitted operation rate is 13.05 tons/hour. {Permitting note: The material loading limitations have been placed in each permit to identify the capacity of each emissions unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the emissions 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 material loading. Instead the owner or operator is expected to determine material loading whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the emissions unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of process variables for emission tests. Material loading determinations may be based on best engineering evaluation of the operating requirements necessary to achieve 90 to 100 percent of the rated loading, unless such operating conditions are otherwise specified by permit condition.}
[Rules 62-4.160(2) and 62-210.200 (PTE), F.A.C.]

<u>Emission Limitations and Standards</u>

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

G.2. Visible Emission. Visible emissions shall not exceed 5% opacity.
{Permitting note: The averaging time for this condition is based on the specified averaging time of the applicable test method, unless otherwise specified in this permit.}
[Rule 62-296.711(2)(a), F.A.C.]

G.3. Particulate Matter. Total allowable particulate matter emissions based on a design flow rate of 11,300 ACFM shall not exceed 2.9 pounds/hour, 12.7 tons/year; and, 0.03 grains/dscf.
{Permitting note: The averaging time for this condition is based on the specified averaging time of the applicable test method, unless otherwise specified in this permit.}
[Rule 62-296.711(2)(b), F.A.C.]

Test Methods and Procedures

{Permitting note: 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.}

G.4.1. Test the emissions from the fly ash silo/baghouse for particulate matter and visible emissions each federal fiscal year (October 1 – September 30).
[Rule 62-297.310, F.A.C.]

G.4.2. Test the emissions from truck loading for visible emissions each federal fiscal year (October 1 – September 30). The visible emission compliance tests on the truck loading shall alternate from year to year, so that over a two-year period both conditioned and unconditioned fly ash loading will be tested.
[Rule 62-297.310, F.A.C.]

Monitoring of Operations

G.5. Operation and Maintenance Plan for Particulate Matter Control:

A. Process Parameters:
1. Source Designators: Units 5 and 6 Fly Ash Silo No. 1
2. Baghouse Manufacturer: United States Filter Corporation
3. Model Name and Number: Mikro-Pulsaire Unit #1F3-24
4. Design Flow Rate: 11,300 ACFM
5. Efficiency Rating at Design capacity: 99.9%
6. Pressure Drop: 5 in water (maximum)
7. Air to Cloth Ratio: 5:1
8. Bag Material: Polyester HCE
9. Filter Cleaning Method: Pulse Jet @ 100 psig
10. Gas Flow Rate: 11,300 ACFM
11. Gas Temperature: inlet and outlet; 300°F
12. Stack Height Above Ground: 104 feet
13. Exit Diameter: 18 in X 26 in
14. Exit Velocity: 58 fps
15. Process controlled by Collection System: Fly Ash Material Handling
16. Material Handling Rate: Calculated to be 13.05 tons/hour Fly Ash

B. The following observations, checks and operations apply to this source and shall be conducted on the schedule specified:

Daily:

1. Baghouse pressure drop - inspect the manometer. Log information. Change filter bags if necessary.
2. Visually inspect baghouse for abnormal emissions.
3. Walk through system listening for proper operation (audible leaks, proper fan and motor functions, bag cleaning etc.)
4. Observe indicators on control panel for abnormal operating conditions.
5. Unplug hopper if necessary.

[Rule 62-296.700(6), F.A.C.]

Reasonable Assurances

G.6. All fly ash silo/baghouse compliance tests shall be conducted under the following conditions:

A. The conveyance blower shall be turned off at least 1 hour prior to the test to allow an adequate build-up of fly ash in the precipitator hoppers.
B. All conveyance hoppers shall be operational during tests.
C. All fly ash shall be directed to the silo, no re-injection of fly ash to the boiler system will occur during the tests.
D. Both boilers shall be operational during the tests.

[Rule 62-4.070(3), F.A.C.]

G.7. These emissions units are also subject to conditions contained in **Subsection K. Common Conditions.**

Subsection H. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
-011	Units 1-4 Fly Ash Silo (No. 2) with baghouse

For the operation of F. J. Gannon Station Units 1-4 Fly Ash Silo No. 2 with baghouse, fly ash that is collected in the hoppers of the electrostatic precipitators of Units 1-4 is pneumatically conveyed to a 30-foot diameter, 45.5-foot high silo. In addition, fly ash from silo No. 2 may be routed to the pugmill at F. J. Gannon Station Silo No. 1 where it is "conditioned" by wetting with water and gravity fed into open bed trucks. The fly ash in the silo is gravity fed by tubing into enclosed tanker trucks for transport to an off-site consumer. Fly ash may also be conveyed from tanker trucks to Fly Ash Silo No. 2 and from Fly Ash Silo No. 2 to Fly Ash Silo No. 1. Particulate matter emissions generated during the filling of the silo are controlled by a 4,690 ACFM Allen-Sherman-Hoff Corporation Flex Kleen 84 WRW C112IIG baghouse system, which is comprised of two (2) bag filters with three (3) common stacks.

{Permitting note: This emissions unit is regulated under Rule 62-296.711, F.A.C., Materials Handling, Sizing, Screening, Crushing and Grinding Operation; and, Rule 62-296.700, F.A.C., Reasonably Available Control Technology (RACT) Particulate Matter.}

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

Essential Potential to Emit (PTE) Parameters

H.1. Permitted Capacity. The maximum permitted operation rate is 14.5 ton/hour.
{Permitting note: The material loading limitations have been placed in each permit to identify the capacity of each emissions unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the emissions 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 material loading. Instead the owner or operator is expected to determine material loading whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the emissions unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of process variables for emission tests. Material loading determinations may be based on best engineering evaluation of the operating requirements necessary to achieve 90 to 100 percent of the rated loading, unless such operating conditions are otherwise specified by permit condition.}
[Rules 62-4.160(2) and 62-210.200 (PTE), F.A.C.]

Emission Limitations and Standards

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

H.2. Visible Emission. Visible emissions shall not exceed 5% opacity.
{Permitting note: The averaging time for this condition is based on the specified averaging time of the applicable test method, unless otherwise specified in this permit.}
[Rule 62-296.711(2)(a), F.A.C.]

H.3. Particulate Matter. Total allowable particulate matter emissions based on a design flow rate of 4,696 ACFM shall not exceed 1.2 pounds/hour, 5.3 tons/year, and, 0.03 grains/dscf. {Permitting note: The averaging time for this condition is based on the specified averaging time of the applicable test method, unless otherwise specified in this permit.}
[Rule 62-296.711(2)(b), F.A.C.]

Test Methods and Procedures

{Permitting note: 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.}

H.4. Test the emissions from the fly ash silo for particulate matter and visible emissions each federal fiscal year (October 1 – September 30).
[Rule 62-297.310, F.A.C.]

Monitoring of Operations

H.5. Operation and Maintenance Plan for Particulate Matter Control:

A. Process Parameters:
1. Source Designators: Units 1-4 Fly Ash Silo
2. Baghouse Manufacturer: Allen-Sherman-Hoff Corporation
3. Model Name and Number: Flex Kleen 84 WRW C112IIG
4. Design Flow Rate: 4,696 ACFM
5. Efficiency Rating at Design capacity: 99.9%
6. Pressure Drop: 8 in water (maximum)
7. Air to Cloth Ratio: 2:1
8. Bag Material: Polyester HCE
9. Filter Cleaning Method: Pulse Jet @ 100 psig
10. Gas Flow Rate: 4,696 ACFM
11. Gas Temperature: inlet, 300°F , Outlet: 350°F
12. Stack Height Above Ground: 3 @ 107 feet
13. Exit Diameter: 3 @ 12 in
14. Exit Velocity: 33 fps
15. Process controlled by Collection System: Fly Ash Material Handling
16. Material Handling Rate: Calculated to be 14.5 tons/hour Fly Ash

B. The following observations, checks and operations apply to this source and shall be conducted on the schedule specified:

Daily:
1. Baghouse pressure drop - inspect the manometer. Log information. Change filter bags if necessary.
2. Visually inspect baghouse for abnormal emissions.
3. Walk through system listening for proper operation (audible leaks, proper fan and motor functions, bag cleaning etc.)
4. Observe indicators on control panel for abnormal operating conditions.
5. Unplug hopper if necessary.

[Rule 62-296.700(6), F.A.C.]

Reasonable Assurance

H.6. All compliance tests will be conducted under the following conditions:

A. Conveyance blower will be turned off at least 1 hour prior to the test to allow an adequate build-up of fly ash in the precipitator hoppers.
B. All conveyance hoppers will be operational during tests.
C. All fly ash will be directed to the silo, no re-injection of fly ash to the boiler system will occur during the tests.
D. At least 3 of the 4 boilers shall be operational during the tests.

[Rule 62-4.070(3), F.A.C.]

H.7. This emissions unit is also subject to conditions contained in **Subsection K. Common Conditions.**

Subsection I. This section addresses the following emissions units.

E.U. ID No.	Brief Description
-013 thru -018	Units Nos. 1-6 Fuel Bunkers with Roto-Clones

For the operation of the F. J. Gannon Station Units 1-6 fuel bunkers with exhaust fan/cyclone collectors (Roto-Clones) controlling dust emissions from each unit's respective bunker, two moving transfer stations via their respective conveyor belts route fuel through enclosed chutes to each of the six bunkers. Fuel bunkers Nos. 1-4 and 6 are each equipped with a 9,600 ACFM American Air Filter Company Type D Roto-Clone to abate dust emissions during ventilation. Fuel bunker No. 5 is equipped with a 5,400 ACFM Type D Roto-Clone. A number of vent pipes convey air from each bunker to a Roto-Clone during particulate matter removal. Particulate matter removed by the Roto-Clones is returned to a fuel bunker via a hopper and return line. Units 1-6 fuel bunkers are situated in a west to east fashion. Unit 1 fuel bunker is located furthest to the west and Unit No. 6 fuel bunker furthest to the east.

{Permitting note: These emissions units are exempt from Rule 62-296.711, F.A.C., Materials Handling, Sizing, Screening, Crushing and Grinding Operation.}

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

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

I.1. <u>Permitted Capacity.</u> The maximum operation rate is 1,600 tons/hour.
{Permitting note: The material loading limitations have been placed in each permit to identify the capacity of each emissions unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the emissions 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 material loading. Instead the owner or operator is expected to determine material loading whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the emissions unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of process variables for emission tests. Material loading determinations may be based on best engineering evaluation of the operating requirements necessary to achieve 90 to 100 percent of the rated loading, unless such operating conditions are otherwise specified by permit condition.}
[Rules 62-4.160(2) and 62-210.200 (PTE), F.A.C.]

<u>Emission Limitations and Standards</u>

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

I.2. <u>Particulate Matter.</u> Since a source having emissions of less than 1.0 ton/year is exempt from the provisions of particulate matter RACT, the maximum allowable particulate matter emission rate from each of the six fuel bunkers shall not exceed 0.99 ton/year. Also, the maximum allowable particulate matter emission rate from each of the six fuel bunkers shall not exceed 0.19 pound/hour.

{Permitting note: The averaging time for this condition is based on the specified averaging time of the applicable test method, unless otherwise specified in this permit.}
[Rule 62-296.700(2)(c), F.A.C.]

I.3. Visible Emissions. Visible emissions from each of the six fuel bunkers shall not be equal to or greater than 20% opacity.
{Permitting note: The averaging time for this condition is based on the specified averaging time of the applicable test method, unless otherwise specified in this permit.}
[Rule 62-296.320(4)(b)1., F.A.C.]

Test Methods and Procedures

{Permitting note: 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.4. Test the emissions from two of the six fuel bunkers for particulate matter and visible emissions each federal fiscal year (October 1 – September 30) so that over a three-year period all six coal bunkers will have been tested.
[Rule 62-297.310, F.A.C. and AO29-250139]

Monitoring of Operations

I.5. These emissions units are also subject to conditions contained in **Subsection K. Common Conditions.**

Subsection J. Common Conditions.

E.U. ID No.	Brief Description
-001 thru -006	Units Nos. 1-6 Fossil Fuel-Fired Steam Generator

The following conditions apply to the emissions units listed above:

Essential Potential to Emit (PTE) Parameters

J.1. Hours of Operation. These emissions units are allowed to operate continuously, i.e., 8,760 hours/year.
[Rules 62-4.160(2) and 62-210.200, F.A.C., (PTE)]

Emission Limitations and Standards

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

{Permitting Note: In accordance with the Acid Rain Phase II requirements, the following continuous monitors are installed on these emissions units: SO_2, NO_X, CO_2 and stack gas flow.}

J.2. Particulate Matter. Particulate matter emissions from each unit shall not exceed 0.1 pound per million Btu heat input, as measured by applicable compliance methods.
{Permitting note: The averaging time for this condition is based on the specified averaging time of the applicable test method, unless otherwise specified in this permit.}
[Rule 62-296.405(1)(b), F.A.C.]

J.3. Particulate Matter - Soot Blowing and Load Change. Particulate matter emissions from each emissions unit 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. A load change occurs when the operational capacity of an emissions 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.
[Rule 62-210.700(3), F.A.C.]

J.4. Sulfur Dioxide (SO_2) Compliance Plan.

a. Sulfur dioxide (SO_2) emissions from each unit shall not exceed the interim limits specified below.

Calendar Year	Station-wide SO_2 Limit Tons per hour (24-hour Average (midnight to midnight))	Basis for Station-wide SO_2 Limit
2001	11.5	Equivalent to 1.9 lbs/MMBTU multiplied by the existing station-wide heat input in MMBTU/hour.

2002	10.3	Equivalent to 1.7 lbs/MMBTU multiplied by the existing station-wide heat input in MMBTU/hour.
2003 *	10.3	Equivalent to 1.7 lbs/MMBTU multiplied by the existing station-wide heat input in MMBTU/hour.
2003 **	**	Equivalent to 1.7 lbs/MMBTU multiplied by the existing station-wide heat input, less any Unit(s) shutdown due to repowering, in MMBTU/hour.
2004 **	**	Equivalent to 1.7 lbs/MMBTU multiplied by the existing station-wide heat input, less any Unit(s) shutdown due to repowering, in MMBTU/hour.

Notes:

All Gannon coal-fired boilers will be removed from service by December 31, 2004.

* Limits applicable to the portion of the year prior to the repowering of any unit(s).

** Limits applicable to the portions of the year following the repowering of any unit(s). The station-wide heat input used in the above equations will be based on the total of the coal-fired boilers remaining after each stage of repowering at the following MMBTU/Hour rates: Boiler No. 1 = 1257; Boiler No. 2 = 1257; Boiler No. 3 = 1599; Boiler No. 4 = 1876; Boiler No. 5 = 2284; Boiler No. 6 = 3798.

b. In addition, the SIP SO_2 emission limits that cover the Unit Nos. 1-6 Fossil Fuel-Fired Steam Generators at Gannon Station shall not be exceeded:

2.4 lbs/MMBTU (individual unit on a weekly average basis); and,
10.6 tons/hour (station-wide cap on a weekly average basis).

[Rules 62-296.405(1)(c)2.a., 62-204.220(1), 62-204.240(1), 62-4.070(3)&(5), and 62-213.440, F.A.C.]

J.5. Not federally enforceable. Sulfur Dioxide - Sulfur Content. The sulfur content of the new No. 2 fuel oil shall not exceed 0.5 percent, by weight.
[Requested in initial Title V permit application received June 14,1996; and, AO29-252615]

J.6. Visible Emissions. Visible emissions shall not exceed 20 percent opacity, except for one six-minute period per hour during which opacity shall not exceed 27 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.

{Permitting note: The averaging time for this condition is based on the specified averaging time of the applicable test method, unless otherwise specified in this permit.}
[Rule 62-296.405(1)(a), F.A.C.]

J.7. Visible Emissions - Soot Blowing and Load Change. Visible emissions from each emissions unit shall not exceed 60 percent opacity, except for up to 4 six-minute periods, during the 3-hours in any 24 hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change. A load change occurs when the operational capacity of an emissions unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the emissions unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.
[Rule 62-210.700(3), F.A.C.]

Excess Emissions

J.8. 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.]

J.9. 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.]

J.10. 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.]

Test Methods and Procedures

J.11. Particulate Matter. The test methods for particulate matter emissions shall be EPA Methods 17, 5, 5B, or 5F, incorporated and adopted 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 at 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 base F-factor computed according to EPA Method 19 is used in lieu of heat input. Acetone wash shall be used with EPA Methods 5 or 17.
[Rules 62-296.405(1)(e)2., 62-297.310 and, 62-297.401, F.A.C.]

J.12. Sulfur Dioxide. The test methods for sulfur dioxide emissions shall be EPA Methods 6, 6A, 6B or 6C, incorporated and adopted by reference in Chapter 62-297, F.A.C. Fuel sampling analysis may be used as an alternate sampling procedure if such a procedure is incorporated in 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 exceedances 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. **Compliance with the SO_2 limits specified in Specific Condition J.4. shall be demonstrated using a continuous emissions monitor.**
{Permitting Note: The permittee has elected to demonstrate compliance by means of a continuous emissions monitoring system (CEMS). In addition to any other requirements associated with the operation and maintenance of these CEMS (i.e., Acid Rain requirements), operation of the CEMS shall be in accordance with the requirements listed below. The annual calibration RATA associated with these CEMS may be used in lieu of the required annual EPA Reference Method 6, as long as all of the requirements of Rule 62-297.310, F.A.C., are met (i.e., prior test notification, proper test result submittal, etc.).}
[Rule 62-296.405(1)(e)3., F.A.C.]

J.12.a. Sulfur Dioxide CEMS. Continuous SO_2 emission monitoring 24-hour averages are required to demonstrate compliance with the standards (limits) of the Department (see Specific Condition **J.4.**). A valid 24-hour average shall consist of no less than 18 hours of valid data capture per calendar day. In the event that valid data capture is interrupted, the permittee shall initiate as-fired fuel sampling to demonstrate compliance with the SO_2 emissions standard. The as-fired fuel sampling shall be initiated no later than 36 hours after the permittee has verified the problem or no later than 36 hours after the end of the affected calendar day. As-fired fuel sampling shall continue until such time as valid data capture is restored. In lieu of as-fired fuel sampling, the permittee may elect to demonstrate SO_2 emissions compliance by the temporary use of a spare SO_2 emissions monitor. The spare, previously calibrated, SO_2 emissions monitor must be installed and collecting data in the same time frame as required above for as-fired fuel sampling. A quality control (QC) program must be maintained. At a minimum, the QC program must include written procedures which shall describe in detail complete, step-by-step procedures and operations for each of the following activities:

1. Calibration of CEMS.
2. Calibration Drift (CD) determination and adjustment of CEMS.
3. Preventative maintenance of CEMS (including spare parts inventory).
4. Data recording, calculations and reporting.
5. Accuracy audit procedures including sampling and analysis methods.
6. Program of corrective action for malfunctioning CEMS.

[Rules 62-213.440, 62-204.800(7)(e)5. and 62-296.405(1)(f)1.b., F.A.C]

J.12.b. Continuous Monitor Performance Specifications. If continuous monitoring systems are required by rule or are elected by the permittee to be used for demonstrating compliance with the standards of the Department, they must be installed, maintained and calibrated, either:

(a) in accordance with the EPA performance specifications listed below. These Performance Specifications are contained in 40 CFR 60, Appendix B, and are adopted by reference in Rule 62-204.800, F.A.C.

(1) Performance Specification 1--Specifications and Test Procedures for Opacity Continuous Emission Monitoring Systems in Stationary Sources.

(2) Performance Specification 2--Specifications and Test Procedures for SO_2 Continuous Emission Monitoring Systems in Stationary Sources.

(3) Performance Specification 3--Specifications and Test Procedures for CO_2 Continuous Emission Monitoring Systems in Stationary Sources. Or,

(b) in accordance with the applicable requirements of 40 CFR 75, Subparts B and C. Excess emissions pursuant to Rule 62-210.700, F.A.C., shall be determined using the 40 CFR part 75 CEMS.

[Rule 62-297.520, F.A.C.; 40 CFR 75; and, Applicant request.]

J.12.c. Fuel Sampling and Analysis. The following fuel sampling and analysis protocol shall be used as an alternate sampling procedure authorized by permit to demonstrate compliance with the sulfur dioxide standard (limits) in the event that the SO_2 continuous emissions monitor is not able to capture valid data:

1) Determine and record the as-fired fuel sulfur content, percent by weight, for coal using ASTM D2013-72 and either ASTM D3177-75 or ASTM D4239-85, or the latest edition, to analyze a representative sample of the blended as-fired pulverized coal.
2) Determine and record the calorific heat value in Btu per pound of the as-fired pulverized coal using ASTM D2013-72 and either ASTM D2015-77 or D3286-(latest version), or the latest edition.
3) Record daily the amount of coal fired, the heating value of coal fired, and the percent sulfur content, by weight, of coal fired.
4) Utilize the information in 1), 2), and 3), 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.]

J.13. Sulfur Dioxide - Sulfur Content. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, or both ASTM D4057-88 and ASTM D129-91 or the latest editions.
[Rules 62-213.440 and 62-297.440, F.A.C.]

J.14. Visible Emissions. The test method for visible emissions shall be DEP Method 9, incorporated in Chapter 62-297, F.A.C. In lieu of Method 9 testing, a transmissometer utilizing a 6-minute block average for opacity measurement may be used, provided such transmissometer is installed, certified, calibrated, operated and maintained in accordance with the provisions of 40 CFR Part 75.
[Rule 62-296.405(1)(e)1., F.A.C.]

J.15. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:

1. EPA Method 9, Section 2.4, Recording Observations. Opacity observations shall be made and recorded by a certified observer at sequential fifteen-second intervals during the required period of observation.

2. EPA Method 9, Section 2.5, Data Reduction. For a set of observations to be acceptable, the observer shall have made and recorded, or verified the recording of, at least 90 percent of the possible individual observations during the required observation period. For single-valued opacity standards (e.g., 20 percent opacity), the test result shall be the highest valid six-minute average for the set of observations taken. For multiple-valued opacity standards (e.g., 20 percent opacity, except that an opacity of 40 percent is permissible for not more than two minutes per hour) opacity shall be computed as follows:

a. For the basic part of the standard (i.e., 20 percent opacity) the opacity shall be determined as specified above for a single-valued opacity standard.

b. For the short-term average part of the standard, opacity shall be the highest valid short-term average (i.e., two-minute, three-minute average) for the set of observations taken.

In order to be valid, any required average (i.e., a six-minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value. [Rules 62-297.310 and 62-297.401, F.A.C.]

J.16. 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.]

J.17. 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.]

J.18. 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.]

J.19. 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, attached.
(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.]

J.20. 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.]

J.21. 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 and/or solid 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; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and

c. Each NESHAP pollutant, if there is an applicable emission standard.

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.

(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.; and, SIP approved]

Monitoring of Operations

J.22. The permittee shall demonstrate compliance with the liquid fuel sulfur limit by means of a fuel analysis provided by the vendor upon each fuel delivery, or some other comparable method (i.e., composite as-delivered fuel sample analysis).

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

J.23. 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.]

Continuous Monitoring Requirements

J.24. Continuous Monitors. The permittee shall calibrate, operate and maintain continuous emissions monitoring systems (CEMS) for monitoring opacity, SO_2 and CO_2.

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

{Permitting Note: NO_X CEMS are also operated and maintained on these units in accordance with the Acid Rain requirements.}

Recordkeeping and Reporting Requirements

J.25. Quarterly Reporting. The owners or operators of facilities for which monitoring is required shall submit to the Environmental Protection Commission of Hillsborough County a written report of emissions in excess of emission limiting standards as set forth in Specific Conditions **J.6.** and **J.7.**, for each calendar quarter. The nature and cause of the excessive emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the source for a period of five years.
[Rules 62-296.405(1)(g) and 62-213.440(1)(b)2.b., F.A.C.]

J.26. Quarterly Reporting - SO_2. A quarterly report summarizing the information necessary to determine compliance with the SO_2 standards for each unit and the facility shall be submitted within 45 days to the Environmental Protection Commission of Hillsborough County following a calendar quarter.
[Rule 62-296.405(1)(c)2.a., F.A.C.]

J.27. The permittee shall notify the Environmental Protection Commission of Hillsborough County 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.
[Rule 297.310(7)(a)9., F.A.C.]

J.28. Operation and Maintenance. Records of inspections, maintenance, and performance parameters shall be retained for a minimum of five years and shall be made available to the Environmental Protection Commission of Hillsborough County upon request.
[Rules 62-213.440(1)(b)2.b. and 62-296.700(6)(e), F.A.C.]

J.29. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Environmental Protection Commission of Hillsborough County on the results of each such test.
(b) The required test report shall be filed with the Environmental Protection Commission of Hillsborough County 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 Department 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.]

J.30. Malfunction Reporting. In case of excess emissions resulting from malfunctions, Tampa Electric Company shall notify the Environmental Protection Commission of Hillsborough County 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 Environmental Protection Commission of Hillsborough County.
[Rule 62-210.700(6), F.A.C.]

Reasonable Assurances

J.31. [Reserved.]

J.32. Visible emissions testing shall be conducted simultaneously with particulate matter testing unless visible emissions testing is not required. In situations where visible emissions testing is not possible during particulate matter testing (i.e., nighttime, overcast days), independent visible

emissions testing may be performed at a later date within but not more than 5 days. Reasons for non-simultaneous testing must be provided in the test report.
[Rule 62-4.070(3), F.A.C.]

Miscellaneous Conditions

J.33. Boiler Cleaning Waste. The owner or operator is allowed to inject nonhazardous boiler chemical cleaning waste, generated on-site, into each boiler during normal operation as a routine maintenance procedure. The following conditions shall apply:

a. Quantity Limitation: The input rate per boiler shall not exceed:
   (1) 50 gal/min on an hourly average basis.
   (2) 960,000 gallons during any 12 consecutive months.

b. Operating Requirements: Boiler chemical cleaning waste that is deemed nonhazardous shall be burned only at normal source operating temperatures. Nonhazardous boiler chemical cleaning waste shall not be burned during periods of startup or shutdown.

c. Testing Requirements: The owner or operator shall sample and analyze each batch of boiler chemical cleaning waste to be burned pursuant to 40 CFR 262.11. If the waste is determined to be hazardous, it will be managed in accordance with all applicable hazardous waste controls under 40 CFR 262.34, 40 CFR 265 Subpart I and 40 CFR 268.

d. Record Keeping Requirements: The owner or operator shall obtain, make, and keep the following records related to the use of boiler chemical cleaning waste in a form suitable for inspection at the facility by the Department:

   (1) The gallons of boiler chemical cleaning waste burned each month in each boiler.

   (2) The total gallons of boiler chemical cleaning waste burned in the preceding consecutive 12-month period in each boiler.

   (3) Results of analyses required above for each boiler.

e. Reporting Requirements: The owner or operator shall submit, with the Annual Operation Report form, the analytical results and the total amount of boiler chemical cleaning waste burned in each boiler during the previous calendar year.

[Rule 62-4.070(3), F.A.C.; and, 40 CFR 262.11]

J.34. Used Oil. Burning of on-specification used oil is allowed in these units in accordance with all other conditions of this permit and the following conditions:

a. On-specification Used Oil Emissions Limitations: These emissions units are permitted to burn on-specification used oil, which contains a PCB concentration of less than 50 ppm. On-specification used oil is defined as used oil that meets the specifications of 40 CFR 279 - Standards for the Management of Used Oil, listed below. "Off-specification" used oil shall not be burned. Used oil which fails to comply with any of these specification levels is considered "off-specification" used oil.

CONSTITUENT/PROPERTY	ALLOWABLE LEVEL
Arsenic	5 ppm maximum
Cadmium	2 ppm maximum
Chromium	10 ppm maximum
Lead	100 ppm maximum
Total Halogens	1000 ppm maximum
Flash point	100 degrees F minimum

b. Quantity Limitation: These emissions units are permitted to burn "on-specification" used oil that is generated by TECO in the production and distribution of electricity, not to exceed 1,000,000 gallons during any consecutive 12 month period.
c. PCB Limitation: 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. Operational Requirements: 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.
e. Testing Requirements: For each batch of used oil to be burned, the owner or operator must be able to demonstrate that the used oil qualifies as on-specification used oil and that the PCB content is less than 50 ppm.

The requirements of this demonstration are governed by the following federal regulations:

Analysis of used oil fuel. A generator, transporter, processor/ re-refiner, or burner may determine that used oil that is to be burned for energy recovery meets the fuel specifications of 40 CFR Sec. 279.11 by performing analyses or obtaining copies of analyses or other information documenting that the used oil fuel meets the specifications. [40 CFR 279.72(a)]

Testing of used oil fuel. 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.

(i) The person who first claims that a used oil fuel does not contain quantifiable level (2 ppm) PCB must obtain analyses or other information to support that claim.
(ii) Testing to determine the PCB concentration in used oil may be conducted on individual samples, or in accordance with the testing procedures described in 40 CFR Sec. 761.60(g)(2). However, for purposes of this part, if any PCBs at a concentration of 50 ppm or greater have been added to the container or equipment, then the total container contents must be considered as having a PCB concentration of 50 ppm or greater for purposes of complying with the disposal requirements of this part.
(iii) Other information documenting that the used oil fuel does not contain quantifiable levels (2 ppm) of PCBs may consist of either personal, special knowledge of the source and composition of the used oil, or a certification from

the person generating the used oil claiming that the oil contains no detectable PCBs.

[40 CFR 761.20(e)(2)]

When testing is 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 and PCBs. 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).

f. Record Keeping Requirements: 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 generated and burned each month in each unit.
(2) The total gallons of on-specification used oil burned in the preceding consecutive 12-month period month in each unit.
(3) Other information, besides testing, used to make a claim that the used oil meets the requirements of on-specification used oil or that the used oil contains less than 50 ppm of PCBs.

g. Reporting Requirements: The owner or operator shall submit, with the Annual Operation Report form, the analytical results and the total amount of on-specification used oil burned in each unit during the previous calendar year.

[Rule 62-4.070(3) and 62-213.440, F.A.C., 40 CFR 279 and 40 CFR 761, unless otherwise noted; AO29-255208]

Subsection K. Common Conditions.

	Brief Description
-009	Unit 4 Economizer Ash Silo with Baghouse
-010	Units 5 and 6 Fly Ash Silo with Baghouse (Fly Ash Silo No. 1)
-011	Units 1-4 Fly Ash Silo with Baghouse (Fly Ash Silo No. 2)
-012	Pugmill and Truck Loading
-013	Unit No. 1 Fuel Bunker with Roto-Clone
-014	Unit No. 2 Fuel Bunker with Roto-Clone
-015	Unit No. 3 Fuel Bunker with Roto-Clone
-016	Unit No. 4 Fuel Bunker with Roto-Clone
-017	Unit No. 5 Fuel Bunker with Roto-Clone
-018	Unit No. 6 Fuel Bunker with Roto-Clone

The following conditions apply to the emissions units listed above:

Essential Potential to Emit (PTE) Parameters

K.1. Hours of Operation. These emissions units may operate continuously, i.e., 8,760 hours/year.
[Rules 62-4.160(2) and 62-210.200 (PTE), F.A.C.]

Test Methods and Procedures

K.2. Due to the expense and complexity of conducting a stack test on a minor source of particulate matter, and because the fly ash silo is equipped with a baghouse emission control device, the Department hereby establishes a visible emission limitation not to exceed an opacity of 5% in lieu of a particulate matter stack test.
{Permitting note: The averaging time for this condition is based on the specified averaging time of the applicable test method, unless otherwise specified in this permit.}
[Rule 62-297.620(4), F.A.C.]

K.3. Compliance with the emission limitations of Specific Condition **K.2.** shall be determined using EPA Method 9 contained in 40 CFR 60, Appendix A, and adopted by reference in Chapter 62-297, F.A.C. The minimum requirements for stationary point source sampling and reporting shall be in accordance with Chapter 62-297, F.A.C., and 40 CFR 60, Appendix A. The visible emissions compliance tests shall be conducted by a certified observer and be a minimum of 30 minutes in duration.
[Rules 62-297.310(7)(a)4. and 62-4.070(3), F.A.C.]

K.4. [Reserved.]

K.5. Should the Department have reason to believe the particulate matter emission standard is not being met, the Department may require that compliance with the particulate matter emission standard be demonstrated by testing in accordance with Chapter 62-297, F.A.C.
[Rule 62-297.620(4), F.A.C.]

Recordkeeping and Reporting Requirements

K.6. Operation and Maintenance. Records of inspections, maintenance, and performance parameters shall be retained for a minimum of five years and shall be made available to the Environmental Protection Commission of Hillsborough County upon request.
[Rules 62-213.440(1)(b)2.b. and 62-296.700(6)(e), F.A.C.]

K.7. The permittee shall notify the Environmental Protection Commission of Hillsborough County 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.
[Rule 297.310(7)(a)9., F.A.C.]

K.8. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Environmental Protection Commission of Hillsborough County on the results of each such test.
(b) The required test report shall be filed with the Environmental Protection Commission of Hillsborough County as soon as practical but no later than 45 days after the last sampling run of each test is completed.
[Rule 62-297.310(8), F.A.C.]

K.9. 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, attached.
(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.]

K.10. 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.]

K.11. 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.
[Rule 62-297.310(7), F.A.C.]

K.12. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.
[Rule 62-297.310(5), F.A.C.]

Section IV. This section is the Acid Rain Part.

Operated by: Tampa Electric Company
ORIS code: **0646**

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

The emissions units listed below are regulated under Phase II of the Federal Acid Rain Program.

	Brief Description
-001	Unit No. 1 Fossil Fuel-Fired Steam Generator
-002	Unit No. 2 Fossil Fuel-Fired Steam Generator
-003	Unit No. 3 Fossil Fuel-Fired Steam Generator
-004	Unit No. 4 Fossil Fuel-Fired Steam Generator
-005	Unit No. 5 Fossil Fuel-Fired Steam Generator
-006	Unit No. 6 Fossil Fuel-Fired Steam Generator

A.1. The Phase II permit applications, the Phase II NO_X compliance plans and the Phase II NO_X averaging plans submitted for this facility, as approved by the Department, are a part of this permit. The owners and operators of these Phase II acid rain units must comply with the standard requirements and special provisions set forth in the applications listed below:

a. DEP Form No. 62-210.900(1)(a)4., F.A.C., received 12/22/99 (signed 12/20/99).
b. DEP Form No. 62-210.900(1)(a)5., F.A.C., received 12/22/99 (signed 12/20/99).
c. Phase II SO_2 Acid Rain Application/Compliance Plan received December 26, 1995.

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

A.2. Sulfur dioxide (SO_2) allowance allocations and nitrogen oxide (NO_X) requirements for each Acid Rain unit are as follows:

E.U. ID No.	**EPA ID**	**Year**	**2001**	**2002**	**2003**	**2004**	**2005**
-001	**GB01**	**SO_2 allowances, under Table 2 of 40 CFR Part 73**	3842*	3842*	3842*	3842*	3842*
-002	**GB02**	**SO_2 allowances, under Table 2 of 40 CFR Part 73**	4425*	4425*	4425*	4425*	4425*

<table>
<tr><th>E.U. ID No.</th><th>EPA ID</th><th>Year</th><th>2001</th><th>2002</th><th>2003</th><th>2004</th><th>2005</th></tr>
<tr><td rowspan="2">-003</td><td>GB03</td><td>SO_2 allowances, under Table 2 of 40 CFR Part 73</td><td>5664*</td><td>5664*</td><td>5664*</td><td>5664*</td><td>5664*</td></tr>
<tr><td>GN03</td><td>NOx limit**</td><td colspan="5"><u>Note:</u> The applicable emission limitation, under 40 CFR 76.6(a)(2), is 0.86 lb/mmBtu for cyclone boilers.

A.2.1. Pursuant to 40 CFR 76.11, the Florida Department of Environmental Protection approves the NOx emissions averaging plan submitted on 12/22/99 for this unit. Under the plan, this unit's NOx emissions shall not exceed the annual average alternative contemporaneous emission limitation of 0.89 lb/mmBtu. In addition, this unit shall not have an annual heat input greater than 8,500,000 MMBtu.

Also, see Additional Requirements 1 and 2 below.</td></tr>
<tr><td rowspan="2">-004</td><td>GB04</td><td>SO_2 allowances, under Table 2 of 40 CFR Part 73</td><td>6223*</td><td>6223*</td><td>6223*</td><td>6223*</td><td>6223*</td></tr>
<tr><td>GN04</td><td>NOx limit**</td><td colspan="5"><u>Note:</u> The applicable emission limitation, under 40 CFR 76.6(a)(2), is 0.86 lb/mmBtu for cyclone boilers.

A.2.2. Pursuant to 40 CFR 76.11, the Florida Department of Environmental Protection approves the NOx emissions averaging plan submitted on 12/22/99 for this unit. Under the plan, this unit's NOx emissions shall not exceed the annual average alternative contemporaneous emission limitation of 0.82 lb/MMBtu. In addition, this unit shall not have an annual heat input less than 7,500,000 MMBtu.

Also, see Additional Requirements 1 and 2 below.</td></tr>
</table>

<table>
<tr><th>E.U. ID No.</th><th>EPA ID</th><th>Year</th><th>2000</th><th>2001</th><th>2002</th><th>2003</th><th>2004</th></tr>
<tr><td>-005</td><td>GB05</td><td>SO_2 allowances, under Table 2 of 40 CFR Part 73</td><td>6537*</td><td>6537*</td><td>6537*</td><td>6537*</td><td>6537*</td></tr>
<tr><td></td><td>GN05</td><td>NOx limit**</td><td colspan="5"><u>Note:</u> The applicable emission limitation, under 40 CFR 76.6(a)(2), is 0.84 lb/mmBtu for wet bottom boilers.

A.2.3. Pursuant to 40 CFR 76.11, the Florida Department of Environmental Protection approves the NOx emissions averaging plan submitted on 12/22/99 for this unit. Under the plan, this unit's NOx emissions shall not exceed the annual average alternative contemporaneous emission limitation of 0.76 lb/MMBtu. In addition, this unit shall not have an annual heat input less than 10,000,000 MMBtu.

Also, see Additional Requirements 1 and 2 below.</td></tr>
<tr><td>-006</td><td>GB06</td><td>SO_2 allowances, under Table 2 of 40 CFR Part 73</td><td>10081*</td><td>10081*</td><td>10081*</td><td>10081*</td><td>10081*</td></tr>
<tr><td></td><td>GN06</td><td>NOx limit**</td><td colspan="5"><u>Note:</u> The applicable emission limitation, under 40 CFR 76.6(a)(2), is 0.84 lb/mmBtu for wet bottom boilers.

A.2.4. Pursuant to 40 CFR 76.11, the Florida Department of Environmental Protection approves the NOx emissions averaging plan submitted on 12/22/99 for this unit. Under the plan, this unit's NOx emissions shall not exceed the annual average alternative contemporaneous emission limitation of 1.10 lb/MMBtu. In addition, this unit shall not have an annual heat input greater than 27,000,000 MMBtu.

Also, see Additional Requirements 1 and 2 below.</td></tr>
</table>

*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 of 40 CFR 73.
**Based on the Phase II NO_X applications.

<u>Additional Requirements</u>

1. Under the plan (NO_X Phase II averaging plan), the actual Btu-weighted annual average NO_X emission rate for the units in the plan shall be less than or equal to the Btu-weighted

annual average NO_X emission rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations under 40 CFR 76.5, 76.6, or 76.7, except that for any early election units, the applicable emission limitations shall be under 40 CFR 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11(d)(1)(ii)(A)) is met for a year under the plan, then this unit shall be deemed to be in compliance for that year with its alternative contemporaneous annual emission limitation and annual heat input limit.

2. 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 requirements covering excess emissions.

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 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(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.
[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.
[40 CFR 70.6(a)(4)(i); and, Rule 62-213.440(1)(c)1., F.A.C.]

A.6. Where an applicable requirement of the Act is more stringent than applicable regulations promulgated under Title IV of the Act, both provisions shall be incorporated into the permit and shall be enforceable by the Administrator.
[40 CFR 70.6(a)(1)(ii); and, Rule 62-210.200, F.A.C., Definitions – Applicable Requirements.]

A.7. Comments, notes, and justifications:
a. The designated representative was changed by letter dated June 27, 1997.
b. The designated representative was changed by letter dated July 1, 1998.

received 12/14/99 from TCC

IN THE CIRCUIT COURT OF THE THIRTEENTH JUDICIAL CIRCUIT
IN AND FOR HILLSBOROUGH COUNTY, FLORIDA

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION,

Plaintiff,

vs. CASE NO.:

TAMPA ELECTRIC COMPANY,

Defendant.
_______________________________/

CONSENT FINAL JUDGMENT

I. INTRODUCTION AND PURPOSE

A. This Consent Final Judgment is entered into between Plaintiff, State of Florida, Department of Environmental Protection (the "DEP"), and Defendant, Tampa Electric Company ("TAMPA ELECTRIC COMPANY"), to reach a settlement of certain matters at issue between them. The Consent Final Judgment provides for the implementation of certain actions, the investigation and implementation of certain pollution prevention technology, and the contribution of funds to assist the DEP in its Bay Regional Air Chemistry Experiment program relating to nitrogen deposition in Tampa Bay.

B. "Consent Final Judgment" means this Consent Final Judgment, including any future modifications, and any reports, plans, specifications and schedules required by the Consent Final Judgment which, upon the approval of each by the DEP, shall be deemed incorporated into and become an enforceable part of this Consent Final Judgment as though each was originally set forth herein.

II. JURISDICTION

A. The DEP is the administrative agency of the State of Florida having the power and duty to protect Florida's air and water resources, and to administer and enforce the provisions of Chapter 403, Florida Statutes, and the rules promulgated thereunder, Florida Administrative Code ("F.A.C.") Title 62 including the rules which Florida has the responsibility to administer and enforce under the federally approved Florida State Implementation Plan (SIP) and the separate Environmental Protection Agency delegation of PSD authority.

B. This Court has jurisdiction over the subject matter herein and over the Parties hereto pursuant to Chapter 403, Florida Statutes.

C. This Court retains jurisdiction over both the subject matter of this Consent Final Judgment and the Parties during the performance of its terms to enforce compliance therewith, if necessary.

III. PARTIES BOUND

This Consent Final Judgment shall apply to and be binding upon the DEP and TAMPA ELECTRIC COMPANY, (hereinafter individually defined as a "Party" or together defined as "Parties") and their successors and assigns. Each person signing this Consent Final Judgment certifies that he or she is authorized to execute the Consent Final Judgment and to legally bind to it the party on whose behalf he or she signs the Consent Final Judgment.

IV. STATEMENT OF FACTS

A. TAMPA ELECTRIC COMPANY owns and is an operator of the Big Bend coal fired electric generation plant in Hillsborough County. Big Bend generates electricity from four steam generating boilers which are designated as Big Bend Unit 1, Big Bend Unit 2, Big Bend Unit 3, and Big Bend Unit 4. TAMPA ELECTRIC COMPANY also owns and is an operator of the Gannon coal fired electric generation plant in Hillsborough County. Gannon generates electricity from six steam generating boilers which are designated as Gannon Unit 1, Gannon Unit 2, Gannon Unit 3, Gannon Unit 4, Gannon Unit 5, and Gannon Unit 6.

B. The DEP has alleged that Tampa Electric Company undertook a number of activities at the Gannon and Big Bend Generating Stations without appropriate regulatory review and permits, in violation of Chapter 403, Florida Statutes, and applicable provisions of the federally approved SIP. These activities include, but are not limited to, the following:

1. TAMPA ELECTRIC COMPANY modified, and thereafter operated, its electric generating units at Big Bend and Gannon, which are coal fired electricity generating power plants in Hillsborough County, Florida, without first obtaining appropriate permits authorizing this construction and without installing the best control technology (BACT) to control emissions of nitrogen oxides, sulfur dioxide, and particulate matter, as required by Florida law.

2. As a result of TAMPA ELECTRIC COMPANY's operation of the power plants, these unlawful modifications and the absence of appropriate controls, sulfur dioxide, nitrogen oxides, and particulate matter have been, and still are being, released into the atmosphere aggravating air pollution locally and downwind from these plants.

3. At various times, TAMPA ELECTRIC COMPANY commenced construction of modifications at Big Bend. These modifications included, but are not

limited to: (1) replacement of steam drum internals in Big Bend Units 1 and 2 in 1994 and 1991, respectively; (2) replacement of the waterwall in Big Bend Unit 2 in 1994, and (3) replacement of the high temperature reheater in Big Bend Unit 2 in 1994.

4. Such modifications by TAMPA ELECTRIC COMPANY were done without obtaining a permit from the DEP and without applying BACT for nitrogen oxide, sulfur dioxide and particulate matter as required by Chapter 403, Florida Statutes.

5. At various times, TAMPA ELECTRIC COMPANY commenced construction of modifications to Gannon. These modifications included, but were not limited to: (1) replacement of the furnace floor in Gannon Unit 3 with a new design in 1996; and, (2) replacement of the cyclone in Gannon Unit 4 in 1994.

6. Such modifications by TAMPA ELECTRIC COMPANY were done without obtaining a permit from the DEP and without applying BACT for nitrogen oxide, sulfur dioxide and particulate matter as required by Chapter 403, Florida Statutes.

C. Tampa Electric Company has agreed to the entry of the Consent Final Judgment and has agreed to implement the requirements of the Consent Final Judgment without an admission of liability and in recognition of the benefits of resolving litigation and elimination of such related expenses as settlement of the claims set forth in the Complaint, which Tampa Electric Company believes to be disputed claims. Tampa Electric Company neither admits nor denies the facts set forth in the Complaint and in Section IV.B. of this Consent Final Judgment.

V. REQUIREMENTS OF THE CONSENT FINAL JUDGMENT

A. TAMPA ELECTRIC COMPANY shall shut down coal-fired Units 1, 2, and 6 at Gannon Station and repower Units 3, 4, & 5 for gas to be phased-in between

January 1, 2003 and December 31, 2004. The repowered Units shall meet BACT for nitrogen oxide applicable to combined cycle gas turbines with an emission rate of 3.5 ppm. This requirement shall be included as a permit condition issued through the normal process.

B. TAMPA ELECTRIC COMPANY shall evaluate using "zero-ammonia" nitrogen oxide control technology at its Gannon facility. If, by May, 2000, such technology is found by the DEP to be commercially viable, TAMPA ELECTRIC COMPANY shall install such technology on one of the units it intends to repower so long as the incremental capital cost differential above the cost of Selective Catalytic Reduction (SCR) does not exceed $8 million and TAMPA ELECTRIC COMPANY obtains acceptable performance guarantees and remedies from the manufacturer of the technology. The installation shall be performed as part of the repowering process and shall be completed no later than December 31, 2004. In the event that the DEP does not find that the technology is commercially viable, then by December 31, 2004, TAMPA ELECTRIC COMPANY shall spend up to $8 million to demonstrate alternative commercially viable nitrogen oxide reduction technologies for natural gas-fired or coal-fired generating facilities as determined by the DEP and TAMPA ELECTRIC COMPANY.

C. At Big Bend Station, the new scrubber serving Units 1&2 is currently going through performance testing and is scheduled for commercial operation on or about January 1, 2000. It has a guaranteed removal efficiency of 93% but is the first Unit with a large, high velocity tower serving approximately 800 mega watts TAMPA ELECTRIC COMPANY shall use reasonable commercial efforts to optimize the removal efficiency to achieve a 95% removal efficiency by May 1, 2002 if such rate is not achieved by commercial operation.

D. TAMPA ELECTRIC COMPANY shall maximize scrubber utilization on all four boilers at Big Bend. The DEP recognizes the need for shut down for operational reasons.

E. TAMPA ELECTRIC COMPANY shall add nitrogen oxide controls, repower or shut down Units 1 through 3 at Big Bend Station by May 2010 and at Unit 4 at Big Bend Station by May 2007. If SCRs or similar nitrogen oxide controls are installed, BACT for nitrogen oxide will be .10 lbs./mmBTU on Unit 4 and .15 lbs./mmBTU on Units 1, 2, and 3.

F. TAMPA ELECTRIC COMPANY shall undertake a performance optimization study and a BACT analysis of its electrostatic precipitators and make reasonable upgrades to the electrostatic precipitators at Big Bend Station by May 1, 2003, if the study indicates that reasonable upgrades are necessary to obtain performance optimization.

G. TAMPA ELECTRIC COMPANY shall report to DEP on the technical feasibility of installing a particulate matter continuous emissions monitor on one stack at Big Bend March 1, 2002. If the DEP determines by May 31, 2002 that installation to be technically feasible, TAMPA ELECTRIC COMPANY shall install a particulate matter continuous emissions monitor on one stack at Big Bend station no later than May 1, 2003. Such monitor shall be installed solely for demonstration and informational purposes.

H. TAMPA ELECTRIC COMPANY shall be entitled to retain all sulfur dioxide reduction credits as currently authorized by law and freely trade them as allowed by the acid rain program. These credits were an integral part of the economics of the repowering project. If a credit trading program is developed by state or federal law for nitrogen oxide, TAMPA ELECTRIC COMPANY shall bank such credits obtained from the reductions achieved through the implementation of this Consent Final Judgment, but such credits shall not be eligible for sale to third parties but shall be held for TAMPA ELECTRIC COMPANY's (or any affiliate's) own account.

I. TAMPA ELECTRIC COMPANY shall agree to cooperate with the DEP on its Bay Regional Air Chemistry Experiment BRACE program relating to nitrogen deposition in Tampa Bay, including allowing necessary stack testing access to the DEP, and contributing $2 million dollars to the Hillsborough Environmental Protection Commission (EPC) for use in the BRACE program, in lieu of civil penalties. The DEP will enter into an agreement with EPC to ensure that the funds are spent on the BRACE program. TAMPA ELECTRIC COMPANY shall make the first payment to EPC in the amount of $500,000 by July 1, 2000, and shall pay $500,000 each six months thereafter until the full $2 million dollars has been paid.

J. TAMPA ELECTRIC COMPANY shall collaborate with the DEP to develop and implement State tax policy aimed at emissions reductions and such other supplemental environmental programs which are agreed to by TAMPA ELECTRIC COMPANY and the DEP.

K. TAMPA ELECTRIC COMPANY shall be entitled to relief from the time requirements of this Consent Final Judgment in the event of a force majeure that includes, among other things, delays in regulatory approvals, construction, labor, material or equipment delays, natural gas and gas transportation availability delays, acts of God or other similar events that are beyond the control of the company and not resulting from its owns actions, for the length of time necessarily imposed by the delay.

L. TAMPA ELECTRIC COMPANY shall be released from civil liability for all past New Source Review (NSR) related acts and State Implementation Plan (SIP) violations associated with the Prevention of Significant Deterioration (PSD), New Source Performance Standards (NSPS) and NSR related matters set forth herein and in the Complaint.

M. TAMPA ELECTRIC COMPANY shall also be protected from triggering NSR requirements with respect to repairs, maintenance and physical or operation changes during the term of the Consent Final Judgment which term shall remain effective until the actions required hereunder have been implemented.

N. The DEP shall cooperate with TAMPA ELECTRIC COMPANY and the United States Environmental Protection Agency in an effort to clarify the NSR regulations for repairs, maintenance, physical and operation changes in the future.

O. TAMPA ELECTRIC COMPANY's obligation to implement the emissions reductions and other requirements set forth herein will be conditioned on the receipt of necessary federal, state and local environmental permits, and acceptable regulatory treatment, including cost recovery by the Florida Public Service Commission.

P. DEP will defend the terms of this Consent Final Judgment in any action to which it is a party.

VI. MISCELLANEOUS

A. This Consent Final Judgment embodies the entire agreement and understanding of the Parties and supersedes any and all prior agreements, drafts, arrangements, conversations, negotiations or understandings relating to matters provided for in the Consent Final Judgment.

B. This Consent Final Judgment may be executed in one or more counterparts, each of which will be deemed an original, but all of which together will constitute one and the same instrument.

C. Each provision of the Consent Final Judgment shall be interpreted in such a manner as to be effective and valid under applicable law, but if any provision of the Consent Final Judgment shall be prohibited or invalid under applicable law, such provision shall be ineffective to the extent of such prohibition or invalidity, without invalidating the remainder of such provision or the remaining provisions of the Consent Final Judgment.

D. This Consent Final Judgment is not, and shall not be construed to be, a permit issued pursuant to any federal, State or local law, rule or regulation.

E. If, for any reason, the Court should decline to enter this Consent Final Judgment in the form in which it is lodged, the Consent Final Judgment as lodged is voidable, at the sole discretion of either Party. The Parties agree that because the claims of the DEP contained herein were disputed as to validity and amount, none of the terms of the lodged but voided Consent Final Judgment may be used as evidence in any litigation for any purpose, except with the written consent of TAMPA ELECTRIC COMPANY.

F. Except as provided for herein, there shall be no modifications or amendments of this Consent Final Judgment without written agreement of the Parties to this Consent Final Judgment and approval by the Court.

VII. FINAL JUDGMENT/RETENTION OF JURISDICTION

This Consent Final Judgment constitutes a final judgment in this action. This Court will retain jurisdiction for the purpose of enabling the Parties to apply to the Court at any time for such further order, direction or relief as may be necessary or appropriate for the construction or modification of this Consent Final Judgment, or to effectuate or enforce compliance with its terms, or to resolve disputes.

DONE AND ORDERED IN CHAMBERS this ___ day of __________________, 1999.

ORIGINAL SIGNED

DEC 16 1999

ROBERT H. BONANNO
CIRCUIT JUDGE

Circuit Judge

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

By: David B. Struhs
Secretary of the Florida Department of Environmental Protection

Date: December 6, 1999

TAMPA ELECTRIC COMPANY

By: J.B. Ramil
John B. Ramil
President

Date: December 6, 1999

Florida Department of Environmental Protection

Phase II NO_X Compliance Plan

For more information, see instructions and refer to 40 CFR 76.9

This submission is: ☐ New X Revised

STEP 1 Indicate plant name, state, and ORIS code from NADB, if applicable.	Plant Name Tampa Electric Company F.J. Gannon Station	State FL	ORIS Code 646
STEP 2	Identify each affected Group 1 and Group 2 boiler using the boiler ID# from NADB, if applicable. Indicate boiler type: "CB" for cell burner, "CY" for cyclone, "DBW" for dry bottom wall-fired, "T" for tangentially fired, "V" for vertically fired, and"WB" for wet bottom. Indicate the compliance option selected for each unit.		

	ID# GN03	ID# GN04	ID# GN05	ID# GN06	ID#	ID#
	Type CY	Type CY	Type WB	Type WB	Type	Type
(a) Standard annual average emission limitation of 0.50 lb/mmBtu (for Phase I dry bottom wall-fired boilers)	☐	☐	☐	☐	☐	☐
(b) Standard annual average emission limitation of 0.45 lb/mmBtu (for Phase I tangentially fired boilers)	☐	☐	☐	☐	☐	☐
(c) EPA-approved early election plan under 40 CFR 76.8 through 12/31/07 (also indicate above emission limit specified in plan)	☐	☐	☐	☐	☐	☐
(d) Standard annual average emission limitation of 0.46 lb/mmBtu (for Phase II dry bottom wall-fired boilers)	☐	☐	☐	☐	☐	☐
(e) Standard annual average emission limitation of 0.40 lb/mmBtu (for Phase II tangentially fired boilers)	☐	☐	☐	☐	☐	☐
(f) Standard annual average emission limitation of 0.68 lb/mmBtu (for cell burner boilers)	☐	☐	☐	☐	☐	☐
(g) Standard annual average emission limitation of 0.86 lb/mmBtu (for cyclone boilers)	☐	☐	☐	☐	☐	☐
(h) Standard annual average emission limitation of 0.80 lb/mmBtu (for vertically fired boilers)	☐	☐	☐	☐	☐	☐
(i) Standard annual average emission limitation of 0.84 lb/mmBtu (for wet bottom boilers)	☐	☐	☐	☐	☐	☐
(j) NO_x Averaging Plan (include NO_x Averaging form)	X	X	X	X	☐	☐
(k) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(A) (check the standard emission limitation box above for most stringent limitation applicable to any unit utilizing stack)	☐	☐	☐	☐	☐	☐

Plant Name (from Step 1)	Tampa Electric Company F.J. Gannon Station

STEP 2, cont'd.

	ID# GN03	ID# GN04	ID# GN05	ID# GN06	ID#	ID#
	Type	Type	Type	Type	Type	Type
(l) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(B) with NO_x Averaging (check the NO_x Averaging Plan box and include NO_x Averaging Form)	☐	☐	☐	☐	☐	☐
(m) EPA-approved common stack apportionment method pursuant to 40 CFR 75.17 (a)(2)(i)(C), (a)(2)(iii)(B), or (b)(2)	☐	☐	☐	☐	☐	☐
(n) AEL (include Phase II AEL Demonstration Period, Final AEL Petition, or AEL Renewal form as appropriate)	☐	☐	☐	☐	☐	☐
(o) Petition for AEL demonstration period or final AEL under review by U.S. EPA or demonstration period ongoing	☐	☐	☐	☐	☐	☐
(p) Repowering extension plan approved or under review	☐	☐	☐	☐	☐	☐

STEP 3
Read the standard requirements and certification, enter the name of the designated representative, sign and date.

Standard Requirements

General. This source is subject to the standard requirements in 40 CFR 72.9 (consistent with 40 CFR 76.8(e)(1)(i)). These requirements are listed in this source's Acid Rain Part of its Title V permit.

Special Provisions for Early Election Units

Nitrogen Oxides. A unit that is governed by an approved early election plan shall be subject to an emissions limitation for NO_x as provided under 40 CFR 76.8(a)(2) except as provided under 40 CFR 76.8(e)(3)(iii).

Liability. The owners and operators of a unit governed by an approved early election plan shall be liable for any violation of the plan or 40 CFR 76.8 at that unit. The owners and operators shall be liable, beginning January 1, 2000, for fulfilling the obligations specified in 40 CFR Part 77.

Termination. An approved early election plan shall be in effect only until the earlier of January 1, 2008 or January 1 of the calendar year for which a termination of the plan takes effect. If the designated representative of the unit under an approved early election plan fails to demonstrate compliance with the applicable emissions limitation under 40 CFR 76.5 for any year during the period beginning January 1 of the first year the early election takes effect and ending December 31, 2007, the permitting authority will terminate the plan. The termination will take effect beginning January 1 of the year after the year for which there is a failure to demonstrate compliance, and the designated representative may not submit a new early election plan. The designated representative of the unit under an approved early election plan may terminate the plan any year prior to 2008 but may not submit a new early election plan. In order to terminate the plan, the designated representative must submit a notice under 40 CFR 72.40(d) by January 1 of the year for which the termination is to take effect. If an early election plan is terminated any year prior to 2000, the unit shall meet, beginning January 1, 2000, the applicable emissions limitation for NO_x for Phase II units with Group 1 boilers under 40 CFR 76.7. If an early election plan is terminated on or after 2000, the unit shall meet, beginning on the effective date of the termination, the applicable emissions limitation for NO_x for Phase II units with Group 1 boilers under 40 CFR 76.7.

STEP 3, cont'd.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Gregory M. Nelson	
Signature Gregory M. Nelson	Date 12/20/99

UNITED STATES DISTRICT COURT
MIDDLE DISTRICT OF FLORIDA

UNITED STATES OF AMERICA, Plaintiff, v. TAMPA ELECTRIC COMPANY, Defendant.	)	CIVIL ACTION NO. 99-2524 CIV-T-23F

CONSENT DECREE

WHEREAS, Plaintiff, the United States of America ("Plaintiff" or "the United States"), on behalf of the United States Environmental Protection Agency ("EPA") filed a Complaint on November 3, 1999, alleging that Defendant, Tampa Electric Company ("Tampa Electric") commenced construction of major modifications of major emitting facilities in violation of the Prevention of Significant Deterioration ("PSD") requirements at Part C of the Clean Air Act ("Act"), 42 U.S.C. §§ 7470-7492;

WHEREAS, EPA issued a Notice of Violation with respect to such allegations to Tampa Electric on November 3, 1999 (the "NOV");

WHEREAS, the parties recognize, and the Court by entering this Consent Decree finds, that this Consent Decree has been negotiated in good faith and at arm's length; that the parties have voluntarily agreed to this Consent Decree; that implementation of this Consent Decree will avoid prolonged and complicated litigation between the parties; and that this Consent Decree is fair, reasonable, consistent with the goals of the Act, and in the public interest;

WHEREAS, the United States alleges that the Complaint states a claim upon which relief can be granted against Tampa Electric under Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477, and 28 U.S.C. § 1355;

WHEREAS, Tampa Electric has not answered or otherwise responded to the Complaint in light of the settlement memorialized in this Consent Decree;

WHEREAS, Tampa Electric has denied and continues to deny the violations alleged in the NOV and the Complaint; maintains that it has been and remains in compliance with the Clean Air Act and is not liable for civil penalties or injunctive relief; and states that it is agreeing to the obligations imposed by this Consent Decree solely to avoid the costs and uncertainties of litigation and to improve the environment in and around the Tampa Bay area of Florida;

WHEREAS, Tampa Electric is the first electric utility of those against which the United States brought enforcement actions in November, 1999, to come forward and invest time and effort sufficient to develop a settlement with the United States;

WHEREAS, Tampa Electric's decision to Re-Power some of its coal-fired electric generating Units with natural gas will significantly reduce emissions of both regulated and unregulated pollutants below levels that would have been achieved merely by installing appropriate pollution control technologies on Tampa Electric's existing coal-fired electric generating Units;

WHEREAS, prior to the filing of the Complaint or issuance of the Notice of Violation in this matter, Tampa Electric already had placed in service or installed both scrubbers and electrostatic precipitators that serve all existing coal-fired electric generating Units at the company's Big Bend electric generating plant;

WHEREAS, the United States recognizes that a BACT Analysis conducted under existing procedures most likely would not find it cost effective to replace Tampa Electric's existing control equipment at Big Bend for particulate matter, in light of the design and performance of that equipment;

WHEREAS, Tampa Electric and the United States have crafted this Consent Decree to take into account physical and operational constraints resulting from the unique, Riley Stoker wet bottom, turbo-fired boiler technology now in operation at Big Bend, which could limit the efficiency of nitrogen oxides emissions controls installed for those boilers;

WHEREAS, Tampa Electric regularly combusts coal with a sulphur content of five or six pounds per mmBTU heat input;

WHEREAS, Tampa Electric is a mid-sized electric utility and is smaller on a financial basis than some of the other electric utilities against which the United States brought similar enforcement actions in November 1999;

WHEREAS, Tampa Electric owns and operates fewer coal-fired electric generating plants than some of the other electric utilities against which the United States brought similar enforcement actions in November 1999;

WHEREAS, the two Tampa Electric plants addressed by this enforcement action constitute over ninety percent of the entire base load generating capacity of Tampa Electric;

WHEREAS, the United States and Tampa Electric have agreed that settlement of this action is in the best interest of the parties and in the public interest, and that entry of this Consent Decree without further litigation is the most appropriate means of resolving this matter; and

WHEREAS, the United States and Tampa Electric have consented to entry of this Consent Decree without trial of any issue;

NOW, THEREFORE, without any admission of fact or law, and without any admission of the violations alleged in the Complaint or NOV, it is hereby ORDERED AND DECREED as follows:

I. JURISDICTION AND VENUE

1. This Court has jurisdiction over the subject matter herein and over the parties consenting hereto pursuant to 28 U.S.C. § 1345 and pursuant to Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477. Venue is proper under Section 113(b) of the Act, 42 U.S.C. § 7413(b), and under 28 U.S.C. § 1391(b) and (c).

Solely for the purposes of this Consent Decree and the underlying Complaint, Tampa Electric waives all objections and defenses that it may have to the claims set forth in the Complaint, the jurisdiction of the Court or to venue in this District. Tampa Electric shall not challenge the terms of this Consent Decree or this Court's jurisdiction to enter and enforce this Consent Decree. Except as expressly provided for herein, this Consent Decree shall not create any rights in any party other than the United States and Tampa Electric. Tampa Electric consents to entry of this Consent Decree without further notice.

II. APPLICABILITY

2. The provisions of this Consent Decree shall apply to and be binding upon the United States and upon Tampa Electric, its successors and assigns, and Tampa Electric's officers, employees and agents solely in their capacities as such. If Tampa Electric proposes to sell or transfer any of its real property or operations subject to this Consent Decree, it shall advise the purchaser or transferee in writing of the existence of this Consent Decree, and shall send a copy of such written notification by certified mail, return receipt requested, to EPA sixty (60) days before such sale or transfer. Tampa Electric shall not be relieved of its responsibility to comply with all requirements of this Consent Decree unless the purchaser or transferee assumes responsibility for full performance of Tampa Electric's responsibilities under this Consent Decree, including liabilities for

nonperformance. Tampa Electric shall not purchase or otherwise acquire capacity and/or energy from a third party in lieu of obtaining it from Gannon or Big Bend unless the seller or provider agrees that the facilities providing such capacity and/or energy will meet the emission control requirements set forth in this Consent Decree or equivalent requirements approved in advance by the United States.

3. Tampa Electric shall provide a copy of this Consent Decree to all vendors, suppliers, consultants, contractors, agents, and any other company or other organization performing any of the work described in Sections IV or VII of this Consent Decree. Notwithstanding any retention of contractors, subcontractors or agents to perform any work required under this Consent Decree, Tampa Electric shall be responsible for ensuring that all work is performed in accordance with the requirements of this Consent Decree. In any action to enforce this Consent Decree, Tampa Electric shall not assert as a defense the failure of its employees, servants, agents, or contractors to take actions necessary to comply with this Consent Decree, unless Tampa Electric establishes that such failure resulted from a Force Majeure event as defined in this Consent Decree.

III. DEFINITIONS

4. "Alternative Coal" shall mean coal with a sulphur content of no more than 2.2 lb/mmBTU, on an as determined basis.

5. "BACT Analysis" shall mean the technical study, analysis, review, and selection of recommendations typically performed in connection with an application for a PSD permit. Except as otherwise provided in this Consent Decree, such study, analysis, review, and selection of recommendations shall be carried out in conformance with applicable federal and state regulations and guidance describing the process and analysis for determining Best Available Control Technology (BACT).

6. "Big Bend" shall mean the electric generating plant, presently coal-fired, owned and operated by Tampa Electric and located in Hillsborough County, Florida, which presently includes four steam generating boilers and associated and ancillary systems and equipment, known as Big Bend Units 1, 2, 3, and 4.

7. "Consent Decree" shall mean this Consent Decree and the Appendix thereto.

8. "Emission Rate" shall mean the average number of pounds of pollutant emitted per million BTU of heat input ("lb/mmBTU") or the average concentration of a pollutant in parts per million by volume ("ppm"), as dictated by the unit of measure specified for the rate in question, where:

1

2 in the case of a coal-fired, steam electric generating unit, such rates shall be calculated as a 30 day rolling average. A 30 day rolling average for an Emission Rate expressed as lb/mmBTU shall be determined by calculating the emission rate for a given operating day, and then arithmetically averaging the emission rates for

the previous 29 operating days with that date. A new 30 day rolling average shall be calculated for each new operating day;

A in the case of a gas-fired, electric generating unit, such rates shall be calculated as a 24-hour rolling average, excluding periods of start up, shutdown, and malfunction as provided by applicable Florida regulations at the time the Emission Rate is calculated. A rolling average for Emission Rates expressed as ppm shall be determined on a given day by summing hourly emission rates for the immediately preceding 24-hour period and dividing by 24;

A the reference methods for determining Emission Rates for SO_2 and NO_x shall be those specified in 40 C.F.R. Part 75, Appendix F. The reference methods for determining Emission Rates for PM shall be those specified in 40 C.F.R. Part 60, Appendix A, Method 5, Method 5B, or Method 17; and

A nothing in this Consent Decree is intended to nor shall alter applicable law concerning the use of data, for any purpose under the Clean Air Act, generated by methods other than the reference methods specified herein.

9. "EPA" shall mean the United States Environmental Protection Agency.

10. "Gannon" shall mean the electric generating plant, presently coal-fired, owned and operated by Tampa Electric, located in Hillsborough County, Florida, which presently includes six steam generating boilers and associated and ancillary systems and equipment, known as Gannon Units 1, 2, 3, 4, 5, and 6. Tampa Electric intends to rename Gannon "Bayside Power Station" upon completion of

the Re-Powering required under this Consent Decree.

11. "lb/mmBTU" shall mean pounds per million British Thermal Units of heat input.

12. "NOx" shall mean oxides of nitrogen.

13. "NOV" shall mean the Notice of Violation issued by EPA to Tampa Electric dated November 3, 1999.

14. "PM" shall mean total particulate matter, and the reference method for measuring PM shall be that specified in the definition of Emission Rate in this Consent Decree.

15. "ppm" shall mean parts per million by dry volume, corrected to 15% O_2.

16. "Project Dollars" shall mean Tampa Electric's expenditures and payments incurred or made in carrying out the dollar-limited projects identified in Paragraph 35 of Section IV of this Consent Decree (Early Reductions of NO_x from Big Bend Units 1 through 3) and in Section VII of this Consent Decree (NO_x Reduction Projects and Mitigation Projects), to the extent that such expenditures or payments both: (A) comply with the Project Dollar and other requirements set by this Consent Decree for such expenditures and payments in Section VII and in Paragraph 35 of Section IV of this Consent Decree, and (B) constitute either Tampa Electric's properly documented external costs for contractors, vendors, as well as equipment, or its internal costs consisting of employee time, travel, and other out-of-pocket expenses specifically attributable to these particular projects.

17. "PSD" shall mean Prevention of Significant Deterioration within the meaning of

Part C of the Clean Air Act, 42 U.S.C. §§ 7470, et seq.

18. "Re-Power" shall mean the removal or permanent disabling of devices, systems, equipment, and ancillary or supporting systems at a Gannon or Big Bend Unit such that the Unit cannot be fired with coal, and the installation of all devices, systems, equipment, and ancillary or supporting systems needed to fire such Unit with natural gas under the limits set in this Consent Decree (or with No. 2 fuel oil, as a back up fuel only, and under the limits specified by this Consent Decree) plus installation of the control technology and compliance with the Emission Rates called for under this Consent Decree.

19. "Reserve / Standby" shall mean those devices, systems, equipment, and ancillary or supporting systems that: (1) are not used as part of the Units that must be Re-Powered under Paragraph 26, (2) are not in operation subsequent to the Re-Powering required under Paragraph 26, (3) are maintained and held by Tampa Electric for system reliability purposes, and (4) may be restarted only by Re-Powering.

20. "SCR" shall mean Selective Catalytic Reduction.

21. "Shutdown" shall mean the permanent disabling of a coal-fired boiler such that it cannot burn any fuel nor produce any steam for electricity production, other than through Re-Powering.

22. "SO_2" shall mean sulphur dioxide.

23. "Title V Permit" shall mean the permit required under Subchapter V of the Clean

A. Tampa Electric shall timely apply for a preconstruction permit under Rule 62-212, F.A.C., prior to commencing such Re-Powering. In applying for such permit Tampa Electric shall seek, as part of the permit, provisions requiring installation of SCR or other EPA-approved control technology and a NO_x Emission Rate no greater than 3.5 ppm.

27. Schedule for Shutdown of Units. Tampa Electric shall Shutdown and cease any and all operation of all six (6) Gannon coal-fired boilers with a combined coal-fired capacity of not less than 1194 MW on or before December 31, 2004. Notwithstanding the requirements of this Paragraph, Tampa Electric may retain any Unit Shutdown pursuant to this Paragraph on Reserve / Standby, unless such Unit is to be, or has been, Re-Powered under Paragraph 26, above. If Tampa Electric later decides to restart any Shutdown Unit retained on Reserve / Standby, then prior to such re-start, Tampa Electric shall timely apply for a PSD permit for the Unit(s) to be Re-Powered, and Tampa Electric shall abide by the permit issued as a result of that application, including installation of BACT and its corresponding Emission Rate, as determined at the time of the restart. Tampa Electric shall operate the Re-Powered Unit to meet the NO_x Emission Rate established in the PSD Permit or an Emission Rate for NO_x of 3.5 ppm, whichever is more stringent. Tampa Electric shall provide a copy of any permit application(s), proposed permit(s), and permit(s) to the United States as specified in Paragraph 82 (Notice). For any Unit Shutdown and placed on Reserve / Standby under this Paragraph, and notwithstanding the definition of Re-Power in

this Consent Decree, Tampa Electric also may elect to fuel such a Unit with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric: applies for and secures a PSD permit before using such fuel in any such Unit, complies with all requirements issued in such a permit, and complies with all other requirements of this Consent Decree applicable to Re-Powering.

28. Permanent Bar on Combustion of Coal. Commencing on January 1, 2005, Tampa Electric shall not combust coal in the operation of any Unit at Gannon.

B. BIG BEND

29. Initial Reduction and Control of SO_2 Emissions from Big Bend Units 1 and 2. Commencing upon the later of the date of entry of this Consent Decree or September 1, 2000, and except as provided in this Paragraph, Tampa Electric shall operate the existing scrubber that treats emissions of SO_2 from Big Bend Units 1 and 2 at all times that either Unit 1 or 2 is in operation. Tampa Electric shall operate the scrubber so that at least 95% of all the SO_2 contained in the flue gas entering the scrubber is removed. Notwithstanding the requirement to operate the scrubber at all times Unit 1 or 2 is operating, the following operating conditions shall apply:

A.

B. Tampa Electric may operate Units 1 and/or 2 during outages of the scrubber serving Units 1 and 2, but only so long as Tampa Electric:

(1) in calendar year 2000, does not operate Unit 1 and/or 2, or any combination of the two of them, on more than sixty (60) calendar days, or any part thereof (providing that when both Units 1 and 2 operate on the same calendar day, such operation shall count as two days of the sixty (60) day limit), and in calendar years 2001 - 2009, does not operate Unit 1 and/or 2, or any combination of the two of them, on more than forty-five (45) calendar days, or any part thereof, in any calendar year (providing that when both Units 1 and 2 operate on the same calendar day, such operation shall count as two days of the forty-five (45) day limit) ; or

A.

B. must operate Unit 1 and/or 2 in any calendar year from 2000 through 2009 either to avoid interruption of electric service to its customers under interruptible service tariffs, or to respond to a system-wide or state-wide emergency as declared by the Governor of Florida under Section 366.055, F.S. (requiring availability of reserves), or under Section 377.703, F.S.

D. (energy policy contingency plan), or under Section 252.36, F.S. (Emergency management powers of the Governor), in which Tampa Electric must generate power from Unit 1 and/or 2 to meet such emergency.

1.

2. Whenever Tampa Electric operates Units 1 and/or 2 without all emissions from such Unit(s) being treated by the scrubber, Tampa Electric shall: (1) combust only Alternative Coal at the Unit(s) operating during the outage (except for coal already bunkered in the hopper(s) for Units 1 or 2 at the time the outage commences); (2) use all existing electric generating capacity at Big Bend and Gannon that is served by fully operational pollution control equipment before operating Big Bend Units1 and/or 2; and (3) continue to control SO_2 emissions from Big Bend Units 1 and/or 2 as required by Paragraph 31 (Optimizing Availability of Scrubbers Serving Big Bend Units 1, 2, and 3).

A. In calendar years 2010 through 2012, Tampa Electric may operate Units 1 and/or 2 during outages of the scrubber serving Units 1 and 2, but only so long as Tampa Electric complies with the requirements of Subparagraphs A and B, above, and uses only coal with a sulphur content of 1.2 lb/mmBTU, or less, in place of Alternative Coal.

A. If Tampa Electric Re-Powers Big Bend Unit 1 or 2, or replaces the scrubber or provides additional scrubbing capacity to comply with Paragraph 40, then upon such compliance the provisions of Subparagraphs 29.A, 29.B, and 29.C shall not apply to the affected Unit.

30. Initial Reduction and Control of SO_2 Emissions from Big Bend Unit 3.

Commencing upon entry of the Consent Decree, and except as provided in this Paragraph, Tampa Electric shall operate the existing scrubber that treats emissions of SO_2 from Big Bend Units 3 and 4 at all times that Unit 3 is in operation. When Big Bend Units 3 and 4 are both operating, Tampa Electric shall operate the scrubber so that at least 93% of all the SO_2 contained in the flue gas entering the scrubber is removed. When Big Bend Unit 3 alone is operating, until May 1, 2002, Tampa Electric shall operate the scrubber so that at least 93% of all SO_2 contained in the flue gas entering the scrubber is removed or the Emission Rate for SO_2 for Unit 3 does not exceed 0.35 lb/mmBTU. When Unit 3 alone is operating, from May 1, 2002 until January 1, 2010, Tampa Electric shall operate the scrubber so that at least 95% of the SO_2 contained in the flue gas entering the scrubber is removed or the Emission Rate for SO_2 does not exceed 0.30 lb/mmBTU. Notwithstanding the requirement to operate the scrubber at all times Unit 3 is operating, and providing Tampa Electric is otherwise in compliance with this Consent Decree, the following operating conditions shall apply:

A.

B. In any calendar year from 2000 through 2009, Tampa Electric may operate Unit 3 in the case of outages of the scrubber serving Unit 3, but only so long as Tampa Electric:

(1) does not operate Unit 3 during outages on more than thirty (30)

calendar days, or any part thereof, in any calendar year; or

A.

B. must operate Unit 3 either: to avoid interruption of electric service to its customers under interruptible service tariffs, or to respond to a system-wide or state-wide emergency as declared by the Governor of Florida under Section 366.055, F.S. (requiring availability of reserves), or under Section 377.703, F.S. (energy policy contingency plan), or under Section 252.36, F.S. (Emergency management powers of the Governor), in which Tampa Electric must generate power from Unit 3 to meet such emergency.

C.

1.

2. Whenever Tampa Electric operates Unit 3 without treating all emissions from that Unit with the scrubber, Tampa Electric shall: (1) combust only Alternative Coal at Unit 3 during the outage (except for coal already bunkered in the hopper(s) for Unit 3 at the time the outage commences); (2) use all existing electric generating capacity at Big Bend and Gannon that is served by fully operational pollution control equipment before operating Big Bend Unit 3; and (3) continue to control SO_2 emissions from Big Bend Unit 3 as required by Paragraph 31 (Optimizing Availability of Scrubbers Serving Big Bend Units, 1, 2, and 3).

A. If Tampa Electric Re-Powers Big Bend Unit 3, or replaces the scrubber or provides additional scrubbing capacity to comply with Paragraph 40, then upon compliance with Paragraph 40 the provisions of Subparagraphs 30.A and 30.B shall not apply to Unit 3.

A.

B. Nothing in this Consent Decree shall alter requirements of the New Source Performance Standards (NSPS), 40 C.F.R. Part 60 Subpart Da, that apply to operation of the scrubber serving Unit 4.

31. Optimizing Availability of Scrubbers Serving Big Bend Units 1, 2, and 3. Tampa Electric shall maximize the availability of the scrubbers to treat the emissions of Big Bend Units 1, 2, and 3, as follows:

A. As soon as possible after entry of this Consent Decree, Tampa Electric shall submit to EPA for review and approval a plan addressing all operation and maintenance changes to be made that would maximize the availability of the existing scrubbers treating emissions of SO_2 from Big Bend Units 1 and 2, and from Unit 3. In order to improve operations and maintenance practices as soon as possible, Tampa Electric may submit the plan in two phases.

(1) Each phase of the plan proposed by Tampa Electric shall include a schedule pursuant to which Tampa Electric will implement measures relating to operation and maintenance of the scrubbers called for by that phase of the plan, within sixty days of its approval by EPA. Tampa Electric shall implement each phase of the plan as approved by EPA.

Such plan may be modified from time to time with prior written approval of EPA.

(2) The proposed plan shall include operation and maintenance activities that will minimize instances during which SO_2 emissions are not scrubbed, including but not limited to improvements in the flexibility of scheduling maintenance on the scrubbers, increases in the stock of spare parts kept on hand to repair the scrubbers, a commitment to use of overtime labor to perform work necessary to minimize periods when the scrubbers are not functioning, and use of all existing capacity at Big Bend and Gannon Units that are served by available, operational pollution control equipment to minimize pollutant emissions while meeting power needs.

(3) If Tampa Electric elects to submit the plan to EPA in two phases, the first phase to be submitted shall address, at a minimum, use of overtime hours to accomplish repairs and maintenance of the scrubber and increasing the stock of scrubber spare parts that Tampa Electric shall keep at Big Bend to speed future maintenance and repairs. If Tampa Electric elects to submit the plan in two phases, EPA shall complete review of the first phase within fifteen business days of receipt. For the second phase of the plan or submission of the plan in its entirety, EPA shall complete review of such plan or phase thereof within 60 days of receipt. Within sixty days after EPA's approval of the plan or any phase of the plan,

Tampa Electric shall complete implementation of that plan or phase and continue operation under it subject only to the terms of this Consent Decree.

32. PM Emission Minimization and Monitoring at Big Bend.

A. Within twelve months after entry of this Consent Decree, Tampa Electric shall complete an optimization study which shall recommend the best operational practices to minimize emissions from each Electrostatic Precipitator (ESP) and shall deliver the completed study to EPA for review and approval. Tampa Electric shall implement these recommendations within sixty days after EPA has approved them and shall operate each ESP in conformance with the study and its recommendations until otherwise specified under this Consent Decree.

B. Within twelve months after entry of this Consent Decree, Tampa Electric shall complete a BACT Analysis for upgrading each existing ESP now located at Big Bend and shall deliver the Analysis to EPA for review and approval. Notwithstanding the definition of BACT Analysis in this Consent Decree, Tampa Electric need not consider in this BACT Analysis the replacement of any existing ESP with a new ESP, scrubber, or baghouse, or the installation of a supplemental pollution control device of similar cost to a replacement ESP, scrubber, or baghouse. Tampa Electric shall simultaneously deliver to EPA all documents that support the BACT

Analysis or that were considered in preparing the Analysis. Tampa Electric shall retain a qualified contractor to assist in the performance and completion of the BACT Analysis. On or before May 1, 2004, after EPA approval of the recommendation(s) made by the BACT Analysis, Tampa Electric shall complete installation of all equipment called for in the recommendation(s) of the Analysis and thereafter shall operate each ESP in conformance with the recommendation(s), including compliance with the Emission Rate(s) specified by the recommendation(s).

C. Within six months after Tampa Electric completes installation of the equipment called for by the BACT Analysis, as approved by EPA, Tampa Electric shall revise the previous optimization study and shall recommend the best operational practices to minimize emissions from each ESP, taking into account the recommendations from the BACT Analysis required by this Paragraph, and shall deliver the completed study to EPA for review and approval. Commencing no later than 180 days after EPA approves the study and its recommendation(s), Tampa Electric shall operate each ESP in conformance with the study's recommendation.

D. Tampa Electric shall include the recommended operational practices for each ESP and the recommendations from the BACT Analysis in Tampa Electric's Title V Permit application and all other relevant applications for operating or construction permits.

E. <u>Installation and Operation of a PM Monitor</u>. On or before March 1, 2002, Defendant shall install, calibrate, and commence continuous operation of a continuous particulate matter emissions monitor (PM CEM) in the duct at Big Bend that services Unit 4. Data from the PM CEM shall be used by Tampa Electric, at a minimum, to monitor progress in reducing PM emissions.

F. "Continuous operation"of the PM CEM shall mean operation at all times that Unit 4 operates, except for periods of malfunction of the PM CEM or routine maintenance performed on the PM CEM. If after Tampa Electric operates this PM CEM for at least two years, and if the parties then agree that it is infeasible to sustain continuous operation of the PM CEM, Tampa Electric shall submit an alternative PM monitoring plan for review and approval by EPA. The plan shall include an explanation of the basis for stopping operation of the PM CEM and a proposal for an alternative monitoring protocol. Until EPA approves such plan, Tampa Electric shall continue to operate the PM CEM.

G. <u>Installation and Operation of Second PM Monitor</u>. If Tampa Electric advises EPA, pursuant to Paragraph 36, that it has elected to continue to combust coal at Big Bend Units 1, 2, or 3, and Tampa Electric has not ceased operating the first PM CEM as described in Subparagraph F, above, then Tampa Electric shall install, calibrate, and commence continuous operation of a PM CEM on a second duct at Big Bend on or before May 1, 2007. The requirement to operate a PM CEM under any provision of this Paragraph shall terminate if and when the Unit monitored by the PM CEM is Re-Powered.

H. Testing and Reporting Requirement. Prior to installation of the PM CEM on each duct, Tampa Electric shall conduct a stack test on each stack at Big Bend on at least an annual basis and report its results to EPA as part of the quarterly report under Section V. The stack test requirement in this Subparagraph may be satisfied by Tampa Electric's annual stack tests conducted as required by its permit from the State of Florida. Following installation of each PM CEM, Defendant shall include in its quarterly reports to EPA pursuant to Section V all data recorded by the PM CEM, in electronic format, if available.

I. Nothing in this Consent Decree is intended to nor shall alter applicable law concerning the use of data, for any purpose under the Clean Air Act, generated by the PM CEMs.

33. Election for Big Bend Unit 4: Shutdown, Re-Power, or Continued Combustion of Coal. Tampa Electric shall advise EPA in writing, on or before May 1, 2005, whether Big Bend Unit 4 will be Shutdown, will be Re-Powered, or will continue to be fired by coal.

34. <u>Reduction of NO_x at Big Bend Unit 4 after 2005 Election</u>. Based on Tampa Electric's election in Paragraph 33, Tampa Electric shall take one of the following actions:

7.

8. If Tampa Electric elects to continue firing Unit 4 with coal, on or before June 1, 2007, Tampa Electric shall install and commence operation of SCR, or other technology if approved in writing by EPA in advance, sufficient to limit the coal-fired Emission Rate of NO_x from Unit 4 to no more than 0.10 lb/mmBTU. Thereafter, Tampa Electric shall continue operation of SCR or other EPA approved control technology, and Tampa Electric shall continue to meet an Emission Rate for NO_x from Unit 4 no greater than 0.10 lb/mmBTU; or

A. If Tampa Electric elects to Re-Power Unit 4, Tampa Electric shall not combust coal at Unit 4 on or after June 1, 2007. Tampa Electric shall timely apply for a preconstruction permit under Rule 62-212, F.A.C., prior to commencing construction of the Re-Powering of Unit 4. In applying for such permit, Tampa Electric shall seek, as part of the permit, provisions requiring installation of SCR or other EPA approved control technology and a NO_x Emission Rate no greater than 3.5 ppm. Tampa Electric shall operate the Re-Powered Unit 4 to meet an Emission Rate for NO_x of no greater than 3.5 ppm or the rate established in the preconstruction permit, whichever is more stringent; or

A. If Tampa Electric elects to Shutdown Big Bend Unit 4, Tampa Electric shall complete Shutdown of Big Bend Unit 4 on or before June 1, 2007. Notwithstanding the requirements of this Subparagraph, Tampa Electric may retain this Unit, after it is Shutdown pursuant to this Subparagraph, on Reserve / Standby. If Tampa Electric later decides to restart Unit 4 then, prior to such restart, Tampa Electric shall timely apply for a PSD permit, and Tampa Electric shall abide by the permit issued as a result of that application, including installation of BACT and its corresponding Emission Rate, as determined at the time of the restart. Tampa Electric shall operate the Re-Powered Unit 4 to meet an Emission Rate for NO_x of no greater than 3.5 ppm or the Emission Rate established in the PSD permit, whichever is more stringent. Tampa Electric shall provide a copy of any permit application(s), proposed permit(s), and permit(s) to the United States as specified in Paragraph 82 (Notice). Upon Shutdown of a Unit under this Subparagraph, Tampa Electric may never again use coal to fire that Unit.

A. Notwithstanding the provisions of Subparagraphs B and C above or the definition of Re-Power in this Consent Decree, Tampa Electric may also elect to fuel Big Bend Unit 4 with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric applies for and secures a PSD permit before using such fuel in this Unit, complies with all requirements issued in such a permit, and complies with all requirements of this Consent Decree applicable to Re-Powering.

35. <u>Early Reductions of NO_x from Big Bend Units 1 through 3</u>: On or before

December 31, 2001, Tampa Electric shall submit to EPA for review and comment a plan to reduce NO_x emissions from Big Bend Units 1, 2 and 3, through the expenditure of up to $3 million Project Dollars on combustion optimization using commercially available methods, techniques, systems, or equipment, or combinations thereof. Subject only to the financial limit stated in the previous sentence, for Units 1 and 2 the goal of the combustion optimization shall be to reduce the NO_x Emission Rate by at least 30% when compared against the NO_x Emissions Rate for these Units during calendar year 1998, which the United States and Tampa Electric agree was 0.86 lb/mmBTU. For Unit 3 the goal of the combustion optimization shall be to reduce the NO_x Emissions Rate by at least 15% when compared against the NO_x Emission Rate for this Unit during calendar year 1998, which the United States and Tampa Electric agree was 0.57 lb/mmBTU. If the financial limit in this Paragraph precludes designing and installing combustion controls that will meet the percentage reduction goals for the NO_x Emission Rates specified in this Paragraph for all three Units, then Tampa Electric's plan shall first maximize the Emission Rate reductions at Units 1 and 2 and then at Unit 3. Unless the United States has sought dispute resolution on Tampa Electric's plan on or before May 30, 2002, Tampa Electric shall implement all aspects of its plan at Big Bend Units 1, 2, and 3 on or before December 31, 2002. On or before April 1, 2003, Tampa Electric shall submit to EPA a report that documents the date(s) of complete implementation of the plan, the results obtained from implementing the plan, including the emission reductions or benefits achieved, and the Project Dollars expended by Tampa Electric in implementing the plan.

36. Election for Big Bend Units 1 through 3: Shutdown, Re-Power, or Continued Combustion of Coal. Tampa Electric shall advise EPA in writing, on or before May 1, 2007, whether Big Bend Units 1, 2, or 3, or any combination of them, will be Shutdown, will be Re-Powered, or will continue to be fired by coal.

37. Further NO_x Reduction Requirements if Big Bend Units 1, 2, and/or 3 Remain Coal-fired. If Tampa Electric advises EPA in writing, pursuant to Paragraph 36, above, that Tampa Electric will continue to combust coal at Units 1, 2, and/or 3, then:

A. Subject only to Subparagraphs B and D, Tampa Electric shall timely solicit contract proposals to acquire, install, and operate SCR, or other technology if approved in writing by EPA in advance, sufficient to limit the Emission Rate of NO_x to no more than 0.10 lb/mmBTU at each Unit that will combust coal. Tampa Electric shall install and operate such equipment on all Units that will continue to combust coal and shall achieve an Emission Rate of NO_x on each such Unit no less stringent than 0.10 lb/mmBTU.

A. Notwithstanding Subparagraph A, Tampa Electric shall not be required to install SCR to limit the Emission Rate of NO_x at Units 1, 2 and/or 3 to 0.10 lb/mmBTU if the "installation cost ceiling" contained in this Paragraph will be exceeded by such installation. If Tampa Electric decides to continue burning coal at Units 1, 2 and 3, the installation cost ceiling for SCR at Units 1, 2, and 3 shall be three times the cost of installing SCR at Big Bend Unit 4 plus forty-five (45%) percent of the cost of installing SCR at Big Bend 4. If Tampa Electric decides to continue burning coal at only two Units at Big Bend, the installation cost ceiling for SCR at those two Units shall be two times the cost of installing SCR at Big Bend 4 plus forty-five (45) percent of the cost of installing SCR at Big Bend Unit 4. If Tampa Electric decides to continue burning coal at only one Unit at Big Bend, the installation cost ceiling for SCR at that Unit shall be the cost of installing SCR at Big Bend 4 plus forty five (45) percent.

A. If, based on the contract proposals obtained under Subparagraph A, Tampa Electric determines that the projected cost of proposed control equipment satisfying a 0.10 lb/mmBTU Emission Rate will not exceed the "installation cost ceiling," Tampa Electric shall install and operate such equipment on all Units that will continue to combust coal and shall achieve a NO_x Emission Rate on each Unit no less stringent than 0.10 lb/mmBTU. If, based on the contract proposals, Tampa Electric determines that the projected cost will exceed the installation cost ceiling, Tampa Electric shall so advise EPA and shall provide EPA with the basis for Tampa Electric's determination, including all documentation sufficient to replicate and evaluate Tampa Electric's cost projections.

A. Unless EPA contests Tampa Electric's determination that the installation cost ceiling will be exceeded by installing control equipment to reduce NO_x emissions to 0.10

lb/mmBTU or less, Tampa Electric shall install, at each Unit that will continue to combust coal, the NO_x control technology designed to achieve the lowest Emission Rate that can be attained within the "installation cost ceiling." Notwithstanding any provision of this Consent Decree, including the "installation cost ceiling," Tampa Electric shall install NO_x control technology that is designed to achieve an Emission Rate no less stringent than 0.15 lb/mmBTU. Each Unit combusting coal and its NO_x controls shall meet the Emission Rate for which they are designed.

A. Tampa Electric shall acquire, install, commence operating emission control equipment, and meet the applicable Emission Rate for NO_x at each of the Units to remain coal-fired, as follows: (1) for the first of the Units to remain coal-fired, or if only one Unit is to be coal-fired, on or before May 1, 2008; (2) for the second Unit, if there is one, on or before May 1, 2009; (3) for the third Unit, if there is one, on or before May 1, 2010.

38. <u>Tampa Electric's NO_x Reduction Requirements if Tampa Electric Re-Powers Units 1, 2, and/or 3</u>. If, by May 1, 2007, Tampa Electric advises EPA that Tampa Electric has elected to Re-Power one or more of Units 1, 2, and 3 at Big Bend, then Tampa Electric shall complete all steps necessary to accomplish such Re-Powering in a time frame to commence operation of the Re-Powered Unit(s) no later than May 1, 2010. Any Unit(s) to be replaced by a Re-Powered Unit may continue to operate until the earlier of six months after the date the Re-Powered

Unit begins commercial operation or December 31, 2010. Tampa Electric shall timely apply for a preconstruction permit under Rule 62-212, F.A.C., prior to commencing construction of any Re-Powered Unit at Big Bend. In applying for such permit Tampa Electric shall seek, as part of the permit, provisions requiring installation of SCR or other EPA approved control technology and a NO_x Emission Rate no greater than 3.5 ppm. Tampa Electric shall operate any Unit Re-Powered under this Paragraph to meet an Emission Rate for NO_x of no greater than 3.5 ppm or the rate established in the preconstruction permit, whichever is more stringent. Notwithstanding the provisions of this Paragraph or the definition of Re-Power in this Consent Decree, Tampa Electric may also elect to fuel Units 1, 2, or 3 with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric applies for and secures a PSD permit before using such fuel in any of these Units, complies with all requirements issued in such a permit, and complies with all requirements of this Consent Decree applicable to Re-Powering.

39. Requirements Applicable to Big Bend Units 1. 2. and/or 3 if Shutdown. If Tampa Electric elects to Shutdown one or more of Units1, 2, and 3, Tampa Electric shall complete Shutdown of the first such Unit on or before May 1, 2008; of the second Unit, if applicable, on or before May 1, 2009, and of the third Unit, if applicable, on or before May 1, 2010. Notwithstanding the requirements of this Paragraph, Tampa Electric may retain any Unit Shutdown pursuant to this Paragraph on

Reserve / Standby. If Tampa Electric later decides to restart such Unit retained on Reserve / Standby by Re-Powering it then, prior to such restart, Tampa Electric shall timely apply for a PSD permit for the Unit(s) to be Re-Powered, and Tampa Electric shall abide by the permit issued as result of that application, including installation of BACT and its corresponding Emission Rate determined at the time of the restart. Tampa Electric shall operate each Unit Re-Powered under this Paragraph to meet an Emission Rate for NO_x of no greater than 3.5 ppm or the Emission Rate established in the PSD permit, whichever is more stringent. Tampa Electric shall provide a copy of any permit application(s), proposed permit(s), and permit(s) to the United States as specified in Paragraph 82 (Notice). Upon Shutdown of a Unit under this Paragraph, Tampa Electric may never again use coal to fire that Unit. For any Unit Shutdown and placed on on Reserve / Standby under this Paragraph, and notwithstanding the definition of Re-Power in this Consent Decree, Tampa Electric also may elect to fuel such a Unit with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric: applies for and secures a PSD permit before using such fuel in any of such Unit, complies with all requirements issued in such a permit, and complies with all requirements of this Consent Decree applicable to Re-Powering.

40. <u>Further SO_2 Reduction Requirements if Big Bend Units 1, 2, or 3 Remains Coal-fired</u>. If Tampa Electric elects under Paragraph 36 to continue combusting coal at Units 1, 2, and/or 3, Tampa Electric shall meet the following requirements.

A. Removal Efficiency or Emission Rate. Commencing on dates set forth in Subparagraph C and continuing thereafter, Tampa Electric shall operate coal-fired Units and the scrubbers that serve those Units so that emissions from the Units shall meet at least one of the following limits:

(1) the scrubber shall remove at least 95% of the SO_2 in the flue gas that entered the scrubber; or

(2) the Emission Rate for SO_2 from each Unit does not exceed 0.25 lb/mmBTU.

A. Availability Criteria. Commencing on the deadlines set in this Paragraph and continuing thereafter, Tampa Electric shall not allow emissions of SO_2 from Big Bend Units 1, 2, or 3 without scrubbing the flue gas from those Units and using other equipment designed to control SO_2 emissions. Notwithstanding the preceding sentence, to the extent that the Clean Air Act New Source Performance Standards identify circumstances during which Bend Unit 4 may operate without its scrubber, this Consent Decree shall allow Big Bend Units1, 2, and/or 3 to operate when those same circumstances are present at Big Bend Units 1, 2, and/or 3.

A. Deadlines. Big Bend Unit 3 and the scrubber(s) serving it shall be subject to the requirements of this Paragraph beginning January 1, 2010 and continuing thereafter. Until January 1, 2010, Tampa Electric shall control $S0_2$ emissions from Unit 3 as required by Paragraphs 30 and 31. Big Bend Units 1 and 2 and the scrubber(s) serving them shall be subject to the requirements of this Paragraph beginning January 1, 2013 and continuing thereafter. Until January 1, 2013, Tampa Electric shall control SO_2 emissions from Units 1 and 2 as required by Paragraphs 29 and 31.

A. Nothing in this Consent Decree shall alter requirements of NSPS, 40 C.F.R. Part 60 Subpart Da, that apply to operation of Unit 4 and the scrubber serving it.

C. BIG BEND AND GANNON -- PERMITS AND RESOLUTION OF CLAIMS

41. Timely Application for Permits. Except as otherwise stated in this Consent Decree, in any instance where otherwise applicable law or this Consent Decree requires Tampa Electric to secure a permit to authorize constructing or operating any device under this Consent Decree, Tampa Electric shall make such application in a timely manner. Such applications shall be completed and submitted to the appropriate authorities to allow sufficient time for all legally required processing and review of the permit request. Failure to comply with this provision shall bar any use by Tampa Electric of the Force Majeure provisions of this Consent Decree.

42. Title V Permits.

A.

B. On or before January 1, 2004, Tampa Electric shall apply for a Title V Permit(s), or for an amendment to an existing Title V Permit(s), to include all performance, operational, maintenance, and control technology requirements established by or determined under this Consent Decree for Gannon, including but not limited to Emission Rates, removal efficiencies, limits on fuel use (including those imposed on Re-Powered or Shutdown Units), and operation and maintenance optimization requirements.

A. On or before January 1, 2009, Tampa Electric shall apply for a Title V Permit(s), or for an amendment to an existing Title V Permit(s), to include all performance, operational, maintenance, and control technology requirements established by or determined under this Consent Decree for Big Bend, including but not limited to Emission Rates, removal efficiencies, limits on fuel use (including those imposed on Re-Powered or Shutdown Units), and operation and maintenance optimization requirements.

A. Except as this Consent Decree expressly requires otherwise, this Consent Decree shall not be construed to require Tampa Electric to apply for or obtain a permit pursuant to the Prevention of Significant Deterioration requirements of the Clean Air Act for any work performed by Tampa Electric within the scope of the Resolution of Claims provisions of Paragraphs 43 and 44, below.

43. Resolution of Past Claims - This Consent Decree resolves all of Plaintiff's civil claims for liability arising from violations of either: (1) the Prevention of Significant Deterioration or Non-Attainment provisions of Parts C and D of the Clean Air Act, 42 U.S.C. § 7401, et seq at Units at Big Bend or Gannon, or (2) 40 C.F.R. Section 60.14 at Units at Big Bend or Gannon, that :

A.

B. are alleged in the Complaint filed November 3, 1999, or in the NOV issued on that date;

A. could have been alleged by the United States in the Complaint filed November 3, 1999, or in the NOV issued on that date; or

A. have arisen from Tampa Electric's actions that occurred between November 3, 1999 and the date on which this Consent Decree is entered by the Court.

44. Resolution of Future Claims - Covenant not to Sue. The United States covenants not to sue Tampa Electric for civil claims arising from the Prevention of Significant Deterioration or Non-Attainment provisions of Parts C and D of the Clean Air Act, 42 U.S.C. § 7401 et seq., at Big Bend or Gannon Units and that are based on failure to obtain PSD or nonattainment New Source Review (NSR) permits for:

A. work that this Consent Decree expressly directs Tampa Electric to undertake; or

A. physical changes or changes in the method of operation of Big Bend or Gannon Units not required by this Consent Decree, if and only if:

A.

B. such change is commenced after Tampa Electric is implementing the plan, or the first phase of the plan if applicable, approved by EPA under Paragraph 31 (Optimizing Availability of Scrubbers),

1. such change is commenced, within the meaning of 40 C.F.R. Section 52.21(b)(9),

during the time this Consent Decree applies to the Unit at which this change has been made ;

(3) Tampa Electric is otherwise in compliance with this Consent Decree;

(4) hourly Emission Rates of NO_X, SO_2, or PM at the changed Unit(s) do not exceed their respective hourly Emission Rates prior to the change, as measured by 40 C.F.R. § 60.14(h); and

(5) in any calendar year following the change, emissions of no pollutant within the scope of Total Baseline Emissions exceed the emissions of that pollutant in the Total Baseline Emissions.

45. Separate Limitation on Resolution of Claims. Notwithstanding the provisions of Section XIII ("Termination"), the provisions of Paragraph 44 ("Resolution of Future Claims - Covenant Not to Sue") shall terminate at Gannon and Big Bend, as follows. On December 31, 2006, the provisions of Paragraph 44 shall terminate and be of no further effect as to physical changes or changes in the method of operation at Gannon. On December 31, 2012, the provisions of Paragraph 44 shall terminate and be of no further effect as to physical changes or changes in the method of operation at Big Bend. If Tampa Electric Re-Powers any Unit at Big Bend under the terms provided by this Consent Decree, then for each such Unit the provisions of Paragraph 44 shall terminate two years after each such Unit is Re-Powered or on December 31, 2012, whichever is earlier.

46. Exclusion of Certain Emission Allowances. For any and all actions taken by Tampa Electric pursuant to the terms of this Consent Decree, including but not limited to upgrading of ESPs and scrubbers, installation of NO_x controls, Re-Powering, and Shutdown, Tampa Electric shall not use or sell any resulting NO_x or SO_2 emission allowances or credits in any emission trading or marketing program of any kind; provided, however, that:

A. SO_2 credits allocated to Tampa Electric by the Administrator of EPA under the Act, due to the Re-Powering or Shutdown of Gannon, may be retained by Tampa Electric during the year in which they are allocated, but only for Tampa Electric's own use in meeting any acid rain requirement imposed under the Act. For any such allowances not used by Tampa Electric for this purpose by June 30 of the following calendar year, Tampa Electric shall not use, sell, trade, or otherwise transfer these allowances for its benefit or the benefit of a third party unless such a transfer would result in the retiring of such allowances without their ever being used.

A. If Tampa Electric decides to Re-Power any Unit at Big Bend, then Tampa Electric shall be entitled to retain for any purpose under law the difference between the emission allowances that would have resulted from installing BACT- level NO_x and SO_2 controls at the existing coal-fired Unit and the emission allowances that result from Re-Powering that Unit. Before Tampa Electric uses any allowances within the scope of this Subparagraph, Tampa Electric shall submit the calculation of the net emission allowances for approval by the United States.

A. Nothing in this Consent Decree shall preclude Tampa Electric from using or selling emission allowances arising from Tampa Electric's activities occurring prior to December 31, 1999, or Tampa Electric's activities after that date that are not related to actions required of Tampa Electric under this Consent Decree. The United States and Tampa Electric agree that the operation of the SO_2 scrubber serving Big Bend Units 1 and 2 meets the requirements of this Subparagraph, and that emission allowances resulting from the operation of this scrubber shall not be treated as an activity related to or required under this Consent Decree.

V. REPORTING AND RECORD KEEPING

47. Beginning at the end of the first calendar quarter after entry of this Consent Decree, and in addition to any other express reporting requirement in this Consent Decree, Tampa Electric shall submit to EPA a quarterly report, consistent with the form attached to this Consent Decree as the Appendix, within thirty (30) days after the end of each calendar quarter until this Consent Decree is terminated.

48. Tampa Electric's report shall be signed by Tampa Electric's Vice President, Environmental and Fuels, or, in his or her absence, Vice President, Energy Supply, or higher ranking official, and shall contain the following certification:

> I certify under penalty of law that this information was prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my directions and my inquiry of the person(s) who manage the system, or the person(s) directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I understand that there are significant penalties for making misrepresentations to

or misleading the United States.

VI. CIVIL PENALTY

49. Within thirty (30) calendar days of entry of this Consent Decree, Tampa Electric shall pay to the United States a civil penalty in the amount of $3.5 million. The civil penalty shall be paid by Electronic Funds Transfer ("EFT") to the United States Department of Justice, in accordance with current EFT procedures, referencing the USAO File Number and DOJ Case Number 90-5-2-1-06932 and the civil action case name and case number of this action. The costs of such EFT shall be Tampa Electric's responsibility. Payment shall be made in accordance with instructions provided by the Financial Litigation Unit of the U.S. Attorney's Office for the Middle District of Florida. Any funds received after 11:00 a.m. (EST) shall be credited on the next business day. Tampa Electric shall provide notice of payment, referencing the USAO File Number, DOJ Case Number 90-5-2-1- 06932, and the civil action case name and case number, to the Department of Justice and to EPA, as provided in Paragraph 82 (Notice). Failure to timely pay the civil penalty shall subject Tampa Electric to interest accruing from the date payment is due until the date payment is made at the rate prescribed by 28 U.S.C. § 1961, and shall render Tampa Electric liable for all charges, costs, fees, and penalties established by law for the benefit of a creditor or of the United States in securing payment.

VII. NO_x REDUCTION PROJECTS AND MITIGATION PROJECTS

50. Tampa Electric shall submit plans for and shall implement the NO_x Reduction and Other Mitigation Projects (referred to together as "Projects") described in this Section, and in Paragraph 35 of this Consent Decree, in compliance with the schedules and terms of this Consent Decree. In performing these Projects, Tampa Electric shall spend no less than $10 million in Project Dollars, in total, unless the Additional NO_x Reduction Project(s) selected under Paragraph 52.C is estimated to cost more than $5 million, in which case Tampa Electric shall spend no less than $10 million but no more than $11 million in Project Dollars, in total. Tampa Electric shall expend the full amount of the Project Dollars required by this Paragraph on or before May 1, 2010. Tampa Electric shall maintain for review by EPA, upon its request, all documents identifying Project Dollars spent by Tampa Electric.

51. All plans and reports prepared by Tampa Electric pursuant to the requirements of Paragraph 35 and this Section of the Consent Decree shall be publicly available without charge.

52. Tampa Electric shall submit the required plans for and complete the following Projects:

(1)

(2) Early NO_x reductions through combustion optimization as described in Paragraph 35 of this Consent Decree.

(A) Performance of Air Chemistry Work in Tampa Bay Estuary. Tampa Electric shall expend no more than $2 million Project Dollars in conducting or financing stack tests, emissions estimation, ambient air monitoring, data acquisition and analysis, and any combination thereof that: (1) is not otherwise required by law, (2) will provide data or analysis that is not already available, (3) will complement work carried out by other persons examining the air chemistry of Tampa Bay Estuary, and (4) will help close gaps in current understanding of air chemistry in the Tampa Bay Estuary. Tampa Electric shall either conduct this work itself, fund other persons already conducting such work on a non-profit basis, or both. For work Tampa Electric intends to conduct itself, the company shall describe the proposed work and a schedule for completion to EPA, in writing, at least 90 days prior to the date on which Tampa Electric intends to start such work, including an explanation of why the proposed work meets all the requirements of this Subparagraph. Unless EPA objects to the proposed work on the grounds it does not comply with the requirements of this Subparagraph, Tampa Electric shall undertake and complete the work according to the proposed schedule. If Tampa Electric elects to spend some or all of the $2 million Project Dollars to finance work to be performed by other persons or organizations, the company shall provide to EPA for review and approval a plan that describes the work to be performed, the persons or organizations conducting the work, the schedule for its completion, the schedule for Tampa Electric's payments, and an explanation of why the proposed payment(s) meets all the requirements of this Subparagraph. The plan shall be provided to EPA at least 90 days prior to the date on which Tampa Electric will begin transferring the money to finance such work. All payments to persons or organizations under such a plan shall be completed by Tampa Electric no later than June 30, 2002. Before Tampa Electric makes such payments for the benefit of any person or organization carrying out work under this Paragraph, Tampa Electric shall secure a written, signed commitment from such person to provide Tampa Electric and EPA with the results of the work.

C. Additional NO_x Reductions Project(s).

(1) General Requirement. Tampa Electric shall expend the remainder of the Project Dollars required under this Consent Decree to: (i) demonstrate innovative NO_x control technologies on any of its Units or boilers at Gannon or Big Bend not Shutdown or on Reserve / Standby; and/or (ii) reduce the NO_x Emission Rate for any Big Bend coal-combusting Unit below the lowest rate otherwise applicable to it under this Consent Decree.

(1) For any Project(s) at Gannon. If Tampa Electric elects to undertake a project on an eligible Gannon Unit(s) to demonstrate any innovative NO_x control technology, within six months after entry of this Consent Decree Tampa Electric shall submit a plan to EPA, for review and approval, which sets forth: (a) the NO_x demonstration or innovative control technology projects being proposed; (b) the anticipated cost of the projects; (c) the reduction in NO_x or other environmental benefits anticipated to result from the project, and (d) a schedule for implementation of the project providing for

commencement and completion in accordance with the requirements of this Subparagraph. . EPA shall complete its review of this plan within 60 days after receipt. If such project is approved, Tampa Electric shall complete installation of the technology no later than December 31, 2004 as part of the Re-Powering of such Units; provided, however, that nothing in this Paragraph alters Tampa Electric's obligation under Paragraph 26 of this Consent Decree.

(1) For any Project(s) at Big Bend. At least three (3) years prior to the date on which the expenditure of any Project Dollars is to commence on Big Bend under this Subparagraph C, Tampa Electric shall submit a plan to EPA for review and approval which sets forth: (a) the NO_x demonstration or innovative control technology projects being proposed; (b) the anticipated cost of the projects; (c) the reduction in NO_x or other environmental benefits anticipated to result from the project, and (d) a schedule for implementation of the project providing for commencement and completion in accordance with the requirements of this Subparagraph. If EPA approves the projects contained in the plan, Tampa Electric shall implement the project(s). Projects that would demonstrate innovative NO_x control technology or reduce the NO_x Emission Rate for any Big Bend coal-fired or Re-Powered Unit shall be operating and achieving reductions or demonstrating the performance of the innovative technology, as applicable, not later than May 1, 2010.

(1) Follow-up Report(s). Within sixty (60) days following the implementation of each EPA-approved project, Tampa Electric shall submit to EPA a report that documents the date that all aspects of the project were implemented, Tampa Electric's results in implementing the project, including the emission reductions or other environmental benefits achieved, and the Project Dollars expended by Tampa Electric in implementing the project.

VIII. STIPULATED PENALTIES

53. For purposes of this Consent Decree, within thirty days after written demand from the United States, and subject to the provisions of Sections X (Force Majeure) and XI (Dispute Resolution), Tampa Electric shall pay the following stipulated penalties to the United States for each failure by Tampa Electric to comply with the terms of this Consent Decree.

    A. For failure to pay timely the civil penalty as specified in Section VI of this Consent Decree, $10,000 per day.

A. For all violations of a 24 hour Emission Rate – (1) Less than 5% in excess of limit: $4,000 per day, per violation; (2) more than 5% but less than 10% in excess of limit: $9,000 per day per violation; (3) equal to or greater than 10% in excess of limit: $27,500 per day, per violation

A. For all violations of 30-day rolling average Emission Rates – (1) Less than 5% in excess of limit: $150 per day per violation; (2) more than 5% but less than 10% in excess of limit: $300 per day per violation; (3) equal to or greater than 10% in excess of limit: $800 per day per violation. Violation of an Emission Rate that is based on a 30 day rolling average is a violation on every day of the 30 day period on which the average is based . Where a violation of a 30 day rolling monthly average Emission Rate (for the same pollutant and from the same source) recurs within periods less than 30 days, Tampa Electric shall not pay a daily stipulated penalty for any day of the recurrence for which a stipulated penalty has already been paid.

A. For all violations of a 95% removal efficiency requirement – (1) For removal efficiency less than 95% but greater than or equal to 94%, $4,000 per day, per violation; (2) for removal efficiency less than 94% but greater than or equal to 91%, $9,000 per day, per violation; (3) for removal efficiency less than 91%, $27,500 per day, per violation. For all violations of a 93% removal efficiency requirement – (1) For removal efficiency less than 93% but greater than or equal to 92%, $4,000 per day, per violation; (2) for removal efficiency less than 92% but greater than or equal to 90%, $9,000 per day, per violation; (3) for removal efficiency less than 90%, $27,500 per day, per violation;

A. Violation of deadlines for Shutdown of boilers or Units or megawatt capacity — $27,500 per day, per violation.

A. Failure to apply for the permits required by Paragraphs 26, 27, 34, 38, and

42 — $1,000 per day, per violation.

A. Failure to implement the recommendations of the PM BACT Analysis or the PM optimization study by May 1, 2004 — $5,000 per day, per violation for first 30 days; $15,000 per day, per violation, for next 30 days; $27,500 per day, per violation, thereafter.

A. Failure to commence combustion optimization at Big Bend Units 1, 2, or 3 on or before May 30, 2003 as required by Paragraph 35, $10,000 per day, per violation.

A. Failure to operate the scrubbers at Big Bend Units 1, 2, or 3 on any day except as permitted by Paragraphs 29, 30, or 31, $27,500 per day, per violation.

A. Failure to submit quarterly progress and monitoring report — $100 per day, per violation, for first ten days late, and $500 per day for each day thereafter.

A. Failure to complete timely any action or payment required by or established under Subparagraph 52(B) (Performance of Air Chemistry Work in Tampa Bay Estuary), $5,000 per day, per violation

A. Failure to perform NO_x reduction or demonstration project(s), by the deadline(s) established in Subparagraph 52.C (Additional NO_x Reductions Project(s)), $10,000 per day, per violation;

A. For failure to spend at least the number of Project Dollars required by this Consent Decree by date specified in Paragraph 50, $5,000 per day, per violation;

A. Violation of any Consent Decree prohibition on use of allowances as provided in Paragraph 46 — three times the market value of the improperly used allowance as measured at the time of the improper use.

54. Should Tampa Electric dispute its obligation to pay part or all of a stipulated penalty demanded by the United States, it may avoid the imposition of a separate stipulated penalty for the failure to pay the disputed penalty by depositing the disputed amount in a commercial escrow account pending resolution of the matter and by invoking the Dispute Resolution provisions of this Consent Decree within the time provided in this Section VIII of the Consent Decree for payment of the disputed penalty. If the dispute is thereafter resolved in Tampa Electric's favor, the escrowed amount plus accrued interest shall be returned to Tampa Electric. If the dispute is resolved in favor of the United States, it shall be entitled to the escrowed amount determined to be due by the Court, plus accrued interest. The balance in the escrow account, if any, shall be returned to Tampa Electric.

55. The United States reserves the right to pursue any other remedies to which it is entitled, including, but not limited to, a new civil enforcement action and additional injunctive relief for Tampa Electric's violations of this Consent Decree. If the United States elects to seek civil or contempt penalties after having collected stipulated penalties for the same violation, any further penalty awarded shall be reduced by the amount of the stipulated penalty timely paid or escrowed by Tampa Electric. Tampa Electric shall not be required

to remit any stipulated penalty to the United States that is disputed in compliance with

Part XI of this Consent Decree until the dispute is resolved in favor of the United

States. However, nothing in this Paragraph shall be construed to cease the accrual of the stipulated penalties until the dispute is resolved.

IX. RIGHT OF ENTRY

56. Any authorized representative of EPA or an appropriate state agency, including independent contractors, upon presentation of credentials, shall have a right of entry upon the premises of Tampa Electric's plants identified herein at any reasonable time for the purpose of monitoring compliance with the provisions of this Consent Decree, including inspecting plant equipment and inspecting and copying all records maintained by Tampa Electric required by this Consent Decree. Tampa Electric shall retain such records for a period of twelve (12) years from the date of entry of this Consent Decree. Nothing in this Consent Decree shall limit the authority of EPA to conduct tests and inspections at Tampa Electric's facilities under Section 114 of the Act, 42 U.S.C. § 7414.

X. FORCE MAJEURE

57. If any event occurs which causes or may cause a delay in complying with any provision of this Consent Decree, Tampa Electric shall notify the United States in writing as soon as practicable, but in no event later than seven (7) business days following the date Tampa Electric first knew, or within ten (10) business days following the date Tampa Electric should have known by the exercise of due

diligence, that the event caused or may cause such delay. In this notice Tampa Electric shall reference this Paragraph of this Consent Decree and describe the anticipated length of time the delay may persist, the cause or causes of the delay, the measures taken or to be taken by Tampa Electric to prevent or minimize the delay, and the schedule by which those measures will be implemented. Tampa Electric shall adopt all reasonable measures to avoid or minimize such delays.

58. Failure by Tampa Electric to comply with the notice requirements of Paragraph 57 shall render this Section X voidable by the United States as to the specific event for which Tampa Electric has failed to comply with such notice requirement. If voided, the provisions of this Section shall have no effect as to the particular event involved.

59. The United States shall notify Tampa Electric in writing regarding Tampa Electric's claim of a delay in performance within (15) fifteen business days of receipt of the Force Majeure notice provided under Paragraph 57. If the United States agrees that the delay in performance has been or will be caused by circumstances beyond the control of Tampa Electric, including any entity controlled by Tampa Electric, and that Tampa Electric could not have prevented the delay through the exercise of due diligence, the parties shall stipulate to an extension of the required deadline(s) for all requirement(s) affected by the delay for a period equivalent to the delay actually caused by such circumstances. Such stipulation shall be filed as a modification to this Consent Decree in order to be

effective. Tampa Electric shall not be liable for stipulated penalties for the period of any such delay.

60. If the United States does not accept Tampa Electric's claim of a delay in performance, to avoid the imposition of stipulated penalties Tampa Electric must submit the matter to this Court for resolution by filing a petition for determination. Once Tampa Electric has submitted the matter, the United States shall have fifteen business days to file its response. If Tampa Electric submits the matter to this Court for resolution, and the Court determines that the delay in performance has been or will be caused by circumstances beyond the control of Tampa Electric, including any entity controlled by Tampa Electric, and that Tampa Electric could not have prevented the delay by the exercise of due diligence, Tampa Electric shall be excused as to that event(s) and delay (including stipulated penalties otherwise applicable), but only for the period of time equivalent to the delay caused by such circumstances.

61. Tampa Electric shall bear the burden of proving that any delay in performance of any requirement of this Consent Decree was caused by or will be caused by circumstances beyond its control, including any entity controlled by it, and that Tampa Electric could not have prevented the delay by the exercise of due diligence. Tampa Electric shall also bear the burden of proving the duration and extent of any delay(s) attributable to such circumstances. An extension of one compliance date based on a particular event may, but will not necessarily, result in

an extension of a subsequent compliance date.

62. Unanticipated or increased costs or expenses associated with the performance of Tampa Electric's obligations under this Consent Decree shall not constitute circumstances beyond the control of Tampa Electric or serve as a basis for an extension of time under this Section. However, failure of a permitting authority to issue a necessary permit in a timely fashion may constitute a Force Majeure event where the failure of the permitting authority to act is beyond the control of Tampa Electric and Tampa Electric has taken all steps available to it to obtain the necessary permit, including, but not limited to, submitting a complete permit application, responding to requests for additional information by the permitting authority in a timely fashion, accepting lawful permit terms and conditions, and prosecuting appeals of any allegedly unlawful terms and conditions imposed by the permitting authority in an expeditious fashion.

63. The parties agree that, depending upon the circumstances related to an event and Tampa Electric's response to such circumstances, the kinds of events listed below could also qualify as Force Majeure events within the meaning of this Section X of the Consent Decree: Construction, labor, or equipment delays; natural gas and gas transportation availability delays;acts of God; and the failure of an innovative technology approved under Paragraph 26.B and 52.C.

64. Notwithstanding any other provision of this Consent Decree, this Court shall not draw any inferences nor establish any presumptions adverse to either party as a

result of Tampa Electric delivering a notice pursuant to this Section or the parties' inability to reach agreement on a dispute under this Part.

65. As part of the resolution of any matter submitted to this Court under this Section, the parties by agreement, or this Court by order, may in appropriate circumstances extend or modify the schedule for completion of work under this Consent Decree to account for the delay in the work that occurred as a result of any delay agreed to by the United States or approved by this Court. Tampa Electric shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule.

XI. DISPUTE RESOLUTION

66. The dispute resolution procedure provided by this Section XI shall be available to resolve all disputes arising under this Consent Decree, except as provided in Section X regarding Force Majeure, or in this Section XI, provided that the party making such application has made a good faith attempt to resolve the matter with the other party.

67. The dispute resolution procedure required herein shall be invoked by one party to this Consent Decree giving written notice to another advising of a dispute pursuant to this Section XI. The notice shall describe the nature of the dispute and shall state the noticing party's position with regard to such dispute. The party receiving such a notice shall acknowledge receipt of the notice, and the parties

shall expeditiously schedule a meeting to discuss the dispute informally not later than fourteen (14) days following receipt of such notice.

68. Disputes submitted to dispute resolution under this Section shall, in the first instance, be the subject of informal negotiations between the parties. Such period of informal negotiations shall not extend beyond thirty (30) calendar days from the date of the first meeting between representatives of the United States and Tampa Electric unless the parties' representatives agree to shorten or extend this period.

69. If the parties are unable to reach agreement during the informal negotiation period, the United States shall provide Tampa Electric with a written summary of its position regarding the dispute. The written position provided by the United States shall be considered binding unless, within thirty (30) calendar days thereafter, Tampa Electric files with this Court a petition which describes the nature of the dispute and seeks resolution. The United States may respond to the petition within forty-five (45) calendar days of filing.

70. Where the nature of the dispute is such that a more timely resolution of the issue is required, the time periods set out in this Section may be shortened upon motion of one of the parties to the dispute.

71. This Court shall not draw any inferences nor establish any presumptions adverse to either party as a result of invocation of this Section or the parties' inability to reach agreement.

72. As part of the resolution of any dispute under this Section, in appropriate circumstances the parties may agree, or this Court may order, an extension or modification of the schedule for completion of work under this Consent Decree to account for the delay that occurred as a result of dispute resolution. Tampa Electric shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule.

73. The Court shall decide all disputes pursuant to applicable principles of law for resolving such disputes; provided, however, that the United States and Tampa Electric reserve their rights to argue for what the applicable standard of law should be for resolving any particular dispute. Notwithstanding the preceding sentence of this Paragraph, as to disputes arising under Paragraph 32, the Court shall sustain the position of the United States as to the BACT Analysis recommendations and the optimization study measures that should be installed and implemented, unless Tampa Electric demonstrates that the position of the United States is arbitrary or capricious.

XII. GENERAL PROVISIONS

74. Effect of Settlement. This Consent Decree is not a permit; compliance with its terms does not guarantee compliance with all applicable Federal, State or Local laws or regulations.

75. Satisfaction of all of the requirements of this Consent Decree constitutes full

settlement of and shall resolve and release Tampa Electric from all civil liability of Tampa Electric to the United States for the claims referred to in Paragraphs 43 and 44 of this Consent Decree. This Consent Decree does not apply to any claim(s) of alleged criminal liability, which are reserved.

76. In any subsequent administrative or judicial action initiated by the United States for injunctive relief or civil penalties relating to the facilities covered by this Consent Decree, Tampa Electric shall not assert any defense or claim based upon principles of waiver, res judicata, collateral estoppel, issue preclusion, claim splitting, or other defense based upon any contention that the claims raised by the United States in the subsequent proceeding were brought, or should have been brought, in the instant case; provided, however, that nothing in this Paragraph is intended to affect the enforceability of the Resolution of Claims provisions of Paragraphs 43 and 44 of this Consent Decree..

77. Other Laws. Except as specifically provided by this Consent Decree, nothing in this Consent Decree shall relieve Tampa Electric of its obligation to comply with all applicable Federal, State and Local laws and regulations. Subject to Paragraph 43 and 44, nothing contained in this Consent Decree shall be construed to prevent or limit the United States' rights to obtain penalties or injunctive relief under the Clean Air Act or other federal, state or local statutes or regulations.

78. Third Parties. This Consent Decree does not limit, enlarge or affect the rights of any party to this Consent Decree as against any third parties.

79. Costs. Each party to this action shall bear its own costs and attorneys' fees.

80. Public Documents. All information and documents submitted by Tampa Electric to the United States pursuant to this Consent Decree shall be subject to public inspection, unless subject to legal privileges or protection or identified and supported as business confidential by Tampa Electric in accordance with 40 C.F.R. Part 2.

81. Public Comments. The parties agree and acknowledge that final approval by the United States and entry of this Consent Decree is subject to the requirements of 28 C.F.R. § 50.7, which provides for notice of the lodging of this Consent Decree in the Federal Register, an opportunity for public comment, and the right of the United States to withdraw or withhold consent if the comments disclose facts or considerations which indicate that the Consent Decree is inappropriate, improper, or inadequate.

82. Notice. Unless otherwise provided herein, notifications to or communications with the United States or Tampa Electric shall be deemed submitted on the date they are postmarked and sent either by overnight mail, return receipt requested, or by certified or registered mail, return receipt requested. Except as otherwise provided herein, when written notification to or communication with the United States, EPA, or Tampa Electric is required by the terms of this Consent Decree, it shall be addressed as follows:

As to the United States of America:

For U.S. DOJ –

Chief
Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611, Ben Franklin Station
Washington, D.C. 20044-7611
DJ# 90-5-2-1-06932

Whitney L. Schmidt
Coordinator, Affirmative Civil Enforcement Program
Office of the United States Attorney
Middle District of Florida
400 N. Tampa Street
Tampa, FL 33602

For U.S. EPA –

Director, Air Enforcement Division
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Ariel Rios Building [2242A]
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

and

Regional Administrator
U.S. EPA Region IV
61 Forsyth Street, S.E.
Atlanta, GA 30303

As to Tampa Electric:

Sheila M. McDevitt
General Counsel
Tampa Electric Company
P.O. Box 111
Tampa, FL 333601-0111

83. Any party may change either the notice recipient or the address for providing notices to it by serving all other parties with a notice setting forth such new notice recipient or address.

84. Modification. Except as otherwise allowed by law, there shall be no modification of this Consent Decree without written approval by the United States and Tampa Electric, and approval of such modification by the Court.

85. Continuing Jurisdiction. The Court shall retain jurisdiction of this case after entry of this Consent Decree to enforce compliance with the terms and conditions of this Consent Decree and to take any action necessary or appropriate for its interpretation, construction, execution, or modification. During the term of this Consent Decree, any party may apply to the Court for any relief necessary to construe or effectuate this Consent Decree.

86. Complete Agreement. This Consent Decree constitutes the final, complete and exclusive agreement and understanding among the parties with respect to the settlement embodied in this Consent Decree. The parties acknowledge that there are no representations, agreements or understandings relating to the settlement other than those expressly contained in this Consent Decree. An Appendix is attached to and incorporated into this Consent Decree by this reference.

XIII. TERMINATION

87. Except as provided in Paragraphs 43, 44, and 45 (involving resolution of claims),

this Consent Decree shall be subject to termination upon motion by either party after Tampa Electric satisfies all requirements of this Consent Decree, including payment of all stipulated penalties that may be due, installation of control technology systems as specified herein, the receipt of all permits specified herein, securing valid Title V Permits for Gannon and Big Bend that incorporate all emission and fuel limits from this Consent Decree as well as all operational limits established under this Consent Decree, and the submission of all final reports indicating satisfaction of the requirements for implementation of all acts called for under Part VII of this Consent Decree.

88. If Tampa Electric believes it has achieved compliance with the requirements of this Consent Decree, then Tampa Electric shall so certify to the United States. Unless the United States objects in writing with specific reasons within 60 days of receipt of Tampa Electric's certification, the Court shall order that this Consent Decree be terminated on Tampa Electric's motion. If the United States objects to Tampa Electric's certification, then the matter shall be submitted to the Court for resolution under Section XI of this Consent Decree. In such case, Tampa Electric shall bear the burden of proving that this Consent Decree should be terminated.

SO ORDERED, THIS _____ DAY OF ________________ 2000.

____

UNITED STATES DISTRICT JUDGE

Signature Page for Consent Decree in United States v. Tampa Electric Company, Civ. No. 99-2524 CIV-T-23F

Steve A. Herman
Assistant Administrator for Enforcement
U.S. Environmental Protection Agency
Washington, D.C.

Bruce Buckheit

Bruce Buckheit
Director

Gregory Jaffe
Senior Enforcement Counsel

Air Enforcement Division
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Washington, D.C.

Signature Page for Consent Decree in United States v. Tampa Electric Company, Civ. No. 99-2524 CIV-T-23F

John H. Hankinson
Regional Administrator
U.S. Environmental Protection Agency (Region IV)
Atlanta, Georgia

Signature Page for Consent Decree in United States v. Tampa Electric Company, Civ. No. 99-2524 CIV-T-23F

THROUGH ITS UNDERSIGNED REPRESENTATIVES, THE UNITED STATES AGREES AND CONSENTS TO ENTRY OF THE FOREGOING CONSENT DECREE:

FOR PLAINTIFF
UNITED STATES OF AMERICA:

Date: 2/28/00

Lois J. Schiffer
Assistant Attorney General
Environment and Natural Resources Division
United States Department of Justice

W. Benjamin Fisherow
Assistant Chief
Thomas A. Mariani, Jr.
Jon A. Mueller
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Environmental Enforcement Section
United States Department of Justice
P.O. Box 7611
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(202) 514-4620

Donna A. Bucella
United States Attorney for the
Middle District of Florida

By:
Whitney L. Schmidt
Affirmative Civil Enforcement Coordinator
Assistant United States Attorney
United States Attorney's Office
Middle District of Florida
Florida Bar No. 0337129
Tampa, Florida 33602
(813) 274-6000
(813) 274-6198 (facsimile)

Signature Page for Consent Decree in United States v. Tampa Electric Company, Civ. No. 99-2524 CIV-T-23F

THROUGH ITS UNDERSIGNED REPRESENTATIVES, TAMPA ELECTRIC COMPANY AGREES AND CONSENTS TO ENTRY OF THE FOREGOING CONSENT DECREE

FOR TAMPA ELECTRIC COMPANY

John B. Ramil
President
Tampa Electric Company

Date: 2/29/00

Sheila M. McDevitt
General Counsel
Tampa Electric Company

Appendix I-1, List of Insignificant Emissions Units and/or Activities.

Tampa Electric Company
F. J. Gannon Station

Permit No. **0570040-017-AV**
Facility ID No. **0570040**

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210.300(3)(a), F.A.C., Categorical Exemptions, or that meet the criteria specified in Rule 62-210.300(3)(b)1., F.A.C., Generic Emissions Unit Exemption, are exempt from the permitting requirements of Chapters 62-210, 62-212 and 62-4, F.A.C.; provided, however, that exempt emissions units shall be subject to any applicable emission limiting standards and the emissions from exempt emissions units or activities shall be considered in determining the potential emissions of the facility containing such emissions units. Emissions units and pollutant-emitting activities exempt from permitting under Rules 62-210.300(3)(a) and (b)1., F.A.C., shall not be exempt from the permitting requirements of Chapter 62-213, F.A.C., if they are contained within a Title V source; however, such emissions units and activities shall be considered insignificant for Title V purposes provided they also meet the criteria of Rule 62-213.430(6)(b), F.A.C. No emissions unit shall be entitled to an exemption from permitting under Rules 62-210.300(3)(a) and (b)1., F.A.C., if its emissions, in combination with the emissions of other units and activities at the facility, would cause the facility to emit or have the potential to emit any pollutant in such amount as to make the facility a Title V source.
The below listed emissions units and/or activities are considered insignificant pursuant to Rule 62-213.430(6), F.A.C.

1. Internal combustion engines in boats, aircraft and vehicles used for transportation of passengers or freight.
2. Cold storage refrigeration equipment, except for any such equipment located at a Title V source using an ozone-depleting substance regulated under 40 CFR Part 82.
3. Vacuum pumps in laboratory operations.
4. Equipment used for steam cleaning.
5. Belt or drum sanders having a total sanding surface of five square feet or less and other equipment used exclusively on wood or plastics or their products having a density of 20 pounds per cubic foot or more.
6. Equipment used exclusively for space heating, other than boilers.
7. Laboratory equipment used exclusively for chemical or physical analyses.
8. Brazing, soldering or welding equipment.
9. One or more emergency generators located within a single facility provided:
    a. None of the emergency generators is subject to the Federal Acid Rain Program; and
    b. Total fuel consumption by all such emergency generators within the facility is limited to 32,000 gallons per year of diesel fuel, 4,000 gallons per year of gasoline, 4.4 million standard cubic feet per year of natural gas or propane, or an equivalent prorated amount if multiple fuels are used.
10. One or more heating units and general purpose internal combustion engines located within a single facility provided:
    a. None of the heating units or general purpose internal combustion engines is subject to the Federal Acid Rain Program; and
    b. Total fuel consumption by all such heating units and general-purpose internal combustion engines within the facility is limited to 32,000 gallons per year of diesel fuel, 4,000 gallons per year of gasoline, 4.4 million standard cubic feet per year of natural gas or propane, or an equivalent prorated amount if multiple fuels are used.

11. Fire and safety equipment.
12. Storage Tanks
13. Degreasing units using heavier-than-air vapors exclusively, except any such unit using or emitting any substance classified as a hazardous air pollutant.
14. Turbine vapor extractors
15. Architectural coatings.
16. Surface coating operations utilizing only coatings containing 5.0 percent or less VOCs, by volume.
17. Evaporation of non-hazardous boiler chemical cleaning waste which was generated on site.
18. No. 2 fuel Oil Storage Tanks
19. Vehicle Refueling Operations
20. Molten Sulfur Storage Tanks
21. Evaporation of Nonhazardous Boiler Chemical Cleaning Waste.
22. The operation of slag tank purge vents to vent emissions to the atmosphere only for the purposes of worker safety during maintenance or to prevent equipment damage due to loss of flow through the normal duct system to the electrostatic precipitator.

{Note: Emissions units or activities which are added to a Title V source after issuance of this permit shall be incorporated into the permit at its next renewal, provided such emissions units or activities have been exempted from the requirement to obtain an air construction permit, and also qualify for exemption from permitting pursuant to Rule 62-213, F.A.C. [Rule 62-213.430(6)(a)]}

Appendix I-1, List of Insignificant Emissions Units and/or Activities.

Tampa Electric Company
F. J. Gannon Station

Permit No. **0570040-017-AV**
Facility ID No. **0570040**

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210.300(3)(a), F.A.C., Categorical Exemptions, or that meet the criteria specified in Rule 62-210.300(3)(b)1., F.A.C., Generic Emissions Unit Exemption, are exempt from the permitting requirements of Chapters 62-210, 62-212 and 62-4, F.A.C.; provided, however, that exempt emissions units shall be subject to any applicable emission limiting standards and the emissions from exempt emissions units or activities shall be considered in determining the potential emissions of the facility containing such emissions units. Emissions units and pollutant-emitting activities exempt from permitting under Rules 62-210.300(3)(a) and (b)1., F.A.C., shall not be exempt from the permitting requirements of Chapter 62-213, F.A.C., if they are contained within a Title V source; however, such emissions units and activities shall be considered insignificant for Title V purposes provided they also meet the criteria of Rule 62-213.430(6)(b), F.A.C. No emissions unit shall be entitled to an exemption from permitting under Rules 62-210.300(3)(a) and (b)1., F.A.C., if its emissions, in combination with the emissions of other units and activities at the facility, would cause the facility to emit or have the potential to emit any pollutant in such amount as to make the facility a Title V source.
The below listed emissions units and/or activities are considered insignificant pursuant to Rule 62-213.430(6), F.A.C.

1. Internal combustion engines in boats, aircraft and vehicles used for transportation of passengers or freight.
2. Cold storage refrigeration equipment, except for any such equipment located at a Title V source using an ozone-depleting substance regulated under 40 CFR Part 82.
3. Vacuum pumps in laboratory operations.
4. Equipment used for steam cleaning.
5. Belt or drum sanders having a total sanding surface of five square feet or less and other equipment used exclusively on wood or plastics or their products having a density of 20 pounds per cubic foot or more.
6. Equipment used exclusively for space heating, other than boilers.
7. Laboratory equipment used exclusively for chemical or physical analyses.
8. Brazing, soldering or welding equipment.
9. One or more emergency generators located within a single facility provided:
    a. None of the emergency generators is subject to the Federal Acid Rain Program; and
    b. Total fuel consumption by all such emergency generators within the facility is limited to 32,000 gallons per year of diesel fuel, 4,000 gallons per year of gasoline, 4.4 million standard cubic feet per year of natural gas or propane, or an equivalent prorated amount if multiple fuels are used.
10. One or more heating units and general purpose internal combustion engines located within a single facility provided:
    a. None of the heating units or general purpose internal combustion engines is subject to the Federal Acid Rain Program; and
    b. Total fuel consumption by all such heating units and general-purpose internal combustion engines within the facility is limited to 32,000 gallons per year of diesel fuel, 4,000 gallons per year of gasoline, 4.4 million standard cubic feet per year of natural gas or propane, or an equivalent prorated amount if multiple fuels are used.

Appendix I-1, List of Insignificant Emissions Units and/or Activities.

Tampa Electric Company
F. J. Gannon Station

Permit No. **0570040-017-AV**
Facility ID No. **0570040**

11. Fire and safety equipment.
12. Storage Tanks
13. Degreasing units using heavier-than-air vapors exclusively, except any such unit using or emitting any substance classified as a hazardous air pollutant.
14. Turbine vapor extractors
15. Architectural coatings.
16. Surface coating operations utilizing only coatings containing 5.0 percent or less VOCs, by volume.
17. Evaporation of non-hazardous boiler chemical cleaning waste which was generated on site.
18. No. 2 fuel Oil Storage Tanks
19. Vehicle Refueling Operations
20. Molten Sulfur Storage Tanks
21. Evaporation of Nonhazardous Boiler Chemical Cleaning Waste.
22. The operation of slag tank purge vents to vent emissions to the atmosphere only for the purposes of worker safety during maintenance or to prevent equipment damage due to loss of flow through the normal duct system to the electrostatic precipitator.

{Note: Emissions units or activities which are added to a Title V source after issuance of this permit shall be incorporated into the permit at its next renewal, provided such emissions units or activities have been exempted from the requirement to obtain an air construction permit, and also qualify for exemption from permitting pursuant to Rule 62-213, F.A.C. [Rule 62-213.430(6)(a)]}

Appendix F, Ambient Air Quality Compliance Plan for SO_2 Emissions

Tampa Electric Company
F. J. Gannon Station

Permit No. **0570040-017-AV**

E.U. ID No.	Brief Description
-001 thru -006	Units Nos. 1-6 Fossil Fuel-Fired Steam Generators

The SIP SO_2 limits that cover the Unit Nos. 1-6 Fossil Fuel-Fired Steam Generators at Gannon Station are as follows:

2.4 lbs/MMBTU (individual unit on a weekly average basis);
10.6 tons/hour (station-wide cap on a weekly average basis).

During the initial Title V permitting of Gannon Station, the FDEP and Tampa Electric Company (TEC) performed ambient air pollution dispersion modeling. This modeling calculated exceedances of the state of Florida 24-hour and 3-hour SO_2 ambient air quality standards of 260 ug/m^3 and 1,300 ug/m^3 respectively, using the existing allowable SO_2 limits.

Based on these conclusions TEC evaluated possible alternatives to the current operations at Gannon Station to eliminate the modeled SO_2 exceedances. These evaluations centered around reducing the sulfur content of the fuel, raising one or more of the existing stacks, or a combination of both. Ultimately, a decision to raise the existing stacks on Units 5 & 6, along with accepting a new limit on SO_2 on a 24-hourly average basis of approximately 11.5 tons/hour, was determined to be the best coarse of action. To this end, an air construction permit application for the stack extension project was submitted in October 1998. The stack extension application was withdrawn.

As a result of the Consent Final Judgement (DEP vs. TECO) dated December 6, 1999 and the Consent Decree (U.S. vs. TECO) dated February 29, 2000, Gannon Station will be repowered using natural gas fired combustion turbines with oil backup and will cease burning coal by January 1, 2005. The repowered facility will be named Bayside.

Based on the short life remaining for the existing Gannon Station coal-fired units, the strategy to extend the stacks to remove the modeled ambient SO_2 exceedances is no longer the best strategy. For this short period of time, it is also unreasonable to make any significant modifications to the units, or the fuel contracts, necessary to reduce the SO_2 levels needed to show no modeled ambient SO_2 exceedances with the existing operations. In light of the foregoing, the interim SO_2 limits specified in permit condition number J.4. shall apply.

Appendix H-1, Permit History/ID Number Changes

Tampa Electric Company
F. J. Gannon Station

Permit No. **0570040-017-AV**
Facility ID No. **0570040**

Permit History (for tracking purposes):

E.U. ID No	Description	Permit No.	Issue Date	Expiration Date	Extended Date[1,2]	Revised Date(s)
-001	Unit No. 1-Fossil Fuel-Fired Steam Generator	AO29-204434 AC29-41943 0570040-012-AC	1/31/92 8/7/81 8/22/01	1/31/97 3/15/87 7/05/02		10/11/94
-002	Unit No. 2-Fossil Fuel-Fired Steam Generator	AO29-189206 AC29-41942 0570040-012-AC	2/7/91 8/7/81 8/22/01	2/6/96 3/15/86 7/05/02	8/14/96	
-003	Unit No. 3-Fossil Fuel-Fired Steam Generator WDF Firing WDF Firing (re-issued)	AO29-172179 AC29-41941 0570040-008-AC 0570040-011-AC	4/26/90 8/7/81 2/16/99 03/07/00	4/19/95 1/15/85 12/31/99 02/28/02	8/14/96	10/11/94
-004	Unit No. 4-Fossil Fuel-Fired Steam Generator	AO29-255208 AC29-41940 0570040-012-AC	12/2/94 8/7/81 8/22/01	10/14/99 7/05/02		
-005	Unit No. 5-Fossil Fuel-Fired Steam Generator	AO29-203511	1/1/92	1/1/97		
-006	Unit No. 6-Fossil Fuel-Fired Steam Generator	AO29-203512	2/15/92	2/15/97		
-007	Combustion Turbine	AO29-252615	8/31/94	8/31/99		
-008	Fuel Yard Fuel Yard Expansion Crusher House Crusher House (re-issued)	AO29-216480 AC29-61276 0570040-006-AC 0570040-007-AC 0570040-010-AC	4/23/93 4/12/83 2/5/99 2/5/99 3/21/00	9/12/97 12/31/84 10/15/00 12/31/99 12/31/00		
-009	Unit 4 Economizer Ash Silo with Baghouse	AO29-218858	8/29/89	11/6/97		
-010	Units 5-6 Fly Ash Silo (No.1) with Baghouse	AO29-250137	7/20/94	7/12/99		2/6/95
-011	Units 1-4 Fly Ash Silo (No. 2) with Baghouse	AO29-250140	7/20/94	7/12/99		2/6/95
-012	Pug Mill & Truck Loading	AO29-250137	7/20/94	7/12/99		2/6/95
-013	Unit 1 Fuel Bunker w/Rotoclone	AO29-250139	7/20/94	7/12/99		2/6/95
-014	Unit 2 Fuel Bunker w/Rotoclone	AO29-250139	7/20/94	7/12/99		2/6/95
-015	Unit 3 Fuel Bunker w/Rotoclone	AO29-250139	7/20/94	7/12/99		2/6/95

-016	Unit 4 Fuel Bunker w/Rotoclone	AO29-250139	7/20/94	7/12/99		2/6/95
-017	Unit 5 Fuel Bunker w/Rotoclone	AO29-250139	7/20/94	7/12/99		2/6/95
-018	Unit 6 Fuel Bunker w/Rotoclone	AO29-250139	7/20/94	7/12/99		2/6/95
	All of the above.	0570040-002-AV	1/01/01	12/31/05		

ID Number Changes (for tracking purposes):

From: **Facility ID No.**: 40HIL290040
To: **Facility ID No.**: 0570040

Notes:
1 - AO permit(s) automatic extension(s) in Rule 62-210.300(2)(a)3.a., F.A.C., effective 03/21/96.
2 - AC permit(s) automatic extension(s) in Rule 62-213.420(1)(a)4., F.A.C., effective 03/20/96.
{Rule 62-213.420(1)(b)2., F.A.C., allows Title V Sources to operate under existing valid permits that were in effect at the time of application until the Title V permit becomes effective}

Attachment 1

PRELIMINARY DETERMINATION
POLLUTION CONTROL PROJECT AND
PSD APPLICABILITY REVIEW
TAMPA ELECTRIC GANNON COAL PROJECT

BACKGROUND

Tampa Electric Company (TEC) operates the Gannon power plant and coal yard in Tampa, Hillsborough County. In June, 1997, TEC applied to increase the permitted coal throughput at the coal yard from 2.85 million tons per year (mmTPY) to 3.77 mmTPY. An addendum submitted in June, 1998 revised the throughput requirement to 3.305 mmTPY. The reason for the increase is that TEC has been progressively using more high moisture/low heat content coals to comply with nitrogen oxides (NO_X) requirements for Phase II units pursuant to the Title IV Acid Rain requirements of the Clean Air Act.

Unless a throughput increase is permitted, use of the lower heat content coals will limit the electrical power production of the Gannon Plant compared to use of high heat content coal. Historically this has not been a problem since the coalyard throughput limit was compatible with use of high heat content fuel and demand. However, with growing electrical demand, lower state-wide electrical reserve capacity, and use of low heat content coal, the throughput limit has become an actual restriction on the overall plant availability. This maximum availability of the plant is approximately 66 percent when burning historical coals, but would be reduced to 57 percent if high moisture, low Btu coals are used while the mass throughput limit is maintained.

TEC maintains that "the coalyard and steam generating units are separate entities with respect to existing operating permits and that the fuel yard permit conditions apply only to the fuel yard, not to the entire facility." Under this view, the coalyard throughput increase would be permitted separately without regard to any emissions changes that might occur from the boilers. Without conceding that the coalyard and steam generating unit permit conditions are mutually applicable, TEC has presented information in subsequent submittals in support of its contention that the project is exempt from the rules for the Prevention of Significant Deterioration (PSD) as a Pollution Control Project."

REGULATIONS

Presuming that the coalyard and the steam units comprise a single facility, an increase in coalyard throughput would result in emissions increases of at least nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM/PM_{10}). There could also be increases in carbon monoxide (CO) and sulfuric acid mist (SAM).

The change in the coalyard throughput limit is a relaxation of a federally enforceable limitation on the capacity of the facility and is therefore a modification. As such, the PSD requirements in Rule 62-212.400, F.A.C. may apply as described in Rule 62-212.400(2)(g), F.A.C. Modifications to Major Facilities are those that result in a *significant net emissions increase* as described in Rule 62-212.400(2)(d)4.a(ii) and 62-212.400(2), F.A.C.

Per Rule 62-212.400(5)(c), F.A.C.:

> *The proposed facility or modification shall apply Best Available Control Technology (BACT) for each pollutant subject to preconstruction review requirements as set forth in Rule 62-212.400(2)(f), F.A.C.*

It is obvious that the definitions and applicability of facility, modification, and any exemptions are of key importance in this review.

A pollution control project (PCP) is defined at 40CFR52.21(b)(32) as:

> *Any activity or project undertaken at an existing electric steam generating unit for purposes of reducing emissions from such unit. Such activities and projects are limited to:*
>
> *(1) The installation of conventional or innovative pollution control technology, including but not limited to advanced flue gas desulfurization, sorbent injection for sulfur dioxide control and nitrogen oxides control and electrostatic precipitators;*
>
> *(2) An activity or project to accommodate switching to a fuel which is less polluting than the fuel in use prior to the activity or project, including, but not limited to natural gas or coal reburning, or the co-firing of natural gas and other fuel for the purpose of controlling emissions;*
>
> *(3) A permanent clean coal technology demonstration project conducted under title II, Section 101(d) of the Further Continuing Appropriations Act of 1985....................; or*
>
> *(4) A permanent clean coal technology demonstration project that constitutes a repowering project.*

The above definition is not specifically listed in the State Rules in Chapter 62, F.A.C. However it is obvious that it is the intent of the State to abide by the Federal definition. Per Rule 62-212.400(2)(a)2., F.A.C., Pollution Control Project Exemption:

> *A pollution control project that is being added, replaced, or used at an existing electric utility steam generating unit and that meets the requirements of 40CFR52.21(b)(2)(iii)(h) shall not be subject to the preconstruction requirements of this rule.*

According to 40CFR52.21(b)(2)(iii)(h), one of the exemptions from review for PSD is:

> *The addition, replacement or use of a pollution control project at an existing electric utility steam generating unit, unless the Administrator determines such addition, replacement, or use renders the unit less environmentally beneficial, or except (1) When the Administrator has reason to believe that the pollution control project would result in a significant net increase in representative actual annual emissions of any criteria pollutant over levels used for that source in the most recent air quality impact analysis in the area conducted for the purpose of title I if any, and (2) The Administrator determines the increase will cause or contribute to a violation of any national ambient air quality standard or PSD increment, or visibility limitation.*

A fuel switch is not actually included in the definition of PCP nor is it listed as an activity in support of a PCP. However, it is not excluded. Furthermore, according to the EPA rule analysis at FR Vol. 57, No. 140, Pages 32320-32321:

> *"Thus EPA is today adopting revisions to its PSD and nonattainment regulations for the addition, replacement or use at an electric steam generating unit of any system or device whose primary function is the reduction of pollutants (including the switching to a less-polluting fuel where the primary purpose of the switch is the reduction of air pollutants)."*

If it is established that the primary purpose of the switch is to reduce emissions, then it can be evaluated for qualification as a PCP. Even if there is an increase in a PSD pollutant associated with the project, it is not necessarily precluded from consideration as a PCP. Per the EPA analysis:

> *"Several commentors pointed out that a pollution control project that reduces one pollutant should not be allowed to increase emissions of another pollutant if that increase will cause or exacerbate a different pollution problem................... Although a pollution control project could theoretically cause a small collateral increase in some emissions, it will substantially reduce emissions of other pollutants. In recognition of this, the rule provides for a case-by-case assessment of the pollution control project's net emissions and overall impact on the environment."*

Therefore, the criteria which the Department must follow are clear. The collateral increase in any PSD pollutant should be small and the decrease in one or more PSD pollutants should be substantial. The increases in any pollutant should not cause or contribute to violation of an ambient air quality standard or PSD increment.

DESCRIPTION OF PROJECT

The project is the use of Powder River Basin (PRB) coal in Units 1-4. According to TEC, there has been a marked reduction in NO_X emissions from using PRB coal at Units 1-4. This has resulted in emissions reductions approaching the "Phase II" NO_X limit of 0.86 pounds per million Btu heat input (lb/mmBtu) at Units 3 and 4 without physical modification of the wet bottom cyclone units. TEC has also experimented with high moisture/low heat content Indonesian coal. For reference following is a comparison of various coals used at the Gannon Plant.

Table 1 - Comparison of 1994 TEC Gannon Coal with 1997 Indonesian and PRB Coals

	Gannon Coal[1]	Indonesian Coal[2]	PRB Coal[3]
Sulfur (%)	1.13	0.35	0.43
Heating Value (Btu/lb)	12,773	9,614	8,720
Ash (%)	6.99	1.44	5.29
Moisture (%)	<10	>25	31[4]

The choice of dates and data for comparison purposes was made by the Department and not TEC. In 1993, TEC imported no Indonesian coal. Receipts of Indonesian coal were 0.147, 0.349, 0.808, and 0.741 mmTPY for 1994, 95, 96, and 97, respectively. In 1994 use of PRB coal by TEC was insignificant. In 1996 and 1997 receipts of PRB coal by TEC (presumably for use at Gannon) were 0.591 and 0.971 mmTPY respectively. The above data indicate that:

1. Use of PRB and Indonesian coals is a recent and increasing practice by TEC.
2. PRB and Indonesian coals have lower sulfur content and lower ash content indicating at least an initial potential for reductions of some pollutants.
3. PRB and Indonesian coals have lower heat content indicating that it is necessary to use more of these coals to achieve the same heat input or electrical power production as achieved with lesser quantities of historical coal used at TEC Gannon.
4. PRB and Indonesian coals have higher moisture content. If NO_X emissions are reduced by the higher moisture content (and presumably some adjustments in combustion practices), then PRB and Indonesian coals have a potential for reductions in NO_X emissions.

EFFECT OF HIGH MOISTURE COAL ON NO_X EMISSIONS

Following the establishment of the above criteria, the Department requested on August 10, 1998 that TEC provide reasonable assurance that high moisture coals do in fact result in NO_X reductions.[5] The Department specifically requested the Sargent & Lundy[6] study and any other information that TEC has to indicate that the actual reason high moisture coal will be used is to reduce NO_X emissions.

TEC promptly provided the Sargent & Lundy Report on August 11 as well as a report submitted to the Public Service Commission (PSC) on NO_X controls[7], a Memorandum of Understanding (MOU) with Hillsborough County on NO_X reductions[8], and an internal summary of NO_X compliance activities[9].

According to the 1998 Compliance Activities document:

> *TEC's cyclone units have shown a reduction in NO_X close to the rule requirements as a result of burning high moisture western coals. However, there are significant penalties as a result and TEC is continuing to investigate other reasonable options............To continually use this fuel will require changes in the coal preparation to reduce operating difficulties. This work will be complete in 1999.*

According to the MOU:

> *Whereas the Tampa Electric Company has already taken the initiative to reduce the nitrogen oxide emissions from some of the individual affected units by more than 20 percent, resulting in an overall reduction of over 10,000 tons from the 1995 levels;*
> *Whereas the EPC believes the modifications and fuel switching proposed by the Tampa Electric Company will address the secondary environmental impacts associated with nitrogen oxides emissions in the Tampa Bay area..........*

Regarding Gannon 1-4, the May 1997 document submitted to the PSC stated:

A blend of Powder River Basin (PRB) and Western Kentucky coal has been used in the cyclone units. The PRB is a low BTU, high moisture, low sulfur coal. The original blend of 75% PRB has been reduced to 70% in order to minimize the problems associated with this fuel. Problems associated with this coal blend include: load restrictions due to low BTU value of the PRB, high fly ash LOI [loss on ignition], slag tank problems (tapping and explosions), fuel switching problems and fires due to spontaneous combustion of the PRB. NO_X was reduced to the 0.8-0.95 lb./MMBTU for a short period of time. It has not been demonstrated that a higher percentage of PRB in the blend will further lower the NO_X emissions rate.

A series of solutions to the problems were described. Of note is one that clearly associates the purpose of the crusher/grinder project to the problems caused by the use of PRB coal. If the use of high moisture coal is a PCP, then the crusher/grinder project can be a project in support of a PCP. Specifically the document states:

Fly ash LOI appears to be controllable by improving the grind of the coal. To meet the required grind, an increase in coalfield crusher operation and maintenance of up to $600,000 per year may be necessary along with probable crusher upgrades which could cost up to $2,500,000.

The summary of conclusions in the document to the PSC states that:

TEC has concluded that combustion modification of its Riley Turbo Furnace boilers (Gannon Units 5 and 6) can achieve significant reductions in NO_X emissions but only at the expense of incurring significant capital and O&M costs ....: Furthermore, TEC has concluded that significant NO_X emission reductions on its cyclone boilers(Gannon Units 1-4) can only be reasonably obtained through fuel switching to a low btu, high moisture fuel with the resulting expense and risk of sole sourcing these units fuel supply.

An independent corroboration of the possible reduction of NO_X by use of PRB coal at the Gannon Plant exists in an inspection report.[10] The letter states:

.....:NO_X emissions from two cyclone units, at or below the proposed EPA limits of 0.94 lb/mmBtu (operation was near full load)......... During my visit I noted that these units had recently switched to Powder River Basin coal. During a visit on August 16, a representative from Hillsborough County noted that NO_X emissions from the two wet bottom turbo units [Units 5 and 6] at the Gannon station were below the proposed levels of 0.86 lb/mmBtu..........Can you confirm if fuel switching for SO_2 allowances have a co-benefit of reducing NO_X?

It is clear from the record that:

1. TEC has a recent history of using the high moisture fuels
2. NO_X reduction through use of high moisture, low Btu fuels has been demonstrated.
3. The use of high moisture, low Btu fuels is in fact the primary strategy employed by TEC at Gannon Units 3 and 4 to comply with the requirements of the Phase II Rules for NO_X control pursuant to Title IV, Acid Rain, Clean Air Act.
4. Additional projects are needed to facilitate the switch to low Btu, high moisture coals.

OTHER CONSIDERATIONS

Based on the application and initial information submitted by TEC, the EPCHC and some Department staff expressed various concerns about the ability of the project to qualify as a PCP. These concerns are:

1. Significant collateral increases of SO_2.[11]
2. Possible impacts on ambient SO_2 concentrations.
3. The possibility that increased annual power generation from the Gannon Plant is the actual reason that greater throughput is needed.
4. The possibility that use of PRB coal is being implemented for economic rather than environmental reasons.
5. Lack of detailed analysis on the collateral increase or decreases of particulate matter, fluorides, and other PSD pollutants.
6. Doubts that it is the use of high moisture coals that causes the lower NO_X emissions.

TEC fully disclosed in its final information submittal that SO_2 emissions may indeed increase. However, it is clear that on balance, the use of PRB coal will actually lower SO2 emissions. TEC stated that the increase is related to the use of a scrubber at Big Bend units 1 and 2 will result in substantial reductions in SO_2 emissions at Big Bend and on a corporate-wide basis as required by Title IV of the Clean Air Act. TEC's reduction at Big Bend will result in available SO_2 allowances, some of which might be sold or possibly used at the Gannon Plant. The emissions are not collateral with the use of high moisture PRB coal, but rather incidental and mostly unrelated.

Any negative impacts on ambient SO_2 concentrations are not related to the use of PRB coal. The subject is being reviewed under Title V permitting. The Department and TEC are working out ways to insure that emission limits are set in the Title V permit to avoid exeedances of the Florida Ambient Air Quality Standard for SO_2.

The electrical generation capacity in the State has fallen below the minimum reserve requirements. Usage of quite a number of plants and even peaking units has increased. Increases in generation due to system-wide growth in demand are normally left out of the calculations for determining increases and decreases in emissions due to modifications at existing power plants. TEC actually left in the future emissions increases attributable to increased growth in demand as well as the unrelated increases due to the scrubber project at Big Bend 1 and 2.

Obviously TEC will ultimately be limited by the coalyard throughput whether it uses high Btu or low Btu fuel. However the use of the low Btu fuel is for reduction of emissions. A compensating increase in allowable coal throughput is a logical way to encourage the use of a less polluting type of coal, while insuring that it does not inadvertently "debottleneck" the rest of the plant.

The Department has seen no evidence that the motivation for using PRB coal is to stimulate demand. Based on the DOE data, the cost of PRB coal delivered to the company's Davant, Louisiana Transfer Station is about the same as other fuels used by TEC. When forwarded to Florida, the cost could be greater than the other fuels because of the low Btu value. As documented above, there is actually a risk related to sole-sourcing the fuel for the Gannon Units using PRB coal. Additionally a host of potential problems were identified by the company that are being progressively solved. The main economic incentive appears to be minimization of the cost to achieve the required NO_X reductions. There appears to be no appreciable economic advantage to using PRB coal that would result in increased unit availability.

TEC submitted estimates on the collateral increases and decreases in particulate emissions. These appear small and controllable. The low sulfur in PRB coal can actually reduce electrostatic precipitator performance. TEC has sulfur trioxide injection systems that can be adjusted to correct for drops in particulate collection efficiency. The Department did not specifically require TEC to document possible small collateral increases and decreases in other PSD pollutants. The changes are difficult to quantify and there is no reason to expect any significant differences attributable to the use of the PRB coal.

The reduction in NO_X at Gannon Units 1-4 has clearly been documented and is attributable to the use of low moisture coals such as PRB coal. Obviously some relatively inexpensive associated fuel system, ash handling and boiler modifications, as well as combustion optimization contribute to the reduction.

Following are the required emissions reductions that TEC must achieve from the units actually covered by the NO_X Acid Rain requirements:

Table 2 - Comparison of NO_X Emissions From Gannon Units 3-6 Before and After Control Projects and Fuel Use Strategies (pounds per million Btu)

	1995	Future
Gannon Unit 3	1.29	0.86
Gannon Unit 4	1.34	0.86
Gannon Unit 5	0.95	0.84
Gannon Unit 6	1.15	0.84

In its application, TEC assumed that Units 3 and 4 would be required to meet 0.95 pounds of NO_X per million Btu (lb/mmBtu) while Units 5 and 6 will have to meet 0.85. A recent Court decision upheld EPA's final determination on the emissions allowed for these units. Therefore TEC will actually have to achieve somewhat greater NO_X reductions than given in the application. Though not regulated by Phase II Rules, Units 1 and 2 will also achieve some NO_X emissions reductions due to the use of high moisture, low Btu fuel.

CONCLUSION

Based on the foregoing analysis, the Department's Preliminary Determination is that TEC's use of high moisture, low Btu coals such as Indonesian and Powder River Basin coals constitutes a Pollution Control Project per Department and EPA regulations. Additionally the coal yard modifications and the installation of new crusher/grinders constitute projects and activities to accommodate switching to a fuel that is less polluting than the fuel in use prior to the project.

To insure that the increase in permitted coal throughput does not result in emissions increases, limits will be set for "total annual heating value throughput." In this manner, the increase in physical throughput will only compensate for the decrease in fuel heating value. Assuming a conservative heating value of 12,250 Btu per pound from the higher Btu coals exclusively used before 1996, the Department estimates that the required heat throughput is 6.98×10^7 mmBTU per year. This limit should be incorporated into the coalyard permit or adjusted in accordance with more detailed information submitted by TEC. For reference, according to the EPA's Acid Rain database, the heat input to the Gannon Plant in 1995 and 1996 was 6.69 and 6.89×10^7 mmBtu respectively.[12]

The Southwest District is directed to process the permit for the coal yard modifications. Although the actual coalyard projects are to accommodate the use of a PCP, emissions should still be minimized. TEC should also describe to the District its plans to minimize any collateral particulate and carbon monoxide increases from the boilers. This Preliminary Determination may be public noticed in conjunction with the coalyard permit Intent or separately at an earlier date. The details of the notice may be finalized between TEC and the District.

REFERENCES

1 Department of Energy. Receipts and Average Cost of Coal by Type, Electric Utility, and Plant (TEC Gannon), 1994

2 Department of Energy. Receipts, Quality, and Average Delivered Cost of Imported Coal (TEC Davant Transfer - Indonesian Coal), 1997.

3 Department of Energy. Receipts of Western Region Coal (TEC), 1997.

4 Babcock and Wilcox Analysis of Campbell County, Wyoming Subbituminous C.

5 Telecon. Linero, A.A., DEP with Watley, T.J., TEC. August 10, 1998. Need for substantiation of properties of high moisture coals with respect to NO_X controls.

6 Carnot/Sargent & Lundy. "Nitrogen Oxide Limitation Study prepared for Tampa Electric company." March 15, 1996.

7 Tampa Electric Company. "Evaluation of NO_X Controls for Tampa Electric Company's Group II Wet Bottom and Cyclone Boilers." May, 1997.

8 TEC and EPCHC. "Memorandum of Understanding Nitrogen Oxides Emissions Rate Reductions." October 29, 1997.

9 TEC. "Tampa Electric Company NOX Compliance Activities." Undated.

10 Letter from Costello, M., DEP to Ho, P., TEC. Request for Information. October 9, 1996.

11 Memorandum from Anderson, L., DEP to Linero, A., DEP. TEC's Coal Modification Project. August 11, 1998.

12 www.epa.gov/acidrain/ardhome.html. Data summarized in Tables accompanying Reference 11 above.

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DEC 26 1995
BUREAU OF
AIR REGULATION

Phase II Permit Application

For more information, see instructions and refer to 40 CFR 72.30 and 72.31 and Chapter 62-214, F.A.C.

This submission is: [X] New [ ] Revised

STEP 1
Identify the source by plant name, State, and ORIS code from NADB

Plant Name	State	ORIS Code
F.J. Gannon	FL	646

STEP 2
Enter the boiler ID# from NADB for each affected unit, and indicate whether a repowering plan is being submitted for the unit by entering "yes" or "no" at column c. For new units, enter the requested information in columns d and e

a	b	c	d	e
	Compliance Plan			
Boiler ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)	Repowering Plan	New Units Commence Operation Date	New Units Monitor Certification Deadline
GB01	Yes	No		
GB02	Yes	No		
GB03	Yes	No		
GB04	Yes	No		
GB05	Yes	No		
GB06	Yes	No		
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			

STEP 3
Check the box if the response in column c of Step 2 is "Yes" for any unit

[ ] For each unit that will be repowered, the Repowering Extension Plan form is included and the Repowering Technology Petition form has been submitted or will be submitted by June 1, 1997.

BEST AVAILABLE COPY

STEP 4
Read the standard requirements and certification, enter the name of the designated representative, and sign and date

Standard Requirements

Permit Requirements.

(1) The designated representative of each Acid Rain source and each Acid Rain unit at the source shall:
(i) Submit a complete Acid Rain part application (including a compliance plan) under 40 CFR part 72, Rules 62-214.320 and 330, F.A.C. in accordance with the deadlines specified in Rule 62-214.320, F.A.C.; and
(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain part application and issue or deny an Acid Rain permit;
(2) The owners and operators of each Acid Rain source and each Acid Rain unit at the source shall:
(i) Operate the unit in compliance with a complete Acid Rain part application or a superseding Acid Rain part issued by the permitting authority; and
(ii) Have an Acid Rain Part.

Monitoring Requirements.

(1) The owners and operators and, to the extent applicable, designated representative of each Acid Rain source and each Acid Rain unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75, and Rule 62-214.420, F.A.C.
(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements.

(1) The owners and operators of each source and each Acid Rain unit at the source shall:
(i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and
(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An Acid Rain unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
(i) Starting January 1, 2000, an Acid Rain unit under 40 CFR 72.6(a)(2); or
(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an Acid Rain unit under 40 CFR 72.6(a)(3).
(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1)(i) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR 72.7 and 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements. The owners and operators of the source and each Acid Rain unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements.

(1) The designated representative of an Acid Rain unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an Acid Rain unit that has excess emissions in any calendar year shall:
(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
(ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the source and each Acid Rain unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
(i) The certificate of representation for the designated representative for the source and each Acid Rain unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with Rule 62-214.350, F.A.C.; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
(ii) All emissions monitoring information, in accordance with 40 CFR part 75;
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

Enter the source AIRS and FINDS identification numbers, if known

AIRS	0570040
FINDS	

MEMORANDUM 10/26

TO: Scott M. Sheplak, P.E. 10M

FROM: Tom Cascio

DATE: October 15, 2002

Re: Intent Package for DRAFT Permit No. **0570040-017-AV**
Tampa Electric Company
F. J. Gannon Station

Day 90: **November 1, 2002**

This permit is a revision of the Title V air operation permit for the subject facility. I recommend that this Intent to Issue be sent out as attached.