FLORIDA

Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

July 29, 1997

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: Purdom Unit 8, Combustion Turbine and
Heat Recovery Steam Generator
DRAFT Permit No. PSD-FL-239/PA97-36

Dear Ms. Curtis

Enclosed is a revised copy of the "PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT". This replaces the earlier version which was sent on July 1, 1997.

The "PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT" must be published within 30 (thirty) days of receipt of this letter. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address. If you have any other questions, please contact Martin Costello or Mr. Linero at 904/488-1344.

Sincerely,

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

CHF/mc

Enclosures

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DRAFT Permit No.: PSD-FL-239
Power Plant Siting No. PA97-36

City of Tallahassee Utility Services
Purdom Generating Station Unit 8
Wakulla County

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit for the Prevention of Significant Deterioration (PSD permit) to the City of Tallahassee for the Purdom Generating Station proposed Unit 8 located in the City of St. Marks, Wakulla County. A Best Available Control Technology (BACT) determination was conducted for particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_x) and carbon monoxide (CO) pursuant to Rule 62-212.400, F.A.C. and 40 CFR 52.21. The applicant's name and address are City of Tallahassee Utility Services, 300 South Adams Street, Tallahassee, FL 32301

The City of Tallahassee has applied to construct Unit 8, a nominal 250 megawatt (MW) combined cycle combustion turbine and heat recovery steam generator to meet its system needs and replace existing conventional steam generating Units 5 and 6. Emissions control will be accomplished by dry low NO_X burners (gas) and water injection (diesel) and primary use of natural gas, an inherently clean fuel. A new 200 foot stack and a cooling tower will be added to the facility for Unit 8.

Other existing units at the plant consist of Unit 7, a nominal 44 MW steam boiler fired by natural gas and/or fuel oil, two older combustion turbines with a nominal rating of 12.3 MW each and a small auxiliary steam boiler fired by natural gas. The City has requested a facility-wide emissions cap for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) to ensure that no increase in these emissions will occur once Unit 8 is constructed. Therefore in the future, NO_X and SO_2 emissions from the facility, including Unit 8, will be less than or equal to these emissions before the addition of Unit 8. Electrical output from this facility will be about three times higher than the current level with the addition of Unit 8.

Total facility-wide annual emissions including those from the project are summarized below:

Pollutants	Current Actual ton/yr	Future Estimated Emissions ton/yr	Net Increase ton/yr
PM_{10}	**10.7**	**59.0**	**48.3**
SO_2	**80.0**	**80.0**	**0**
NO_X	**467.0**	**467.0**	**0**
CO	**66.0**	**193.0**	**127.0**

An air quality impact analysis was conducted. Emissions from the facility will not significantly contribute to or cause a violation of any state or federal ambient air quality standards. The maximum predicted PSD Class II increments of NO_2, SO_2, and PM_{10} consumed by all sources in the area, including this project, will be as follows:

PSD Class II Increment Consumed (mg/m^3)		Allowable Increment (mg/m^3)	Percent 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

The maximum predicted PSD Class I increments of NO_2, SO_2, and PM_{10} in the St. Marks National Wilderness Area and the Bradwell Bay National Wilderness Area consumed by all sources in the area, including this project, will be as follows:

PSD Class I Increment Consumed (mg/m^3)		Allowable Increment (mg/m^3)	Percent Increment Consumed
PM_{10}			
24-hour	0.73	8	9
Annual	0.16	4	4
SO_2			
3-hour	16.9	25	68
24-hour	4.9	5	98
Annual	0.0	2	0
NO_2			
Annual	0.91	2.5	36

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

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

The issuance of this PSD permit is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501.519, Florida Statutes). If a petition for an administrative hearing on the preliminary determination and proposed PSD permit is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3), Florida Statutes.

The Department will issue FINAL Permit with the conditions of the DRAFT Permit unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S. Mediation under Section 120.573 is not available for this Draft Permit.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57 F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000, telephone: 904/488-9370, fax: 904/487-4938. Petitions must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. A petitioner must 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 28-5.207 of the Florida Administrative Code.

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

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

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

Department of Environmental Protection Bureau of Air Regulation 111 S. Magnolia Drive, Suite 4 Tallahassee, Florida, 32301 Telephone: 850/488-1344 Fax: 850/922-6979	Department of Environmental Protection NW District Office 160 Government Center Pensacola, Florida 32501 Telephone:(850) 444-8300 Fax: :(850) 444-8417

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 904/488-1344, for additional information.

In the Matter of an
Application for Permit by:

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

DRAFT Permit No.: PSD-FL-239
Power Plant Siting: PA97-36
Purdom Generating Station
Wakulla County

INTENT TO ISSUE PSD PERMIT

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

The applicant, the City of Tallahassee, applied on March 17, 1997 to the Department for a PSD permit and Siting Certification to construct and operate a 250 megawatt combustion turbine and heat recovery steam generator for its Purdom Generating Station located at 667 Port Leon Drive, St. Marks, Wakulla, County.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The above actions are not exempt from permitting procedures. The Department has determined that a PSD permit is required for the proposed work.

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

Pursuant to Section 403.815, F.S., and Rule 62-103.150, F.A.C., you (the applicant) are required to publish at your own expense the enclosed "PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT". The notice shall be published one time only within 30 (thirty) days 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. Where there is more than one newspaper of general circulation in the county, the newspaper used must be one with significant circulation in the area that may be affected by the permit. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 904/488-1344; Fax 904/ 922-6979) within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit pursuant to Rule 62-103.150 (6), F.A.C.

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

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

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S., or a party requests mediation as an alternative remedy under Section 120.573 F.S. before the deadline for filing a petition. Choosing mediation will not adversely affect the right to a hearing if mediation does not result in a settlement. The procedures for petitioning for a hearing are set forth below, followed by the procedures for requesting mediation.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57 F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000, telephone: 904/488-9730, fax: 904/487-4938. Petitions must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. A petitioner must 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 (or a request for mediation, as discussed below) 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 28-5.207 of the Florida Administrative Code.

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

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

A person whose substantial interests are affected by the Department's proposed permitting decision, may elect to pursue mediation by asking all parties to the proceeding to agree to such mediation and by filing with the Department a request for mediation and the written agreement of all such parties to mediate the dispute. The request and agreement must be filed in (received by) the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000, by the same deadline as set forth above for the filing of a petition.

A request for mediation must contain the following information: (a) The name, address, and telephone number of the person requesting mediation and that person's representative, if any; (b) A statement of the preliminary agency action; (c) A statement of the relief sought; and (d) Either an explanation of how the requester's substantial interests will be affected by the action or proposed action addressed in this notice of intent or a statement clearly identifying the petition for hearing that the requester has already filed, and incorporating it by reference.

The agreement to mediate must include the following: (a) The names, addresses, and telephone numbers of any persons who may attend the mediation; (b) The name, address, and telephone number of the mediator selected by the parties, or a provision for selecting a mediator within a specified time; (c) The agreed allocation of the costs and fees associated with the mediation; (d) The agreement of the parties on the confidentiality of discussions and documents introduced during mediation; (e) The date, time, and place of the first mediation session, or a deadline for holding the first session, if no mediator has yet been chosen; (f) The name of each party's representative who shall have authority to settle or recommend settlement; and (g) The signatures of all parties or their authorized representatives.

As provided in Section 120.573 F.S., the timely agreement of all parties to mediate will toll the time limitations imposed by Sections 120.569 and 120.57 F.S. for requesting and holding an administrative hearing. Unless otherwise agreed by the parties, the mediation must be concluded within sixty days of the execution of the agreement. If mediation results in settlement of the administrative dispute, the Department must enter a final order incorporating the agreement of the parties. Persons whose substantial interests will be affected by such modified final decision of the Department have a right to petition for a hearing only in accordance with the requirements for such petitions set forth above. If mediation terminates without settlement of the dispute, the Department shall notify all parties in writing that the administrative hearing processes under Sections 120.569 and 120.57 F.S. remain available for disposition of the dispute, and the notice will specify the deadlines that then will apply for challenging the agency action and electing remedies under those two statutes.

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

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

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

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

Executed in Tallahassee, Florida.

for 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 PSD PERMIT (including the PUBLIC NOTICE, Technical Evaluation and Preliminary Determination, Draft BACT Determination, and the DRAFT permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 7-1-97 to the person(s) listed:

Ms. Jennette Curtis, City of Tallahassee *
Mr. Darrel Graziani, P.E.
Mr. Brian Beals, EPA
Mr. John Bunyak, NPS
Mr. Ed Middleswart, NWD
Mr. Buck Oven, DEP

Clerk Stamp

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

(Clerk) 7-1-97 (Date)

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

City of Tallahassee Utility Services

Purdom Generating Station Unit 8
250 Megawatt Combustion Turbine and
Heat Recovery Steam Generator
Wakulla County

Permit No. PSD-FL-239 / PA 97-36

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

July 1, 1997

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

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

Authorized Representative

Ms. Jennette Curtis, Environmental Administrator

1.2 Reviewing and Process Schedule

03-17-97	Date of Receipt of Application
04-21-97	Bureau of Air Regulation Preliminary Sufficiency Review
05-01-97	Department's Sufficiency Review
05-07-97	COT letter response to Bureau's Sufficiency Review
07-01-97	Intent Issued

2. FACILITY INFORMATION

2.1 Facility Location:

The Sam O. Purdom Generating Station is located on the north side of St. Marks, in Wakulla county. This site is approximately 0.7 kilometers Northeast of the Saint Marks Wilderness Area, a Class 1 PSD Area. The UTM: coordinates of this facility (the stack for Unit 8) are Zone 16 ; 769.611 km E ; 3339.767 km N.

2.2 Standard Industrial Classification Code (SIC)

Major Group No.	49
Group No.	11

2.3 Facility Category

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, Table 62-212.400-1. This facility is also classified as a Title V facility.

3. PROJECT DESCRIPTION

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 with DLN-2 dry low NO_X burners (Unit 8) 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 an electric motor. 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. 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, and residual fuel oil or distillate fuel oil, two pre-NSPS distillate fuel oil or natural gas fired combustion turbines with a nominal rating of 12.5 MWs each (GT1 and GT2), and a Subpart Dc auxiliary steam boiler fired by natural gas.

4. PROCESS DESCRIPTION

Unit 8 is a combined cycle combustion turbine which will primarily fire natural gas to power an electrical generator rated at 160 MWs. Steam generated in the HRSG will power a steam turbine which will drive a second electrical generator rated at 90 MWs (see attached figure 2-1).

5. RULE APPLICABILITY

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

This facility is located in Wakulla county, an area designated as attainment for all criteria pollutants in accordance with Rule 62-204.360, F.A.C. The proposed project is subject to review under Rule 62-212.400., F.A.C., Prevention of Significant Deterioration (PSD), because the potential emission increases for PM/PM_{10}, NO_X, SO_2, and CO exceed the significance emission rates given in Chapter 62-212, Table 62-212.400-2, F.A.C.

This PSD review consists of a determination of Best Available Control Technology (BACT) for PM/PM_{10}, CO, NO_X, and SO_2 and an analysis of the air quality impact of the proposed project's impacts on soils, vegetation and visibility; along with air quality impacts resulting from associated commercial, residential and industrial growth. This project will also be reviewed and regulated pursuant to the Power Plant Siting Act requirements.

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

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

6. SOURCE IMPACT ANALYSIS

6.1 Emission Limitations

The proposed Purdom Unit 8 will emit the following PSD pollutants (Table 212.400-2): particulate matter, sulfur dioxide, nitrogen oxides, volatile organic compounds, carbon monoxide, sulfuric acid mist, and negligible quantities of fluorides, beryllium, mercury and lead. The permitted allowable emissions for this Purdom Unit 8 are summarized in the BACT (Tables 1-1, Air Pollutant Standards and Terms and the compliance procedures are summarized in Table 1-2 Compliance Requirements).

6.2 *Emission Summary*

Table 1 PSD Applicability Summary

Pollutants	Current Actual ton/yr	Future Estimated Emissions ton/yr	Net Increase ton/yr	PSD Significant Level ton/yr
PM	10.7	59.0	48.3	25
PM10	10.7	59.0	48.3	15
SO_2	80.0	80.0	0**	0*
NO_X	467.0	467.0	0**	0*
CO	66.0	193.0	127.0	0*
Ozone(VOC)	2.8	14.7	11.9	40
Sulfuric Acid Mist	3.0	8.6	5.6	7
Fluorides	0.08	1.64	1.56	3
Total Reduced Sulfur	N/A	N/A	N/A	10
Mercury	0.0020	0.0024	0.0004	0.1
Beryllium	0.00052	0.00030	0.00022	0.0004
Lead	0.091	0.011	0.080	0.6

Footnotes:
Several modeling scenarios were evaluated and the above table represents the worst case emission rates while maintaining emissions within the emissions cap for NO_X and SO_2.

N/A - means no emissions expected or no emissions information available.

*Due to the proximity to the St. Marks Class I Area, lower criteria apply for those pollutants with a maximum projected 24-hour average impact of 1.0 microgram per cubic meter or more on the Class I Area.

**Net emissions increase will be limited to zero by the annual emissions cap for these pollutants. The netting procedure in 62-212.400(2)(d) F.A.C. results in a net emissions increase which exceeds the levels in Table 212.400-2 and therefore PSD requirements apply for these pollutants.

6.3 *Control Technology Review*

The emission control technology for Unit 8 will consist of a water injection system/dry low NO_X burner system to control NO_X emissions when firing fuel oil and natural gas respectively. Computer controlled and monitored systems on the combustion turbine will assist in maintaining good combustion practices to minimize products of incomplete combustion (CO, PM/PM_{10}, VOC). Low sulfur fuels will be used to keep SO_2 and sulfuric acid mist emissions at low levels. Particulate matter from the cooling tower will be minimized using drift eliminators.

The BACT document is included as a separate document (see Appendix BD)

6.3.1 Nitrogen Oxides (NO_X)

The city evaluated the use of Selective Catalytic Reduction (SCR) control technology as the top control option. SCR was rejected as BACT due to several factors including cost, energy impacts, and environmental considerations. Nitrogen Oxides (NO_X) emissions will be controlled by using GE's DLN-2 which is a second generation dry low NO_X burner technology for the high firing temperature frame units. The firing temperature on the Frame 7FA combustion turbine is 2400 F. When firing natural gas, the combustor operates in a diffusion mode at low loads (less than 50% of capacity) and in a premixed mode at high loads. When firing fuel oil, the combustors operate in a diffusion mode at all loads and diluent injection (water) is used to control NO_X formation. The DLN-2 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 IV control system will be used to continuously maintain the NO_X concentration in the exhaust at the specified level throughout the 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.

6.3.2 NO_X Averaging Time

Section 403.0872(13), Florida Statutes was enacted in 1994 and states that for emission units that are subject to continuous monitoring requirements under 42 U.S.C. sections 7661-7661f or 40 CFR Part 75, compliance with nitrogen oxides emission limits shall be demonstrated based on a 30-day rolling average, except as specifically provided by 40 CFR Parts 60 or 76. The Department amended the following rule to clarify the applicability of this statute for pre-NSPS boilers:

> **62-296.405 Fossil Fuel Steam Generators with more than 250 million Btu per Hour Heat Input.**
> (1) Existing Emissions Units....
>
> (e) Test Methods and Procedures...
>
> 4. For emission units not subject to nitrogen oxides continuous monitoring requirements, the test methods for nitrogen oxides emissions shall be EPA Methods 7, 7A, or 7E, incorporated and adopted by reference in Chapter 62-297, F.A.C. Four grab samples at 15 minute intervals (±2 min.) per run shall be required for EPA Methods 7 and 7A. For emission units that are subject to continuous monitoring requirements under 42 U.S.C. sections 7661-7661f or 40 CFR Part 75, compliance with nitrogen oxides emission limits shall be demonstrated based on a 30-day rolling average, except as specifically provided by 40 CFR Parts 60 or 76.

No other rules have been changed to incorporate this statute. The applicability of that statute to Unit 8 is uncertain because this unit has a NO_X emission limit under 40 CFR part 60 (NSPS). Unit 8 is an NSPS unit subject to the continuous monitoring requirements under the Acid Rain Program. It is also not clear at this time whether this statute was intended to apply more broadly than to the pre-NSPS boilers regulated under Rule 62-296.405 F.A.C.

The Department agreed to allow the city to determine compliance with nitrogen oxide emission limits based on a 30-day rolling average in this case due to three other factors: 1) the city has committed that there would be no increase in emissions over past actual levels using a facility wide NO_X cap; 2) the emission rate on a 30-day basis is so low that there is reasonable assurance that there will be no extended periods during which emissions will be high on a short term basis; and 3) the facility is located over one hundred miles from the nearest ozone maintenance area and therefore shorter averaging times are less important to avoid aggravating ozone formation from NO_X and other precursors.

6.3.3 *Sulfur Dioxide (SO_2)*

Sulfur dioxide (and sulfuric acid mist) will be controlled by firing low sulfur fuels. Only natural gas or distillate fuel oil with a maximum sulfur content of 0.05% by weight will be fired. These fuels have the lowest sulfur levels of any commercially available fuels.

6.3.4 *Carbon Monoxide (CO)*

An oxidation catalyst was evaluated as the top control option but was rejected as BACT due to several considerations including cost and energy impacts. 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 will be optimized in order to minimize CO emissions while keeping NO_X emissions as low as practicable. Low load operation will result in the highest levels of CO emissions. The BACT emission limit for CO was set at the level which could be achieved for worst case operation i.e., low load operation. 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.

6.3.5 *Particulate Matter (PM/PM10)*

The emission control technology for PM/PM_{10} will be good combustion practices and 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.

6.4 ***Air Quality Analysis***

6.4.1 *Introduction*

The proposed project will increase emissions of four pollutants at levels in excess of PSD significant amounts: SO_2, PM/PM_{10}, CO and NO_X. The air quality impact analyses required by the PSD regulations for these pollutants include:

* An analysis of existing air quality;
* A significant impact analysis;

- A PSD increment analysis for SO_2, PM_{10} and NO_X;
- An Ambient Air Quality Standards (AAQS) analysis, and
- An analysis of impacts on soils, vegetation, and visibility and of growth-related air quality modeling impacts.

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

Based on the required analyses, the Department has reasonable assurance that the proposed project, as described in this report and subject to the conditions of approval proposed herein, will not cause or significantly contribute to a violation of any AAQS or PSD increment. However, the following EPA-directed stack height language is included: "In approving this permit, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification if and when EPA revises the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators." A discussion of the required analyses follows.

6.4.2 Analysis of Existing Air Quality and Determination of Background Concentrations

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review unless otherwise exempted or satisfied. This monitoring requirement may be satisfied by using previously existing representative monitoring data, if available. An exemption to the monitoring requirement may be obtained if the maximum air quality impact resulting from the projected emissions increase, as determined by air quality modeling, is less than a pollutant-specific deminimus concentration. In addition, if an acceptable monitoring method for the specific pollutant has not been established by EPA, monitoring may not be required.

If preconstruction ambient monitoring is exempted, determination of background concentrations for PSD significant pollutants with established AAQS may still be necessary for use in any required AAQS analysis. These concentrations may be established from the required preconstruction ambient air quality monitoring analysis or from previously existing representative monitoring data. These background ambient air quality concentrations are added to pollutant impacts predicted by modeling and represent the air quality impacts of sources not included in the modeling.

The table below shows that SO_2, PM_{10}, NO_2 and CO impacts from the project are predicted to be less than the de minimus levels; therefore, preconstruction ambient air quality monitoring is not required for these pollutants.

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

Pollutant	Averaging Time	Maximum Predicted Impact (ug/m^3)	Impact Greater Than De Minimus?	De Minimus Level(ug/m^3)
SO_2	24-hour	0.02	NO	13
PM_{10}	24-hour	6.5	NO	10
CO	8-hour	5.4	NO	575
NO_2	Annual	6.1	NO	14

However, previously existing representative monitoring data from SO_2, PM_{10}, NO_2 and CO monitors in North Florida were used to establish background concentrations for use in the AAQS analysis. These values are shown in the following table.

Background Concentrations for Use in AAQS Analysis

Pollutant	Averaging Time	Background Concentration (ug/m^3)
SO_2	Annual	9
	24-hour	71
	3-hour	183
PM_{10}	Annual	22.4
	24-hour	47
CO	8-hour	5290
	1-hour	8050
NO_X	Annual	14

6.4.3 Models and Meteorological Data Used in Significant Impact, PSD Increment and AAQS Analyses

The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project and other existing major facilities. The model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. The model incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISCST3 model allows for the separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options in each modeling scenario. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all satisfy the good engineering practice (GEP) stack height criteria.

Initially, the applicant conducted preliminary modeling for the purpose of determining the worst case fuel/load/temperature scenarios for each applicable averaging time. Preliminary modeling runs were conducted using one year of meteorological data at three ambient temperatures (95°F, 59°F and 20°F) and three combustion turbine loads (100%, 75% and 50%) for both natural gas and Number 2 (0.05% sulfur content) diesel fuel oil. Thus, there were a total of 18 preliminary modeling runs conducted. As a result of these runs, the applicant determined that the 20°F at 50% load fuel oil combinations produced the "worst case" predicted ground-level ambient air quality impacts for the short-term averaging periods (1-hour, 3-hour, 8-hour and 24-hour) for all pollutants. The annual average "worst case" predicted ground-level ambient air quality impacts were determined to occur with the 59°F and 100% load fuel oil/natural gas mixed combination (1735 hours per year fuel oil/7025 hours per year natural gas).

Meteorological data used in the ISCST3 model for all other but the preliminary "worst case" determination modeling consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) stations at Tallahassee, Florida (surface data) and Apalachicola, Florida (upper air data). The 5-year period of meteorological data was from 1985 through 1989. These NWS stations were selected for use in the study because they are the closest primary weather stations to the study area and are most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

Since five years of data were used in ISCST3, the highest-second-high (HSH) short-term predicted concentrations were compared with the appropriate AAQS or PSD increments. For the annual averages, the highest predicted yearly average was compared with the standards. For determining the project's significant impact area in the vicinity of the facility and if there are significant impacts from the project on any PSD Class I area, both the highest short-term predicted concentrations and the highest predicted yearly averages were compared to their respective significant impact levels.

6.4.4 Significant Impact Analysis

Initially, the applicant conducted modeling using only the proposed project's worst case emission scenario for each pollutant and applicable averaging time. A total of 632 receptors were placed along the site boundary and within 10 km of the facility, which is located in a PSD Class II area. A total of 68 receptors were placed in and along the boundary of the St. Marks National Wilderness Area (NWA) and a total of 18 receptors were placed in and along the boundary of the Bradwell Bay National Wilderness Area (NWA). Both of these areas are PSD Class I areas. They are located approximately 0.7 km and 28 km, respectively, from the project at their closest points. For each pollutant subject to PSD and also subject to PSD increment and/or AAQS analyses, this modeling compared maximum predicted impacts due to the project with PSD significant impact levels to determine whether significant impacts due to the project were predicted in the vicinity of the facility or in the two Class I areas. The tables below show the results of this modeling. The radius of significant impact, if any, for each pollutant and applicable pollutant averaging time is also shown in the tables below.

Maximum Project Air Quality Impacts for Comparison to the PSD Class II Significant Impact Levels in the Vicinity of the Facility.

Pollutant	Averaging Time	Maximum Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Significant Impact?	Radius of Significant Impact (km)
SO_2	Annual	0.024	1	NO	NONE
	24-hour	0.023	5	NO	NONE
	3-hour	0.051	25	NO	NONE
PM_{10}	Annual	0.35	1	NO	NONE
	24-hour	6.5	5	YES	0.3
CO	8-hour	5.1	500	NO	NONE
	1-hour	21.9	2000	NO	NONE
NO_X	Annual	6.1	1	YES	0.3

Maximum Project Air Quality Impacts in the St. Marks and Bradwell Bay NWA for Comparison to the PSD Class I Significant Impact Levels

Pollutant	Averaging Time	Maximum Predicted Impact (ug/m³)		Significant Impact?		National Park Service (NPS) Significant Impact Level (ug/m³)
		St. Marks	Bradwell Bay	St. Marks	Bradwell Bay	
SO_2	Annual	0.0	0.0	NO	NO	0.03
	24-hour	0.0	0.0	NO	NO	0.07
	3-hour	0.0043	0.0	NO	NO	0.48
PM_{10}	Annual	0.0	0.0	NO	NO	0.08
	24-hour	0.14	0.0	NO	NO	0.27
NO_2	Annual	0.86	0.038	YES	YES	0.03

As shown in the tables the maximum predicted air quality impacts due to PM_{10} and NO_X emissions from the proposed project are greater than the significant impact levels in the vicinity of the facility for the 24-hour and annual averaging times, respectively. The maximum predicted air quality impacts due to NO_X emissions are greater than the significant impact level in the Class I areas. Therefore, the applicant was required to do further PM_{10} and NO_2 modeling in the vicinity of the facility, within the applicable significant impact area, to determine the impacts of the project along with all other sources in the vicinity of the facility. The significant impact area is based upon the predicted radius of significant impact. Further modeling for Class I impacts was also required for NO_2. No further modeling of any other pollutants were required. However, the applicant performed full impact modeling in the vicinity of the project and in the Class I areas for SO_2, PM_{10}, NO_2 and CO to provide further reasonable assurance that the proposed project would not violate any AAQS or PSD increments. Full impact modeling is modeling that considers not only the impact of the project but the impacts of the existing facility and other major sources, including background concentrations, located within the vicinity of the project and the Class I areas.

6.4.5 Receptor Networks For PSD Increment And AAQS Analyses

For the AAQS and PSD Class II analyses, receptor grids normally are based on the size of the significant impact area for each pollutant. The size of the significant impact areas for the required PM_{10} and NO_2 analyses were based on only a 0.3 km radius of significant impact as discussed in the significant impact analysis section above. However, the receptor grids used in AAQS and PSD Class II analyses were the same and were as extensive (receptors out to 10 km) as those used in the original analyses to determine the extent of significant impact for each pollutant.

Both preliminary and refined modeling runs were performed for these analyses. In the refined runs additional receptors (11X11, 121 point receptor grid) spaced 100 m apart were placed over critical receptors identified during preliminary AAQS and PSD increment modeling. The results of these analyses are discussed below.

6.4.6 PSD Increment Analysis

The PSD increment represents the amount that new sources in an area may increase ambient ground level concentrations of a pollutant. The results of the PSD Class II increment analysis presented in the table below show that all of the maximum predicted impacts are less than the allowable Class II increments.

PSD Class II Increment Analysis

Pollutant	Averaging Time	Maximum Predicted Impact (ug/m³)	Impact Greater Than Allowable Increment?	Allowable Increment (ug/m³)
SO_2	Annual	0.0	NO	20
	24-hour	2.4	NO	91
	3-hour	14.4	NO	512
PM_{10}	Annual	0.32	NO	17
	24-hour	3.3	NO	31
NO_2	Annual	6.2	NO	25

The results of the PSD Class I increment analysis presented in the tables below show that all of the maximum predicted impacts are less than the allowable increments.

PSD Class I Increment Analysis for St. Marks NWA and Bradwell Bay NWA

Pollutant	Averaging Time	Maximum Predicted Impact (ug/m³)		Impacts Greater Than Allowable Increment?		Allowable Increment (ug/m³)
		St. Marks	Bradwell Bay	St. Marks	Bradwell Bay	
SO_2	Annual	0.0	0.0	NO	NO	2
	24-hour	2.7	4.9	NO	NO	5
	3-hour	10.7	16.9	NO	NO	25
	Annual	0.11	0.16	NO	NO	4

PM_{10}	24-hour	0.73	0.0023	NO	NO	8
NO_2	Annual	0.91	0.57	NO	NO	2.5

6.4.7 AAQS Analysis

For pollutants subject to an AAQS review, the total impact on ambient air quality is obtained by adding a "background" concentration to the maximum modeled concentration. This "background" concentration takes into account all sources of a particular pollutant that are not explicitly modeled. The results of the AAQS analysis are summarized in the table below. As shown in this table, emissions from the proposed facility are not expected to cause or significantly contribute to a violation of any AAQS.

Ambient Air Quality Impacts

Pollutant	Averaging Time	Major Sources Impact (ug/m³)	Background Concentration (ug/m³)	Total Impact (ug/m³)	Total Impact Greater Than AAQS	Florida AAQS (ug/m³)
SO_2	Annual	26	9	36	NO	60
	24-hour	137	71	208	NO	260
	3-hour	402	183	585	NO	1300
PM_{10}	Annual	19	22	41	NO	50
	24-hour	84	47	131	NO	150
NO_2	Annual	21	14	35	NO	100
CO	8-hour	16	5290	5306	NO	10,000
	1-hour	103	8050	8153	NO	40,000

6.5 Additional Impacts Analysis

6.5.1 Impacts On Soils, Vegetation, Wildlife, and Visibility

The maximum ground-level concentrations predicted to occur for PM_{10}, NO_X, SO_2 and CO as a result of the proposed project, including background concentrations and all other nearby sources, will be below the associated AAQS. The AAQS are designed to protect both the public health and welfare. As such, this project is not expected to have a harmful impact on soils and vegetation in the PSD Class II area. An air quality related values (AQRV) analysis was done by the applicant for the Class I area. No significant impacts on this area are expected.

6.5.2 Growth-Related Air Quality Impacts

There may be some temporary residential growth associated with this project, but there is little potential for new industrial development nearby as a result of it. Although it is not possible to reliably quantify the emissions and impacts resulting from this project, they are expected to be small and well-distributed throughout the area.

6.5.3 Air Toxics Air Quality Impacts

The maximum predicted impacts of regulated and non-regulated toxic air pollutants that are proposed to be emitted by the project are all less than the Department's draft annual Ambient Reference Concentrations (ARC).

7. CONCLUSION

Based on the foregoing technical evaluation of the application and additional information submitted by the city, the Department has made a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations provided the Department's Best Available Control Technology Determination is implemented and certain conditions are met. The General and Specific Conditions are listed in the attached draft conditions of approval .

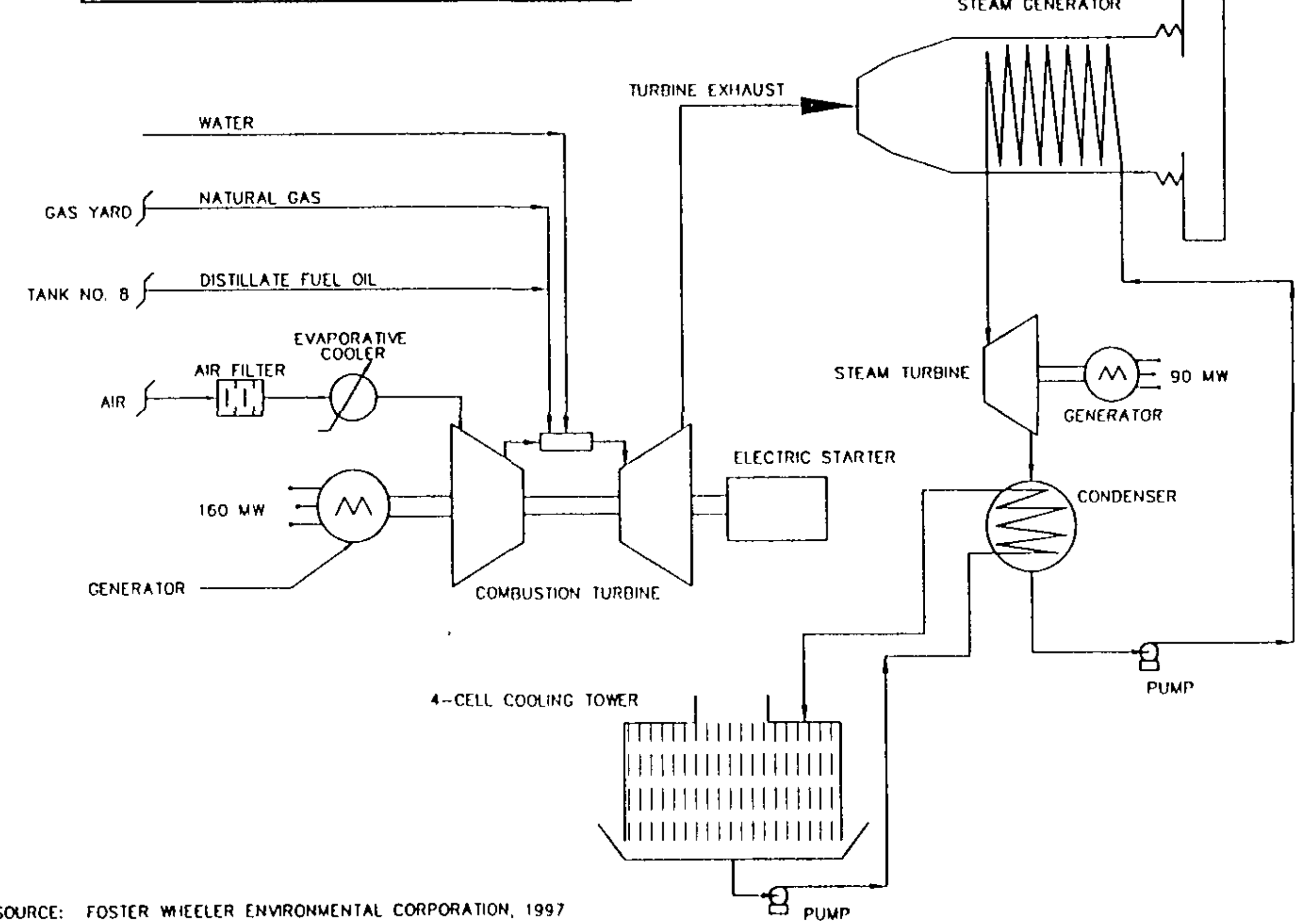
Permit Engineer: Martin Costello, P.E.
Meteorologist: Cleve Holladay

Reviewed and Approved by A. A Linero, P.E.
Administrator, New Source Review Section

PLOT DATE MAR 1 G:\DARREL\PUNIT8.DWG

GE OPERATING DATA		
PARAMETER	NATURAL GAS	DISTILLATE FUEL OIL
HEAT INPUT (MMBTU/HR) – LHV	1682.2	1914.1
FEED RATE (MMCF/HR)	1.62	N/A
FEED RATE (KGAL/HR)	N/A	14.50
FULL LOAD AND 20 °F		

EU13 – EXHAUST PARAMETERS
EXHAUST TEMP. – 171 TO 203 °F
STACK HEIGHT – 200'
SO2 EMISSIONS – 80 TPY
NOx EMISSIONS – 467 TPY
OPACITY – 20% EXCEPT AS ALLOWED



SOURCE: FOSTER WHEELER ENVIRONMENTAL CORPORATION, 1997

CITY OF TALLAHASSEE

SIMPLIFIED PROCESS FLOW DIAGRAM

PURDOM UNIT 8 PROJECT - ST MARKS, FLORIDA

Figure 2-1

Department of Environmental Protection

DRAFT

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

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

PERMITTEE:

City of Tallahassee
Purdom Generating Station
300 South Adams Street
Tallahassee, FL 32301

Authorized Representative:
Jennette Curtis
Environmental Administrator

FID No.	1290001
PSD No.	PSD-FL-239
PPS No.	PA97-36
Expires:	N/A

LOCATED AT:

City of Tallahassee
Purdom Generating Station
Project: Purdom Unit 8
Standard Industrial Classification Code (SIC): 4911
Wakulla County, Florida

UTM: Zone 16 ; 769.611 km E ; 3339.767 km N
Directions: *On the north end of the City of St. Marks on SR 363, Wakulla County*

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

SECTION I. FACILITY INFORMATION

SUBSECTION A. FACILITY DESCRIPTION

The City of Tallahassee (COT) 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 with DLN-2 dry low NO_x burners (Unit 8) 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 an electric motor. 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 cities' Sam O. Purdom Generating Station near St. Marks, in Wakulla county. Existing steam generating Units 5 and 6 will be permanently shut down once Unit 8 has completed the initial compliance test. Other existing units at the plant consist of Unit 7, pre-NSPS boiler with a nominal rating of 44 MW fired by natural gas, and cofired or fired alone with residual fuel oil or distillate fuel oil, two pre-NSPS distillate fuel oil or natural gas fired combustion turbines with a nominal rating of 12.5 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, Table 62-212.400-1. This facility is also classified as a Title V facility.

SUBSECTION C. PERMIT SCHEDULE:

- 03-17-97: Date of Receipt of Application
- 04-21-97: Department's Preliminary Incompleteness Letter
- 05-01-97: PPS Department's Incompleteness Letter sent
- 05-07-97: Company's Response to Department's letter
- 05-07-97: Application deemed complete
- 07-01-97: Intent Issued

SUBSECTION D. 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.

1. Application
2. Department's letters dated 4/21/97
3. Company letters dated 5/7/97
4. Department of Interior's letters dated 1/21/97
5. [EPA's letter dated ...]
6. [Third party's letters dated ...]

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 Blairstone Road, Tallahassee, Florida 32399-2400 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 not expire.

SECTION III. SPECIFIC CONDITIONS

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.]

1. 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 or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) at least 90 days prior to initial compliance testing. These curves or equations shall be used to establish the maximum allowable heat inputs at other ambient conditions for compliance determinations.

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

3. 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.

4. The permittee shall install duct module(s) suitable for possible future installation of an oxidation catalyst and/or SCR equipment on the combined cycle generating unit.

5. Dry low NO_Xcombustors 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_Xemissions.

6. 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.

7. 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.]

8. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guideines 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.]

9. The dry low NO_Xburner system shall be tuned upon initial operation to optimize emissions reductions and shall be maintained to minimize NO_Xemissions and CO emissions. Operation of the unit when the dry low NO_Xburner system is in the diffusion firing mode shall be minimized.

10. 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.

(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 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% O_2 on a 30-day rolling average basis (except during periods of startup, shutdown, malfunction or fuel switching), as measured by applicable compliance measures, when fuel bound nitrogen values are less than or equal to 0.015 percent. For higher fuel bound nitrogen values (up to 0.03 percent), oxides of nitrogen shall be limited 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).

5. Oxides of Nitrogen. 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. 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. In case of excess emissions resulting from malfunctions, the owner or operator shall notify Permitting Authority within one (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the problem; and the corrective actions being taken to prevent recurrence. [Rule 62-210.700(6), F.A.C.]

3. Excess Emissions Report: If excess emissions occur due to malfunction, the owner or operator shall notify the Permitting Authority 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 at which this unit will be operated, but not later than 180 days of initial operation of the

unit 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.

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

- 40 CFR 75 Determination of Oxides of Nitrogen emissions will be by a Continuous Emissions Monitoring System (CEMs). 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 a separate compliance test is conducted at the end of each operating day and 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 SO_2 and PM_{10}. For the purposes of demonstrating compliance with 40 CFR 60.333 SO_2 emission limit 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 an EPA approved custom fuel monitoring schedule. For the purposes of demonstrating compliance with the emissions caps (Conditions B5 and B6) and for acid rain compliance purposes, 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. However, the applicant 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).

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. 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 data shall be made available to the DEP representatives.
2. Emission Compliance Stack Test Reports: A test report indicating the results of the required compliance tests shall be filed with the Permitting Authority 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 this source. 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 General Condition #8. 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 following the format of 40 CFR 60.7 (1997 version). Subject to EPA approval, the NO_x CEMS will be used in lieu of the water/fuel monitoring system and fuel bound nitrogen (FBN) monitoring, which are required in accordance with 40 CFR 60, 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 NO_X CEMS.
2. The following custom monitoring schedule for No. 2 fuel oil is approved (pending EPA concurrence). For all bulk shipments of No. 2 fuel oil received at the Purdom Station, an analysis which reports the sulfur content and the fuel bound nitrogen content of the fuel shall be provided by the fuel vendor. 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 shall obtain the sulfur content of the natural gas form the fuel supplier (Florida Gas Transmission Company) 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 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 annual NO_X emissions calculated for existing 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 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)

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)

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

SECTION III. SPECIFIC CONDITIONS

6. Compliance with the annual facility-wide SO_2 cap shall be determined by adding the annual SO_2 emissions in tons per year determined by the CEMS required by 40 CFR 75 for Unit 8 along with existing Unit 7 to annual SO_2 emissions calculated for existing 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)

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 (% Sulfur Content of oil) X (Molecular weight SO2 / Molecular weight of S) X (Conversion factor)

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
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 (Heat Rate of Natural Gas) X (0.0006 lb/mmBtu)

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 in compliance with all applicable provisions of Chapter 403, F.S., and Chapters 62-4, 210, 212, 275, 296 and 297, F.A.C., except as otherwise specified herein.

2 The emission unit shall be 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.

3. 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.).

4. Except as otherwise specified herein, the emission unit shall be 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.

SECTION III. SPECIFIC CONDITIONS

5. 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)).

6. Quarterly excess emission reports, in accordance with 4 CFR 60.7 (7) (c) (1997 version), shall be submitted to the DEP's Northwest District office.

7. 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 calendar year.

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

9. 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. <u>Modifications</u>

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.

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 *( )*
(b) Determination of Prevention of Significant Deterioration *( )*; and
(c) Compliance with New Source Performance Standards *( )*.

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.

DRAFT

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

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 applicant, the City of Tallahassee plans to construct Unit 8, a new combined cycle combustion turbine system at the existing Purdom facility consisting of a 160 MW (nominal rating) GE MS7231FA combustion turbine with DLN-2 dry low NO_X 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 an electric motor. 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 near St. Marks, in Wakulla county. Existing steam generating units 5 and 6 will be permanently shut down once Unit 8 is fully operational. 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, and cofired or fired alone with residual fuel oil or distillate fuel oil, two pre-NSPS distillate fuel oil or natural gas fired combustion turbines with a nominal rating of 12.5 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 the attached Table 4-8 (from the application) 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:

- 40 CFR 60, Subpart GG
- 40 CFR 75

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

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:

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. NO_X emissions represent a significant portion of the total emissions generated by this project, and must be minimized using BACT.

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. Fabric filters (baghouses) and electrostatic precipitator (ESPs) have not been used/needed 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.

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., 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 BACT/LAER Clearinghouse (BACT Clearinghouse) 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 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 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.

Dry low NO_X burner technology is the next most stringent control technology for combustion turbines. The applicant proposes to use GE's DLN-2 controls which is a second 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, GE has guaranteed an emission rate of less than 9 ppm for Purdom Unit 8. This guarantee is based on operation above the 50% load range since emissions will be higher at low loads. Because the city requested compliance to be demonstrated on a continuous basis (by CEMS), which would involve a limited amount of low load operation when emissions of NO_X will be more than the guaranteed 9 ppm, the Department considered a BACT limit above 9 ppm to compensate for low load operation. 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.

The current level of dry low NO_X burner technology which can be reliably be 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 and size of the unit. In general the smaller aeroderivative designs have not been able to achieve 15 ppm without having problems with reliability. At least 4 units in Florida have been granted extensions for the time limit 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.

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. It was permitted in 1992 and has recently demonstrated emissions less than 9ppmvd 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.

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.

Nitrogen Oxides (NO_X) emissions will be controlled by using GE's DLN-2 which is a second generation dry low NO_X burner technology for the high firing temperature frame units. The firing temperature on the Frame 7FA combustion turbine is 2400 F. When firing natural gas, the combustor operates in a diffusion mode at low loads (less than 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 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 IV control system will be used to continuously maintain the NO_X concentration in the exhaust at the specified level throughout the 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 the BACT 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 equal 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 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 significant 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 the lowest sulfur fuels available anywhere. 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 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 all 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 would have a two year guaranteed 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 is considered BACT. 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 semiannually to the Department pursuant to 40 CFR 60.7. Subject to EPA approval, 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 as 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
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 and O_2 CEMS
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 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:	Approved By:
C. H. Fancy, P.E., Chief Bureau of Air Regulation	Howard L. Rhodes, Director Division of Air Resources Management
Date:	Date:

Purdom Unit 8

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)

Source: Foster Wheeler Environmental, 1997

DRAFT