Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

June 3, 2002

Mr. Robert E. McGarrah, Production Superintendent
City of Tallahassee - Electric Utilities
300 South Adams Street
Tallahassee, Florida 32301

Re: Sam O. Purdom Generating Station
Draft Air Construction Project No. 1290001-005-AC
{Modification of Permit No. PSD-FL-239 (Unit 8) and Permit No. 1290001-002-AC (Auxiliary Boiler)}
DRAFT Title V Air Operation Permit Revision Project No. 1290001-006-AV
{Revision to Title V Air Operation Permit No. 1290001-003-AV}

Dear Mr. McGarrah:

One copy of the Technical Evaluation and Preliminary Determination, the combined Public Notice, the Draft Air Construction Permit Modifications, and the DRAFT Title V Air Operation Permit Revision for the Sam O. Purdom Generating Station located at 667 Port Leon Drive in St. Marks, Wakulla County, Florida, is enclosed. The permitting authority's "Intent to Issue Air Construction Permit Modifications and Title V Air Operation Permit Revision" and the "Public Notice of Intent to Issue an Air Construction Permit and Title V Air Operation Permit Revision" are also included.

An electronic version of the DRAFT Title V Air Operation Permit Revision has been posted on the Division of Air Resources Management's world wide web site for the United States Environmental Protection Agency (USEPA) Region 4 office's review. The web site address is:

"http://www.dep.state.fl.us/air/permitting/tv/TitleVSearch.asp"

The "Public Notice of Intent to Issue Air Construction Permit Modifications and 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 seven (7) 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 permits 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 Jeff Koerner, at the above letterhead address. If you have any other questions, please contact Mr. Koerner, at 850/921-9536.

Sincerely,

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

CHF/AAL/SMS/jfk

Enclosures

U.S. EPA, Region 4 (INTERNET E-mail)

Memorandum

Florida Department of Environmental Protection

TO: Clair Fancy, Chief of Bureau of Air Regulation

THRU: Al Linero, New Source Review Section *AL 6/3*

FROM: Jeff Koerner, Project Engineer *JK*

DATE: May 31, 2002

SUBJECT: Sam O. Purdom Generating Station

Permit Project No. 1290001-005-AC
Modification of Air Permit No. PSD-FL-239 (Unit 8)
Modification of Permit No. 1290001-002-AC (Auxiliary Boiler)

Permit Project No. 1290001-006-AV
Revision of Title V Air Operation Permit No. 1290001-003-AV

Attached is the Draft Permit package for a modification of the original PSD permit for Purdom's Unit 8 that authorizes an increase in the heat input rate for the combined cycle unit as well as increased periods of excess emissions due to cold startups and hot startups. The Draft Package also includes a modification to the original air construction permit for the 16.74 MMBtu/hour auxiliary boiler that allows its operation when either Unit 7 or Unit 8 is shutdown. In addition, the package includes a concurrent revision to the Title V Air Operation Permit. A detailed review of the project is provided in the attached Technical Evaluation.

Day 74 of the permit time clock is June 28, 2002. I recommend your approval and signature.

Attachments

AAL/jfk

In the Matter of an
Application for Permits by:

City of Tallahassee - Electric Utilities
300 South Adams Street
Tallahassee, Florida 32301

Air Construction Permit Project No. 1290001-005-AC
DRAFT Title V Permit Revision No. 129001-006-AV
Sam O. Purdom Generating Station
Wakulla County, Florida

Authorized Representative/Responsible Official
Mr. Robert E. McGarrah, Production Superintendent

INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT AND TITLE V AIR OPERATION PERMIT REVISION

The City of Tallahassee (applicant) applied on November 14, 2001 for Air Construction Permit Modifications and Title V Air Operation Permit Revision for the Sam O. Purdom Generating Station located at 667 Port Leon Drive in St. Marks, Wakulla County, Florida. The Florida Department of Environmental Protection (permitting authority) gives notice of its intent to issue Air Construction Permit Modifications and Title V Air Operation Permit Revision for the Title V source detailed in the application specified above and the attached Technical Evaluation and Preliminary Determination, for the reasons stated below. Copies of the Draft Air Construction Permit Modifications and DRAFT Title V Air Operation Permit Revision are attached.

Permit Project No. 1290001-005-AC involves the modification of two air construction permits; Permit No. PSD-FL-239 for the Unit 8 combined cycle gas turbine and Permit No. 1290001-002-AC for the auxiliary boiler. The applicant requested the following changes to the Unit 8 permit: clarify that the heat input rate is a function of the compressor inlet temperature and not necessarily ambient temperature; revise the temperature basis for the heat input rate from 95° F to 59° F; increase the heat input rate by approximately 8.5% for gas firing and 6.6% for distillate oil firing; allow periods of excess emissions resulting from major tuning of the dry low NOx combustion system for up to 72 hours per year; increase authorized periods of excess emissions from 4 to 6 hours per day during days with cold startups; and increase authorized periods of excess emissions from 2 to 4 hours per day during days with hot startups. For the auxiliary boiler permit, the applicant requested authorization to operate the auxiliary boiler when either Unit 7 or Unit 8 is not in operation. Lastly, the applicant requested a concurrent revision of Title V Air Operation Permit No. 1290001-003-AV to: incorporate the above requests; revise the permit subsection regulating Boilers 5 and 6 to reflect permanent shutdown; and revise the emissions unit ID number for the Unit 8 combined cycle gas turbine to be consistent with the state's database. The revision will be issued as DRAFT Title V Air Operation Permit No. 1290001-006-AV.

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, 62-212 and 62-213. This source is not exempt from construction and Title V permitting procedures. The permitting authority has determined that Air Construction Permit Modifications and Title V Air Operation Permit Revision are required to modify and commence or continue operations at the facility.

The permitting authority intends to issue the Air Construction Permit Modifications and the Title V Air Operation Permit Revision based on the belief that reasonable assurances have been provided to indicate that the construction activity and 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, 62-256, 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 Air Construction Permit Modifications and Title V Air Operation Permit Revision" ("Public Notice"). 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 Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400, 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 permits pursuant to Rule 62-110.106(11), F.A.C.

The permitting authority will issue the Air Construction Permit Modifications and the PROPOSED Title V Air Operation Permit Revision and subsequent FINAL Title V Air Operation Permit Revision, in accordance with the conditions of the attached Draft Air Construction Permit Modifications and the DRAFT Title V Air Operation Permit Revision 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 Air Construction Permit Modifications and the Title V Air Operation Permit Revision issuance actions for a period of 30 (thirty) days from the date of publication of the "Public Notice". Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in significant changes, the permitting authority shall issue a revised Draft Air Construction Permit and a revised DRAFT Title V Air Operation Permit Revision 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 Department's Office of General Counsel at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the applicant or any of the parties listed below must be filed within 14 (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 14 (fourteen) days of publication of the public notice or within 14 (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 14 (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.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this "Intent to Issue an Air Construction Permit and Title V Air Operation Permit Revision" (including the combined "Public Notice", the Draft Air Construction Permit Modifications and the DRAFT Title V Air Operation Permit Revision) and all copies were sent by certified mail* or U.S. mail before the close of business on 6/6/02 to the persons listed:

Mr. Robert E. McGarrah, City of Tallahassee*
Mr. Karl Bauer, City of Tallahassee
Ms. Jennette Curtis, City of Tallahassee
Ms. Sandra Veazey, NWD
Mr. Hamilton Oven, DEP Siting Office
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

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.

Victoria Gibson June 6, 2002
(Clerk) (Date)

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

Florida Department of Environmental Protection

Draft Air Construction Permit Project No. 1290001-005-AC
{Modification of Permit No. PSD-FL-239 (Unit 8) and Permit No. 1290001-002-AC (Auxiliary Boiler)}
DRAFT Title V Air Operation Permit Revision Project No. 1290001-006-AV
{Revision to Title V Air Operation Permit No. 1290001-003-AV}

Sam O. Purdom Generating Station
Wakulla County, Florida

The Florida Department of Environmental Protection (permitting authority) gives notice of its intent to issue Air Construction Permit Modifications and Title V Air Operation Permit Revision to the City of Tallahassee (applicant) for the Sam O. Purdom Generating Station located at 667 Port Leon Drive in St. Marks, Wakulla County, Florida. The applicant's authorized representative and responsible official is Mr. Robert E. McGarrah, Production Superintendent. The applicant's address is: City of Tallahassee - Electric Utilities, 300 South Adams Street, Tallahassee, Florida 32301.

Permit Project No. 1290001-005-AC involves the modification of two air construction permits; Permit No. PSD-FL-239 for the Unit 8 combined cycle gas turbine and Permit No. 1290001-002-AC for the auxiliary boiler. The applicant requested the following changes to the Unit 8 permit: clarify that the heat input rate is a function of the compressor inlet temperature and not necessarily ambient temperature; revise the temperature basis for the heat input rate from 95° F to 59° F; increase the heat input rate by approximately 8.5% for gas firing and 6.6% for distillate oil firing; allow periods of excess emissions resulting from major tuning of the dry low NOx combustion system for up to 72 hours per year; increase authorized periods of excess emissions from 4 to 6 hours per day during days with cold startups; and increase authorized periods of excess emissions from 2 to 4 hours per day during days with hot startups. For the auxiliary boiler permit, the applicant requested authorization to operate the auxiliary boiler when either Unit 7 or Unit 8 is not in operation. Lastly, the applicant requested a concurrent revision of Title V Air Operation Permit No. 1290001-003-AV to: incorporate the above requests; revise the permit subsection regulating Boilers 5 and 6 to reflect permanent shutdown; and revise the emissions unit ID number for the Unit 8 combined cycle gas turbine to be consistent with the state's database. The Title V revision is issued as DRAFT Title V Air Operation Permit No. 1290001-006-AV.

The changes are expected to result in slight increases in potential emissions of the following pollutants: 19.52 tons of carbon monoxide per year; 3.6 tons of particulate matter per year; and 4.8 tons of volatile organic compounds per year. Although the Unit 8 combined cycle gas turbine is a Phase II Acid Rain Unit, potential emissions of nitrogen oxides and sulfur dioxide remain unchanged due to enforceable emissions caps. A review for the Prevention of Significant Deterioration is not required because any increases are well below the significant emission rate thresholds.

The permitting authority will issue the Air Construction Permit Modifications and the PROPOSED Title V Air Operation Permit Revision and subsequent FINAL Title V Air Operation Permit Revision, in accordance with the conditions of the Draft Air Construction Permit Modifications and the DRAFT Title V Air Operation Permit Revision 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 Air Construction Permit Modifications and the DRAFT Title V Air Operation Permit Revision issuance actions 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 at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in significant changes, the permitting authority shall issue revised Draft Air Construction Permit Modifications and a revised DRAFT Title V Air Operation Permit Revision 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 Department's Office of General Counsel at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within 14 (fourteen) days of publication of the public notice or within 14 (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 14 (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:

<u>Permitting Authority:</u>
Bureau of Air Regulation
Florida Department of Environmental Protection
111 S. Magnolia Drive, Suite 4
Tallahassee, FL 32301
Telephone: 850/488-0114

<u>Affected District Office</u>
Northwest District Office
Florida Department of Environmental Protection
160 Governmental Center
Pensacola, FL 32501-5794
Telephone: 850/595-8300

The complete project file includes the Technical Evaluation and Preliminary Determination, the Draft Air Construction Permit Modifications, the DRAFT Title V Air Operation Permit Revision, the application, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact permit engineer at the above address, or call 850/488-0114, for additional information.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION

PROJECT

Permit Project No. 1290001-005-AC
Modification of Air Permit No. PSD-FL-239 (Unit 8)
Modification of Permit No. 1290001-002-AC (Auxiliary Boiler)

Permit Project No. 1290001-006-AV
Revision of Title V Air Operation Permit No. 1290001-003-AV

Miscellaneous Permit Modifications

COUNTY

Leon

APPLICANT

City of Tallahassee, Electric Utilities
Sam O. Purdom Generating Station
ARMS Facility ID No. 1290001

PERMITTING AUTHORITY

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

May 31, 2001

{Filename: 1290001-005-AC TEPD.doc}

1. GENERAL INFORMATION

Applicant Name and Address

City of Tallahassee, Electric Utilities
300 South Adams Street
Tallahassee, Florida 32301

Authorized Representative/Responsible Official:
Mr. Robert E. McGarrah, Production Superintendent

Processing Schedule

11/14/01	Received application.
12/05/01	Requested additional information.
02/27/02	Received partial additional information.
04/16/02	Received remaining additional information; complete.

Facility Description and Location

The City of Tallahassee operates an electric power plant (SIC No. 4911) located at 667 Port Leon Drive in St. Marks, Wakulla County, Florida. The UTM coordinates are Zone 16, 769.5 km East, and 3339.97 km North (Latitude: 30° 09' 47" North and Longitude: 84° 12' 10" West). This is an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to the Florida and National Ambient Air Quality Standards (NAAQS).

Regulatory Categories

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

Title IV: The facility operates emissions units subject to the acid rain provisions of the Clean Air Act.

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

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

NSPS: The facility operates units subject to the New Source Performance Standards of 40 CFR 60 (Subpart GG for the gas turbine and Subpart Dc for the auxiliary boiler.).

2. PROJECT DESCRIPTION

The proposed changes will affect the following emission units.

EU No.	Emissions Unit Description
005	Unit 5: 300 MMBtu per hour boiler (Permanently Shutdown)
006	Unit 6: 300 MMBtu per hour boiler (Permanently Shutdown)
007	Unit No. 7: 621 MMBtu per hour boiler
011	Auxiliary Boiler: 17 MMBtu per hour boiler
014	Unit No. 8: 1897 MMBtu per hour combined cycle combustion turbine

The applicant requests the following changes to Permit No. PSD-FL-239 for the Unit 8 combined cycle gas turbine.

1. Heat Input Rate: Clarify that the heat input rate is a function of compressor inlet temperature and not necessarily ambient temperature. Revise the heat input rate based on the unit as constructed.

2. Tuning: Authorize excess emissions resulting from major DLN tuning of the dry low NOx combustion system for no more than 72 hours per year. NOx emissions from such periods would still be included to demonstrate compliance with the facility-wide emission cap.

3. Cold Startup: Authorize up to 4 hours of excess emissions per day resulting from cold startups. For any day that includes a cold startup, authorize up to 6 hours of excess emissions per day resulting from all startups, shutdowns, malfunctions, and fuel switching. For any day that does not include a cold startup, authorize up to 4 hours of excess emissions per day resulting from all startups, shutdowns, malfunctions, and fuel switching.

The applicant requests the following change to Permit No. 1290001-002-AC for the auxiliary boiler.

4. Auxiliary Boiler: Revise permit condition to allow the auxiliary boiler to operate when either Unit 7 or Unit 8 is not in operation.

The applicant also requests the following changes to air Permit No. 1290001-003-AV.

5. Title V Revision: Simultaneous revision of the Title V Permit to incorporate the above changes.

3. DEPARTMENT REVIEW

Heat Input Rate (Permit No. PSD-FL-239)

For this project, the applicant requests the following changes to the original PSD air permit for Unit 8.

- Revise the term "ambient temperature" to "compressor inlet temperature";
- Revise the temperature basis for the maximum heat input rates from 95° F to 59° F;
- Revise the maximum heat input rate for gas firing from 1,467.7 to 1696 MMBtu/hour; and
- Revise the maximum heat input rate for distillate oil firing from 1,659.5 to 1897 MMBtu/hour.

The change in terms from "ambient" to "compressor inlet" temperature is acceptable. If the heat input rates are first corrected for the requested change in compressor inlet temperature (95° F to 59° F), then the equivalent heat input rates would be 1563 MMBtu/hour (gas firing) and 1780 MMBtu (oil firing). Therefore, the request to increase the heat input rates is actually from 1563 to 1696 MMBtu/hour (gas firing) and from 1780 to 1897 MMBtu/hour (oil firing). This is approximately an 8.5% and a 6.6% increase over the previous maximum heat input rates for gas and oil firing, respectively.

Manufacturers guarantee maximum power production for a specific gas turbine model with a corresponding maximum heat input rate. Frequently, actual power production and maximum heat input rates are slightly higher than the initial guarantee. In this particular case, the application was based on an earlier version of the Frame 7FA (Model No. MS7231) rather than the actual delivered unit, which was the Model No. PG7241(FA). Recent permit applications for the Model No. PG7241(FA) shows General Electric specifications of more than 1600 MMBtu/hour for gas firing and more than 1800 MMBtu per hour for oil firing.

Construction on the Unit 8 combined cycle gas turbine was completed in 2000. Based on information in the Department's Air Resource Management System, the unit operated approximately 3 months in 2000, including the initial shakedown operation. In 2001, the unit operated approximately 12 months. The unit has begun commercial operation, but has less than 24 months of actual commercial operation. The proposed change does not require any physical change to the unit.

For the original project, the Department made BACT determinations for CO, NOx, PM/PM_{10}, and SO_2. The requested change in heat input would not have triggered PSD review for any additional pollutants with respect to the original project. The applicant does not request any changes to the NOx and SO_2 emissions caps established in the initial PSD permit. Based on additional fuel consumption to achieve the requested heat input, the applicant estimates the following emission increases: 19.52 tons per year of carbon monoxide; 3.6 tons per year of particulate matter; and 4.8 tons per year of volatile organic compounds. The Department also estimated annual emissions increases due to the increased heat input as shown in Attachment A. The increases are well below the PSD significant emission rates identified in Table 62-212.400-2, F.A.C. Therefore, the requested change in heat input does not trigger a PSD review.

The Purdom Generating Station is located within 1 km of the St. Marks National Wilderness Area and approximately 28 km from the Bradwell Bay National Wilderness Area. Due to the proximity of these federally protected areas, the applicant performed an air quality analyses for the original PSD permit application. The Department reviewed the original analyses to determine whether additional modeling would be necessary to evaluate possible impacts from the small increase in heat input. The following tables summarize the PSD increment analyses as provided in the original project's public notice.

Table 3A. Summary of Increment Analysis for PSD Class II Areas (From Initial PSD Project Review) Multi-Source Modeling Impacts to Areas in the Vicinity of the Plant

Pollutant	Averaging Period	Increment Consumed With Project, ug/m^3	Allowable Class II Increment, ug/m^3	% Increment Consumed
PM_{10}	24-hour	3.3	30	11%
	Annual	0.3	17	2%
SO_2	3-hour	14.4	512	3%
	24-hour	2.4	91	3%
	Annual	0.0	20	0%
NO_2	Annual	6.2	25	25%

Table 3B. Summary of Increment Analysis for PSD Class I Areas (From Initial PSD Project Review) Multi-Source Modeling Impacts to the St. Marks and Bradwell Bay National Wilderness Areas

Pollutant	Averaging Period	Increment Consumed With Project, ug/m^3		Allowable Class I Increment, ug/m^3	% Increment Consumed With Project	
		St. Marks	Bradwell Bay		St. Marks	Bradwell Bay
PM_{10}	24-hour	**0.7**	0.0	8	9%	0%
	Annual	0.1	**0.2**	4	2.5%	5%
SO_2	3-hour	10.7	**16.9**	25	43%	68%
	24-hour	2.7	**4.9**	5	54%	98%
	Annual	**0.0**	**0.0**	2	0%	0%
NO_2	Annual	**0.9**	0.6	2.5	36%	24%

As shown in Table 3A, the initial multi-source modeling analysis predicts increment consumption in the Class II areas to be well below the allowable levels for all pollutants. In Table 3B, the initial multi-source modeling analysis predicts increment consumption in the St. Marks National Wilderness Area and the Bradwell Bay National Wilderness Area to be below allowable PSD Class I increment levels for all pollutants. However, the analysis predicts that 98% of the allowable PSD Class I increment will be consumed for the 24-hour averaging period in the Bradwell Bay National Wilderness Area, which is farthest from the Purdom site. Taking a closer look at the analysis, it indicates that Purdom Unit 8 was less than the significance criterion for SO_2 and contributes less than 0.00001 ug/m^3 to this overall impact. (See Tables 7-4 through 7-8 in the original PSD application.) Therefore, the requested change in heat input rates would have a negligible affect on the Bradwell Bay National Wilderness Area and no further modeling for SO_2 was required.

To satisfy concerns regarding increases in emissions of carbon monoxide and particulate matter, the applicant performed an additional modeling analysis to determine whether the requested heat input increase would result in an impact of greater than 1 ug/m^3 in the St. Marks National Wilderness Area. This is a Class I area that is less than 10 km from the Purdom site. The analysis used EPA's ISC3 modeling software (version 02035) and the preprocessed meteorological data from the National Weather Service for the years 1985 to 1989. The analysis also used surface data from Tallahassee Station No. 93805 and mixing height data from Apalachicola Station No. 12832. The following table summarizes the modeling results.

Table 3C. Purdom Unit 8 Impacts on St. Marks National Wilderness Area (Class I Area)

Pollutant	Input Data Source	Emission Rate grams/second	Maximum Refined Concentration, ug/m^3
Carbon Monoxide	Original PSD Application	24.21	6.58
	Proposed Project	25.18	6.64
	Difference	0.97	**0.06**

Particulate Matter	Original PSD Application	2.14	0.582
	Proposed Project	2.28	0.601
	Difference	0.14	**0.019**
Analysis is based on the following worst-case parameters: Meteorological Year: 1988 Unit Load: 50% capacity Compressor Inlet Temperature: 20° F for gas firing and 95° for oil firing			

The analysis shows that the requested increase in heat input will not result in an impact greater than 1 ug/m^3 in the nearby St. Marks National Wilderness Area. Emissions of nitrogen oxides and sulfur dioxide will not increase due to the federally enforceable emissions caps; therefore, no analysis of these pollutants was required. The Department approves the increase in heat input provided the permittee continues to tune the gas turbine in accordance with the manufacturer's specifications.

Tuning (Permit No. PSD-FL-239)

During the initial shakedown and operation of a lean-premix gas turbine, it is necessary to perform major tuning sessions of the dry low NOx combustion system. The tuning process involves stepping the unit through various load conditions and making necessary adjustments to achieve the operational specifications established by the manufacturer, which is intended to result efficient combustion. During this process, the unit may experience elevated emission levels until the system is properly tuned. Such major tuning sessions would be repeated at scheduled maintenance intervals and after a major repair or combustor change-out. Although tuning sessions typically last only a few hours during a single day, it is possible that several days of tuning could be necessary to correct a problem.

The applicant requests the authorization of excess emissions resulting from major tuning sessions, which would occur no more than 72 hours during any given year. Again, scheduled and unscheduled tuning sessions are necessary to return the unit to the manufacturer's specifications. The benefit of performing such tuning sessions is to increase combustion performance as well as restore dry low-NOx combustion system parameters in accordance with the manufacturer's specifications. Therefore, the Department approves the request and the PSD permit will be revised accordingly. However, all valid NOx CEMS data must be used to determine compliance with the NOx emission cap.

Startup (Permit No. PSD-FL-239)

The original PSD permit for Unit 8 included the following condition (C.1):

> "Excess emissions resulting from startup, shutdown, malfunction or fuel switching shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized but in no case exceed four hours in any 24-hour period for cold startup or two hours in any 24-hour period for other reasons unless specifically authorized by DEP for longer duration."

For a day with a cold startup, the applicant requests up to 6 hours of excess per day to allow for multiple linked events (cold startup, malfunctions, shutdown, etc.). Similarly, the applicant requests 4 hours of excess emissions per day for days with a hot startup. Although the likelihood of such multiple occurrences is relatively low, the Department does recognize the possibility. The Department approves the request and will modify the PSD air permit accordingly, provided the applicant meets the following three provisions:

- NOx emissions data shall not be excluded from the annual NOx emissions cap. This is necessary to maintain an enforceable emissions cap.
- The permittee shall maintain a NOx monitor availability of at least 95%. This is necessary to ensure that Unit 8 is demonstrating compliance with the NOx BACT standards and the NOx emissions cap based on its actual emissions.
- The permittee shall submit quarterly reports that identify the amount of NOx data exclusion, malfunctions and corrective actions, and monitor downtime. The reports will be used to demonstrate compliance with the authorized periods of data exclusion as well ensure that malfunctions and frequent startups do not become routine methods of operation.

Auxiliary Boiler (Permit No. 1290001-002-AC)

In December of 1996, the Department's Northwest District issued air construction permit No. 1290001-002-AC for an auxiliary steam boiler with a maximum heat input rate of 16.7 MMBtu/hour fired exclusively with natural gas and limited to no more than 2000 hours per year of operation. Although the boiler was not permitted subject to PSD preconstruction review, BACT determinations were made for particulate matter and sulfur dioxide in accordance with state Rule 62-296.406, F.A.C. The initial construction permit contained the following text in Condition No. 6.

> "This emissions unit shall only be operated as an auxiliary source of steam when the existing steam generating units (boilers 5, 6, & 7) are not operating."

Previous Units 5 and 6 are now permanently shutdown. The applicant requests that this condition be revised to allow operation of the auxiliary steam boiler when either Unit 7 or Unit 8 are not operating. The applicant performed additional modeling to evaluate the impacts for carbon monoxide and particulate matter resulting from the different operating scenarios with regard to the St. Marks National Wilderness Area. No additional modeling was performed for nitrogen oxides of sulfur dioxide because the current project is not believed to result in increased emissions of these pollutants due to the federally enforceable emissions caps included in the PSD permit for Unit 8. The following table summarizes the applicant's modeling analysis.

Table 3C. CO and PM Impacts at Nearby St. Marks National Wilderness Area (Class I Area)

Pollutant	Averaging Period	Operating Scenario	Maximum Refined Concentration, ug/m^3
CO	24-hour	Units 7 and 8	7.75
		Auxiliary Boiler and Unit 7	4.90
		Auxiliary Boiler and Unit 8	6.68
PM	24-hour	Units 7 and 8	4.84
		Auxiliary Boiler and Unit 7	4.58
		Auxiliary Boiler and Unit 8	0.86

As shown in the above table, the requested revision will not result in any impacts greater than those allowed by the existing permit. The Department approves this request and the initial air construction permit will be revised accordingly.

Permit Project No. 1290001-006-AV (Revision to Title V Permit Air Operation Permit No. 1290001-003-AV)

The applicant requests a simultaneous revision of the Title V operating permit to incorporate the above changes. The Department approves the request and will provide a single public notice package for the three revised permits. The public notice will allow 30 days for public comment. If no administrative hearing is requested and no comments are received that would result in substantial changes, the two air construction permits (PSD-FL-239A and 1290001-002a-AC) will be issued as final permitting actions. The Title V revision will continue to the "proposed permit" phase of the Title V permitting process.

4. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the draft permits. This determination is based on a technical review of the complete application, reasonable assurances provided by the applicant, and the specific conditions of the draft permits. Jeff Koerner is the project engineer responsible for reviewing the application and drafting the permit. Deborah Galbraith was the project meteorologist responsible for review of the air quality analyses. Additional details of this analysis may be obtained by contacting the project engineer at the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

DRAFT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Robert E. McGarrah, Production Superintendent
City of Tallahassee - Electric Utilities
300 South Adams Street
Tallahassee, Florida 32301

Re: City of Tallahassee – Purdom Generating Station
Project No. 1290001-005-AC
Modification of Permit No. PSD-FL-239, Unit 8 Heat Input Increase and Excess Emissions Conditions
Modification of Permit No. 1290001-002-AC, Operation of Auxiliary Boiler with Unit 7 or Unit 8

Dear Mr. McGarrah:

On November 14, 2001, the Department received your request to make several changes to the original PSD permit for Unit 8 and the original air construction permit for the auxiliary boiler. Based on your initial application and subsequent additional information, the Department makes the following determinations and modifies these permits accordingly.

MODIFICATION OF PERMIT NO. PSD-FL-239 (UNIT 8)

Request No. 1: Revise the term "ambient temperature" to "compressor inlet temperature"; revise the temperature basis for the maximum heat input rates from 95° F to 59° F; revise the maximum heat input rate from gas firing to 1696 MMBtu/hour; and revise the maximum heat input rate from distillate oil firing to 1897 MMBtu/hour.

Determination: The request is approved subject to the following revisions of Permit No. PSD-FL-239.

Revise Condition No. A.2 from:

> "The maximum heat input rates, based on the lower heating value (LHV) of each fuel to Purdom Unit 8 at ambient conditions of 95° F temperature, 60% relative humidity, and 14.7 psi pressure shall not exceed 1,467.7 mmBtu/hr when firing natural gas, or 1659.5 mmBtu/hr when firing No. 2 fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. These curves or equations shall be used to establish the maximum allowable heat inputs at other ambient conditions for compliance determination."

To:

> "The maximum heat input rates, based on the lower heating value (LHV) of each fuel to Purdom Unit 8 at compressor inlet conditions of 59° F temperature, 60% relative humidity, and 14.7 psi pressure shall not exceed 1696 MMBtu/hour when firing natural gas or 1897 MMBtu/hour when firing No. 2 fuel oil. These maximum heat input rates will vary depending upon compressor inlet conditions and the combustion

turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other compressor inlet conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. These curves or equations shall be used to establish the maximum allowable heat inputs at other compressor inlet conditions for compliance determination."

Request No. 2: Authorize excess emissions due to major tuning of the dry low NOx (DLN) combustion system limited to no more than 72 hours per year.

Determination: The request is approved subject to the following revisions to Permit No. PSD-FL-239.

"Note a" under Condition B.1 is revised from:

"(a) 30-day rolling average excluding startup, shutdown, malfunction, and fuel switching."

To:

"(a) 30-day rolling average excluding authorized periods of startup, shutdown, malfunction, major DLN tuning sessions, and fuel switching."

Condition No. B.3 is revised from:

"Oxides of Nitrogen. Oxides of nitrogen emissions when firing natural gas shall not exceed 12 ppmvd at 15% O_2 on a 30-day rolling average basis (except during periods of startup, shutdown, malfunction, or fuel switching) as measured by CEMS. When monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate the 30-day rolling average."

To:

"Oxides of Nitrogen. Oxides of nitrogen emissions when firing natural gas shall not exceed 12 ppmvd at 15% O_2 on a 30-day rolling average basis (except during authorized periods of startup, shutdown, malfunction, major DLN tuning sessions, or fuel switching) as measured by CEMS. When monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate the 30-day rolling average."

Condition No. B.4 is revised from:

"Oxides of Nitrogen. Oxides of nitrogen emissions when firing No. 2 fuel oil shall not exceed 42 ppmvd at 15% O_2 on a 30-day rolling average basis (except during periods of startup, shutdown, malfunction or fuel switching), as measured by CEMS, when fuel bound nitrogen (FBN) values are less than or equal to 0.015 percent. For fuel bound nitrogen values up to 0.03 percent, the allowance (and the adjusted standard) shall be determined, recorded, and maintained for each fuel delivery by the following formula:"

To:

"Oxides of Nitrogen. Oxides of nitrogen emissions when firing No. 2 fuel oil shall not exceed 42 ppmvd at 15% O_2 on a 30-day rolling average basis (except during authorized periods of startup, shutdown, malfunction or fuel switching), as measured by CEMS, when fuel bound nitrogen (FBN) values are less than or equal to 0.015 percent. For fuel bound nitrogen values up to 0.03 percent, the allowance (and the adjusted standard) shall be determined, recorded, and maintained for each fuel delivery by the following formula:"

Also, Condition No. C.1 is revised as indicated under Request No. 3.

Request No. 3: For the 30-day rolling compliance average, allow excess emissions for a total of 6 hours in a 24-hour period that includes a cold startup and for a total of 4 hours in any 24-hour period and that includes a hot startup.

Determination: The request is approved and the following conditions of Permit No. PSD-FL-239 are revised.

Condition No. C.1 revised from:

"Excess emissions resulting from startup, shutdown, malfunction or fuel switching shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized but in no case exceed four hours in any 24-hour period for cold startup or two hours in any 24-hour period for other reasons unless specifically authorized by DEP for longer duration."

To:

"Excess emissions resulting from startup, shutdown, malfunction, or fuel switching shall be permitted providing best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed the following in any 24-hour period: a total of six hours during any day including a cold startup; a total of four hours during any day that includes a hot startup; and a total of two hours during days not including a hot or cold startup. A cold startup is startup after the combined cycle unit has been down for more than 48 hours. A hot startup is startup after the combined cycle unit has been down for 48 hours or less. A documented malfunction is a malfunction that is documented within one working day of detection by contacting the Department's Northwest District Office by telephone, facsimile transmittal, or electronic mail.

In addition to the above, excess emissions resulting from a major DLN tuning session shall be permitted provided the tuning session is performed in accordance with the manufacturer's specifications and in no case shall exceed 72 hours in any calendar year. A "major tuning session" would occur after a combustor change-out, a major repair to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice that details the activity and proposed tuning schedule. The notice may be made by telephone, facsimile transmittal, or electronic mail.

All quality-assured hourly NOx emissions data shall be used when demonstrating compliance with the emissions cap. When monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75).

[Rule 62-210.700(5), F.A.C.]"

Paragraph 6 in Condition D.1 revised from:

Determination of Oxides of Nitrogen emissions will be by a Continuous Emissions Monitoring System (CEMS). A CEMS operated and maintained in accordance with 40 CFR 75 may be used. Compliance with the NO_X emissions standards in Table 1 shall be demonstrated with this CEMS system based on a 30 day rolling average. Based on CEMS data at the end of each operating day, a new 30 day average emission rate is calculated from the arithmetic average of all valid hourly emission rates during the previous 30 operating days. Valid hourly emission rates shall not include periods of startup (including fuel switching), shutdown, or malfunction as defined in Rule 62-210.200 where emissions exceed the NO_X standard in Table 1. These excess emission periods shall be reported as required in Section C. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart.

To:

Determination of Oxides of Nitrogen emissions will be by a Continuous Emissions Monitoring System (CEMS). A CEMS operated and maintained in accordance with 40 CFR 75 may be used. Compliance with the NO_X emissions standards in Table 1 shall be demonstrated with CEMS data based on a 30-day rolling average. Based on CEMS data at the end of each operating day, a new 30-day average emission rate is calculated from the arithmetic average of all valid hourly emission rates during the previous 30 operating days. In accordance with Condition C.1, hourly emission rates shall not include periods of startup, shutdown, documented malfunction, fuel switching, or major tuning sessions where emissions exceed the NO_X standard in Table 1. These excess emission periods shall be reported as required in Section C. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart.

New Condition No. C.4 is added.

"Quarterly NOx Monitoring Report. Within 30 days following each calendar quarter, the permittee shall submit a report to the Department's Northwest District Office that summarizes the following information for the quarter.

a. Identify the hours of NOx emission data excluded from the compliance determination due to each of the following: startups, shutdowns, documented malfunctions, major tuning sessions, and fuel switches.

b. For each malfunction, identify the: date; approximate time range; duration (hours) of the malfunction; NOx emission levels during the malfunction; problem and cause of the problem (if known); and corrective action taken (if any).

c. Identify the hours of NOx monitoring system down time due to each of the following: monitor malfunctions; non-monitor malfunctions; quality assurance calibrations; other known causes; and unknown causes. Identify the monitor availability.

d. Monitor availability shall not be less than 95% in any calendar quarter. In the event that 95% availability is not achieved, the permittee shall include a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit.

[Rules 62-4.070(3), 62-4.130, 62-4.160(14)(b), 62-210.700(6), and Rule 62-212.400(BACT), F.A.C.]"

Revise Condition No. F.1 from:

"The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from Unit 8. Thirty day rolling average periods when NO_X emissions (ppmvd @ 15% oxygen) are above the BACT standards (12/42 ppmvd for gas/oil) shall be reported to the DEP Northwest District Office pursuant to Rule 62-4.160(8), F.A.C. The continuous emission monitoring systems must comply with the certification and quality assurance, and other applicable requirements from 40 CFR 75. Periods of startup, shutdown, malfunction, and fuel switching shall be monitored, recorded, and reported as excess emissions when emission levels exceed the standards in Table 1 following the format of 40 CFR 60.7 (1997 version). The NO_x CEMS shall be used in lieu of the water/fuel monitoring system and fuel bound nitrogen (FBN) monitoring required for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1997 version). The calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) (1997 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS. Upon request from DEP, the CEMS emission rates for NO_X on Unit 8 shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332."

To:

"The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from Unit 8. Thirty day rolling average periods when NO_X emissions (ppmvd @ 15% oxygen) are above the BACT standards (12/42 ppmvd for gas/oil) shall be reported to the DEP Northwest District Office pursuant to Rule 62-4.160(8), F.A.C. The continuous emission monitoring systems must comply with the certification and quality assurance, and other applicable requirements from 40 CFR 75. In accordance with Condition C.1, periods of startup, shutdown, malfunction, fuel switching, and major DLN tuning sessions shall be monitored, recorded, and reported as excess emissions when emission levels exceed the BACT standards in Table 1. With respect to NSPS Subpart GG, excess emissions shall be reported in accordance with 40 CFR 60.7 (2001 version). The NO_x CEMS shall be used in lieu of the water/fuel monitoring system and fuel bound nitrogen (FBN) monitoring required for reporting excess emissions in accordance with 40 CFR 60.334(c)(1) (2001 version). The calibration of the water/fuel monitoring device required in 40 CFR 60.335(c)(2) (2001 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS. Upon a request from the Department, the CEMS emission rates for NO_X on Unit 8 shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332."

Revise Condition G.5 from:

"Quarterly excess emission reports, in accordance with 40 CFR 60.7 (7) (c) (1997 version), shall be submitted to the DEP's Northwest District office."

To:

"In accordance with 40 CFR 60.7(7) (2001 version), semiannual excess emission reports shall be submitted to the Department's Northwest District Office. Each report is due no later than 30 days following the reporting period (January through June and July through December). The report shall summarize any emissions in excess of the NSPS Subpart GG standards and monitor downtime."

MODIFICATION OF PERMIT NO. 1290001-002-AC (AUXILIARY BOILER)

Request No. 4: Revise original air construction permit to allow operation of the auxiliary steam boiler when either Unit 7 or Unit 8 is not operating.

Determination: The request is approved and Condition No. 6 of Permit No. 1290001-002-AC is revised as follows.

From:

"This emissions unit shall only be operated as an auxiliary source of steam when the existing steam generating units (boilers 5, 6, & 7) are not operating. (Construction permit application)"

To:

"This emissions unit shall only be operated as an auxiliary source of steam when either Unit 7 or Unit 8 is not operating. {Permitting Note: Units 5 and 6 are permanently shut down.} (Construction permit application)"

Details of the Department's review are available in the Technical Evaluation and Preliminary Determination that accompanied the Draft Permit modification package. This permit modification is issued pursuant to Chapter 403 of the Florida Statutes. Attached are copies of original air permit Nos. PSD-FL-239 and 1290001-002-AC. A copy of this letter shall be filed with the referenced permit and shall become part of the permit.

Any party to this order (permit modification) has the right to seek judicial review of it under Section 120.68 of the Florida Statutes by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty (30) days after this order is filed with the clerk of the Department.

Sincerely,

(DRAFT)

____

Howard L. Rhodes, Director
Division of Air Resources Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit Modification was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on ____________ to the persons listed:

Mr. Robert E. McGarrah, City of Tallahassee *
Ms. Jennette Curtis, City of Tallahassee
Mr. Karl Bauer, P.E., City of Tallahassee
Ms. Sandra Veazey, NWD
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

Clerk Stamp

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

__________________________ __________
(Clerk) Date)

Purdom Generating Station
DRAFT Permit No. 1290001-006-AV
Revision of Title V Air Operation Permit No. 1290001-003-AV

PERMITTEE

City of Tallahassee
Sam O. Purdom Generating Station
Facility ID No. 1290001
Wakulla County, Florida

FACILITY DESCRIPTION

The facility consists of a fossil fuel-fired steam generator with steam-electrical turbine, a combined cycle gas turbine, two simple cycle combustion turbines, and one gas-fired auxiliary boiler. The total combined electrical generating capacity from the facility is a nominal 319 megawatts (MW), of which 134 megawatts are steam-generated electrical power and 185 megawatts are direct, shaft-driven electrical power from the combustion turbines. The facility-wide emissions of nitrogen oxides and sulfur dioxide are capped at 467 and 80 tons per year, respectively. The facility is considered a major source of air pollution with respect to Title III (hazardous air pollutants), Title IV (Acid Rain), Title V (operating permits), and the Prevention of Significant Deterioration (PSD). A description of each emissions unit follows.

Emissions Units 001 through 006: The emissions units are boilers that have been permanently shutdown.

Emission Units 007: The emissions unit is a Riley Stoker Corporation steam generator (Model No. RX-33), which is designated by the plant as "Unit 7". It is rated at a maximum heat input of 621 MMBtu per hour when fired with natural gas and/or No. 2 thru No. 6 fuel oil. It nominally produces 500,000 pounds of steam per hour to run a nominal 44 MW turbine-generator. It is a Phase II Acid Rain unit.

Emission Units 008 and 009: The emissions units are simple cycle combustion turbines manufactured by Westinghouse (Model No. W171G) and are designated as "Combustion Turbine Number 1" and "Combustion Turbine Number 2". Each unit is rated at a maximum heat input of 228 MMBtu per hour when fired with natural gas and/or No. 2 fuel oil. Each combustion turbine powers a nominal 12.3 MW generator. Emissions from the combustion turbines are uncontrolled.

Emission Units 010: The emissions unit includes miscellaneous fugitive sources of volatile organic compounds, such as plant painting operations.

Emission Units 011: The emission unit is a natural gas-fired auxiliary boiler (Kewanee Model No. H3S-400-G) rated at a maximum heat input rate of 16.74 MMBtu per hour. The unit is used as a source of steam for plant operations.

Emission Units 012: The emissions unit includes miscellaneous general purpose internal combustion engines.

Emission Units 011: The emissions unit includes miscellaneous emergency generators.

Emission Units 014: This emissions unit is a combined cycle combustion turbine system designated as Unit 8. It consists of a nominal 160 MW General Electric Series 7FA combustion turbine, an unfired heat recovery steam generator, and a nominal 90 MW steam-electrical turbine. NOx emissions are controlled with dry low NOx combustion when firing natural gas and water injection when firing distillate oil. An evaporative cooling system can reduce the compressor inlet air temperature when needed. It is a Phase II Acid Rain unit.

PROJECT DESCRIPTION

Initial Title V Permit No. 1290001-001-AV became effective on January 1, 1998. On August 7, 1998, Project No. 1290001-003-AV revised the initial permit to incorporate permit number PSD-FL-239/PA97-36, which authorized construction of Unit 8, a new combined cycle combustion turbine. Project No. 1290001-006-AV is a revision to incorporate Permit Project No. 1290001-005-AC, which modified air construction Permit No. PSD-FL-239 for Unit 8 and modified air construction Permit No. 1290001-002-AC for the auxiliary boiler.

For Unit 8, the following changes are:

- Clarify that the heat input rate is a function of the compressor inlet temperature and not necessarily ambient temperature. The unit includes an evaporative cooling system to lower the compressor inlet temperature during warm weather to provide additional power. Revise the temperature basis for the heat input rate from 95° F to 59° F.
- Increase the heat input rate by approximately 8.5% for gas firing and 6.6% for distillate oil firing. As constructed, the General Electric 7FA gas turbine is capable of higher heat input rates and power production.
- Allow periods of excess emissions resulting from major tuning of the dry low NOx combustion system (up to 72 hours per year). A "major tuning session" would occur after a combustor change-out, a major repair to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice that details the activity and proposed tuning schedule. The notice may be made by telephone, facsimile transmittal, or electronic mail.
- Increase authorized periods of excess emissions from 4 to 6 hours per day during days with cold startups. A cold startup is startup after the combined cycle unit has been down for more than 48 hours. This clarifies that it may be necessary to operate the gas turbine at low loads for up to four hours to bring all components up to operating temperatures. It also recognizes that other incidents could occur within the same day, such as a malfunction, fuel switch, shutdown, or hot startup.
- Increase authorized periods of excess emissions from 2 to 4 hours per day during days with a hot startup. This recognizes that multiple incidents could occur within the same day, such as a hot startup, malfunction, fuel switch, or shutdown.

For the auxiliary boiler, the original construction permit limited operation to periods when Units 5, 6, and 7 were not in operation. Units 5 and 6 have been permanently shutdown. The change authorizes operation when either Unit 7 or Unit 8 is not in operation.

Conditions throughout the Title V permit were revised to be consistent with the above modifications. The emissions unit ID number for Unit 8 was corrected from "012" to "014" to be consistent with the state database. In addition, the specific conditions for Units 5 and 6 were deleted because these units have been permanently shutdown. The section was kept as a placeholder and text was added about the permanent shutdowns. This section will be removed entirely during the Title V renewal project.

AGENCY ACTION

The Title V air operation permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-210, and 62-213 of the Florida Administrative Code (F.A.C.).

City of Tallahassee

Sam O. Purdom Generating Station

Facility ID No. 1290001

Leon County

Title V Air Operation Permit

DRAFT Permit No. 1290001-006-AV

Project Description:

Permit Revision to Include

Miscellaneous Changes for Unit 8 and the Auxiliary Boiler

Permitting Authority

State of Florida

Department of Environmental Protection

Division of Air Resources Management

Bureau of Air Regulation

Title V Section

Mail Station #5505

2600 Blair Stone Road

Tallahassee, Florida 32399-2400

Telephone: 850/488-1344

Fax: 850/922-6979

Title V Air Operation Permit

Table of Contents

Permittee:
City of Tallahassee, Electric Utilities
300 South Adams Street
Tallahassee, Florida 32301

DRAFT Permit No. 1290001-006-AV
Facility ID No. 1290001
SIC Nos. 49, 4911
Project: Revised Title V Operation Permit Miscellaneous Changes for Unit 8 and the Auxiliary Boiler

This permit is for the operation of the Sam O. Purdom Generating Station. This facility is located at 667 Port Leon Drive, St. Marks, Wakulla County; UTM Coordinates: Zone 16, 769.5 km East and 3339.97 km North; Latitude: 30° 09' 47" North and Longitude: 84° 12' 10" West.

STATEMENT OF BASIS: This Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213, and 62-214. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit. This revision modified the Title V air operation permit to reflect: increased heat input rates for Unit 8, revised periods of authorized excess emissions for Unit 8, a revised operational restriction for the auxiliary boiler, and permanent shutdown of Boilers 5 and 6.

Referenced attachments made a part of this permit:
Appendix I-1, List of Insignificant Emissions Units and/or Activities
Appendix U-1, List of Unregulated Emissions Units and/or Activities
Phase II Acid Rain Permit Application/Compliance Plan received December 20, 1995
Permit Number 1290001-002-AC (as modified)
BACT Determination Dated October 8, 1996
Permit Number PSD-FL-239/PA97-36 (as modified), Including BACT Determination
Appendix SS-1, Stack Sampling Facilities (version dated 10/7/96)
Appendix TV-1, Title V Conditions (version dated 12/2/97)
ASP Number 97-B-01
Scrivener's Order Correcting ASP Number 97-B-01 (dated July 9, 1997)
Figure 1: Summary Report-Gaseous and Opacity Excess Emission and Monitoring System Performance (40 CFR 60, July, 1996)

Effective Date: January 1, 1998
Revised Date: (Draft)
Renewal Application Due Date: July 5, 2002
Expiration Date: December 31, 2002

DRAFT

Howard L. Rhodes, Director
Division of Air Resources Management

HLR/SMS/jfk

Section I. Facility Information.

Subsection A. Facility Description.

This facility consists of ~~three~~ a fossil fuel-fired steam generators, two simple cycle combustion turbines, ~~and~~ one auxiliary boiler, and a combined cycle gas turbine. ~~One of the steam generators, Boiler Number 7, is an~~ Units 7 and 8 are Acid Rain Phase II Units. The total combined electrical generating capacity from the facility is a nominal ~~112.6~~ 318.6 megawatts (MW), of which a nominal ~~88~~ 134 megawatts are provided by the steam generators and a nominal ~~24.6~~ 184.6 megawatts are provided by the combustion turbines. The fuels used at this facility are natural gas and fuel oil. The auxiliary boiler is only used as a source of steam for plant operations when ~~none of the other steam generating units are~~ either Unit 7 or 8 is not operating. Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

~~In addition to the above described emissions units, a new combined cycle combustion turbine is being added. It is expected to begin operation during the spring/summer of 2000 and will be subject to Acid Rain, Phase II. This new unit will be designated as Unit 8. It will provide an additional 250 megawatts (nominal rating) of electrical output by burning natural gas and/or No. 2 fuel oil. After the initial compliance testing is completed on Unit 8, Units 5 and 6 will permanently cease operations, leaving the facility with a combined electrical output of 318.6 megawatts (nominal rating). With the operation of this new unit, t~~The facility-wide emissions of nitrogen oxides and sulfur dioxide ~~will be~~ are capped at 467 and 80 tons per year, respectively.

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

The use of 'Permitting Notes' throughout this permit are for informational purposes, only, and are not permit conditions.

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

Regulated Emissions Units:

E.U. ID No.	Brief Description
-005	Boiler Number 5 - 300 MMBtu/hour (Permanently Shutdown)
-006	Boiler Number 6 - 300 MMBtu/hour (Permanently Shutdown)
-007	Boiler Number 7 - 621 MMBtu/hour (Acid Rain, Phase II Unit)
-008	Combustion Turbine Number 1 - 228 MMBtu/hour
-009	Combustion Turbine Number 2 - 228 MMBtu/hour
-010	Fugitive VOC Sources - Painting Operations
-011	Auxiliary Boiler - 16.74 MMBtu/hour
~~-012~~ 014	Combustion Turbine Number 8 - ~~1,659.5~~ 1897 MMBtu/hour (Acid Rain, Phase II Unit)

Unregulated emissions Units and/or Activities (See Appendix U-1):

E.U. ID No.	**Brief Description**
-010	Fugitive VOC Sources - Painting Operations
~~-xxx~~012	General Purpose Engines
~~-yyy~~013	Emergency Generators

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

Subsection C. Relevant Documents.

The following documents are part of this permit:
Appendix I-1, List of Insignificant Emissions Units and/or Activities
Appendix U-1, List of Unregulated Emissions Units and/or Activities
Phase II Acid Rain Permit Application/Compliance Plan received December 20, 1995
Appendix SS-1, Stack Sampling Facilities (version dated 10/7/96)
Appendix TV-1, Title V Conditions (version dated 12/2/97)
Permit Number 1290001-002-AC (as modified)
BACT Determination Dated October 8, 1996
Permit Number PSD-FL-239/PA97-36 (as modified), including BACT Determination Dated, May 28, 1998
ASP Number 97-B-01
Scrivener's Order Correcting ASP Number 97-B-01 (dated July 9, 1997)
Figure 1: Summary Report-Gaseous and Opacity Excess Emission and Monitoring System Performance (40 CFR 60, July, 1996)

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

These documents are provided to the permittee for information purposes only:
Appendix H-1, Permit History / ID Number Changes
Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers (version dated 2/5/97)
Table 1-1, Summary of Air Pollutant Standards and Terms
Table 2-1, Summary of Compliance Requirements

These documents are on file with the permitting authority:
Initial Title V Permit Application Received June 14, 1996
Additional Information Request Dated September 26, 1996
Additional Information Response Received December 24, 1996
Site Certification Application/Application to Amend Initial Title V Permit Dated March 7, 1997
City of Tallahassee Letter Dated March 7, 1997
City of Tallahassee Letter Dated March 21, 1997
City of Tallahassee Letter Dated April 16, 1997
City of Tallahassee Letter Dated April 25, 1997
Jonathan Holtom Memo to file dated May 9, 1997
City of Tallahassee Letter Dated June 24, 1997
City of Tallahassee Letter Dated October 29, 1997
Application to Amend Initial Title V Permit (as revised July 16, 1997)
Initial Title V permit - 1290001-001-AV
(Final on August 27, 1997, Issued October 9, 1997, Effective January 1, 1998)
City of Tallahassee Letter Dated December 12, 1997
City of Tallahassee Letter Dated December 15, 1997
Administrative Correction (Permit/Project Number 1290001-004-AV) dated January 2, 1998
Application No. 1290001-005-AV Received on November 14, 2001 to Revise Permit No. PSD-FL-239 (Unit 8) and 1290001-002-AC (Auxiliary Boiler)
Application No. 1290001-006-AV Received on November 14, 2001 to Revise Initial Title V Permit

Section II. Facility-wide Conditions.

The following conditions apply facility-wide:

1. Appendix TV-1, Title V Conditions (version dated 12/2/97), is a part of this permit.

{Permitting note: Appendix TV-1, 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. Prevention of Accidental Releases (Section 112(r) of CAA). If required by 40 CFR 68, the permittee shall submit to the implementing agency:

a. a risk management plan (RMP) when, and if, such requirement becomes applicable, and
b. certification forms and/or RMPs according to the promulgated rule schedule.

[40 CFR 68]

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

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

6. General Pollutant Emission Limiting Standards. Volatile Organic Compounds Emissions or Organic Solvents Emissions. The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department.
{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.}
[Rule 62-296.320(1)(a), F.A.C.]

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

8. Not federally enforceable. Reasonable precautions to prevent emissions of unconfined particulate matter at this facility include:

a. The portable concrete mixer shall be operated on an as-needed basis. Reasonable precautions include enclosing the activity where practical.

b. Abrasive blasting activities that are associated with normal maintenance and corrosion control activities shall be enclosed where practical.

c. Unconfined emissions associated with the limited on-site traffic shall be controlled by limiting vehicle speeds and unnecessary traffic within the plant grounds.

d. During construction of unit 8, a combination of the following techniques will be implemented:
   1. Contractors will be instructed to comply with any applicable state and local regulations governing open-bodied trucks hauling sand, gravel, or soil between on-site and off-site areas.
   2. Areas disturbed during construction will be stabilized by mulching or seeding as soon as practicable.
   3. When construction occurs on bare ground, water (possibly together with non-hazardous wetting agents) will be used as necessary to help suppress dust.
   4. Temporary vehicular surfaces of crushed rock may be used in high traffic areas. Areas not subject to heavy traffic or continual disturbance will be wetted down as needed using non-toxic substances to help suppress dust.
   5. Sandblasting operations will be localized to minimize effects on adjacent work areas. Protective covers will also be utilized where practicable.
   6. Surface coating activities will include the initial painting of the combined cycle unit 8 and the associated facilities. Activities will be enclosed whenever practicable.

[Rule 62-296.320(4)(c)2., F.A.C.; and, proposed by applicant in initial Title V permit application received June 14, 1996, and amended by comments received April 25, 1997; and by Site Certification Application received March 7, 1997, and amended July 16, 1997.]

{Permitting Note: Condition No. 8 presents the reasonable precautions to be implemented in accordance with Rule 62-296.320(4)(c)2, F.A.C., in lieu of the requirements of Condition No. 58 of Appendix TV-1.}

9. 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.]

10. The Department's Northwest District Branch Office (Tallahassee) telephone number for reporting problems, malfunctions or exceedances under this permit is 850/488-3704, day or night, and for emergencies involving a significant threat to human health or the environment is 850/413-9911. The Department's Northwest District Office (Pensacola) telephone number for routine business, including compliance test notifications, is 850/444-8364 during normal working hours.

11. The permittee shall submit all compliance related notifications and reports required of this permit (other than Acid Rain Program Information) to the Department's Northwest District office:

Department of Environmental Protection
Northwest District Office
160 Governmental Center
Pensacola, Florida 32501-5794
Telephone: 850/444-8364
Fax: 850/444-8417

Acid Rain Program Information shall be submitted, as necessary, to:

Department of Environmental Protection
2600 Blair Stone Road
Mail Station #5510
Tallahassee, Florida 32399-2400
Telephone: 850/488-6140
Fax: 850/922-6979

12. Any reports, data, notifications, certifications, and requests (other than Acid Rain Program Information) 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
Operating Permits Section
61 Forsyth Street
Atlanta, Georgia 30303
Telephone: 404/562-9099
Fax: 404/562-9095

Acid Rain Program Information should be sent to:

United States Environmental Protection Agency, Region 4
Air, Pesticides & Toxics Management Division
Acid Rain Section
61 Forsyth Street
Atlanta, Georgia 30303
Telephone: 404/562-9102
Fax: 404/562-9095

Emission Limitations and Standards

13. Sulfur Dioxide. Beginning with the calendar year following successful completion of the initial performance test for Unit 8, annual emissions of SO_2 shall not exceed 80 tons per year from the Purdom facility (Unit 8, Unit 7, GT1, GT2, and the auxiliary boiler) on a calendar year basis, as measured by applicable compliance methods.
[PSD-FL-239/PA97-36; and, Applicant request.]

14. Compliance with the annual facility-wide SO_2 cap shall be reported as required in Condition G.6. (Appendix GC) and shall be determined by adding the annual SO_2 emissions (in tons per year) determined by the methods required by 40 CFR 75 for Unit 8 along with existing Unit 7 to the annual SO_2 emissions calculated for existing units GT1, GT2 and the auxiliary boiler, as determined by the following formulas:

GT 1 & GT 2 SO_2 Emissions (natural gas) =
(Fuel Usage) **x** (Heating Value of Natural Gas) **x** (0.0006 lb/MMBtu) **x** (units conversion factors)

-Fuel usage shall be measured by a fuel meter, recorded daily, when the units are operated
-Heating Value of Natural Gas shall be determined from fuel supplier data
-Sulfur Content default of NADB = 0.0006 lb-SO_2/mmBtu

GT 1 & GT 2 SO_2 Emissions (fuel oil) = (Fuel Usage) **x** (Fraction Sulfur in the fuel oil) **x** (Molecular weight SO_2 / Molecular weight of S) **x** (Conversion factor) **x** (units conversion factors)

-Fuel usage shall be measured by a fuel meter, recorded daily when units are operated
-% Sulfur will be determined from fuel oil analysis each time fuel is delivered
(i.e., 0.05% S = 0.0005 in above formula)
-Molecular weight of SO_2 = 64
-Molecular weight of S = 32
-Conversion factor of 95% = 0.95

Aux. Boiler SO_2 Emissions (natural gas) =
(Fuel Usage) **x** (Heating Value of Natural Gas) **x** (0.0006 lb/MMBtu) **x** (units conversion factors)

-Fuel usage shall be measured by a fuel meter, recorded daily, when the unit is operated
-Heating Value of Natural Gas shall be determined from fuel supplier data
-Sulfur Content default of NADB = 0.0006 lb/MMBtu
[PSD-FL-239/PA97-36; and, Applicant request.]

15. Nitrogen Oxides. Beginning with the calendar year following successful completion of the initial performance test for Unit 8, annual emissions of NO_X shall not exceed 467 tons per year from the Purdom facility (Unit 8, Unit 7, GT1, GT2, and the auxiliary boiler) on a calendar year basis, as measured by applicable compliance methods.
[PSD-FL-239/PA97-36; and, Applicant request.]

16. Compliance with the annual facility-wide NO_X cap shall be reported as required in Condition G.6. (Appendix GC) and shall be determined by adding the annual NO_X emissions (in tons per year) determined by the CEMS required by 40 CFR 75 for Unit 8 along with existing Unit 7 to the annual NO_X emissions calculated for existing units GT1, GT2 and the auxiliary boiler, as determined by the following formulas:

GT 1 & GT 2 NO_X (natural gas) =
(Fuel Usage) **x** (Heating Value of Natural Gas) **x** (0.44 lb/MMBtu) **x** (units conversion factors)

-Fuel usage shall be measured by a fuel meter, recorded daily, when the units are operated
-Heating Value of Natural Gas will be determined from fuel supplier data
0.44 lb/MMBtu = AP-42 emission factor

GT 1 & GT 2 NO_X (fuel oil) =
(Fuel Usage) **x** (Heating Value of Fuel Oil) **x** (0.698 lb/MMBtu) **x** (units conversion factors)

-Fuel usage shall be measured by a fuel meter, recorded daily, when the units are operated
-Heating Value of Fuel Oil will be determined from fuel supplier data
-0.698 lb/MMBtu = AP-42 emission factor

Aux. Boiler NO_X (natural gas) = (Fuel Usage) **x** (140 lb/MMCF) **x** (units conversion factors)

-Fuel usage shall be measured by a flow meter, recorded daily, when the unit is operated
-140 lb/MMCF = AP-42 emission factor
[PSD-FL-239/PA97-36; and, Applicant request.]

Reporting Requirements

17. 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 No. 52., Appendix TV-1, Title V Conditions.}
[Rule 62-214.420(11), F.A.C.]

Section III. Emissions Units.

Subsection A. This section addresses the following emissions units.

E.U. ID No.	**Brief Description**
-005	Boiler Number 5 (Permanently Shutdown)
-006	Boiler Number 6 (Permanently Shutdown)

Boiler Nos. 5 and 6 are permanently shutdown and are specifically NOT authorized to operate. This action was required as part of the PSD permit project for Unit 8 combined cycle gas turbine project. References to Boiler Nos. 5 and 6 will be removed during the renewal of the Title V operation permit.

<u>Subsection B. This section addresses the following emissions unit.</u>

E.U. ID No.	**Brief Description**
-007	Boiler Number 7, (Phase II Acid Rain Unit)

This is a Riley Stoker Corporation model RX-33 steam generator designated as "Boiler Number 7". It is rated at a maximum heat input of 621 MMBtu/hour while being fueled with natural gas and/or No. 2 thru No. 6 fuel oil. It nominally produces 500,000 pounds of steam per hour to run a nominal 44 MW turbine-generator.

{Permitting notes: This emissions unit is regulated under Acid Rain, Phase II. This unit pre-dates PSD regulations, but is regulated under Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators With More Than 250 Million BTU per Hour Heat Input. Boiler Number 7 began commercial operation in 1966. Stack height = 180 feet, exit diameter = 9.0 feet, exit temperature = 300 °F, actual volumetric flow rate = 180,798 acfm. Emissions from this boiler are uncontrolled.}

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

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

B.1. <u>Permitted Capacity</u>. The maximum operation heat input rates are as follows:

Unit No.	MMBtu/hr Heat Input	Fuel Type
7	621	Natural Gas
	621	No. 2 thru No. 6 Fuel Oil; On-Specification Used Oil

[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.405, F.A.C.; and, Applicant's request.]

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

B.3. <u>Methods of Operation - Fuels</u>. The fuels that are allowed to be burned in this boiler are natural gas and/or new No. 2 thru No. 6 fuel oil and/or on-specification used oil. See specific condition **B.24.**
[Rule 62-213.410, F.A.C.; and, Applicant Request dated June 24, 1997.]

B.4. <u>Hours of Operation</u>. This emissions unit may operate continuously, i.e. 8760 hours/year. The permittee shall maintain an operation log available for Department inspection that documents the total hours of annual operation, including a detailed account of the hours operated on each of the allowable fuels.
[Rule 62-210.200(PTE), F.A.C.; and, AO65-242831, Specific Condition #3.]

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.}

B.5. Visible Emissions. Visible emissions shall not exceed 20 percent opacity, except for one two-minute period per hour during which opacity shall not exceed 40 percent. Emissions units governed by this visible emissions limit shall compliance test for particulate matter emissions annually and as otherwise required by Chapter 62-297, F.A.C.
[Rule 62-296.405(1)(a), F.A.C.]

B.6. Visible Emissions - Soot Blowing and Load Change. Visible emissions shall not exceed 60 percent opacity 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 a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.
[Rule 62-210.700(3), F.A.C.]

B.7. Particulate Matter. Particulate matter emissions shall not exceed 0.1 pound per million Btu heat input, as measured by applicable compliance methods.
[Rule 62-296.405(1)(b), F.A.C.]

B.8. Particulate Matter - Soot Blowing and Load Change. Particulate matter emissions shall not exceed an average of 0.3 pound per million Btu heat input during the 3 hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.
[Rule 62-210.700(3), F.A.C.]

B.9. Sulfur Dioxide. Sulfur dioxide emissions shall not exceed 1.87 pounds per million Btu heat input , as measured by applicable compliance methods.
[Rule 62-296.405(1)(c)1.h., F.A.C.]

B.10. Sulfur Dioxide - Sulfur Content. The No. 2 thru No. 6 fuel oil sulfur content shall not exceed 1.70 percent, by weight. See specific condition **B.17.** and common condition **C.9.**
[Rule 62-296.405(1)(e)3., F.A.C.; and, requested by applicant in a letter dated April 16, 1997.]

B.11. This emissions unit is also subject to the conditions contained in **Subsection C. Common Conditions**, as specified below.

Excess Emissions

B.12. See common conditions **C.1. - C.3.**

Monitoring of Operations

{Permitting Note: In accordance with the Acid Rain Phase II requirements, the following continuous monitors are installed on this unit: Gas Fuel Flow, Oil Fuel Flow, NO_x and CO_2.}

B.13. Sulfur Dioxide. **The permittee elected to demonstrate compliance by accepting a liquid fuel sulfur limit that will be verified with a fuel analysis provided by the vendor upon each fuel delivery.** This protocol is allowed because the emissions unit does not have an operating flue gas desulfurization device. See specific conditions **B.10., C.8. and C.9.**
[Rule 62-296.405(1)(f)1.b., F.A.C.; and, requested by applicant in a letter dated April 16, 1997.]

B.14. Determination of Process Variables. See common condition **C.4.**

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.15. Visible Emissions. See common conditions **C.5., C.6.** and **C.16.**

B.16. Particulate Matter. See common conditions **C.7., C.17.** and **C.21.**

B.17. Sulfur Dioxide. See specific condition **B.13** and common conditions **C.8.** and **C.9.**

B.18. Operating Rate During Testing. See common condition **C.11.**

B.19. Calculation of Emission Rate. See common condition **C.12.**

B.20. Applicable Test Procedures. See common condition **C.13.**

B.21. Required Stack Sampling Facilities. See common condition **C.14.**

B.22. Frequency of Compliance Tests. See common condition **C.15.**

Recordkeeping and Reporting Requirements

B.23. See common conditions **C.18. - C.20.**

Miscellaneous Conditions.

B.24. Used Oil. Burning of on-specification used oil is allowed in this emissions unit in accordance with all other conditions of this permit and the following conditions:

a. On-specification Used Oil Emissions Limitations: This emissions unit is 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: This emissions unit is permitted to burn "on-specification" used oil that is generated by the City of Tallahassee in the production and distribution of electricity, not to exceed 10,000 gallons during any calendar year.

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 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 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).

In addition to the above requirements, the owner or operator shall sample and analyze each batch of used oil to be burned for the sulfur content (by weight), density and heat content in accordance with approved test 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:

(1) The gallons of on-specification used oil placed into inventory to be burned and the gallons of on-specification used oil burned each month.

(2) Results of the analyses of each deposit of used oil, as required by the above conditions.

(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.

[40 CFR 279.72(b), 40 CFR 279.74(b) and 40 CFR 761.20(e)]

g. Reporting Requirements: The owner or operator shall submit, with the Annual Operation Report form, the analytical results required above and the total amount of on-specification used oil placed into inventory to be burned and the total amount of on-specification used oil burned during the previous calendar year.

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

B.25. Sufficient records shall be maintained to ensure that the total facility-wide SO_2 emissions do not exceed 80 tons per year (see facility-wide conditions **13. & 14.**).
[Rule 62-213.440, F.A.C.; PSD-FL-239/PA97-36; and, Applicant request.]

B.26. Sufficient records shall be maintained to ensure that the total facility-wide NO_X emissions do not exceed 467 tons per year (see facility-wide conditions **15. & 16.**).
[Rule 62-213.440, F.A.C.; PSD-FL-239/PA97-36; and, Applicant request.]

Subsection C. Common Conditions.

{Permitting Note: The following conditions are common to Boiler~~s No. 5, No. 6 and~~ No. 7, as specified in Subsections A and B, and to the auxiliary boiler as specified in Subsection E. They are placed here as a convenience and to avoid duplication.}

Excess Emissions

C.1. Excess emissions resulting from 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.]

C.2. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.
[Rule 62-210.700(2), F.A.C.]

C.3. 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

C.4. 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

C.5. Visible Emissions. The test method for visible emissions shall be DEP Method 9, incorporated in Chapter 62-297, F.A.C. A transmissometer may be used and calibrated according to Rule 62-297.520, F.A.C. See specific condition **C.6.**
[Rule 62-296.405(1)(e)1., F.A.C.]

C.6. 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.
[Rule 62-297.401, F.A.C.]

C.7. Particulate Matter. The test methods for particulate emissions shall be EPA Methods 17, 5, 5B, or 5F, incorporated by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be 30 dry standard cubic feet. EPA Method 5 may be used with filter temperature no more than 320 degrees Fahrenheit. For EPA Method 17, stack temperature shall be less than 375 degrees Fahrenheit. The owner or operator may use EPA Method 5 to demonstrate compliance. EPA Method 3 or 3A with Orsat analysis shall be used when the oxygen based F-factor, computed according to EPA Method 19, is used in lieu of heat input. Acetone wash shall be used with EPA Method 5 or 17.
[Rules 62-296.405(1)(e)2. and 62-297.401, F.A.C.]

C.8. Sulfur Dioxide. The test methods for sulfur dioxide emissions shall be EPA Methods 6, 6A, 6B, or 6C, incorporated by reference in Chapter 62-297, F.A.C. Fuel sampling and analysis may be used as an alternate sampling procedure if such a procedure is incorporated into the operation permit for the emissions unit. If the emissions unit obtains an alternate procedure under the provisions of Rule 62-297.620, F.A.C., the procedure shall become a condition of the emissions unit's permit. The Department will retain the authority to require EPA Method 6 or 6C if it has reason to believe that exceedences of the sulfur dioxide emissions limiting standard are occurring. Results of an approved fuel sampling and analysis program shall have the same effect as EPA Method 6 test results for purposes of demonstrating compliance or noncompliance with sulfur dioxide standards. **The permittee may use the EPA test methods, referenced above, to demonstrate compliance; however, as an alternate sampling procedure authorized by permit, the permittee elected to demonstrate compliance by accepting a**

liquid fuel sulfur limit that will be verified with a fuel analysis provided by the vendor upon each fuel delivery. See specific conditions **A.10., B.10. and C.9.**
[Rules 62-213.440, 62-296.405(1)(e)3. and 62-297.401, F.A.C.; and, AO65-242831.]

C.9. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest editions.
[Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.440, F.A.C.]

<u>Compliance Test Requirements</u>

C.10. <u>Required Number of Test Runs</u>. 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.]

C.11. <u>Operating Rate During Testing</u>. 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 (i.e., at less than 90 percent of the maximum operation rate allowed by the permit); 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.
[Rules 62-297.310(2) & (2)b., F.A.C.]

C.12. <u>Calculation of Emission Rate</u>. 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.]

C.13. 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.

TABLE 297.310-1
CALIBRATION SCHEDULE

ITEM	MINIMUM CALIBRATION FREQUENCY	REFERENCE INSTRUMENT	TOLERANCE
Liquid in glass thermometer	Annually	ASTM Hg in glass ref. thermometer or equivalent, or thermometric points	+/-2%
Bimetallic thermometer	Quarterly	Calib. liq. in glass thermometer	5 degrees F
Thermocouple	Annually	ASTM Hg in glass ref. thermometer, NBS calibrated reference and potentiometer	5 degrees F
Barometer	Monthly	Hg barometer or NOAA station	+/-1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Fig. 2-2 & 2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded	Micrometer	+/-0.001" mean of at least three readings Max. deviation between readings .004"
Dry Gas Meter and Orifice Meter	1. Full Scale: When received, When 5% change observed, Annually 2. One Point: Semiannually	Spirometer or calibrated wet test or dry gas test meter	2%
	3. Check after each test series	Comparison check	5%

(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.]

C.14. 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.]

C.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.

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 fuel for more than 400 hours other than during startup.
3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
    a. Did not operate; or
    b. In the case of a fuel burning emissions unit, burned liquid fuel for a total of no more than 400 hours.
4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
    a. Visible emissions, if there is an applicable standard;
    b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 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 fuel, other than during startup, for a total of more than 400 hours.
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.

9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

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

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

[Rule 62-297.310(7), F.A.C.; AO65-242831, Specific Condition #5 (frequency); and, SIP approved.]

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

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

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

C.17. Particulate Matter testing - Annual and Permit Renewal. Annual and permit renewal compliance testing for particulate matter emissions is not required for these emissions units while burning:

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

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

Recordkeeping and Reporting Requirements

{Permitting Note: The reports that are required by the following conditions are to be sent to the Department of Environmental Protection's Northwest District Office, 160 Governmental Center, Pensacola, Florida 322501-5794}

C.18. In the case of excess emissions resulting from malfunctions, the owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rule 62-210.700(6), F.A.C.]

C.19. The owner or operator shall submit to the Department a written report of emissions in excess of emission limiting standards as set forth in Rule 62-296.405(1), F.A.C., for each calendar quarter. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the Source for a period of five years.
[Rules 62-213.440 and 62-296.405(1)(g), F.A.C.]

C.20. Test Reports.

(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.

(b) The required test report shall be filed with the Department 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.]

<u>**Miscellaneous Conditions**</u>

C.21. If particulate matter and visible emissions tests are required, the tests shall be conducted concurrently and shall be performed using the maximum fuel oil/natural gas ratio that can be fired while meeting the standards.
[Rule 62-4.070(3), F.A.C.; and, Applicant request dated April 25, 1997.]

<u>Subsection D. This section addresses the following emissions units.</u>

E.U. ID No.	**Brief Description**
-008	Combustion Turbine Number 1
-009	Combustion Turbine Number 2

These emissions units are simple cycle combustion turbines manufactured by Westinghouse (model number W171G) and are designated as "Combustion Turbine Number 1" and "Combustion Turbine Number 2". They are each rated at a maximum heat input of 228 million Btu per hour (MMBtu/hour) while being fueled by natural gas and/or No. 2 fuel oil. Each of these combustion turbines run a nominal 12.3 MW generator. Emissions from the combustion turbines are uncontrolled.

{Permitting notes: These emissions units are regulated under Rule 62-210.300, F.A.C., Permits Required. These units are not subject to 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines. Combustion Turbine Number 1 began commercial operation in 1963. Combustion Turbine Number 2 began commercial operation in 1963. Each combustion turbine has its own stack. Stack height = 38 feet, exit diameter = 10 feet, exit temperature = 880 °F, actual volumetric flow rate = 395,080 acfm.}

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

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

D.1. <u>Permitted Capacity</u>. The maximum operation heat input rates are as follows:

Unit No.	MMBtu/hr Heat Input	Fuel Type
8	228 (LHV @ 80 degrees Fahrenheit)	Natural Gas
	228 (LHV @ 80 degrees Fahrenheit)	No. 2 Fuel Oil
9	228 (LHV @ 80 degrees Fahrenheit)	Natural Gas
	228 (LHV @ 80 degrees Fahrenheit)	No. 2 Fuel Oil

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

D.2. <u>Emissions Unit Operating Rate Limitation After Testing</u>. See specific condition **D.13.**
[Rule 62-297.310(2), F.A.C.]

D.3. <u>Methods of Operation - Fuels</u>. Only natural gas and/or new No. 2 fuel oil shall be fired in these turbines.
[Rule 62-213.410, F.A.C.]

D.4. Hours of Operation. Until the initial performance test on Unit 8 has been completed, each combustion turbine may operate 6993 hours per year. After that time, the hours of operation are not limited, but the units are subject to the NO_x and SO_2 facility wide emissions caps. The permittee shall maintain an operation log available for Department inspection that documents the total hours of annual operation, including a detailed account of the hours operated on each of the allowable fuels.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and, AO65-242827, Specific Condition #3.]

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 from each turbine shall not be equal to or greater than 20 percent opacity.
[Rule 62-296.320(4)(b)1., F.A.C.; and, AO65-242827.]

D.6. Sulfur Dioxide - Sulfur Content. The sulfur content of the No. 2 fuel oil shall not exceed 0.4 percent, by weight. After the initial performance test for Unit 8 is completed, the sulfur content of the No. 2 fuel oil shall not exceed 0.05%, by weight. See specific condition **D.12.**
[AO65-242827; applicant request on initial Title V application received June 14, 1996; PSD-FL-239/PA97-36; and, BACT.]

Excess Emissions

D.7. Excess emissions from these 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. Sulfur Dioxide. 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. See specific conditions **D.6. and D.12.**
[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 Content. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest editions.
[Rules 62-213.440 and 62-297.440, F.A.C.]

D.13. Operating Rate During Testing. Testing of emissions shall be conducted with each emissions unit operating at permitted capacity, which is defined as 95-100 percent of the manufacturer's rated heat input achievable for the average ambient (or conditioned) air temperature during the test. If it is impracticable to test at capacity, then sources may be tested at less than capacity. In such cases, the entire heat input vs. inlet temperature curve will be adjusted by the increment equal to the difference between the design heat input value and 105 percent of the value reached during the test. Data, curves, and calculations necessary to demonstrate the heat input rate correction at both design and test conditions shall be submitted to the Department with the compliance test report.
[AO65-242827 Specific Condition No. 2; and, Applicant Request dated June 24, 1997.]

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., 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.
9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

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

[Rule 62-297.310(7), F.A.C.; AO65-242827, Specific Condition #5 (frequency); and, SIP approved.]

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

a. only gaseous fuels; or
b. gaseous fuels in combination with any amount of liquid fuels for less than 400 hours per year; or
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

{Permitting Note: The reports that are required by the following conditions are to be sent to the Department of Environmental Protection's Northwest District Office, 160 Governmental Center, Pensacola, Florida 322501-5794}

D.17. Malfunction Reporting. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rule 62-210.700(6), F.A.C.]

D.18. Test Reports.

(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.
(b) The required test report shall be filed with the Department 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.]

D.19. Sufficient records shall be maintained to ensure that the total facility-wide SO_2 emissions do not exceed 80 tons per year (see facility-wide conditions **13. & 14.**).
[Rule 62-213.440, F.A.C.; PSD-FL-239/PA97-36; and, Applicant request.]

D.20. Sufficient records shall be maintained to ensure that the total facility-wide NO_X emissions do not exceed 467 tons per year (see facility-wide conditions **15. & 16.**).
[Rule 62-213.440, F.A.C.; PSD-FL-239/PA97-36; and, Applicant request.]

Subsection E. This section addresses the following emissions unit(s).

E.U. ID No.	Brief Description
-011	Auxiliary Boiler

This is a Kewanee model H3S-400-G steam generator rated at a maximum heat input of 16.74 MMBtu/hour while being fueled with natural gas.

{Permitting note(s): This emissions unit is regulated under 40 CFR 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. However, since it is only permitted to combust natural gas, the standards, the monitoring and the associated reporting requirements contained in Subpart Dc do not apply, with the exception that the reporting requirements pertaining to "start-up", as referenced in 40 CFR 60.7, do apply. Except for compliance testing, this boiler may only operate when ~~Boilers Number 5, Number 6, Number 7, and~~ Unit 7 or Unit 8 ~~are~~is not operating; therefore, there will be no significant increase in emissions for PSD purposes. Stack height = 30 feet, exit diameter = 2.0 feet, exit temperature = 420 °F, actual volumetric flow rate = 4,000 acfm (exit temperature and flow rate estimated by manufacturer service representative). Emissions from this boiler are uncontrolled.}

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

E.1. All of the terms and conditions of permit number 1290001-002-AC, as modified, are a part of this permit (see attachment 1290001-002-AC)~~, except for the following changes to Specific Condition Number 12:~~

~~Exception to Specific Condition Number 12. The Professional Engineer's certification that construction of the auxiliary boiler was completed according to the permit application and associated documents must be submitted to the Department within 105 days after achieving the maximum production rate at which the unit will be operated, but no later than 180 days after initial start-up of the emission unit.~~

~~Operation of the auxiliary boiler beyond the time frames established by permit number 1290001-002-AC is allowed, and the conditions of this section apply, only after the Department has received and verified a properly signed and sealed certification from the permittee's Professional Engineer stating that 1) the construction of the auxiliary boiler was completed in accordance with permit number 1290001-002-AC (issued December 5, 1996) and 2) the unit has been tested and compliance with the terms and conditions contained within permit number 1290001-002-AC has properly been demonstrated.~~
~~[Rules 62-212.400(7)(b) and 62-213.420(1)(a)5., F.A.C.]~~

Essential Potential to Emit (PTE) Parameters

E.2. Permitted Capacity. The maximum operation heat input rate is as follows:

Unit No.	MMBtu/hr Heat Input	Fuel Type
11	16.74	Natural Gas

[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.406, F.A.C.]

E.3. Emissions Unit Operating Rate Limitation After Testing. See common condition **C.11.**
[Rule 62-297.310(2), F.A.C.]

E.4. Methods of Operation - Fuels. Only natural gas shall be fired in this boiler.
[Rules 62-4.160(2) and 62-213.440(1), F.A.C.]

E.5. Hours of Operation. This emissions unit may operate 2,000 hours/year as an auxiliary source of steam; however, except for compliance testing, it may only operate when ~~the existing steam generating units (Boilers Number 5, Number 6 and Number 7 and Unit 8) are~~ either Unit 7 or Unit 8 is not operating. The Permittee shall maintain an operation log available for Department inspection certifying the total hours of operation and fuel consumption annually.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; 1290001-002-AC; and, initial Title V permit application as amended December 24, 1996.]

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.}

E.6. Visible Emissions. Visible emissions shall not exceed 20 percent opacity, except for one two-minute period per hour during which opacity shall not exceed 40 percent.
[Rule 62-296.406(1), F.A.C.]

E.7. Particulate Matter. Particulate matter emissions shall be controlled by the firing of natural gas.
[Rule 62-296.406(2), F.A.C.; and, BACT determination dated October 8, 1996.]

E.8. Sulfur Dioxide. Sulfur dioxide emissions shall be controlled by the firing of natural gas.
[Rule 62-296.406(3), F.A.C.; and, BACT determination dated October 8, 1996.]

Excess Emissions

{Permitting Note: The excess emissions rule at 62-210.700, F.A.C., cannot vary any requirement of a NSPS, NESHAP, or Acid Rain program provision.}

E.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.]

E.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.]

Monitoring of Operations

E.11. 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.]

E.12. This emissions unit is also subject to the conditions contained in **Subsection C. Common Conditions**, as specified below.

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.13. Visible Emissions. See common conditions **C.5. and C.6.**

E.14. Operating Rate During Testing. See common condition **C.11.**

E.15. Applicable Test Procedures. See common condition **C.13.(a)2.**

E.16. Frequency of Compliance Tests. See common condition **C.15. except (a)5. & 8.**

E.17. Visible Emissions - Annual. By this permit, annual emissions compliance testing for visible emissions is not required for this emissions unit.
[Rules 62-297.310(7)(a)4., F.A.C.]

Recordkeeping and Reporting Requirements

E.18. The permittee shall record and maintain records of the amount of natural gas combusted during each day the auxiliary boiler is operated.
[40 CFR 60.48c(g)]

E.19. See common conditions **C.18.** and **C.20.(a) & (b).**

E.20. Sufficient records shall be maintained to ensure that the total facility-wide SO_2 emissions do not exceed 80 tons per year (see facility-wide conditions **13. & 14.**).
[Rule 62-213.440, F.A.C.; PSD-FL-239/PA97-36; and, Applicant request.]

E.21. Sufficient records shall be maintained to ensure that the total facility-wide NO_X emissions do not exceed 467 tons per year (see facility-wide conditions **15. & 16.**).
[Rule 62-213.440, F.A.C.; PSD-FL-239/PA97-36; and, Applicant request.]

Subsection F. This section addresses the following emissions units.

E.U. ID No.	**Brief Description**
~~-012~~014	Combustion Turbine - Unit Number 8

This emissions unit is a combined cycle combustion turbine (CT) system designated as Unit 8. It consists of a 160 MW (nominal rating) GE Series 7FA combustion turbine with DLN-2.6 (or later version) dry low NO_x (gas) and water injection (diesel) burners and a non-fired heat recovery steam generator (HRSG) with a nominal 90 MW steam turbine. The turbine can be fired either by natural gas or No. 2 fuel oil. The compressor inlet air will be conditioned by an evaporative cooler when needed. The turbine will be started using the generator and a static start system. Unit 8 also includes a new cooling tower.

{Permitting notes: The emissions unit is regulated under NSPS - 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (1997 version), adopted and incorporated by reference in Rule 62-204.800(7)(b)38., F.A.C; PSD-FL-239, Prevention of Significant Deterioration (PSD), in Rule 62-212.400, F.A.C.; Best Available Control Technology (BACT), in Rule 62-212.410, F.A.C. Stack height = 200 feet; exit diameter = 16.5 feet; exit temperature = 171°F - 205°F, depending upon fuel, ambient temperature and load; actual volumetric flow rate = 0.6 x 10^6 - 1.1 x 10^6 acfm depending upon fuel, ambient temperature and load (exit temperatures and flows based on manufacturer data).}

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

Essential Potential to Emit (PTE) Parameters

F.1. All of the terms and conditions of permit number PSD-FL-239/PA97-36 are a part of this permit (see attachment PSD-FL-239/PA97-36).

~~Operation of combustion turbine No. 8 beyond the time frames established by permit number PSD-FL-239/PA97-36 is allowed, and the conditions of this section apply, only after the Department has received and verified a properly signed and sealed certification from the permittee's Professional Engineer stating that 1) the construction of the combined cycle combustion turbine was completed in accordance with permit number PSD-FL-239/PA97-36 and 2) the unit has been tested and compliance with the terms and conditions contained within permit number PSD-FL-239/PA97-36 has properly been demonstrated.~~
~~[Rules 62-212.400(7)(b) and 62-213.420(1)(a)5., F.A.C.]~~

General

F.2. Definitions. For the purposes of Rule 62-204.800(7), F.A.C., the definitions contained in the various provisions of 40 CFR 60, shall apply except that the term "Administrator" when used in 40 CFR 60, shall mean the Secretary or the Secretary's designee.
[40 CFR 60.2; and, Rule 62-204.800(7)(a), F.A.C.]

F.3. Circumvention. No owner or operator subject to the provisions of 40 CFR 60 shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.
[40 CFR 60.12.]

F.4. Modifications. The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change.
[40 CFR 60.14; and, PSD-FL-239/PA97-36.]

Essential Potential to Emit (PTE) Parameters

F.5. Permitted Capacity. The maximum operation heat input rates are as follows:

Unit No.	MMBtu/hr Heat Input	Fuel Type
8	~~1,467.7~~1696	Natural Gas
	(LHV @ ~~95~~ 59 degrees Fahrenheit, 60% Relative Humidity, and 14.7 psi)	
	~~1,659.5~~1897	No. 2 Fuel Oil
	(LHV @ ~~95~~ 59 degrees Fahrenheit, 60% Relative Humidity, and 14.7 psi)	

Until annual performance tests demonstrating compliance with the emissions standards are conducted within 90% of the above heat input rates, the maximum heat input rates are limited to 1467.7 MMBtu/hr (gas firing) and 1659.5 MMBtu/hr (oil firing) based on the LHV of each fuel and compressor inlet conditions of 95° F, 60% relative humidity, and 14.7 psi. See Condition F.23. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves or equations for correction to other ambient conditions shall have been provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. These curves or equations shall be used to establish the maximum allowable heat inputs at other ambient conditions for compliance determinations.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; 40 CFR 60.332(b); and, PSD-FL-239/PA97-36.]

F.6. Emissions Unit Operating Rate Limitation After Testing. See specific condition **F.34.**
[Rule 62-297.310(2), F.A.C.]

F.7. Methods of Operation - Fuels. Only natural gas and/or new No. 2 distillate fuel oil shall be fired in this turbine. The burning of other fuels requires review, public notice, and approval through the preconstruction process (Chapters 62-210 and 62-212, F.A.C.).

a. Dry low NO_X combustors shall be used on Unit 8 when firing natural gas. The dry low NO_X burner system shall be maintained to minimize NO_X and CO emissions. While firing natural gas, operation of the unit when the dry low NO_X burner system is in the diffusion mode shall be minimized.

b. Water injection shall be used when firing No. 2 fuel oil for control of NO_X emissions.

[Rule 62-213.410, F.A.C.; PSD-FL-239 and BACT.]

F.8. Hours of Operation. This emissions unit may operate 8,760 hours/year.
[Rule 62-210.200(PTE), F.A.C.; and, PSD-FL-239.]

Emission Limitations and Standards

{Permitting note: Table 1-1, Summary of Air Pollutant Standards and Terms (attached), summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit. The following table is a summary of the BACT determination by the Department (also attached), it is only included here for reference. For NO_X and SO_2, meeting the BACT limits assures compliance with the NSPS limits.

Table 1. Emission Limits (from BACT)

Pollutant	Fuel	BACT Standard
NO_X	Gas Oil	12 ppmvd @ 15 % O_2 (a) (d) 42 ppmvd @ 15 % O_2 (a) (b) (d)
SO_2	Gas Oil	Good combustion Good combustion of low sulfur fuel oil (0.05%, *by weight*)
PM/PM_{10}	Gas Oil	Good combustion Good combustion of low sulfur fuel oil (0.05%, *by weight*)
Visible Emissions	Gas Oil	10 percent opacity 10 percent opacity
CO	Gas Oil	25 ppmvd (c) 90 ppmvd (c)
(a) 30-day rolling average excluding startup, shutdown, malfunction, major DLN tuning sessions, and fuel switching.		
(b) Plus an allowance for fuel bound nitrogen using the formula provided in Condition B.4. (of PSD-FL-239)		
(c) By testing concurrent to RATA testing or by 3 one-hour runs of Method 10.		
(d) Not corrected to ISO conditions.		

(End of Permitting Note).}

F.9. Visible Emissions. Visible emissions shall not exceed 10 percent opacity when firing either natural gas or No. 2 fuel oil. Drift eliminators shall be installed on the cooling tower to reduce PM/PM_{10} emissions.
[PSD-FL-239/PA97-36; and, BACT.]

F.10. Sulfur Dioxide - Sulfur Content. The sulfur content of the No. 2 fuel oil shall not exceed 0.05 percent, by weight. See specific condition **F.25.**
[PSD-FL-239/PA97-36; and, BACT.]

F.11. Nitrogen Oxides. Nitrogen Oxides emissions when firing natural gas shall not exceed 12 ppmvd at 15% O_2, not corrected to ISO conditions, on a 30-day rolling average basis (except during authorized periods of startup, shutdown, malfunction, major DLN tuning sessions or fuel switching), as measured by continuous emissions monitoring systems (CEMS). When monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) for calculation of the 30-day rolling average.
[PSD-FL-239/PA97-36; and, BACT.]

F.12. Nitrogen Oxides. Nitrogen Oxides emissions when firing No. 2 fuel oil shall not exceed 42 ppmvd at 15% O_2, not corrected to ISO conditions, on a 30-day rolling average basis (except during authorized periods of startup, shutdown, malfunction or fuel switching), as measured by CEMS, when fuel bound nitrogen values are less than or equal to 0.015 percent. For fuel bound nitrogen values up to 0.03 percent, the allowance (and the adjusted standard) shall be determined, recorded, and maintained upon each new fuel delivery by the following formula:

$$STD = 0.0042 + F$$

where:

STD = allowable NO_X emissions (percent by volume at 15 percent O_2 and on a dry basis).
F = NO_X emission allowance for fuel-bound nitrogen defined by the following table:

Fuel-Bound Nitrogen (% by Weight)	**F (NO_X % by Volume)**
$0 < N \leq 0.015$	0
$0.015 < N \leq 0.03$	0.04 (N-0.015)

where: N = the nitrogen content of the fuel (% by weight)
Note: 0.0042 percent = 42 ppm
[40 CFR 60.332(a)(1); PSD-FL-239/PA97-36; and, BACT.]

F.13. Carbon Monoxide. Carbon monoxide emissions when firing natural gas shall not exceed 25 ppmvd as measured by applicable compliance methods (see specific condition **F.26.**).
[PSD-FL-239/PA97-36; and, BACT.]

F.14. Carbon Monoxide. Carbon monoxide emissions when firing No. 2 fuel oil shall not exceed 90 ppmvd as measured by applicable compliance methods (see specific condition **F.31.**).
[PSD-FL-239/PA97-36; and, BACT.]

Excess Emissions

F.15. ~~Excess emissions resulting from startup, shutdown, malfunction or fuel switching of this emissions unit 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 four hours in any 24-hour period for cold startup or two hours in any 24 hour period for other reasons unless specifically authorized by the Department for longer duration.~~Excess emissions resulting from startup, shutdown, malfunction, or fuel switching shall be permitted providing best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed the following in any 24-hour period: a total of six hours during any day including a cold startup; a total of four hours during any day that includes a hot startup; and a total of two hours during days not including a hot or cold startup. A cold startup is startup after the combined cycle unit has been down for more than 48 hours. A hot startup is startup after the combined cycle unit has been down for 48 hours or less. A documented malfunction is a malfunction that is documented within one working day of detection by contacting the Department's Northwest District Office by telephone, facsimile transmittal, or electronic mail.

In addition, excess emissions resulting from a major DLN tuning session shall be permitted provided the tuning session is performed in accordance with the manufacturer's specifications and in no case shall exceed 72 hours in any calendar year. A "major tuning session" would occur after a combustor change-out, a major repair to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice that details the activity and proposed tuning schedule. The notice may be made by telephone, facsimile transmittal, or electronic mail.

All quality-assured hourly NOx emissions data shall be used when demonstrating compliance with the emissions cap. When monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75).

[Rule 62-210.700(1) & (5), F.A.C.; and, PSD-FL-239/PA97-36.]

F.16. 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.]

F.17. At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.
[40 CFR 60.11(d)]

Monitoring of Operations

F.18. The permittee shall have installed and shall calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from Unit 8. Thirty day rolling average periods when NO_X emissions (ppmvd @ 15% oxygen) are above the BACT standards (12/42 ppmvd for gas/oil) shall be reported to the Department's Northwest District Office pursuant to Rule 62-4.160(8), F.A.C. The continuous emissions monitoring systems must comply with the certification and quality assurance, and other applicable requirements from 40 CFR 75. Periods of startup, shutdown, malfunction, major DLN tuning sessions, and fuel switching shall be monitored, recorded, and reported as excess emissions when emission levels exceed the standards in specific conditions **F.11 and F.12.** following the format of 40 CFR 60.7 (1997 version). The NO_X CEMS will be used in lieu of the water/fuel monitoring system and fuel bound nitrogen monitoring required for reporting excess emissions in accordance with 40 CFR 60.334, Subpart GG (1997 version). The calibration of the water/fuel monitoring device required in 40 CFR 60.335(c)(2) (1997 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS. Upon request from DEP, the CEMS emission rates for NO_X on Unit 8 shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332.
[PSD-FL-239/PA97-36; and, BACT.]

F.19. The following monitoring schedule for No. 2 fuel oil shall be followed: For all bulk shipments of No. 2 fuel oil received at the Purdom Station, an analysis which reports the sulfur content and fuel bound nitrogen content of the fuel shall be provided by the fuel vendor or other sources which follow the appropriate fuel test methods listed in specific condition **F.25.** The analysis shall also specify the methods by which the analyses were conducted and shall comply with the requirements of 40 CFR 60.335(d).
[PSD-FL-239/PA97-36; and, BACT.]

F.20. The following custom monitoring schedule for natural gas is approved in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2):

a. Monitoring of natural gas nitrogen content shall not be required.
b. Analysis of the sulfur content of natural gas shall be conducted using one of the EPA-approved ASTM reference methods for the measurement of sulfur in gaseous fuels, or an approved alternative method. Monitoring of the sulfur content of the natural gas shall be conducted semi-annually.
c. Should any sulfur analysis indicate noncompliance with 40 CFR 60.333, the City shall notify the Department of such excess emissions and the customized fuel monitoring schedule shall be reexamined. The sulfur content of the natural gas will be monitored weekly during the interim period while the monitoring schedule is being reexamined.
d. The City shall notify the Department of any change in natural gas supply for reexamination of this monitoring schedule. A substantial change in natural gas quality (i.e., sulfur content variation of greater than 1 grain per 100 cubic foot of natural gas) shall be considered as a change in the natural gas supply. Sulfur content of the natural gas will be monitored weekly by the natural gas supplier during the interim period when this monitoring schedule is being reexamined.

e. Records of sampling analysis and natural gas supply pertinent to this monitoring schedule shall be retained by the City for a period of five years, and shall be made available for inspection by the appropriate regulatory personnel.
f. The City may obtain the sulfur content of the natural gas from the fuel supplier provided the test methods listed in specific condition **F.37.** are used.

[PSD-FL-239/PA97-36.]

F.21. 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

F.22. Nitrogen Oxides. Determination of Oxides of Nitrogen emissions will be by a Continuous Emissions Monitoring System (CEMS). A CEMS operated and maintained in accordance with 40 CFR 75 may be used. Compliance with the NO_X emissions standards in specific conditions **F.11. and F.12.** shall be demonstrated with this CEMS system based on a 30-day rolling average. Based on CEMS data at the end of each operating day, a new 30-day average emission rate is calculated from the arithmetic average of all valid hourly emission rates during the previous 30 operating days.

Note: No other methods may be used for compliance testing unless prior DEP approval is received in writing. The DEP may request a special compliance test pursuant to Rule 62-297.340(2), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

[PSD-FL-239/PA97-36; and, BACT.]

Required Tests, Test Methods and Procedures

{Permitting note: 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.23. Annual Tests Required. Unit -012 must be tested annually for visible emissions, and carbon monoxide in accordance with the requirements listed below.

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

F.24. 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., and

40 CFR 60, Appendix A, shall be used to determine compliance with the visible emissions standard in specific condition **F.9.**
[Rules 62-204.800, 62-296.320(4)(b)4.a. and 62-297.401, F.A.C.; 40 CFR 60, Appendix A; PSD-FL-239/PA97-36; and, BACT.]

F.25. Sulfur Dioxide and Particulate Matter. Notwithstanding the requirements of Rule 62-297.340, F.A.C., the exclusive use of fuel oil with a maximum sulfur content limit of 0.05% or less, by weight, is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard and the 0.05% S limit, fuel oil analysis using ASTM D2880-71 or D4294 (or latest edition) for the sulfur content of liquid fuels and D1072-80, D3031-81, D4084-82 or D3246-81 (or latest edition) for sulfur content of gaseous fuel shall be utilized in accordance with the custom fuel monitoring schedule in specific condition **F.20.** However, the permittee is responsible for ensuring that the procedures above are used for determination of fuel sulfur content. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335 (e) (1997 version). For the purposes of demonstrating compliance with the emissions caps, natural gas and fuel oil supplier data for sulfur content may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized.
[PSD-FL-239/PA97-36; and, BACT.]

F.26. Carbon Monoxide. The test method for carbon monoxide emissions shall be EPA Method 10, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and referenced in Chapter 62-297, F.A.C. Testing may be conducted at less than capacity. Annual compliance testing may be conducted concurrent with the annual RATA testing required pursuant to 40 CFR 75 (gas only). See specific conditions **F.13. & F.14.**
[Rules 62-204.800 and 62-297.401, F.A.C.; PSD-FL-239/PA97-36; and, BACT.]

F.27. Nitrogen Oxides. To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 percent and are approved by the Department to determine the nitrogen content of the fuel being fired.
[40 CFR 60.335(a).]

F.28. Nitrogen and Sulfur Contents. To meet the requirements of 40 CFR 60.334(b), the owner or operator shall use the methods specified in 40 CFR 60.335(a) and 40 CFR 60.335(d) of 40 CFR 60.335 to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.
[40 CFR 60.335(e).]

F.29. General. Compliance with standards in 40 CFR 60, other than opacity standards, shall be determined only by performance tests established by 40 CFR 60.8, unless otherwise specified in the applicable standard.
[40 CFR 60.11(a).]

F.30. Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.
[40 CFR 60.8(c).]

F.31. The owner or operator shall provide, or cause to be provided, stack sampling and performance testing facilities as follows:

(1) Sampling ports adequate for test methods applicable to such facilities.
(2) Safe sampling platform(s).
(3) Safe access to sampling platform(s).
(4) Utilities for sampling and testing equipment.

[40 CFR 60.8(e)(1), (2), (3) & (4).]

F.32. 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.]

F.33. 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.]

F.34. Operating Rate During Testing. Except for carbon monoxide emissions testing, testing of emissions shall be conducted with each emissions unit operating at permitted capacity, which is defined as 95-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient conditions). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum

permitted heat input (corrected for ambient conditions) and 105 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Compliance test results shall be submitted to the Department's Northwest District office no later than 45 days after completion of the last test run.
[Rules 62-297.310(2), F.A.C.; PSD-FL-239/PA97-36; and, BACT.]

F.35. 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.]

F.36. 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 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.

(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).

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

F.37. 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;
   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.
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.
9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

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

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

[Rule 62-297.310(7), F.A.C.; and, SIP approved.]

F.38. Visible Emissions Testing - Annual. By this permit, annual emissions compliance testing for visible emissions is not required for this emissions unit while burning:

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

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

Recordkeeping and Reporting Requirements

F.39. To determine compliance with the oil firing heat input limitation, the permittee shall maintain daily records of fuel oil consumption and hourly usage for the turbine and the heating value for each fuel. All records shall be maintained for a minimum of five (5) years after the date of each record and shall be made available to representatives of the Department upon request.
[Rule 62-213.440, F.A.C.]

F.40. The owner or operator subject to the provisions of 40 CFR 60 shall furnish the Administrator written notification as follows:

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

[40 CFR 60.7(a)(4).]

F.41. The owner or operator subject to the provisions of 40 CFR 60 shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or, any periods during which a continuous monitoring system or monitoring device is inoperative.
[40 CFR 60.7(b).]

F.42. The owner or operator required to install a continuous monitoring system (CMS) or monitoring device shall submit an excess emissions and monitoring systems performance report and/or a summary report form [see 40 CFR 60.7(d)] to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or, the CMS data are to be used directly for compliance determination, in which case quarterly reports shall be submitted; or, the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each calendar half (or quarter, as appropriate). Written reports of excess emissions shall include the following information:

(1) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.
(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.
(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

[40 CFR 60.7(c)(1), (2), (3), and (4).]

F.43. The summary report form shall contain the information and be in the format shown in Figure 1 (attached) unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.

(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in 40 CFR 60.7(c) need not be submitted unless requested by the Administrator.

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

[40 CFR 60.7(d)(1) and (2).]

{See attached Figure 1: Summary Report-Gaseous and Opacity Excess Emission and Monitoring System Performance}

F.44. Notification.

(1) Notwithstanding the frequency of reporting requirements specified in 40 CFR 60.7(c), an owner or operator who is required by an applicable subpart to submit excess emissions and monitoring systems performance reports (and summary reports) on a quarterly (or more frequent) basis may reduce the frequency of reporting for that standard to semiannual if the following conditions are met:

(i) For 1 full year (e.g., 4 quarterly or 12 monthly reporting periods) the affected facility's excess emissions and monitoring systems reports submitted to comply with a standard under this part continually demonstrate that the facility is in compliance with the applicable standard;

(ii) The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in 40 CFR 60, Subpart A, and the applicable standard; and,

(iii) The Administrator does not object to a reduced frequency of reporting for the affected facility, as provided in 40 CFR 60.7(e)(2).

(2) The frequency of reporting of excess emissions and monitoring systems performance (and summary) reports may be reduced only after the owner or operator notifies the Administrator in writing of his or her intention to make such a change and the Administrator does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Administrator may review information concerning the source's entire previous performance history during the required recordkeeping period prior to the intended change, including performance test results, monitoring data, and evaluations of an owner or operator's conformance with operation and maintenance requirements. Such information may be used by the Administrator to make a judgment about the source's potential for noncompliance in the future. If the Administrator disapproves the owner or operator's request to reduce the frequency of

reporting, the Administrator will notify the owner or operator in writing within 45 days after receiving notice of the owner or operator's intention. The notification from the Administrator to the owner or operator will specify the grounds on which the disapproval is based. In the absence of a notice of disapproval within 45 days, approval is automatically granted.

(3) As soon as monitoring data indicate that the affected facility is not in compliance with any emission limitation or operating parameter specified in the applicable standard, the frequency of reporting shall revert to the frequency specified in the applicable standard, and the owner or operator shall submit an excess emissions and monitoring systems performance report (and summary report, if required) at the next appropriate reporting period following the noncomplying event. After demonstrating compliance with the applicable standard for another full year, the owner or operator may again request approval from the Administrator to reduce the frequency of reporting for that standard as provided for in 40 CFR 60.7(e)(1) and (e)(2).

[40 CFR 60.7(e)(1).]

F.45. The owner or operator subject to the provisions of 40 CFR 60 shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and, all other information required by 40 CFR 60 recorded in a permanent form suitable for inspection. The file shall be retained for at least **5 (five)** years following the date of such measurements, maintenance, reports, and records.
[40 CFR 60.7(f); and, Rule 62-213.440(1)(b)2.b., F.A.C.]

F.46. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rule 62-210.700(6), F.A.C.]

F.47. Test Reports.

(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.

(b) The required test report shall be filed with the Department 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 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.]

F.48. In each compliance test report, submit the maximum input/production rate at which each emissions unit was operated since the most recent compliance test.
[Rule 62-213.440, F.A.C.]

F.49. Sufficient records shall be maintained to ensure that the total facility-wide SO_2 emissions do not exceed 80 tons per year (see facility-wide conditions **13. & 14.**).
[Rule 62-213.440, F.A.C.; PSD-FL-239/PA97-36; and, Applicant request.]

F.50. Sufficient records shall be maintained to ensure that the total facility-wide NO_X emissions do not exceed 467 tons per year (see facility-wide conditions **15. & 16.**).
[Rule 62-213.440, F.A.C.; PSD-FL-239/PA97-36; and, Applicant request.]

Section IV. Acid Rain Part.

Operated by: City of Tallahassee
ORIS Code: 689

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

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

E.U. ID No.	Description
-007	Boiler Number 7 - 621 MMBtu/hour
-~~012~~014	Combustion Turbine Number 8 - ~~1,659.5~~1897 MMBtu/hour

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

a. DEP Form No. 62-210.900(1)(a), dated 07/01/95.
b. DEP Form No. 62-210.900(1)(a), dated 03/04/97.

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

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

E.U. ID No.	EPA ID	Year	2000	2001	2002
-007	7	SO_2 allowances, under Table 2 or 3 of 40 CFR 73	438*	438*	438*
-~~012~~014	12	SO_2 allowances, under Table 2 or 3 of 40 CFR 73	0*	0*	0*

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

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

1. No permit revision shall be required for 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)1., 2. & 3., F.A.C.]

A.4. 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 No. 52., Appendix TV-1, Title V Conditions.}
[Rule 62-214.420(11), F.A.C.]

A.5. 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, Fast-Track Revisions of Acid Rain Parts.
[Rules 62-213.413 and 62-214.370(4), F.A.C.]

A.6. Comments, notes, and justifications: None.

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

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210.300(3)(a), F.A.C., Categorical Exemptions, are exempt from the permitting requirements of Chapters 62-210 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 Rule 62-210.300(3)(a), 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 Rule 62.210.300(3)(a), 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.

Brief Description of Emissions Units and/or Activities:

Exempt Emissions Related to Combustion Turbine No. 1

1. Oil Vapor Extractor
2. Fuel Oil Piping
3. Lube Oil Tank

Exempt Emissions Related to Combustion Turbine No. 2

4. Oil Vapor Extractor
5. Fuel Oil Piping
6. Lube Oil Tank

Exempt Emissions Related to Steam Generator No. 5[(1)]

7. Fuel Oil Piping
8. Hydrogen Gas Vents
9. Deareator Tank Vents
10. Oil Vapor Extractors
11. Lube Oil Tank (storage)
12. Lube/Fuel Oil Drip Pans
13. Noncondensable Gas Extractor
14. On-site Generated Non-hazardous Boiler Chemical Cleaning Wastes

Exempt Emissions Related to Steam Generator No. 6[(1)]

15. Fuel Oil Piping
16. Hydrogen Gas Vents
17. Deareator Tank Vents
18. Oil Vapor Extractors
19. Lube Oil Tank (storage)
20. Lube/Fuel Oil Drip Pans
21. Noncondensable Gas Extractor
22. On-site Generated Non-hazardous Boiler Chemical Cleaning Wastes

Appendix I-1, Continued.

Exempt Emissions Related to Steam Generator No. 7

23. Fuel Oil Piping
24. Hydrogen Gas Vents
25. Deareator Tank Vents
26. Oil Vapor Extractors
27. Lube Oil Tank (storage)
28. Lube/Fuel Oil Drip Pans
29. Noncondensable Gas Extractor
30. On-site Generated Non-hazardous Boiler Chemical Cleaning Wastes

Fuel Farm

31. Fuel Oil Tank No. 1
32. Fuel Oil Tank No. 2(2)
33. Fuel Oil Tank No. 3
34. Fuel Oil Reclaim Tank
35. Distillate Oil Tank
36. Gasoline Tank
37. Diesel Oil Tank
38. (New) Diesel Oil Tank Associated With the Hydrant Main

Fuel Dispensing Operations

39. Truck Loading/Unloading (for items 29-33)
40. Truck Loading/Unloading for Distillate Oil Tank
41. Truck Loading/Unloading for Gasoline Tank
42. Fuel Dispensing Operations for Diesel Oil Tank
43. Barge Unloading Station
44. Truck Loading/Unloading Rack 1
45. Truck Loading/Unloading Rack 2

Fugitive VOC Emissions

46. (1-15) Parts Washers - Nonhalogenated Solvents

Space Heaters

47. (1-7) Space Heaters

Fugitive PM_{10} Emissions

48. Paved Roads
49. Unpaved Roads
50. Heavy Construction Activities
51. Aggregate Handling & Storage

Laboratory

52. Laboratory Equipment
53. Chemical Usage
54. Vacuum Pumps
55. Laboratory Fume Hoods

56. Central Vacuum System

Appendix I-1, Continued.

Maintenance Activities
57. Welding - Exempt per Rule 62-210.300(3)(a)16., F.A.C.

Plant Operations
58. Lube Oil Storage Tanks
59. Propane Storage Tanks

Exempt Emissions Related to the Auxiliary Boiler
60. Deaerator Tank Vents
61. Noncondensable Gas Extractor

Exempt Emissions Related to the Combined Cycle Combustion Turbine (Unit 8)[3]
62. Oil Vapor Extractor
63. Fuel Oil Piping
64. Hydrogen Gas Vents
65. Lube Oil Tanks
66. Deaerator Tank Vents
67. Noncondensable Gas Extractor
68. Lube/Fuel Oil Drip Pans

Notes: [1] - Emissions Units will be shut down as part of the Purdom Unit 8 Project.
[2] - Emissions unit will be re-commissioned as a waste water tank as part of the Purdom Unit 8 Project.
[3] - New emissions units associated with the Purdom Unit 8 Project.

Appendix U-1, List of Unregulated Emissions Units and/or Activities.

City of Tallahassee, Electric Utilities
Sam O. Purdom Generating Station

DRAFT Permit No. 1290001-006-AV
Facility ID No. 1290001

Unregulated Emissions Units and/or Activities. An emissions unit which emits no "emissions-limited pollutant" and which is subject to no unit-specific work practice standard, though it may be subject to regulations applied on a facility-wide basis (e.g., unconfined emissions, odor, general opacity) or to regulations that require only that it be able to prove exemption from unit-specific emissions or work practice standards.

The below listed emissions units and/or activities are neither 'regulated emissions units' nor 'insignificant emissions units'.

E.U. ID No.	**Brief Description of Emissions Units and/or Activity**
-010	Fugitive VOC Sources - Painting Operations
-012	General Purpose Internal Combustion Engines
-013	Emergency Generators

-010 Fugitive VOC Emissions. Fugitive VOC emissions are generated from the painting operations associated with normal plant maintenance. SCC: 4-90-999-98, Miscellaneous Volatile Organic Compound Evaporation.

-012 General purpose internal combustion engines.
Located for use at this source are(2) Welding Generators and a single Fire Pump.

-013 Emergency generators.
Located for use at this source are (4) Emergency Generators.

Appendix H-1, Permit History/ID Number Changes

City of Tallahassee
Sam O. Purdom Generating Station

DRAFT Permit No. 1290001-006-AV
Facility ID No. 1290001

Permit History (for tracking purposes):

E.U. ID No.	Description	Permit No.	Issue Date	Expiration Date	Extended Date[1,2]	Revised Date(s)
-001	Boiler #1	AO65-242828	3/25/94	3/1/99*		
-002	Boiler #2	AO65-242828	3/25/94	3/1/99*		
-003	Boiler #3	AO65-242828	3/25/94	3/1/99*		
-004	Boiler #4	AO65-242828	3/25/94	3/1/99*		
-005	Boiler #5	AO65-242831	3/8/94	3/1/99**		
-006	Boiler #6	AO65-242831	3/8/94	3/1/99**		
-007	Boiler #7	AO65-242831	3/8/94	3/1/99		
-008	Combustion Turbine #1	AO65-242827	3/8/94	3/1/99		6/10/94, 6/24/94
-009	Combustion Turbine #2	AO65-242827	3/8/94	3/1/99		6/10/94, 6/24/94
-011	Auxiliary Boiler	1290001-002-AC	12/5/96	12/31/97		(Draft)
		BACT	10/8/96			
-012	Combustion Turbine #8	PSD-FL-239/PA97-36 (Includes BACT)	5/28/98	5/15/03		(Draft)

* Permit surrendered October 2, 1996.
** Permanently shutdown as part of the Unit 8 combined cycle combustion turbine project.

ID Number Changes (for tracking purposes):

From: **Facility ID No.** 10TLH650001
To: **Facility ID No.** 1290001

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., effective 03/20/96, allows Title V Sources to operate under existing valid permits}

Referenced Attachments

Phase II Acid Rain Application/Compliance Plan

Appendix A-1, Abbreviations, Definitions, Citations, and Identification Numbers

Appendix SS-1, Stack Sampling Facilities (version dated 3/25/96)

Appendix TV-1, Title V Conditions (version dated 12/2/97)

Permit Number 1290001-002-AC

BACT Determination Dated October 8, 1996

Permit Number PSD-FL-239/PA97-36, Including BACT Determination

ASP Number 97-B-01
(With Scrivener's Order Dated July 9, 1997)

Figure 1: Summary Report-
Gaseous and Opacity Excess Emission and Monitoring System Performance

Table 1-1, Summary of Air Pollutant Standards and Terms

Table 2-1, Summary of Compliance Requirements

Best Available Copy

Department of Environmental Protection

Lawton Chiles
Governor

Northwest District
160 Governmental Center
Pensacola, Florida 32501-5794

Virginia B. Wetherell
Secretary

CITY OF TALLAHASSEE
DEC -9 PM 1:09
ELECTRIC UTILITIES ( )
GAS UTILITIES ( )
WATER UTILITIES ( )

December 6, 1996

Robert E. McGarrah
Production Superintendent
City of Tallahassee, Electric Utility
2602 Jackson Bluff Road
Tallahassee, Florida 32304

Dear Mr. McGarrah:

On December 5, 1996, the Department issued permit 1290001-002-AC to construct an auxiliary boiler. This letter will correct an error made in that permit.

The Emission Unit number for the auxiliary boiler was listed incorrectly. The correct Emission Unit number for the auxiliary boiler is 011.

By this letter Specific Condition 13 is changed

From:

13. The emission unit covered by this permit is 1290001010. Please cite this number on all test reports and other correspondence specific to this permitted emission unit. [FAC Rule 62-297.310(8)]

To:

13. The emission unit covered by this permit is 1290001011. Please cite this number on all test reports and other correspondence specific to this permitted emission unit. [FAC Rule 62-297.310(8)]

Sincerely,

Ed K. Middleswart

Ed K. Middleswart, P.E.
Air Program Administrator

EKM:cmc

cc: Jennette Curtis, City of Tallahassee
DEP Northwest District Branch Office, Tallahassee

Best Available Copy

RECEIVED
CITY OF TALLAHASSEE

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

12: 52

ELECTRIC UTILITIES ( )
GAS UTILITIES ( )
WATER UTILITIES ( )

In the matter of an
Application for Permit
By:
Robert E. McGarrah, Production Superintendent
City of Tallahassee, Electric Utility
2602 Jackson Bluff Road
Tallahassee, FL 32304
_______________________/

DEP File No. 1290001-002-AC
Wakulla County

Enclosed is Permit Number 1290001-002-AC, issued pursuant to Section 403.087, Florida Statutes.

Any party to this Order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, Florida Statutes, by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Office of General Counsel, 3900 Commonwealth Boulevard, Tallahassee, Florida 32399-3000, and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date this Notice is filed with the Clerk of the Department.

Executed in Pensacola, Florida.

State of Florida Department
of Environmental Protection

Ed K. Middleswart

ED K. MIDDLESWART, P.E.
Director of District Management

160 Governmental Center
Pensacola, Florida 32501-5794
(904) 444-8364

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF PERMIT and all copies were mailed before the close of business on December 5, '96 to the listed persons.

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

Clerk [signature] Date 12/5/96

Copies Furnished to:
Jennette D. Curtis, City of Tallahassee
DEP Northwest District Branch Office, Tallahassee

Lawton Chiles
Governor

Northwest District
160 Governmental Center
Pensacola, Florida 32501-5794

Virginia B. Wetherell
Secretary

PERMITTEE:

City of Tallahassee
Sam O. Purdom Generating Station

AIRS I.D. Number: 1290001
Air Permit Number: 1290001-002-AC
Emission Unit: 010
Date of Issue: December 5, 1996
Expiration Date: December 31, 1997
County: Wakulla
Project: Natural Gas Fired Auxiliary Boiler

This permit is issued under the provisions of Section 403.087, Florida Statutes, and Florida Administrative Code Rules 62-296, 62-297 and 62-4. The above named applicant, hereinafter called Permittee, is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

Construction of a 16.74 MMBtu/hr natural gas fired auxiliary steam generating boiler (Kewanee, model number H3S-400-G) at the City of Tallahassee's Sam O. Purdom Generating Station.

Construction shall be consistent with the construction permit application signed September 20, 1996.

Located on the east side of State Road 363 at 667 Port Leon Drive, St. Marks

PERMITTEE:

Sam O. Purdom Generating Station

AIRS I.D. Number: 1290001
Air Permit Number: 1290001-002-AC
Emission Unit: 010
Date of Issue: December 5, 1996
Expiration Date: December 31, 1997

SPECIFIC CONDITIONS:

General

1. The attached General Conditions are part of this permit. [FAC Rule 62-4.160]

Construction

2. The Department shall be notified of the date construction of this emission unit commences postmarked no later than 30 days after such date, of the anticipated date of initial startup postmarked not more than 60 days nor less than 30 days prior to such date, and of the actural date of initial startup postmarked within 15 days after such date. [FAC Rule 62-4.070, 62.204.800(7)(d)]

3. The Department shall be notified and prior approval shall be obtained of any changes or revisions made during construction. [FAC Rule 62-4.030]

Operation

4. The maximum allowable operating rate is 16.74 MMBtu/hr heat input. [FAC Rule 62-4.070]

5. The maximum hours of operation are 2000 hours per year. The Permittee shall maintain an operation log available for Department inspection certifying the total hours of operation and fuel consumption annually. [FAC Rule 62-4.070 and construction permit application]

6. This emission unit shall only be operated as an auxiliary source of steam when the existing steam generating units (boilers 5,6, &7) are not operating. (Construction permit application)

7. All applicable requirements of 40 CFR 60 Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, shall be met. (FAC Rule 62-204.800)

PERMITTEE:

Sam O. Purdom Generating Station

AIRS I.D. Number: 1290001
Air Permit Number: 1290001-002-AC
Emission Unit: 010
Date of Issue: December 5, 1996
Expiration Date: December 31, 1997

SPECIFIC CONDITIONS:

Emissions

8. The maximum allowable emission limit for each pollutant is as follows:

Pollutant	FAC Rule	Allowable Emissions
VE	62-296.406	20% opacity except for one two minute period per hour during which the opacity shall not exceed 40%.

9. Excess emissions resulting from startup, shutdown or malfunction shall be allowed providing (1) best operational practices to minimize emissions are adhered to and (2) 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. The Permittee shall immediately notify the Department's Tallahassee Branch Office of excess emissions resulting from malfunctions. The notification shall include pertinent information as to the cause of the problem, and what steps are being taken to correct the problem and to prevent its recurrence. (Rules 62-210.700, 62-4.130)

Testing

10. Visible emissions tests are required to show compliance with the standards of the Department. The test results must provide reasonable assurance that the source is capable of compliance at the permitted maximum operating rate. [FAC Rule 62-297.310(2)] A sixty minute visible emissions tests shall be conducted in accordance with DEP method 9 within 60 days after achieving the maximum production rate at which the emission unit will be operated, but not later than 180 days after initial startup of the emission unit. The Department shall be notified at least 15 days prior to testing to allow witnessing. Results shall be submitted to the Department within 45 days after testing.

The test report shall comply with F.A.C. Rule 62-297.310(8), Test Reports.

The Department can require special compliance tests in accordance with F.A.C. Rule 62-297.310(7)(b).

Other test methods and alternate compliance procedures may be used only after prior Departmental approval has been obtained in writing.

SPECIFIC CONDITIONS:

[10. (cont.'d)]

Testing of emissions shall be conducted with the source operating at capacity. Capacity is defined as 90 to 100% of the maximum allowable heat input rate. If it is impractical to test at capacity, then sources may be tested at less than capacity; in this case subsequent source operation is limited to 110% of the test load until a new test is conducted. Once the unit is so limited, then operation at higher capacities is allowed for no more than fifteen days for purposes of additional compliance testing to regain the rated capacity in the permit, with prior notification to the Department. [FAC Rule 62-297.310(2)]

Administrative

11. An annual operating report for air pollutant emitting facility, DEP Form 62-210.990(5), shall be submitted by March 1 of each year. A copy of the form and instructions may be obtained from the Department of Environmental Protection, Northwest District Air Resources Management Program, (904) 444-8364. [FAC Rule 62-210.370(3)]

12. The applicant shall retain a Professional Engineer, registered in the State of Florida, for the inspection of this project. Upon completion the engineer shall inspect for conformity to the permit application and associated documents. An application for an operation permit [Form DEP 62-210.900(1), Long Form]shall be submitted with the compliance test results and appropriate fee when applicable. These are to be submitted within 105 days after achieving the maximum production rate at which the emission unit will be operated, but no later than 225 days after initial startup of the emission unit. The permittee shall obtain an operating permit for this source before the expiration of this construction permit if the permittee desires to continue operation. [FAC Rule 17-210.300]

13. The emission unit covered by this permit is 1290001010. Please cite this number on all test reports and other correspondence specific to this permitted emission unit. [FAC Rule 62-297.310(8)]

14. The Permittee, for good cause, may request that this construction permit be extended. Such a request with the required $50 extension fee shall be submitted 60 days prior to the expiration date of this permit. (FAC Rule 17-4.080(3)

PERMITTEE:

Sam O. Purdom Generating Station

AIRS I.D. Number: 1290001
Air Permit Number: 1290001-002-AC
Emission Unit: 010
Date of Issue: December 5, 1996
Expiration Date: December 31, 1997

SPECIFIC CONDITIONS:

15. The Department telephone number for reporting problems, malfunctions or exceedances under this permit is (904) 444-8364, day or night, and for emergencies involving a significant threat to human health or the environment is (904) 413-9911. For routine business, telephone (904) 488-3704 during normal working hours. [FAC Rule 62-4.130]

Expiration Date:

December 31, 1997

Issued this 5th day of DEC, 1996.

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Ed K. Middleswart

ED K MIDDLESWART, P.E.
Air Program Administrator

GENERAL CONDITIONS:

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "permit conditions", and are binding and enforceable pursuant to Sections 403.141, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

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

3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Nor does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit does not constitute a waiver of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

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

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

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

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

GENERAL CONDITIONS:

a. Having access to and copying any records that must be kept under the conditions of this permit;
b. Inspecting the facility, equipment, practices, or operations regulated or required under this permit; and,
c. Sampling or monitoring any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

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

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

a. A description of and cause of noncompliance; and
b. The period of noncompliance, including exact dates and times; or, if not corrected, the anticipated time the noncompliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the noncompliance. The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

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

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

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, as applicable. The permittee shall be liable for any noncompliance of the permitted activity until the transfer is approved by the Department.

12. This permit is required to be kept at the work site of the permitted activity during the entire period of construction or operation.

GENERAL CONDITIONS:

13. The permittee shall comply with the following:

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

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

c. Records of monitoring information shall include:

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

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

BACT Determination Dated October 8, 1996

BEST AVAILABLE CONTROL TECHNOLOGY (BACT) DETERMINATION
City of Tallahassee, Purdom Generating Station Auxiliary Boiler
Wakulla County

The City of Tallahassee submitted a construction permit application September 23, 1996 for an auxiliary boiler to be located at their Purdom Generating Station, Wakulla County. The proposed boiler is a 16.74 MMBtu/hr natural gas fired boiler that will be used for steam only when the existing, larger steam generating units (boilers 5,6,or 7) are not operating.

This BACT determination is required for the source as set forth in FAC Rule 62-296.406 - Fossil Fuel Steam Generators with Less than 250 MMBtu/hr Heat Input.

BACT Determination Requested by Applicant:

Particulate matter and sulfur dioxide emissions shall be controlled by the firing of natural gas and operation of this proposed auxiliary boiler only when the existing steam generating units are not operating.

Date of Receipt of BACT Application: September 23, 1996

BACT Determination by DEP:

As requested by applicant.

BACT Determination Rationale:

Emissions will be minimal as a result of firing clean burning natural gas. Additionally, any emissions associated with this proposed auxiliary boiler will be offset by not operating the existing, larger steam generating units.

Details of the Analysis May be Obtained by Contacting:

Bob Kriegel
Department of Environmental Protection
160 Governmental Center
Pensacola, FL 32503

Recommended by:

A.S. Allen for Bob

Bob Kriegel
Environmental Specialist

Approved by:

Ed K. Middleswart
10/8/96

Ed Middleswart, P.E.
Air Program Administrator

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit

Ms. Jennette Curtis
Environmental Administrator
City of Tallahassee Utility Services
300 South Adams Street
Tallahassee, Florida 32301

DEP File No. 1290001
Permit Nos: PSD-FL-239 / PA97-36

Enclosed is the FINAL Permit Nos. PSD-FL-239 / PA97-36 for Purdom Unit 8, a new combined cycle combustion turbine. This permit is issued pursuant to Chapter 403, Florida Statutes and 62-4 through 297 F.A.C and 40 CFR 52.21-Prevention of Significant Deterioration (PSD).

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 5-29-98 to the person(s) listed:

Ms. Jennette Curtis *
Mr. Brian Beals, EPA
Mr. John Bunyak, NPS
Mr. Ed Middleswart, NWD

Clerk Stamp

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

5-29-98
(Clerk) (Date)

FINAL DETERMINATION

City of Tallahassee

Permit No. PSD-FL-239 / PA97-36
Purdom Generating Station

An Intent to Issue an Air Construction Permit for the City of Tallahassee Utilities Services, Purdom Generating Station located on the north end of the City of St. Marks on SR 363, Wakulla County, Florida, was distributed on July 1, 1997. The Public Notice of Intent to Issue Air Construction Permit was published in the Tallahassee Democrat on September 29, 1997. No Comments on the PSD permit were submitted in response to the public notice.

On October 30, 1997 a public meeting was held in the Crawfordville Elementary school. Interested parties asked about control options including selective catalytic reduction, dry low NO_X burners on the combustion turbine and mist eliminators on the cooling tower. There was also a concern about sulfuric acid emissions. Department representatives at the meeting described the process by which the best available control technology (BACT) determination was made. The technical evaluation and preliminary determination (part of the Intent to Issue and Air Construction Permit package referenced above) explains in detail how the Department determined BACT for each pollutant regulated under the Prevention of Significant Deterioration (PSD) rule.

No written comments have been received from the public meeting. A summary of the substantive verbal questions/comments from the public meeting and answers to those questions are provided in the following paragraphs:

Question: Potential impacts of fugitive dust generated during construction on water quality in the St. Marks River.

Response: The PSD construction permit requires dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary to control fugitive dust (specific condition A7 of the permit).

Question: Would like cleaner air; standards may not be protective enough.

Response: The Ambient Air Quality Standards (AAQS) have been designed to protect public health and welfare with an adequate margin of safety. The primary standards are designed to protect public health and the secondary standards are designed to protect public welfare (effects on soils, water, crops, vegetation, manmade materials, animals, wildlife, weather, visibility and climate, damage to and deterioration of property, and hazards to transportation, as well as effects on economic values and on personal comfort and well-being). Florida's standards are as stringent as, or in one case, more stringent than the National standards, and are considered to be fully protective of the public health and welfare. Further, the PSD program is designed to keep areas with good air quality such as Wakulla County from having their air quality deteriorate significantly. The Purdom 8 Project will not cause exceedences of the AAQS and will not cause significant deterioration of the existing air quality conditions in Wakulla County.

Question: Why not use the "top" technology to control emissions; why not pay a little more for cleaner air?

Response: The Department considered several factors in it's Best Available Control Technology (BACT) determination and concluded that the use of dry low NO_x (DLN) combustion technology is BACT in this case. The Department considered the energy, environmental, and economic impacts of available control options in this case. The "top" control technology reference in the question, presumably selective catalytic reduction (SCR), has some adverse environmental impacts and increased costs associated with the use of ammonia injection and the oxidation catalyst. These factors were considered in the Department's BACT determination.

Question: How much fuel oil use would be expected?

Response: The Purdom 8 Project will use natural gas as its primary fuel. Low sulfur diesel will be used as an alternate fuel, most likely if there is a natural gas curtailment situation. The Project will use the existing 10,770 barrel tank for this diesel oil; this will supply Purdom Unit 8 with only one and a half days of capacity at full load. Also, because of the facility-wide caps on emission of SO_2 and NO_x, the amount of fuel oil firing must be limited as emissions of both pollutants are higher when firing fuel oil than when firing natural gas.

Question: Winds in Wakulla County are from SW to the NE; the plume may impact residents of a new housing development.

Response: The modeling of the air quality impacts of the Project was done using a data base of five years of actual hourly meteorological data from available sources. These computer simulations of plume impacts took into account all wind directions and all wind speeds observed during the entire five year period. Impacts were estimated for a large number of receptor points, including close to the plant site and at distances of up to six miles in all directions. Additional simulations evaluated impacts on the St. Marks and Bradwell Bay National Wilderness Areas, at distances ranging from less than half a mile to up to 25 miles from the Purdom Station. In summary, plume impacts were thoroughly evaluated in accordance with Department modeling procedures and will be in compliance with all standards.

Question: Does the Department have reasonable assurance that the GE Dry Low NO_x (DLN) combustor can achieve the required emission rates?

Response: Based on the operation of GE units in Clark County Washington and Fort St. Verain Colorado which have achieved single digit levels of NO_X concentrations, as well as laboratory test results, and a guaranteed NO_X emission rate from GE, the Department has reasonable assurance that 12 ppmvd NO_x by summer of 2000 is feasible for natural gas and 42 ppmvd for fuel oil, each on a 30 day rolling average basis. Other GE combustion turbines in Florida such as Kissimmee Utility Authority unit 2, a frame 7 EA unit rated at 120 MW combined cycle, currently operate at concentrations of less than 12 ppm NO_X according to operators at this plant.

Question: How often will the unit run at less than 50 percent load? What about emissions during start-up, shut down, and malfunction?

Response: The unit is not planned to run at less than 50 percent load at all except during periods of time when the unit is ramping up during start-up (including fuel switching), or ramping down during shutdown. Of course, if there is a malfunction, the unit could operate briefly at less than 50 percent load. These periods of start-up (including fuel switching), shut down and malfunction are strictly limited by the Department's rules. There is no incentive for the City to operate the unit at low load because the unit is most efficient at high load. Furthermore, as the unit is subject to the emission standards at all times except during these transient conditions (start-up(including fuel switching), shut down, and malfunction), there is a strong incentive to operate at greater than 50 percent load where the emission levels are guaranteed by the combustion turbine vendor. Excess emissions must be reported to the Department within one working day and excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during start-up (including fuel switching), shut down, or malfunction are prohibited by the Department's rules.

Question: What assurance is there that the emissions will be properly recorded and reported? Are there logs kept?

Response: Continuous emissions monitoring systems (CEMS) will be used to continuously track the emissions from the plant for priority pollutants. The results of the monitoring are stored in computer data files which are available to the Department at any time. In accordance with the Department's rules, these monitors must be kept in good working order and the results must be reported quarterly (excess emission and Acid Rain Program operating reports) and annually (annual operating report).

Question: There will be an increase in CO emissions. Why not use a catalyst to reduce those emissions?

Response: The Department considered several factors in it's Best Available Control Technology (BACT) determination and concluded that the proper tuning of the dry low NO_x (DLN) burners and good operating practices is BACT in this case. The Department considered the energy, environmental, and economic impacts of the available control options in this case. An oxidation catalyst was found to be too expensive compared to other similar projects. CO concentrations are generally problematic only in large cities with congested intersections and major traffic problems. Maximum off-site ambient impacts due to this Project will be about one tenth of one percent of the ambient air quality standard or less.

Question: There will be an increase in sulfuric acid mist from about 3 tpy to over 8 TPY; this seems like a large increase. Why will sulfuric acid mist emissions increase even if SCR is not used?

Response: Sulfuric acid mist emissions are minimized through the use of low sulfur fuels like natural gas or No. 2 fuel oil with a limit of 0.05% sulfur content. Little or no increase in sulfuric acid mist emissions is expected because the facility-wide cap on SO_2 emissions will limit the amount of sulfur in the fuels which in turn limits the emissions of both SO_2 and sulfuric acid mist. Sulfuric acid emissions from gas fired units are relatively low. Although sulfuric acid emissions have not been measured on the existing boilers, the emission factor estimated by EPA literature (AP-42) is lower than the emission factor estimated for the new combustion turbine. Sulfuric acid mist emissions are a small fraction (typically about 3%) of the sulfur dioxide emissions.

Question: The Class I PSD increments to protect the plants and animals seem more protective than the Class II PSD increments which protect humans.

Response: The Ambient Air Quality Standards(AAQS) are the standards designed to protect human health and welfare. Welfare protection includes the protection of plants and animals, some species of which are more sensitive to certain levels of certain pollutants than are humans. On the other hand, the PSD classifications and PSD increments were established to prevent air quality from deteriorating from baseline levels (the air quality levels which existed when the increments were promulgated). The increments allowed within each PSD classification are designed to keep air quality from deteriorating significantly while still allowing for some growth in the economy. In developing the PSD program Congress decided that certain areas should be designated as Class I areas in which only extremely small increases in pollutant concentrations should be allowed. These included certain large National Parks and National Wilderness Areas in and around which only very limited economic growth and associated growth in emissions would be allowed. The remainder of the country was designated as Class II, where moderate increases in pollutant concentrations would be allowed to accommodate some growth in the economy and associated emissions. Thus, it is the AAQS which are protective of human health as well as that of the animals and plants; these standards are the same regardless of the PSD classification. The PSD increments are designed to prevent deterioration in air quality in all areas, with certain areas (Class I) allowed even less deterioration than most (Class II). Because of its Class I areas, Wakulla County and its citizens are even better protected from air quality deterioration than persons located elsewhere.

Question: With the Outstanding Florida Waters (OFW) nearby and the sensitive sea grasses in the St. Marks River and Apalachee Bay, how will the Project be protective of them?

Response: The emissions from the Project were evaluated to determine whether there would be a negative impact on water quality in the St. Marks River and ultimately in Apalachee Bay. The analysis indicated that there would be no measurable changes in water quality parameters as a result of the Project except for two parameters, where the changes are improvements. Any chemical changes in the water due to the Project would be far too small compared to natural changes that occur from rainfall, from deposition, from fires, etc. to cause any negative impact on sea grasses.

Similarly, there would be insufficient changes in salinity or turbidity of the water to affect the sea grasses.

Question: Is a higher or lower stack better?

Response: The proposed stack height for Unit 8 is the height calculated in accordance with the "Good Engineering Practice (GEP)" stack height regulations, and is an appropriate height for a source of this type. The GEP stack height calculations take into account nearby building heights so as to determine a height which is sufficient to avoid problems with aerodynamic downwash caused by these structures and yet is not so high as to be considered excessive.

Question: Emissions of mercury are projected to increase. With the fish consumption warnings, isn't this going to be a problem?

Response: Mercury emissions are typically a concern only with solid fuel projects where emissions are higher. For this Project actual emissions of mercury are only expected to increase by 0.0004 tons per year or less. This is less than one tenth of one percent of the value considered "significant" under the PSD rules. Maximum modeled ambient concentrations of mercury due to the Purdom Station will be well below the draft Florida Ambient Reference Concentrations (FARCs), which are conservative estimates of values below which there are not likely to be any health effects. Contrary to some statements which were made, the Florida Game and Fresh Water Fish Commission and the Florida Department of Health do not list the St. Marks or Wakulla Rivers among the rivers for which limited or no consumption of fish is recommended and, in fact, the St. Marks National Wildlife Refuge is listed among the wildlife refuges as having all species of fish being safe for unlimited consumption.

Question: Will there be an odor from the chlorine in the wastewater that gets put into the cooling tower?

Response: There will not be any noticeable odor from the cooling tower. There will be little or no emissions of chlorine gas from the water because: (1) chlorine concentrations in the water in the cooling tower will be very small, and (2) the water will not be sufficiently acid to allow significant emissions of free chlorine. Furthermore, the emissions of "drift" (small water droplets in the cooling tower that get carried out the top of the tower by the air stream) will be minimized through the use of high efficiency drift eliminators. These drift eliminators will limit drift to 0.002 percent of the circulating water flow. The amount of reuse water from the City of St. Marks will be a small fraction of the total cooling tower makeup water. Most of the makeup water will come from the river.

Question: If an SCR were added to control NO_x emissions, would there be a noticeable odor from the ammonia?

Response: If an SCR were to be used, it would likely be designed to have an ammonia slip of less than 10 ppm. At this emission rate, an off-site ammonia odor would not be expected:

Question: Would the Purdom 8 Project rely on emission trading or purchasing emission credits from other plants?

Response: If the question is referring to Acid Rain Program emission allowances, then the answer is that the Purdom Station has sufficient acid rain emission allowances to operate the new unit without purchasing additional allowances from any other source. If the question is referring to emission reductions or emission credits from the shut down of other units, then the answer is that the Purdom 8 Project is relying on the permanent shut down of Units 5 and 6 at the Purdom Station and the facility-wide caps for SO_2 and NO_x to "make room" for the emissions from Unit 8, but that no emission trades, reductions, or credits from other plants are needed.

Question: Will the Purdom 8 Project use up the available PSD increment and possibly preclude other sources from locating in Wakulla County?

Response: The Purdom Unit 8 Project actually consumes very little PSD increment in the Class II area in which the plant is located and in the two Class I areas which are nearby - St. Marks NWA and Bradwell Bay NWA. This is because the emission reductions from the units which have been shut down or will be shut down at the Purdom Station more than make up for the emissions from Unit 8 for most pollutants. In fact, the available increment is expanded for SO_2 as a result of the Project. While it is true that much of the available increment for SO_2 for the Bradwell Bay NWA Class I area is used up, this does not preclude new sources from locating in Wakulla County. Depending upon their locations, the levels of their SO_2 emissions, and any emission reductions available from the shut down or clean up of existing sources, new sources could be located in the area. They would have to comply with the same kind of stringent emission control limitations (BACT) as was applied to the Purdom 8 Project and demonstrate through modeling that the total increment consumption from the proposed new source and all other increment consuming and increment expanding sources do not exceed the allowable values.

The final action of the Department will be to issue the permit as proposed with minor clarifications.

Department of
Environmental Protection

Lawton Chiles Governor	Twin Towers Office Building 2600 Blair Stone Road Tallahassee, Florida 32399-2400	Virginia B. Wetherell Secretary

PERMITTEE:

City of Tallahassee
Utilities Services
300 South Adams Street
Tallahassee, FL 32301

FID No.	1290001
PSD No.	PSD-FL-239
SIC No.	4911
PPS No.	PA97-36
Expires:	May 15, 2003

Authorized Representative:
Jennette Curtis
Environmental Administrator

PROJECT AND LOCATION:

Permit for the construction of Unit 8, a combined cycle combustion turbine generating system at the Purdom Generating Station, located on the north end of the City of St. Marks on SR 363, Wakulla County, Florida.

UTM: Zone 16; 769.611 km E; 3339.767 km N

STATEMENT OF BASIS:

This construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and the Florida Administrative Code (F.A.C.) Chapters 62-4, 62-204, 62-210, 62-212, 62-296, 62-297. The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

Attached appendices and Tables made a part of this permit:

Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions

Howard L. Rhodes

Howard L. Rhodes, Director
Division of Air Resources
Management

SECTION I. FACILITY INFORMATION

SUBSECTION A. FACILITY DESCRIPTION

The City of Tallahassee is authorized to install a new combined cycle combustion turbine system, Unit 8, at the existing Purdom facility consisting of a 160 MW (nominal rating) GE Series MS7FA combustion turbine with DLN-2.6 (or later version) dry low NOx (gas) and water injection (diesel) burners and a nonfired heat recovery steam generator (HRSG) with a nominal 90 MW steam turbine. The compressor inlet air will be conditioned by an evaporative cooler when needed. The turbine will be started using the generator and a static start system. A new 200 foot stack and a cooling tower will be added to the facility for Unit 8.

Unit 8 will be located at the City's Sam O. Purdom Generating Station in St. Marks, Wakulla County. Existing steam generating Units 5 and 6 will be permanently shut down once Unit 8 has completed the initial performance test for natural gas firing. Other existing units at the plant consist of: Unit 7, a pre-NSPS boiler with a nominal rating of 44 MW fired by natural gas, residual fuel oil or distillate fuel oil; two pre-NSPS distillate fuel oil or natural gas fired combustion turbines with a nominal rating of 12.3 MWs each (GT1 and GT2); and a Subpart Dc auxiliary steam boiler fired by natural gas.

SUBSECTION B. REGULATORY CLASSIFICATION

The Purdom Generating Station is classified as a major air pollutant emitting facility. Air pollutant emissions are over 100 TPY for nitrogen oxides (NO_x) and carbon monoxide (CO).

This facility is on the list of the 28 Major Facility Categories in Table 62-212.400-1. This facility is also classified as a Title IV and Title V facility.

SUBSECTION C. RELEVANT DOCUMENTS:

The documents listed below are the basis of the permit. They are specifically related to this permitting action. These documents are on file with the Department.

Application (as revised 7/16/97, and 12/22/97)
Department's letter dated 5/1/97
Department of Interior's letter dated 1/21/97
EPA's letter dated October 14, 1997

SECTION II. EMISSION UNIT(S) GENERAL REQUIREMENTS

SUBSECTION A. ADMINISTRATIVE

1. Regulating Agencies: All documents related to applications for permits to operate, reports, tests, minor modifications and notifications or for permits to construct or modify an emission unit(s) *subject to the Prevention of Significant Deterioration (PSD) or to Nonattainment Areas (NA) Review requirements* should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP) located at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, Mail Station 5505, and phone number (850) 488-0114.

2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in *Appendix GC* of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.

4. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]

SECTION III. SPECIFIC CONDITIONS

SUBSECTION A. SPECIFIC CONDITIONS:

A. General Operation Requirements

1. Applicable Regulations: Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-103, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Part 60 including Subpart A and GG (1997 version), adopted by reference in the Florida Administrative Code regulation [Rule 62-204.800 F.A.C.]. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]

2. The maximum heat input rates, based on the lower heating value (LHV) of each fuel to Purdom Unit 8 at ambient conditions of 95°F temperature, 60% relative humidity, and 14.7 psi pressure shall not exceed 1,467.7 mmBtu/hr when firing natural gas, nor 1,659.5 mmBtu/hr when firing No. 2 fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. These curves or equations shall be used to establish the maximum allowable heat inputs at other ambient conditions for compliance determinations.

3. Purdom Unit 8 may operate continuously (i.e., 8760 hours per year).

4. Only natural gas or No. 2 fuel oil with a maximum sulfur content of 0.05% by weight shall be fired in the combined cycle combustion turbine.

5. The permittee shall install duct module(s) suitable for possible future installation of SCR equipment on the combined cycle generating unit.

6. Dry low NO_X combustors shall be used on Unit 8 when firing natural gas and water injection shall be used when firing No. 2 fuel oil for control of NO_X emissions.

7. During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary.

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

9. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.]

10. The dry low NO_X burner system shall be tuned upon initial operation to optimize emissions reductions and shall be maintained to minimize NO_X emissions and CO emissions. While firing natural gas, operation of the unit when the dry low NO_X burner system is in the diffusion firing mode shall be minimized.

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

B. *Emission Limits and Standards*

The following shall apply upon completion of the initial compliance tests:

1. Best Available Control Technology. The following is a summary of the BACT determinations by DEP:

Table 1. Emission Limits

Pollutant	Fuel	BACT Standard
NO_x	Gas Oil	12 ppmvd @ 15 % O_2 (a) (d) 42 ppmvd @ 15 % O_2 (a) (b) (d)
SO_2	Gas Oil	Good combustion Good combustion of low (0.05%) sulfur fuel oil
PM/PM_{10}	Gas Oil	Good combustion Good combustion of low (0.05%) sulfur fuel oil
Visible Emissions	Gas Oil	10 percent opacity 10 percent opacity
CO	Gas Oil	25 ppmvd (c) 90 ppmvd (c)

(a) 30-day rolling average excluding startup, shutdown, malfunction, and fuel switching.

(b) Plus an allowance for fuel bound nitrogen using the formula provided in Condition B4.

(c) By testing concurrent to RATA testing or by 3 one hour runs of Method 10.

(d) Not corrected to ISO conditions.

2. Visible Emissions. Visible emissions shall not exceed 10 percent opacity when firing either natural gas or No. 2 fuel oil. Drift eliminators shall be installed on the cooling tower to reduce PM/PM_{10} emissions.

3. Oxides of Nitrogen. Oxides of nitrogen emissions when firing natural gas shall not exceed 12 ppmvd at 15% O_2 on a 30-day rolling average basis (except during periods of startup, shutdown, malfunction or fuel switching) as measured by CEMS. When monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate the 30 day rolling average.

4. Oxides of Nitrogen. Oxides of nitrogen emissions when firing No. 2 fuel oil shall not exceed 42 ppmvd at 15% O_2 on a 30-day rolling average basis (except during periods of startup, shutdown, malfunction or fuel switching), as measured by CEMS, when fuel bound nitrogen(FBN) values are less than or equal to 0.015 percent. For fuel bound

SECTION III. SPECIFIC CONDITIONS

nitrogen values up to 0.03 percent, the allowance (and the adjusted standard) shall be determined, recorded, and maintained for each fuel delivery by the following formula:

$$STD = 0.0042 + F \text{ where:}$$

STD = allowable NO_X emissions (percent by volume at 15 percent O_2 and on a dry basis).

F = NO_X emission allowance for fuel-bound nitrogen defined by the following table:

Fuel-Bound Nitrogen (% by Weight)	F (NO_X % by Volume)
$0 < N \leq 0.015$	0
$0.015 < N \leq 0.03$	0.04 (N-0.015)

where: N = the nitrogen content of the fuel (% by weight) Note: 0.0042 percent = 42 ppm

Adjustments to the NO_X standard (either up or down) shall be calculated based on volume weighted averages of the nitrogen content for each fuel oil shipment and the nitrogen content of the existing fuel in the storage tank.

5. Oxides of Nitrogen. Beginning with the calendar year following successful completion of the initial performance test for Unit 8, annual emissions of NO_X shall not exceed 467 tons per year from the Purdom facility (Unit 8, Unit 7, GT1, GT2, and the auxiliary boiler) on a calendar year basis, as measured by applicable compliance methods. [Requested by the applicant]

6. Sulfur Dioxide. Beginning with the calendar year following successful completion of the initial performance test for Unit 8, annual emissions of SO_2 shall not exceed 80 tons per year from the Purdom facility (Unit 8, Unit 7, GT1, GT2, and the auxiliary boiler) on a calendar year basis, as measured by applicable compliance methods. [Requested by the applicant]

7. Carbon Monoxide. Carbon monoxide emissions when firing natural gas shall not exceed 25 ppmvd as measured by Method 10.

8. Carbon Monoxide. Carbon monoxide emissions when firing No. 2 fuel oil shall not exceed 90 ppmvd as measured by Method 10.

C. Excess Emissions

1. Excess emissions resulting from startup, shutdown, malfunction or fuel switching shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized but in no case exceed four hours in any 24-hour period for cold startup or two hours in any 24-hour period for other reasons unless specifically authorized by DEP for longer duration.

2. 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 pursuant to Rule 62-210.700, F.A.C.

3. Excess Emissions Report: If excess emissions occur due to malfunction, the owner or operator shall notify DEP's Northwest District office within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. [Rules 62-4.130 and 62-210.700(6), F.A.C.]

SECTION III. SPECIFIC CONDITIONS

D. Compliance Determination

1. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, for each fuel, but not later than 180 days from the initial operation date for each fuel, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1997 version), and adopted by reference in Chapter 62-297, F.A.C.

   Initial (I) compliance tests shall be performed on Unit 8 while firing each fuel (gas, oil). Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.340, F.A.C., on Unit 8 as indicated. The following reference methods shall be used:

   -Method 9 Visual Determination of the Opacity of Emissions from Stationary Sources (I, A); annual on oil if greater than 400 hours of oil firing; however, testing on gas is required only once every five years.

   -Method 10 Determination of Carbon Monoxide Emissions from Stationary Sources (I, A). Testing may be conducted at less than capacity when compliance testing is conducted concurrent with the RATA testing required pursuant to 40 CFR 75 (annual for gas firing and annual for oil only if greater than 400 hours of oil firing).

   -Method 20 Determination of Oxides of Nitrogen and diluent emissions from Stationary Gas Turbines (I only, for compliance with 40 CFR 60 Subpart GG)

   Determination of Oxides of Nitrogen emissions will be by a Continuous Emissions Monitoring System (CEMs). A CEMS operated and maintained in accordance with 40 CFR 75 may be used. Compliance with the NO_X emissions standards in Table 1 shall be demonstrated with this CEMS system based on a 30 day rolling average. Based on CEMS data at the end of each operating day, a new 30 day average emission rate is calculated from the arithmetic average of all valid hourly emission rates during the previous 30 operating days. Valid hourly emission rates shall not include periods of startup (including fuel switching), shutdown, or malfunction as defined in Rule 62-210.200 where emissions exceed the NO_X standard in Table 1. These excess emission periods shall be reported as required in Section C. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart.

   Note: No other methods may be used for compliance testing unless prior DEP approval is received in writing. The DEP may request a special compliance test pursuant to Rule 62-297.340(2), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

2. Notwithstanding the requirements of Rule 62-297.340, F.A.C., the exclusive use of fuel oil with a maximum sulfur content limit of 0.05% or less, by weight, or pipeline quality natural gas is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard and the 0.05% S limit, fuel oil analysis using ASTM D2880-71 or D4294 (or equivalent) for the sulfur content of liquid fuels and D1072-80, D3031-81, D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA approved custom fuel monitoring schedule in Condition F.3. However, the permittee is responsible for ensuring that the procedures above are used for determination of fuel sulfur content. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335 (e) (1997 version). For the purposes of demonstrating compliance with the emissions caps (Conditions B5 and B6), natural gas and fuel oil supplier data for sulfur content may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized.

3. An initial test for CO, concurrent with the initial NO_X test, is required. The initial NO_X and CO test results shall be the average of three valid one-hour runs. The DEP's Northwest District office shall be notified, in writing, at least 30

days prior to the initial compliance tests and at least 15 days before annual compliance test(s). Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 95-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 105 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity.

E. Notification, Reporting and Recordkeeping

1. All measurements, records, and other data required to be maintained by the City of Tallahassee shall be retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP representatives upon request.

2. Compliance Test Reports: A test report indicating the results of the required compliance tests shall be filed with the DEP NW District Office as soon as practical, but no later than 45 days after the last sampling run is completed. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.

F. Monitoring Requirements

1. The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from Unit 8. Thirty day rolling average periods when NO_X emissions (ppmvd @ 15% oxygen) are above the BACT standards (12/42 ppmvd for gas/oil) shall be reported to the DEP Northwest District Office pursuant to Rule 62-4.160(8), F.A.C. The continuous emission monitoring systems must comply with the certification and quality assurance, and other applicable requirements from 40 CFR 75. Periods of startup, shutdown, malfunction, and fuel switching shall be monitored, recorded, and reported as excess emissions when emission levels exceed the standards in Table 1 following the format of 40 CFR 60.7 (1997 version). The NO_x CEMS shall be used in lieu of the water/fuel monitoring system and fuel bound nitrogen (FBN) monitoring required for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1997 version). The calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) (1997 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS. Upon request from DEP, the CEMS emission rates for NO_X on Unit 8 shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332.

2. The following monitoring schedule for No. 2 fuel oil shall be followed: For all bulk shipments of No. 2 fuel oil received at the Purdom Station, an analysis which reports the sulfur content and fuel bound nitrogen content of the fuel shall be provided by the fuel vendor or other sources which follow the appropriate fuel test methods listed in Specific Condition D2. The analysis shall also specify the methods by which the analyses were conducted and shall comply with the requirements of 40 CFR 60.335(d).

3. The following custom monitoring schedule for natural gas is approved in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2):

   a. Monitoring of natural gas nitrogen content shall not be required.

SECTION III. SPECIFIC CONDITIONS

b. Analysis of the sulfur content of natural gas shall be conducted using one of the EPA-approved ASTM reference methods in Condition D2 for the measurement of sulfur in gaseous fuels, or an approved alternative method. Once Unit 8 becomes operational, monitoring of the sulfur content of the natural gas shall be conducted twice monthly for six months. If this monitoring shows little variability in the fuel sulfur content, and indicates consistent compliance with 40 CFR 60.333, then fuel sulfur monitoring shall be conducted once per quarter for six quarters and after that, semiannually.

c. Should any sulfur analysis indicate noncompliance with 40 CFR 60.333, the City shall notify DEP of such excess emissions and the customized fuel monitoring schedule shall be reexamined. The sulfur content of the natural gas will be monitored weekly during the interim period while the monitoring schedule is reexamined.

d. The City shall notify DEP of any change in natural gas supply for reexamination of this monitoring schedule. A substantial change in natural gas quality (i.e., sulfur content variation of greater than 1 grain per 100 cubic foot of natural gas) shall be considered as a change in the natural gas supply. Sulfur content of the natural gas will be monitored weekly by the natural gas supplier during the interim period when this monitoring schedule is being reexamined.

e. Records of sampling analysis and natural gas supply pertinent to this monitoring schedule shall be retained by the City for a period of five years, and shall be made available for inspection by the appropriate regulatory personnel.

f. The City may obtain the sulfur content of the natural gas from the fuel supplier provided the test methods listed in Specific Condition D2 are used.

4. Determination of Process Variables:

(a) The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

(b) Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh 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]

5. Compliance with the annual facility-wide NO_X cap shall be reported as required in Condition G6 and shall be determined by adding the annual NO_X emissions in tons per year for Unit 8 and Unit 7 (determined by the CEMS as required by 40 CFR 75) to annual NO_X emissions calculated for units GT1, GT2 and the auxiliary boiler determined by the following formulas:

GT 1 & GT 2 NO_X(natural gas)= (Fuel Usage)X (Heating Value of Natural Gas) X (0.44 lb/mmBtu) X units conversion factors

Fuel Usage shall be measured by fuel meter, recorded daily when unit is operated
Heating Value of Natural Gas will be determined from fuel supplier data
0.44 lb/mmBtu = AP-42 emission factor

GT 1 & GT 2 NOx (fuel oil)= (Fuel Usage)X (Heating Value of Fuel Oil) X (0.698 lb/mmBtu) X units conversion factors

Fuel Usage shall be measured by fuel meter, recorded daily when unit is operated
Heating Value of Fuel Oil will be determined from fuel supplier data
0.698 lb/mmBtu = AP-42 emission factor

Aux. Boiler NO_X(natural gas)= (Fuel Usage)X (140 lb/mmCF) X units conversion factors

Fuel Usage shall be measured by flow meter, recorded daily when unit is operated
140 lb/mmCF = AP-42 emission factor

6. Compliance with the annual facility-wide SO_2 cap shall be reported as required in Condition G6 and shall be determined by adding the annual SO_2 emissions in tons per year for Unit 8 and Unit 7 (determined by the methods required by 40 CFR 75) to the annual SO_2 emissions calculated for units GT1, GT2 and the auxiliary boiler determined by the following formulas:

GT 1 & GT 2 SO2 Emissions (natural gas)= (Fuel Usage) X (Heating Value of Natural Gas) X (0.0006 lb/mmBtu) X units conversion factors

Fuel Usage shall be measured by fuel meter, recorded daily when unit is operated
Heating Value of Natural Gas from fuel supplier data
Sulfur Content default of NADB = 0.0006 lb-SO2/mmBtu

GT 1 & GT 2 SO2 Emissions (fuel oil) = (Fuel Usage) X (Fraction Sulfur in the fuel oil) X (Molecular weight SO2 / Molecular weight of S) X (Conversion factor) X units conversion factors

Fuel Usage shall be measured by fuel meter, recorded daily when unit is operated % Sulfur will be determined from fuel oil analysis each time fuel is delivered (i.e., 0.05% S = 0.0005 in the above formula).

Molecular weight of SO2 = 64
Molecular weight of S = 32
Conversion factor of 95% = 0.95

Aux. Boiler SO2 Emissions (natural gas)= (Fuel Usage) X (Heating Value of Natural Gas) X (0.0006 lb/mmBtu) X units conversion factors

Fuel Usage shall be measured by fuel meter, recorded daily when unit is operated
Heating Value of Natural Gas from fuel supplier data
Sulfur Content default of NADB = 0.0006 lb/mmBtu

G. Rule Requirements

1. The emission unit shall be operated in compliance with all applicable requirements of 40 CFR 60, Subpart A, Appendix A and Appendix B (1997 version), Subpart GG - Standards of Performance for Stationary Gas Turbines (1997 version), and Rule 62-204.800 (7) (b) 38, F.A.C., except as otherwise specified herein. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance

determinations with the BACT standard(s). All notifications and reports specified in this section shall be submitted to the DEP's Northwest District office.

2. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements and regulations (Rule 62-210.300(1), F.A.C.).

3. Except as otherwise specified herein, the emission unit shall be operated in compliance with all applicable provisions of Rule 62-210.650, F.A.C.: Circumvention; Rule 62-210.700, F.A.C.: Excess Emissions; Rule 62-204.800 (7) (b) 38, F.A.C.: Standards of Performance for New Stationary Sources (NSPS); Chapter 62-297, F.A.C.: Stationary Sources - Emissions Monitoring; and, Rule 62-4.130, F.A.C.: Plant Operation - Problems.

4. Notification of the following dates shall be provided to the DEP Northwest District office: 1)anticipated date of the initial startup of Unit 8 shall be postmarked not more than 60 days nor less than 30 days prior to such date, 2) the actual date of the initial startup shall be postmarked within 15 days after such date, and 3) commencement of construction shall be postmarked no later than 30 days after such date pursuant to 40 CFR 60.7. If construction does not commence within 18 months of issuance of this permit, the permittee shall obtain from the DEP's Bureau of Air Regulation a review and, if necessary, a modification of the BACT determination and allowable emissions (40 CFR 52.21(r)(2) (1997 version)).

5. Quarterly excess emission reports, in accordance with 40 CFR 60.7 (7) (c) (1997 version), shall be submitted to the DEP's Northwest District office.

6. Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Northwest District office by March 1st of each year.

7. Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.

8. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (Rule 62-4.090, F.A.C.).

H. Modifications

1. The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change.

APPENDIX GC
GENERAL PERMIT CONDITIONS [F.A.C. 62-4.160]

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

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

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

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

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

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

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

(a) Have access to and copy and records that must be kept under the conditions of the permit;
(b) Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
(c) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

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

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

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

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

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

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

G.11 This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

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

G.13 This permit also constitutes:

(a) Determination of Best Available Control Technology *(X)*
(b) Determination of Prevention of Significant Deterioration *(X)*; and
(c) Compliance with New Source Performance Standards *(X)*.

G.14 The permittee shall comply with the following:

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

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

(c) Records of monitoring information shall include:

1. The date, exact place, and time of sampling or measurements;
2. The person responsible for performing the sampling or measurements;
3. The dates analyses were performed;
4. The person responsible for performing the analyses;
5. The analytical techniques or methods used; and
6. The results of such analyses.

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

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Purdom Generating Station/Unit 8
City of Tallahassee

Facility ID No. 1290001 - Unit No. 8
Wakulla County, Tallahassee, Florida

Air Construction Permit No. PSD-FL-239
Power Plant Siting No. PA 97-36

The City of Tallahassee plans to install a new combined cycle combustion turbine system, Unit 8, at the existing Purdom facility consisting of a 160 MW (nominal rating) GE Series MS7FA combustion turbine with DLN-2.6 (or later version) dry low NOx (gas) and water injection (diesel) burners and a nonfired heat recovery steam generator (HRSG) with a nominal 90 MW steam turbine. The compressor inlet air will be conditioned by an evaporative cooler when needed. The turbine will be started using the generator and a static start system. A new 200 foot stack and a cooling tower will be added to the facility for Unit 8.

Unit 8 will be located at the City's Sam O. Purdom Generating Station in St. Marks, Wakulla County. Existing steam generating Units 5 and 6 will be permanently shut down once Unit 8 has completed the initial performance test for natural gas firing. Other existing units at the plant consist of: Unit 7, a pre-NSPS boiler with a nominal rating of 44 MW fired by natural gas, residual fuel oil or distillate fuel oil; two pre-NSPS distillate fuel oil or natural gas fired combustion turbines with a nominal rating of 12.3 MWs each (GT1 and GT2); and a Subpart Dc auxiliary steam boiler fired by natural gas. A process description is included in the Technical Evaluation and Preliminary Determination.

BACT DETERMINATION REQUESTED BY THE APPLICANT:

See Table 4-8 (ATTACHMENT A) for the BACT requested by the applicant.

The Sam O. Purdom facility is among the major facilities listed in Florida Administrative Code (F.A.C.) Chapter 62-212, Prevention of Significant Deterioration (PSD), Table 62-212.400-1, "Major Facilities Categories." A BACT determination is required for each pollutant exceeding the significant emission rates in Table 62-212.400-2, "Regulated Air Pollutants Significant Emissions Rates," which in this case are particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), carbon monoxide (CO), and nitrogen oxides (NO_X),

This facility is also subject to:

- o 40 CFR 60, Subpart GG
- o 40 CFR 75

DATE OF RECEIPT OF A BACT APPLICATION:

03-17-97

REVIEW GROUP MEMBERS:

Martin Costello, P.E., of the New Source Review Section.

BACT DETERMINATION PROCEDURE:

In accordance with Chapter 62-212, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

(a) Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 - Standards of Performance for New Stationary Sources or 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants.

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

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

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

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically infeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

The air pollutant emissions from this facility can be grouped into categories based upon the control equipment and techniques that are available to control emissions from these emission units. Using this approach, the emissions can be classified as follows:

o *Combustion Products* (e.g. NO_X and SO_2)

Nitrogen Oxides (NO_X)

Oxides of nitrogen (NO_X) are generated during fuel combustion by oxidation of chemically bound nitrogen in the fuel (fuel NO_X) and by thermal fixation of nitrogen in the combustion air (thermal NO_X). As flame temperature increases, the amount of thermally generated NO_x increases. Fuel type affects the quantity and type of NO_X generated. Natural gas is very low in fuel bound nitrogen and therefore the dominant mechanism for NO_X formation is thermal NO_X. On combustion turbines, controls for NO_X include Selective Catalytic Reduction (SCR) systems, wet injection or dry low NO_X burner systems.

Sulfur Dioxide (SO_2)

In a combustion turbine (CT) sulfur dioxide emissions result from the oxidation of fuel bound sulfur. Natural gas has very low levels of sulfur and low sulfur distillate fuel oils have 0.05% sulfur by weight which is also low compared to heavy fuel oils or coal. Add on controls (e.g. wet scrubber or spray dryer absorber systems) are not feasible nor are they needed when low sulfur fuels are fired in combustion turbines. SO_2 emissions are minimized solely by firing low sulfur fuels. As discussed below, sulfur dioxide (and sulfuric acid mist) emissions will be controlled on unit 8 by firing low sulfur fuels.

o *Products of Incomplete Combustion* (e.g., PM_{10}, CO, VOC).

Particulate Matter less than 10 micrometers aerometric diameter (PM_{10})

Particulate Matter is generated by various physical and chemical processes during combustion. The particulate matter emitted from this combustion turbine will predominately be less than 10 micrometers in diameter (PM_{10}). Common control devices for stack gases include settling chambers, inertial separators, impingement separators, wet scrubbers, fabric filters, and electrostatic precipitators. These add on control devices have not been used on combustion turbines mainly due to the low particulate loadings and the increased back pressure. Filtering of the compressor inlet air and good combustion practices constitute the top control option for combustion turbines firing natural gas or low sulfur distillate fuel oil.

The cooling tower will emit PM/PM_{10} as particulate laden water is emitted and evaporated from the tower. A single BACT determination for a cooling tower was identified in the technology review. The BACT in this case specified drift eliminators to control PM/PM_{10} emissions from the cooling tower drift losses.

Carbon Monoxide (CO)

Carbon monoxide (CO) is a pollutant formed by the incomplete combustion (oxidation) of hydrocarbons in the turbine's combustors. The most stringent control technology for CO emissions is the use of an oxidation catalyst. This control option is not considered cost effective as discussed in the next section. The second most stringent control option, combustion controls and good combustion practices is considered BACT for this project.

- *Other Pollutants:*

VOC is also a pollutant formed by the incomplete combustion of fuel. It will be controlled in the same manner as chosen for CO control. Other pollutants (sulfuric acid mist, heavy metals) will be minimized by the exclusive use of clean fuels and the same good combustion practices listed above.

Grouping the pollutants in this manner facilitates the BACT analysis because it enables the equipment available to control the type or group of pollutants emitted and the corresponding energy, economic, and environmental impacts to be examined on a common basis. Although all of the pollutants addressed in the BACT analysis may be subject to a specific emission limiting standard as a result of PSD review, the control of "non-regulated" air pollutants is considered in imposing a more stringent BACT limit on a "regulated" pollutant (i.e., PM_{10}, NO_X, SO_2, etc.), if a reduction in "non-regulated" air pollutants can be directly attributed to the control device selected as BACT for the abatement of the "regulated" pollutants.

BACT POLLUTANT ANALYSIS

NITROGEN OXIDES (NO_X)

A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) information indicates that NO_X emissions for most new combustion turbines in attainment areas for ozone and nitrogen dioxides are controlled by either wet injection or dry low NO_X burner technology. The applicant has proposed dry low NO_X burner technology for gas firing and water injection for fuel oil firing. It is compared below with previous determinations documented by the BACT Clearinghouse.

BACT Clearinghouse Determinations

BASIS:	*Limit*	*Technology*	*Facility ID*
LAER- gas fired	*3.5 ppm*	*SCR*	*NY-0044*
LAER- oil fired	*10 ppm*	*SCR*	*NY-0044*
BACT-gas	*9ppm*	*DLNB*	*NY-0047*
BACT-oil	*42ppm*	*water injection*	*NY-0047*

The most stringent or top control option for controlling NO_X emissions from a combustion turbine is the above listed facility (NY-0044) from EPA's RACT/BACT/LAER Clearinghouse Information System (RBLC). The Brooklyn Navy Yard Cogeneration Partnership L.P. facility consists of two CTs which are gas/oil fired cogeneration units rated at 240 MW total (160 MW simple cycle) and is located in a nonattainment area for ozone. In addition to SCR add on controls for NO_X emissions, offsets (reductions in NO_X emissions at a nearby facility) were purchased when this unit was permitted.

The city analyzed the feasibility of installing a SCR system for Purdom unit 8. The initial capital cost based on a vendor quote was $1,676,000 based on a design which would meet 3.5 ppm on gas and 10 ppm on fuel oil. The total levelized annual cost was estimated to be $1.5 million per year for 20 years resulting in an incremental cost effectiveness of *$7,225* per ton of NO_X removed. This incremental cost effectiveness value is considerably higher than those determined to constitute BACT for other projects in Florida of similar nature. Therefore SCR is deemed too expensive in this application.

The most stringent emission limit for a large industrial combustion turbine with dry low NO_X burners is listed in the table above (NY-0047). This unit is located in Holtsville New York at the PASNY Holtsville Combined Cycle Plant. This unit is a Siemens model V84.2 rated at 150 MW simple cycle. This unit uses a single vertical silo combustor in contrast to the GE frame 7FA unit which uses a can annular combustor. The silo design allows for longer residence time in the combustor and may operate at lower peak flame temperatures (which reduces thermal NOx). It was permitted in 1992 and has recently demonstrated emissions less than 9 ppmvd except during startup (up to 3 hours) /shutdown/malfunction and is required to demonstrate compliance using the NO_X CEMS. The firing temperature and the reliability of this unit are not known as this time. The majority of the 9 ppm units listed in EPA's database employ both SCR and dry low NOx burners.

The current level of dry low NO_X burner technology which can be reliably achieved over a long time period appears to be approximately 15 ppm of NO_X at full load firing natural gas. This standard is shown on at least 10 units listed in EPA's RACT/BACT/LAER Clearinghouse. The actual emissions level achieved from dry low NO_X burner technology is dependent on firing temperature, size of the unit and type of combustor (silo vs. annular combustor designs). In general the smaller aeroderivative designs have not been able to achieve 15 ppm without having problems with reliability. Several units in Florida have been granted extensions for the deadline to attain 15 ppm. Some of the smaller industrial turbines (frame units) are able to achieve less than 15 ppm today. For instance, Unit 2 at the Kissimmee Utility Authority's Cane Island plant has actual emissions of 6 to 12 ppm at full load on this GE frame 7 EA unit. It is rated at 80 MW and has a firing temperature of about 2025 F. Because the city requested compliance to be demonstrated on a continuous basis (by CEMS) using a 30 day rolling average, the Department considered a BACT limit below 15 ppm to compensate for the longer averaging time. An additional consideration in determining BACT for NO_X was the fact that the technology for this dry low NO_X system is still under development, even though it has been demonstrated on a lower firing temperature unit.

Dry low NO_X technology is a combustion staging technology which reduces the formation of thermal NO_X by keeping peak flame temperatures as low as possible. But higher firing temperatures enable higher thermal efficiencies because these hotter exhaust gases have more energy to turn the turbine blades. Because thermal NO_X can be higher for the higher firing temperature units (e.g. the unit proposed by the City of Tallahassee) it is more difficult to achieve low NO_X emissions on these units with firing temperatures of 2400 F. Compensating for this is the higher electrical power output for a given heat input, therefore on a (lbs of NO_X emissions) / (KW-hr) basis, the more efficient units may not be at a disadvantage to the lower firing temperature units.

Dry low NO_X burner technology is the next most stringent control technology (after SCR) for combustion turbines. The applicant proposes to use GE's DLN-2.6 (or later version) controls which is a third generation dry low NO_X burner technology that was first demonstrated in commercial operation in 1996. Emissions from this unit were less than 9 ppm. This application was a Frame 7FA unit with a firing temperature of 2350 F. The first application of a Frame 7FA with a 2400 F firing temperature is scheduled for operation this summer and has a contract for less than 15 ppm. Although not currently demonstrated on the higher firing temperature unit which the city of Tallahassee will purchase, the contractor has guaranteed an emission rate of less than 9 ppm for Purdom Unit 8. This guarantee is based on operation above the 50-55% load range since emissions (ppm) will be higher at loads below this.

Nitrogen Oxides (NO_X) emissions will be controlled by using GE's DLN-2.6 (or later version) with a BACT standard of 12 ppmvd corrected to 15% oxygen, compliance by CEMS and using a 30 day rolling average. The firing temperature on this Frame 7FA combustion turbine is 2400 F. When firing natural gas, the combustor operates in a diffusion mode at low loads (less than about 50% of capacity) and in a premixed mode at high loads. When firing fuel oil, the combustors are operated in a diffusion mode at all loads and diluent injection (water) is used to control NO_X formation. The DLN-2.6 control system regulates fuel distribution to the primary, secondary, tertiary and quaternary fuel systems for each of the five combustors. As the combustion turbine is started and operated through the full range, the diffusion, piloted premix, and premix flames are established by changing the distribution of fuel flow in the combustors. Fuel and air flow to the combustors are controlled by GE's Speedtronic control system. GE's Mark V control system will be used to continuously maintain the NO_X concentration in the exhaust at the specified level throughout a range of loads and ambient conditions. This system receives inputs from a compressor inlet temperature and humidity sensor, load sensors, speed sensors, and ambient pressure sensors.

SULFUR DIOXIDE (SO_2)

SO_2 control processes can be classified into five categories: fuel/material sulfur content limitations, absorption by a solution, adsorption on a solid bed, direct conversion to sulfur, or direct conversion to sulfuric acid.

A review of the BACT determinations for combustion turbines as contained in EPA's Clearinghouse shows that the exclusive use of low sulfur fuels constitutes the top control option for SO_2. The applicant has proposed the exclusive use of natural gas or distillate fuel oil with sulfur content limited to 0.05% by weight. This is considered BACT for this project.

PARTICULATE MATTER (PM/PM_{10})

A technology review indicated that the top control option for PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air. The applicant has proposed this top control option. In addition, GE indicates that the PM_{10} emissions will not exceed 9 lb/hr (0.0058 lb/mmBtu) for natural gas and 17 lb/hr (0.0096 lb/mmBtu) for low sulfur distillate fuel oil exclusive of background dust loadings. Because these low emission levels are difficult to reliably measure by EPA reference methods over a one hour test period, BACT is not an emission limit but is based on good combustion practices and the exclusive use of clean, low sulfur fuels. The emission control technology for PM_{10} will be good combustion practices and the use of only low sulfur, and low ash content fuels including natural gas and distillate fuel oil containing no more than 0.05% sulfur by weight. The inlet air for the combustion turbine will be filtered to protect the internal components from wear. This filtration may also reduce PM_{10} emissions. Good combustion practices shall be implemented by using computer monitored and controlled systems with appropriate alarms for improper operating parameters. Proper tuning and operation of the dry low NO_X burner system shall be employed to minimize products of incomplete combustion (PM_{10}, VOC, and CO) while meeting the NO_X emission limit.

BACT for the cooling tower is the use of drift eliminators to control PM/PM_{10} emissions from the cooling tower drift losses.

CARBON MONOXIDE(CO)

The most stringent control technology for CO emissions is the use of an oxidation catalyst. The city evaluated the use of an oxidation catalyst designed for 90 percent reduction and having a two year catalyst life. The oxidation catalyst control system is estimated to increase the capital cost of the project by $1.5 million and results in an incremental cost effectiveness of $7,720 per ton of CO reduced. In addition, there will be a reduction in the unit's output by as much as 0.5% or 1.25 MW due to the increased pressure drop across the catalyst. The catalyst may also result in an increase in the oxidation of SO_2 to SO_3 which combines with moisture in the exhaust to form sulfuric acid mist. This impact is not considered significant. The catalyst life is limited and may result in an additional solid waste load to the local landfill if the catalyst can not be rejuvenated by the manufacturer. This control option is not considered cost effective. The second most stringent control option, combustion controls and good combustion practices is considered BACT for this project. Carbon monoxide (CO) will be controlled by proper tuning of the dry low NO_X burner system and good combustion practices. Operation of the dry low NO_X burner system shall be optimized in order to minimize CO emissions while keeping NO_X emissions below the emission limit. Low load operation will result in the highest levels of CO emissions (ppm and lb/hr). The BACT emission limit for CO, 25 ppm for gas and 90 ppm for fuel oil, was set at the level which could be achieved for worst case operation i.e., low load operation (50% load) so that the full range of operation of this unit could be employed. It may be cost effective to conduct annual CO emission tests concurrent with the annual relative accuracy test audits (RATA) which are conducted at 50 % load or higher. According to GE's data, operation at higher loads should result in CO emissions which are at or below 10 ppmvd when firing natural gas.

BACT DETERMINATION RATIONALE:

The BACT emission level chosen for NO_X, 12 ppm and compliance by CEM, is similar to the basis for the 165 MW units (simple cycle rating) at for FPC's Hines Energy Center and is the lowest NO_X limit (ppm level) to date in Florida. In contrast to Unit 8, the Hines Energy Center units are not required to demonstrate compliance on a continuous basis but EPA Method 20 is required once per year. Selective Catalytic Reduction (SCR) was not considered cost effective for the city of Tallahassee. SCR is an add on NO_X control technology which requires ammonia injection and the installation of a catalyst bed downstream of the combustion turbine. Because combustion turbines pump large volumes of exhaust gases, the pressure drop introduced by the catalyst causes energy losses on these large industrial combustion turbines. Water usage associated with an SCR system would increase by 136,000 gallons per year.

BACT for SO_2 emissions from the combustion turbine was based on the top control option which is the exclusive use of low sulfur distillate fuel oil and pipeline quality natural gas. These fuels are among the lowest sulfur fuels available. This BACT will also insure that ambient SO_2 impacts on the nearby St. Marks Class I area are minimized to the greatest extent possible.

BACT for PM_{10} was determined to be good combustion practices, inlet air filtering, and clean, low ash and low sulfur fuels which is currently the only feasible PM_{10} control technology for combustion turbines. Particulate matter is generated by various physical and chemical processes during combustion and will be affected by the design and operation of the NO_X controls. The particulate matter emitted from this unit will mainly be less than 10 micrometers in diameter (PM_{10}). Common control devices for stack gases include settling chambers, inertial separators, impingement separators, wet scrubbers, fabric filters, and electrostatic precipitators. Fabric filters (baghouses) and electrostatic precipitator (ESPs) have not been used on combustion turbines mainly due to the low particulate loadings and the increased back pressure. Filtering of the compressor inlet air and good combustion practices constitute the top control option for combustion turbines firing natural gas or low sulfur distillate fuel oil. The applicant has proposed this top control option. This is considered BACT for this project.

The city evaluated the use of an oxidation catalyst designed for 90 percent reduction of CO and a two year catalyst life. The oxidation catalyst control system is estimated to increase the capital cost of the project by $1.5 million and results in an incremental cost effectiveness of $7,720 per ton of CO reduced. In addition, there will be a reduction in the unit's output by as much as 0.5% or 1.25 MW due to the increased pressure drop across the catalyst. The catalyst may also result in an increase in the oxidation of SO_2 to SO_3 which combines with moisture in the exhaust to form sulfuric acid mist. This impact is not considered significant. The catalyst life is limited and may result in an additional solid waste load to the local landfill if the catalyst can not be rejuvenated by the manufacturer. This control option is not considered cost effective. The second most stringent control option, combustion controls and good combustion practices is considered BACT for this project. The BACT emission limit for CO, 25 ppm for gas and 90 ppm for fuel oil, was set at the level which could be achieved for worst case operation i.e., low load operation (50% load) so that the full range of operation of this unit could be employed. It may be cost effective to conduct annual CO emission tests concurrent with the annual relative accuracy test audits (RATA) which are conducted at 50 % load or higher. According to GE's data, operation at higher loads should result in CO emissions which are at or below 10 ppmvd when firing natural gas.

BACT DETERMINATION BY DEP:

Based on the information provided by the applicant and the information searches conducted by the Department, lower emissions limits can be obtained employing the top-down BACT approach for SO_2, NO_X, PM_{10}, and CO.

PM_{10} DETERMINATION

Filtering of the compressor inlet air and good combustion practices while firing low sulfur fuels (natural gas or distillate fuel oil with no more than 0.05% sulfur content).

BACT for the cooling tower is the use of drift eliminators to control PM/PM_{10} emissions from the cooling tower drift.

SO_2 DETERMINATION

The exclusive use of pipeline quality natural gas or distillate fuel oil with sulfur content limited to 0.05% by weight is considered BACT for this project.

NO_x DETERMINATION

An emission limit of 12 ppmvd corrected to 15% oxygen firing natural gas and 42 ppmvd corrected to 15% oxygen firing fuel oil is considered BACT. The NO_X standard for firing fuel oil shall be adjusted from 42 ppm up to 48 ppm based on fuel bound nitrogen (FBN) levels above 0.015 percent according to the equation submitted by the applicant and incorporated into the draft PSD permit (Section III Condition B4). This adjustment, upward or downward between 42 and 48 ppm, shall be made only at the time of each new fuel shipment. Compliance shall be demonstrated on a

30 day rolling average basis using the NO_X CEMS system. Emissions during startup (including fuel switching), shutdown and malfunction shall be excluded from the calculation of these 30 day rolling averages provided the operator minimizes the occurrence, magnitude, and duration of excess emissions pursuant to 62-210.700 Florida Administrative Code (version dated 10/15/96). Excess Emissions during these transient periods shall be reported quarterly to the Department pursuant to 40 CFR 60.7. Excess emissions shall be reported based on the NO_X CEMS data in lieu of the water/fuel monitoring specified in 40 CFR 60.334. When monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate of the 30 day rolling average.

CO DETERMINATION

Carbon monoxide (CO) will be controlled by proper tuning of the dry low NO_X burner system and good combustion practices. Operation of the dry low NO_X burner system shall be optimized during the initial compliance test and at other times as needed in order to minimize CO emissions while keeping NO_X emissions below the emission limit. The BACT emission limit for CO, 25 ppm for gas and 90 ppm for fuel oil, was set at the level which could be achieved for worst case operation i.e., low load operation (50% load) so that the full range of operation of this unit could be employed. It may be cost effective to conduct annual CO emission tests concurrent with the annual relative accuracy test audits (RATA) which are conducted at 50 % load or higher.

OTHER POLLUTANTS

Visible Emissions shall be limited to 10 % opacity as a secondary and ongoing indicator of PM_{10} emissions.

The BACT emission levels established by the Department are as follows:

Table 1-1: Air Pollutant Standards and Terms

POLLUTANT	EMISSION LIMIT
	Natural Gas / Fuel Oil
Particulate Matter (PM_{10})	good combustion of clean, low sulfur fuels
	drift eliminators for the cooling tower
Visible Emissions	10% opacity / 10 % opacity
Carbon Monoxide	25ppm / 90 ppm
NO_X (30 day rolling average)	12 ppm @ 15 % O_2 / 42 ppm @ 15% O_2 and adjusted for FBN
SO_2	natural gas / limit of 0.05% sulfur by weight

Table 1-2: Compliance Procedures

POLLUTANT	COMPLIANCE DETERMINED BY
Visible Emissions	Method 9
Carbon Monoxide	Method 10 (can conduct concurrent with RATA testing)
NO_X (30 day rolling average)	NO_X CEMS and O_2 or CO_2 diluent monitor
SO_2	ASTM D 3246 gas / ASTM D 4294 fuel oil, or other gas and fuel oil test methods in 40 CFR 60

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

Martin Costello, PE II
New Source Review Section
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:

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

Date: 5/28/98

Approved By:

Howard L. Rhodes, Director
Division of Air Resources Management

Date:

ATTACHMENT A

BACT DETERMINATION REQUESTED BY THE CITY OF TALLAHASSEE

TABLE 4-8
SUMMARY OF PROPOSED BEST AVAILABLE CONTROL TECHNOLOGY

Pollutant	Proposed BACT
Carbon Monoxide (CO)	Good Combustion Practices
Particulate Matter (TSP)	Fuel Quality (Clean Pipeline Quality natural gas and No. 2 (0.05% S) diesel fuel oil, Good Combustion Practices, and Combustion Inlet Air Filtration
PM_{10}	Fuel Quality (Clean Pipeline Quality natural gas and No. 2 (0.05% S) diesel fuel oil, Good Combustion Practices, and Combustion Inlet Air Filtration
Sulfur Dioxide (SO_2)	Fuel Quality (Clean Pipeline Quality natural gas and No. 2 (0.05% S) diesel fuel oil.
Sulfuric Acid Mist (H_2SO_4)	Fuel Quality (Clean Pipeline Quality natural gas and No. 2 (0.05% S) diesel fuel oil.
Nitrogen Oxides (NO_x)	Fuel Quality (Clean Pipeline Quality natural gas and No. 2 (0.05% S) diesel fuel oil and Good Combustion Practices including Dry-Low NOx Combustors and Water Injection
Volatile Organic Compounds (Including Benzene)	Good Combustion Practices
Trace Metals Lead (Pb) Beryllium (Be) Mercury (Hg) Arsenic (As)	Fuel Quality (Clean Pipeline Quality natural gas and No. 2 (0.05% S) diesel fuel oil and Combustion Inlet Air Filtration
Total Fluorides (Fl)	Fuel Quality (Clean Pipeline Quality natural gas and No. 2 (0.05% S) diesel fuel oil.
Cooling Tower (TSP & PM_{10})	Drift Eliminators (0.002 percent - Recirculation Water)

Note: Pollutants presented in bold and italics are subject to BACT by rule.

Source: Foster Wheeler Environmental, 1997

Table 1-2: Compliance Procedures

POLLUTANT	COMPLIANCE DETERMINED BY
Visible Emissions	Method 9
Carbon Monoxide	Method 10 (can conduct concurrent with RATA testing)
NO_X (30 day rolling average)	NO_X CEMS and O_2 or CO_2 diluent monitor
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