AL

THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In the Matter of an
Application for Permit by:

OGC CASE NO. ____________________

City of Tallahassee, Utility Services
300 South Adams Street
Tallahassee, FL 32301
____________________________________/

DRAFT Permit No.: PSD-FL-239
Sam O. Purdom Generating Station
Wakulla County

NOTICE OF WITHDRAWAL OF REQUEST FOR EXTENSION OF TIME

The City of Tallahassee (Tallahassee), by and through undersigned counsel, hereby withdraws its Request for Extension of Time to file a petition for formal administrative proceedings in accordance with Chapter 120, Florida Statutes. Tallahassee filed its third Request for Extension of Time on August 13, 1997, in response to the "Intent to Issue PSD Permit" (Permit No. PSD-FL-239) for the Sam. O. Purdom Generating Station located in Wakulla County, Florida, to negotiate certain changes in the draft proposed PSD permit and Best Available Control Technology (BACT) Determination with the Department of Environmental Protection (Department). Tallahassee withdraws its Request because the Department has agreed to issue the final permit and BACT Determination with changes negotiated with Tallahassee, as reflected in the revised draft permit and BACT Determination received August 28, 1997, (attached as Exhibit A).

Respectfully submitted this 29th day of August, 1997.

HOPPING GREEN SAMS & SMITH, P.A.

Angela R. Morrison, Fla. Bar No. 0855766
123 South Calhoun Street
Post Office Box 6526
Tallahassee, FL 32314
(904) 222-7500

Attorney for CITY OF TALLAHASSEE, UTILITY SERVICES

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing has been furnished to the following by U.S. Mail on this 29th day of August, 1997:

Clair H. Fancy, P.E.
Chief
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2600

Charles T. Collette, Esq.
Office of General Counsel
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2600

Angela R. Morrison
Attorney

98081

Permittee:

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

Authorized Representative:
Jennette Curtis
Environmental Administrator

FID No.	1290001
PSD No.	PSD-FL-239
SIC No.	4911
PPS No.	PA97-36
Expires:	5 years from issuance

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, Director
Division of Air Resources
Management

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 MS7231FA 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 (NOx) 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)
Department's letter dated 5/1/97
Department of Interior's letter dated 1/21/97
[EPA's letter dated ...]
[Third party's letters dated ...]

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) 488-1344.

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.]

5. Expiration: This air construction permit shall expire five years from the date of issuance.

Subsection A. Specific Conditions:

A. General Operation Requirements

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 NOX 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 NOX 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 NOX burner system shall be tuned upon initial operation to optimize emissions reductions and shall be maintained to minimize NOX emissions and CO emissions. While firing natural gas, operation of the unit when the dry low NOX 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
NOx	Gas Oil	12 ppmvd @ 15 % O2 (a) (d) 42 ppmvd @ 15 % O2 (a) (b) (d)
SO2	Gas Oil	Good combustion Good combustion of low (0.05%) sulfur fuel oil
PM/PM10	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/PM10 emissions.

3. Oxides of Nitrogen. Oxides of nitrogen emissions when firing natural gas shall not exceed 12 ppmvd at 15% O2 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 of 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% O2 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 upon each new fuel delivery by the following formula:

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

STD = allowable NOX emissions (percent by volume at 15 percent O2 and on a dry basis).

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

Fuel-Bound Nitrogen **(% by Weight)**	**F (NOX % 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

5. <u>Oxides of Nitrogen</u>. Beginning with the calendar year following successful completion of the initial performance test for Unit 8, annual emissions of NOX 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. <u>Sulfur Dioxide</u>. Beginning with the calendar year following successful completion of the initial performance test for Unit 8, annual emissions of SO2 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. <u>Carbon Monoxide</u>. Carbon monoxide emissions when firing natural gas shall not exceed 25 ppmvd as measured by Method 10.

8. <u>Carbon Monoxide</u>. 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.]

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, at which this unit will be operated, but not later than 180 days of initial operation of the unit for that 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. Annual compliance testing may be conducted concurrent with the annual RATA testing required pursuant to 40 CFR 75 (gas only).

   - 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 NOX 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.

   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, is the method for determining compliance for SO2 and PM10. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO2 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 NOX test, is required. The initial NOX 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. Compliance test results shall be submitted to the DEP's Northwest District office no later than 45 days after completion of the last test run.

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. Emission Compliance Stack 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. [Rule 62-297.310(8), F.A.C.]. 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 NOX 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). Subject to EPA approval, the NOx CEMS will 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). Subject to EPA approval, 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 NOX CEMS.

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 (pending EPA concurrence) 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. Once Unit 8 becomes operational, monitoring of the sulfur content of the natural gas shall be conducted 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 NOX cap shall be determined by adding the annual NOX emissions in tons per year determined by the CEMS required by 40 CFR 75 for Unit 8 along with existing Unit 7 to annual NOX emissions calculated for existing units GT1, GT2 and the auxiliary boiler determined by the following formulas:

GT 1 & GT 2 NOX(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 NOX(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 SO2 cap shall be determined by adding the annual SO2 emissions in tons per year determined by the methods required by 40 CFR 75 for Unit 8 along with existing Unit 7 to annual SO2 emissions calculated for existing 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 required by this specific condition 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. 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.

Purdom Generating Station/ Unit 8
City of Tallahassee

Facility ID No. :1290001
Unit No. 8
Tallahassee, FL
Wakulla County

Air Construction Permit No. PSD-FL-239
Power Plant Siting No. PA97-36

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 MS7231FA 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/PM10), sulfur dioxide (SO2), carbon monoxide (CO), and nitrogen oxides (NOX),

This facility is also subject to:

- 40 CFR 60, Subpart GG
- 40 CFR 75

Date of Receipt of a BACT Application:

03-17-97

Review Group Members:

Martin Costello, P.E., A. A. Linero, P.E., Administrator 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:

- ***Combustion Products*** (e.g. NOX and SO2)

  Nitrogen Oxides (NOX)

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

  Sulfur Dioxide (SO2)

  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. SO2 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.

- ***Products of Incomplete Combustion*** (e.g., PM10, CO, VOC).

  Particulate Matter less than 10 micrometers aerometric diameter (PM10)

  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 (PM10). 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/PM10 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/PM10 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.

o ***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., PM10, NOX, SO2, 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 (NOX)

A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) information indicates that NOX emissions for most new combustion turbines in attainment areas for ozone and nitrogen dioxides are controlled by either wet injection or dry low NOX burner technology. The applicant has proposed dry low NOX 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 NOX emissions from a combustion turbine is the above listed facility (NY-0044) from EPA's RACT/BACT/LAER Clearinghouse Information System (RBLC). The Brooklin 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 NOX emissions, offsets (reductions in NOX 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 NOX 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 NOX 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 NOX 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 NOX burner technology which can be reliably achieved over a long time period appears to be approximately 15 ppm of NOX 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 NOX 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 NOX was the fact that the technology for this dry low NOX system is still under development, even though it has been demonstrated on a lower firing temperature unit.

Dry low NOX technology is a combustion staging technology which reduces the formation of thermal NOX 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 NOX 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 NOX 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 NOX emissions) / (KW-hr) basis, the more efficient units may not be at a disadvantage to the lower firing temperature units.

Dry low NOX 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 NOX 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 (NOX) 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 NOX 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 NOX 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 (SO2)

SO2 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 SO2. 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/PM10)

A technology review indicated that the top control option for PM10 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 PM10 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 PM10 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 PM10 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 NOX burner system shall be employed to minimize products of incomplete combustion (PM10, VOC, and CO) while meeting the NOX emission limit.

BACT for the cooling tower is the use of drift eliminators to control PM/PM10 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 SO2 to SO3 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 NOX burner system and good combustion practices. Operation of the dry low NOX burner system shall be optimized in order to minimize CO emissions while keeping NOX 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 NOX, 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 NOX 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 NOX 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 SO2 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 SO2 impacts on the nearby St. Marks Class I area are minimized to the greatest extent possible.

BACT for PM10 was determined to be good combustion practices, inlet air filtering, and clean, low ash and low sulfur fuels which is currently the only feasible PM10 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 NOX controls. The particulate matter emitted from this unit will mainly be less than 10 micrometers in diameter (PM10). 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 , NOX , PM10 , and CO.

PM10 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/PM10 emissions from the cooling tower drift.

SO2 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.

NOx 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 NOX 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 NOX 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. Subject to EPA approval, excess emissions shall be reported based on the NOX 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 NOX burner system and good combustion practices. Operation of the dry low NOX burner system shall be optimized during the initial compliance test and at other times as needed in order to minimize CO emissions while keeping NOX 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 PM10 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 (PM10)	good combustion of clean, low sulfur fuels
	drift eliminators for the cooling tower
Visible Emissions	10% opacity / 10 % opacity
Carbon Monoxide	25ppm / 90 ppm
NOX (30 day rolling average)	12 ppm @ 15 % O2 / 42 ppm @ 15% O2 and adjusted for FBN
SO2	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)
NOX (30 day rolling average)	NOX CEMS and O2 or CO2 diluent monitor
SO2	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 or
A. A. Linero, Administrator, 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:

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
PM10	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 (SO2)	Fuel Quality (Clean Pipeline Quality natural gas and No. 2 (0.05% S) diesel fuel oil.
Sulfuric Acid Mist (H2SO4)	Fuel Quality (Clean Pipeline Quality natural gas and No. 2 (0.05% S) diesel fuel oil.
Nitrogen Oxides (NOx)	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 & PM10)	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

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:

Have access to and copy and records that must be kept under the conditions of the permit;
Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
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 description of and cause of non-compliance; and
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:

Determination of Best Available Control Technology *(X)*
Determination of Prevention of Significant Deterioration *(X)*; and
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:

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

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.

Is your RETURN ADDRESS completed on the reverse side?

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

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

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

Consult postmaster for fee.

3. Article Addressed to:

Mr. Brian Beals, Section Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA - Region IV
61 Forsyth Street
Atlanta, GA 30303

4a. Article Number
P265657309

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

7. Date of Delivery
9/18/97

5. Signature (Addressee)

6. Signature (Agent)
Lisa Aldridge

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

PS Form 3811, December 1991 ☆U.S. GPO: 1993—352-714 **DOMESTIC RETURN RECEIPT**

Thank you for using Return Receipt Service.

309

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

Sent to Brian Beals	
Street & Number 61 Forsyth St	
Post Office, State, & ZIP Code Atlanta, GA 30303	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date	

PS Form 3800, April 1995

Mowrey & Newman, P.A.

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Tallahassee, Florida, 32301-1111

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** Certified Circuit Court Mediator*
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Of Counsel:
Stuart E. Goldberg, (LL.M. Tax)
*Charles E. Barrett****
****Also Admitted in Alabama*

RECEIVED
AUG 25 1997
BUREAU OF
AIR REGULATION

August 22, 1997

DEP Bureau of Air Regulation
2600 Blair Stone Road
Mail Station # 5505
Tallahassee, Florida 32399-2400

Re: Draft Permit No.: PSD-FL-239 City of Tallahassee Purdom 8.
Power Plant Siting No. PA97-36

Dear Sir or Madam:

Wakulla County, Florida requests a public meeting concerning the proposed draft Prevention of Significant Deterioration Permit issuance action, pursuant to Section 403.508(8), Fla. Stat. (1995). This public meeting shall be conducted in Crawfordville, Wakulla County, Florida.

Thank you for your time and attention to this matter.

Very truly yours,

Ronald A. Mowrey
County Attorney

RAM/ds

C:\Data\Wakulla\Purdom\Meeting Request{ds}

cc: M. Costello, BAR
B. Oven, PPS, DEP
D. Beason, OGC
C. Collette, OGC
J. Curtis, C. of T.
E. Middleswart, NWD

RECEIVED
AUG 14 1997
BUREAU OF
AIR REGULATION

THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In the Matter of an
Application for Permit by:

OGC CASE NO. ____________________

City of Tallahassee Utility Services
300 South Adams Street
Tallahassee, FL 32301
____________________________________/

DRAFT Permit No.: PSD-FL-239
Purdom Generating Station
Wakulla County

REQUEST FOR EXTENSION OF TIME

By and through undersigned counsel, the City of Tallahassee (Tallahassee) hereby requests, pursuant to Florida Administrative Code Rules 28-106.111(3) and 62-103.050(1), an extension of time, to and including August 29, 1997, in which to file a Petition for Administrative Proceedings in the above-styled matter. As good cause for granting this request, Tallahassee states the following:

1. On or about July 8, 1997, Tallahassee received from the Department of Environmental Protection (Department) an "Intent to Issue PSD Permit" (Permit No. PSD-FL-239) for the Purdom Generating Station in Wakulla County, Florida. Along with the Intent to Issue, Tallahassee received a draft PSD permit and "Public Notice of Intent to Issue PSD Permit."

2. Tallahassee previously requested an extension to and including August 19, 1997. While Charles T. (Chip) Collette with the Department's Office of General Counsel orally agreed to this extension, an Order formally granting the extension has not yet been issued.

3. The draft permit and notice contain several provisions that warrant clarification or correction.

4. Representatives of Tallahassee have met and corresponded with staff of the Department's Bureau of Air Regulation in an effort to resolve the issues identified by Tallahassee. Final resolution of a few remaining issues is expected soon.

5. This request is filed simply as a protective measure to avoid waiver of Tallahassee's right to challenge certain conditions contained in the draft PSD permit. Grant of this request will not prejudice either party, but will further their mutual interest and likely avoid the need to file a petition and proceed to a formal administrative hearing.

6. On behalf of the Department, Charles T. (Chip) Collette with the Department's Office of General Counsel has agreed to Tallahassee's request for an extension of time until August 29, 1997.

WHEREFORE, Tallahassee respectfully requests that the time for filing of a Petition for Administrative Proceedings in regard to the Department's Intent to Issue PSD Permit for Permit No. PSD-FL-239 be formally extended to and including August 29, 1997.

Respectfully submitted this 13st day of August, 1997.

HOPPING GREEN SAMS & SMITH, P.A.

Angela R. Morrison

Angela R. Morrison, Fla. Bar No. 0855766
123 South Calhoun Street
Post Office Box 6526
Tallahassee, FL 32314
(904) 222-7500

Attorney for CITY OF TALLAHASSEE UTILITY SERVICES

<u>**CERTIFICATE OF SERVICE**</u>

I HEREBY CERTIFY that a copy of the foregoing has been furnished to the following by U.S. Mail on this 13st day of August, 1997:

Clair H. Fancy, P.E.
Chief
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2600

Charles T. (Chip) Collette, Esq.
Office of General Counsel
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2600

Angela R. Morrison
Attorney

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