STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the Matter of an
Application for Permit by:

Mr. Gregory M. Nelson, P.E.
Manager, Environmental Planning
Tampa Electric Company
6944 U.S. Highway 41 North
Apollo Beach, Florida 33572-9200

Facility I.D. No. 1050233
DEP Permit No. PSD-FL-263
Polk Power Station
Polk County

Enclosed is the Final Permit Number PSD-FL-263 for an air construction permit to construct/install two nominal 165 megawatt General Electric PG7241FA simple cycle, intermittent duty natural gas and No. 2 fuel oil-fired combustion turbine-electrical generators at the existing Polk Power Station, Polk County. This permit is issued pursuant to Chapter 403, Florida Statutes and 40CFR52.21.

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

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 10-8-99 to the person(s) listed:

Gregory M. Nelson, TEC*
Gregg Worley, EPA
John Bunyak, NPS
Bill Thomas, DEP SWD
Buck Oven, DEP PPSO
Thomas W. Davis, P.E, ECT

Clerk Stamp

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

10-8-99
(Clerk) (Date)

FINAL DETERMINATION

Tampa Electric Company
Polk Power Station
165 MW Simple Cycle Combustion Turbines
DEP File No: PSD-FL-263

The Department distributed a public notice package on June 30, 1999 for the project to construct two nominal 165 megawatt (MW) natural gas and distillate fuel oil-fired simple cycle combustion turbine-electrical generators and two 114-foot stacks at the Polk Power Station, 9995 State Route 37 South, Mulberry, Polk County. The Public Notice of Intent to Issue PSD Permit was published in the Lakeland Ledger on Saturday July 10, 1999.

Comments were received and considered from the U.S. Fish and Wildlife Service and Hillsborough County prior to issuance of the Intent, but none were received from any agencies or the public after issuance of the Intent. Written comments were received from Tampa Electric Company (TEC) dated August 9, and September 14, 1999. TEC commented on the Public Notice, Draft Permit, Draft BACT Determination and the Technical Evaluation and Preliminary Determination. TEC's comments (italics and keyed to the respective documents) and the Department's responses follow.

Public Notice of Intent to Issue PSD Permit

TEC states that although the notice was published as requested by the Department, it should be noted that the referenced units do not have "evaporative inlet coolers." The reference to these coolers was inadvertently included in the original permit application, but removed in the revised application.

The Department acknowledges that there will not be evaporative inlet coolers. All references to coolers in the final documents have been removed.

Technical Evaluation and Preliminary Determination (TEPD)

The reference to evaporative inlet coolers should be deleted from this section (page TE-4 of 10) for the above stated reason.

The reference to volatile organic compounds (VOC) in the "Significant emission rate increases" paragraph (page TE-4 of 10) should be deleted. Based on the emissions estimates provided in the revised permit application, VOC emission increases are less than the PSD significance level.

The "Project Emissions (TPY) and PSD Applicability" table (page TE-7 of 10) "PSD Review" column for "Ozone (VOC)" should be changed from "Yes" to "No" based on the above comment

The Department acknowledges these comments and has included them in the project file. The TEPD will not be re-issued, but the final Permit and BACT documents comport with TEC's comments.

Draft Permit

Specific Condition 8:

Condition 8 (page 7 of 13) should be corrected from "higher heating value (LHV)" to "higher heating value (HHV)" or "lower heating value (LHV)", which ever one is intended.

The term has been corrected to reflect "lower heating value (LHV)."

Specific Condition No. 13

Condition 13 (page 7 of 13) should allow 876 hours per year on fuel oil, as this was the basis of the permit application and associated analysis. Also, this condition should be clarified to indicate that allowable hours of operation on gas and oil are both "per year" and based on "full load equivalent hours" since this was the basis for which the emission estimates and associated analysis were completed.

This matter was fully addressed in both the draft and Final BACT determination as part of the rationale for requiring a NO_X limit of 10.5 ppmvd @15 percent O_2 instead of 9 ppmvd. Also, because emissions on oil are relatively high (42 ppmvd), it is important to limit oil firing. The annual limit on hours of oil operation given in the permit is clearly within the description of the oil firing scenario given by TEC which is "these units will only burn oil as necessary for backup which is expected to be for short periods of time and fairly sporadic." The hours on oil can still be increased if TEC agrees to the 9 ppmvd NO_X limit on natural gas (such as the Oleander and Vandolah Projects). They can also be increased if emissions from fuel oil can be reduced to less than 42 ppmvd on oil. TEC is also a major supplier of gas and can certainly insure that operation on oil firing is limited without experiencing undue hardship.

Specific Condition No. 17:

Condition 17 (page 8 of 13) requires DLN systems to be maintained to minimize NO_x and CO emissions and requires operation of the DLN combustor in the diffusion-firing mode to be minimized. These are broad, general requirements which could be open to differing interpretations. This condition should be re-written to simply require the DLN systems be properly maintained to comply with permitted NO_x and CO emission rates.

The Department reworded this condition as follows:

The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN and wet injection systems prior to their installation. DLN systems shall each be tuned upon initial operation to optimize emissions reductions consistent with normal operation and maintenance practices and shall be maintained to minimize NO_X emissions and CO emissions, consistent with normal operation and maintenance practices. Operation of the DLN systems in the diffusion-firing mode shall be minimized when firing natural gas. [Rule 62-4.070, and 62-210.650, F.A.C.]

Specific Condition No. 18

TEC request the following change: Condition 18 (page 8 of 13) should state emission limits for VOC, CO, SO_2, SAM and NO_x in terms of "pounds per hour" only, using the relevant ppm rate as the basis for these limits. VOC basis should be expressed as ppmvw.

The Department's BACT limits for combustion turbines are expressed in "unit of the standard." In the case of NO_X the unit is ppmvd (corrected to 15% oxygen as applicable). Proper permitting practice dictates both a technology-based BACT limit that reflects the capabilities of the selected technology (ppmvd) and a pounds per hour limit requirement to demonstrate protection of short term ambient standards and to calculate potential-to-emit. The NO_X ppmvd units are clearly consistent with the guarantee provided by the General Electric and the value is actually higher than the guarantee.

Natural gas sulfur content limit should be 2 gr S/100 ft^3 (missing "t").

This typographical error was corrected as requested.

Specific Condition No. 19:

The Condition 19 (page 8 of 13) requirement to substitute missing data per Title IV (40 CFR 75) is overly punitive when applied to averaging periods shorter than what is contained in Title IV (calendar year annual average). Missing data periods, as well as startup/shutdown (less than fifty percent load) and malfunction periods should be excluded from the calculation of short-term averages.

The Department will delete the reference to missing data substitution from Title IV. In its place, the Department will add a new paragraph in accordance with 40CFR60.13 to address this issue under Specific Condition No. 29 as follows:

All continuous monitoring systems (CEMS) shall be in continuous operation except for breakdowns, repairs, calibration checks, and zero and span adjustments. These CEMS shall meet minimum frequency of operation requirements: one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data average. Although recorded, emissions during period of start up, shutdown and malfunction are subject to the excess emissions conditions of this permit. [40CFR60.13]

The NO_x limits in this condition should be stated in terms of "pounds per hour" only, using the ppm rate as the basis.

This comment is already addressed above (Specific Condition 18)

The averaging period while firing fuel oil should be changed from "3 hr average" to "24 hour block average" similar to the requirement for gas firing.

The Department has received input from EPA on similar projects recommending that emissions be averaged over shorter time periods rather than longer ones as requested by TEC. They would prefer that the averaging time be reduced for gas firing rather than extended for oil firing. The

Department has determined that it is not difficult to maintain the 42 ppmvd standard on a three hour basis by injecting steam or water as needed. It is much more difficult to continuously maintain the lower 10.5 ppmvd applicable when firing gas partly because it is not possible to add more of a reagent or inject water to quickly effect the necessary reduction. This condition will not be relaxed as requested by TEC or made stricter as suggested by EPA.

The requirement to submit an engineering report related to lower NO_x emission rate while burning oil should be removed. TEC feels this requirement is completely unwarranted based on the fact that the vendor will only guarantee oil fired NO_x emissions rates at 42 ppm. In addition, these units will only burn oil as necessary for backup which is expected to be for short periods of time and fairly sporadic; therefore, it will be extremely difficult to determine an emission rate that can consistently be achieved while taking into account long-term performance expectations and good operating and maintenance practices.

The Department accepts TEC statement that these units will only burn oil as necessary for back up which is expected to be for short periods of time and fairly sporadic. However, the Department feels as it was explained in the BACT determination rationale that it is conceivable that NO_X emissions while firing oil may be reduced from 42 ppmvd by increasing the water injection rate or even by development of a DLN oil burner (Page BD-13 Appendix BD). Based on the above, will be modified as follows:

> ~~Within 18 months after the initial compliance test, the permittee shall prepare and submit for the Department's review and acceptance an engineering report regarding the lowest NO_X emission rate that can consistently be achieved when firing distillate oil. This lowest recommended rate shall include a reasonable operating margin, taking into account long-term performance expectations and good operating and maintenance practices. The Department may revise the NO_X emission rate based upon this report. [BACT determination]~~
>
> The permittee shall develop a NO_X reduction plan when the hours of oil firing reach the allowable limit of 750 hour per year equivalent hours. This plan shall include a testing protocol designed to establish the maximum water injection rate and the lowest NO_X emissions possible without affecting the actual performance of the gas turbine. The testing protocol shall set a range of water injection rates and attempt to quantify the corresponding NO_X emissions for each rate and noting any problems with performance. Based on the test results, the plan shall recommend a new NO_X emissions limiting standard and shall be submitted to the Department's Bureau of Air Regulation and Compliance Authority for review. If the Department determines that a lower NO_X emissions standard is warranted for oil firing, this permit shall be revised. [BACT Determination]

Specific Condition No. 20

The CO limits in Condition 20 (page 9 of 13) should be stated in terms of "pounds per hour" only, using the ppm rate as the basis. In addition, the only vendor guarantee received to-date has CO limit of 15 ppmvd for gas and 33 ppmvd for oil; therefore, these rates should be used as *the basis.*

The requested limits are substantially higher than measured values for other F-Class installations. For example, the DLN 2.0 combustors on the FPL Martin Plant units emitted less than 5 ppmvd of CO. Similarly tests at the FPC Hines Energy Complex Westinghouse 501F units indicted less than 5 ppmvd of CO. General Electric literature clearly describes as one of its options a DLN 2.6 technology with emissions of 9 ppmvd of NO_X and 9 ppmvd of CO. Although emissions on oil may be higher, they will still be low particularly because of the very high firing temperature for F-Class units.

The Department will set a limit of 15(gas)/33(oil) ppmvd during the first 12 months of operation after start up. Thereafter this limit will be revised and lowered to 12 (gas)/20 (oil) ppmvd. This condition is modified as follows:

<u>During the first 12 months after initial start up, the concentration of CO in the stack exhaust gas shall exceed neither 15 ppmvd nor 48 lb/hr while firing gas (at ISO conditions) and neither 33 ppmvd nor 106 lb/hr while firing oil (at ISO conditions) based on stack test. Thereafter, these limits will be revised and lowered to 12 ppmvd and 38 lb/hr while firing gas (at ISO conditions) and 20 ppmvd and 65 lb/hr while firing oil (at ISO conditions). The permittee shall demonstrate compliance with these limits by stack test using EPA Method 10.</u>

Concentrations should be expressed as ppmvd for both gas and oil firing. Mass (lb/hr) limits should be referenced to ISO conditions.

Concentrations will be expressed as ppmvd if they are not already expressed this way. Mass (lb/hr) limits will be referenced to ISO conditions.

<u>Specific Condition No. 21</u>

The VOC limits in Condition 21 (page 9 of 13) should be stated in terms of "pounds per hour" only, using the ppm<u>vw</u> rate as the basis. Concentration should be expressed as ppm<u>vw</u>. Mass (lb/hr) limits should be referenced to ISO conditions.

This condition will not be changed to lbs/hr with ppmvw as a basis, this rationale is already explained in Specific Condition No. 18. Concentrations will be expressed as ppmvw if they are not already expressed this way. Mass (lb/hr) limits will be referenced to ISO conditions.

<u>Specific Condition No. 22</u>

SO_2 lb/hr limits should be referenced to ISO conditions.

The Department agrees with TEC and made the change as requested.

In Condition 23 (page 9 of 13) the words "operating with or without the duct burner and" should be removed, as it does not apply here. The opacity limit for oil firing should be 20 percent.

The Department agrees with TEC and made the change as requested. TEC subsequently retracted its request and accepted the Department's 10 percent BACT limitation.

In Condition 24 (page 9 of 13), the wording "Operation below 50% output shall be limited to 2 hours per unit cycle (breaker closed to breaker open)" is unclear and should be changed to "Operation below 50% output shall be limited to 2 hours per startup or shutdown".

By agreement with TECO, the condition will remain as drafted.

In Condition 26 (page 10 of 13) the wording "for greater than 2 hours in a 24-hour period" should be inserted after the word "malfunction" in the first sentence.

The Department agrees with TEC and changed this condition as requested.

"Condition No. 26" should read "Condition No. 36." Condition 40 seems to be the same (but uncompleted version) as Condition 41, and can be eliminated.

The Department agrees with TEC and corrected No.26 to No.36. Additionally Specific Conditions 39, 40 and 41 are modified as follows:

39. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from each CT in accordance with the requirements of 40 CFR 75. ~~Periods when NO_x emissions (ppmvd at 15% oxygen) are above the standards, listed in Specific Conditions No. 18 and 19, shall be provided to the DEP Southwest District Office within one working day (verbally) followed up by a written explanation not later than three (3) working days (alternately by facsimile).~~ Upon request from EPA or DEP, the CEMS emission rates for NO_x on each CT shall be corrected to ISO conditions to demonstrate compliance with the NO_x standard established in 40 CFR 60.332.

 [Rules 62-4.130., 62-4.160(8), 62.210.700, 62-204.800 F.A.C., 40CFR75 and 40 CFR 60.7]

40. CEMS Excess Emissions Reports: ~~Subject to EPA approval the NO_x CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1998 version). Upon request from EPA or DEP, the CEMS emission rates for NO_x on each CT shall be corrected to ISO conditions to demonstrate compliance with the NO_x standard established in 40 CFR 60.332. [Rule 62-204.800 F.A.C., 40CFR75 and 40 CFR 60.7]~~ Excess Emissions and Monitoring System Performance Reports shall be submitted as specified in 40 CFR 60.7(c). CEM monitor downtime shall be calculated and reported according to the requirements of 40 CFR 60.7(c)(3) and 40 CFR 60.7(d)(2). Periods when NO_x emissions (ppmvd at 15% oxygen) are above the standards, listed in Specific Conditions No. 18 and 19, shall be provided to the DEP Southwest District Office within one working day (verbally) followed up by a written explanation not later than three (3) working days (alternately by facsimile).

~~41.~~ CEMS in lieu of Water to Fuel Ratio: The NO_x CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1998 version). The calibration of the water/fuel monitoring device required in 40 CFR 60.335(c) (2) (1998 version) will be replaced by the 40 CFR 75 certification tests of the NO_x CEMS. ~~Upon request from EPA or DEP, the CEMS emission rates for NO_x on each~~

~~CT shall be corrected to ISO conditions to demonstrate compliance with the NO_x standard established in 40 CFR 60.332.~~

42. The title of this condition was change from Continuous Monitoring System Report to Continuous Monitoring Certification and Quality Assurance Requirements.

Appendix BD.

The BACT determination should be modified to reflect the changes referenced above, such as stating the proposed limits in terms of "pounds per hour" and removing the determination requiring a follow-up report on NO_x limits while firing oil, for example

BACT for combustion turbines are expressed in unit of the standard. This is ppmvd (corrected to 15% oxygen). The follow-up report requirements were revised as previously discussed.

*Although the SCR vendor specified a guarantee of 3 years, 5 years **was** conservatively used in the submitted permit application BACT cost-analysis; reference Page 5-16, Table 5-7 of the permit application.*

The Department acknowledges TEC comments and will delete the reference to the 3 year life guarantee.

Basis for lower CO limits is the proposed Oleander project levels. GE needs to confirm that these lower limits are attainable.

This comment was addressed above. The Department has reasonable assurance from GE and from test results for very similar units that the BACT limits for CO are easily attainable.

FDEP lowers the oil-firing hours from 876 to 750 per year without any explanation for the decrease.

EPA and the Fish and Wildlife Service have commented that the NO_X BACT limit while firing natural gas should be 9 ppmvd (based on the Oleander BACT determination) and not 10.5 ppmvd as requested by JEA and TEC for the identical units. The Department has reduced hours on fuel oil to justify the 10.5 ppmvd value with limited fuel oil firing as BACT. The Department would increase the hours of fuel oil to 876 as requested by TEC (or to 1000 as allowed for Oleander), if TEC accepts the lower 9 ppmvd NO_X limit on gas.

CONCLUSION

The final action of the Department will be to issue the permit with the changes noted above.

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

PERMITTEE:

Tampa Electric Company (TEC)
6944 U.S. Highway 41 North
Apollo Beach, Florida 33572-9200

File No.	PSD-FL-263 (PA92-32)
FID No.	1050233
SIC No.	4911
Expires:	December 31, 2002

Authorized Representative

Gregory M. Nelson, Manager, Environmental Planning

PROJECT AND LOCATION:

Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit) for the construction of: two dual-fuel nominal 165 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators and two 114-foot stacks. The units will operate in simple cycle mode and intermittent duty. The units will be equipped with Dry Low NO_X (DLN-2.6) combustors and wet injection capability. They are designated by TEC as CTGs Nos. 2 and 3 and by the Department as ARMS Emissions Units 009 and 010.

The project will be located at the existing Polk Power Station, 9995 State Route 37 South, Mulberry, Polk County. UTM coordinates are: Zone 17; 402.45 km E; 3067.35 km N.

STATEMENT OF BASIS:

This PSD permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and 40CFR52.21. The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

Attached Appendices and Tables made a part of this permit:

Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions

Howard L. Rhodes
Howard L. Rhodes, Director
Division of Air Resources
Management

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-263

SECTION I - FACILITY INFORMATION

FACILITY DESCRIPTION

This facility presently generates electric power from a 260 megawatt (MW) integrated coal gasification and combined cycle turbine unit. The primary mover is a General Electric MS 7001F combustion turbine capable of firing syngas or No. 2 fuel oil. Associated support facilities include: a solid fuel gasification system; a hydrogen sulfide to sulfur dioxide converter; a sulfuric acid plant; solid fuel handling and storage; and fuel oil handling and storage.

This permitting action is to install two dual-fuel nominal 165 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators with two 114-foot stacks. The project will utilize existing infrastructure including oil storage and auxiliary equipment.

Emissions from the new units will be controlled by Dry Low NO_X (DLN-2.6) combustors when operating on natural gas and wet injection when firing fuel oil. Inherently clean fuels and good combustion practices will be employed to control all pollutants.

EMISSION UNITS

This permit addresses the following emission units:

ARMS EMISSIONS UNIT	SYSTEM	EMISSION UNIT DESCRIPTION
009 (CTG-2)	Power Generation	One nominal 165 Megawatt Gas Simple Cycle Combustion Turbine-Electrical Generator
010 (CTG-3)	Power Generation	One nominal 165 Megawatt Simple Cycle Gas Combustion Turbine-Electrical Generator

REGULATORY CLASSIFICATION

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

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Pursuant to Table 62-212.400-2, modifications at this facility resulting in emissions increases greater than any of the following values require review per the PSD rules as well as a determination of Best Available Control Technology (BACT): 40 TPY of NO_X, SO_2, or VOC; 25/15 TPY of PM/PM_{10}; 100 TPY of CO; or 7 TPY of sulfuric acid mist (SAM).

This project is subject to certain requirements of Chapter 403. Part II, F.S., Electric Power Plant and Transmission Line Siting, including a modification of the Conditions of Certification (reference Site Certification PA92-32).

SECTION I - FACILITY INFORMATION

This facility and the project are also subject to applicable provisions of Title IV, Acid Rain, of the Clean Air Act..

PERMIT SCHEDULE

- xx/xx/99 Modification of Conditions of Certification Approved.
- 07/10/99 Notice of Intent to Issue PSD Permit published in the Lakeland Ledger.
- 06/30/99 Distributed Intent to Issue Permit.
- 06/10/99 Application deemed complete for PSD review.
- 02/08/99 Received revised PSD Application.

RELEVANT DOCUMENTS:

The documents listed below are the basis of the permit. They are specifically related to this permitting action, but not all are incorporated into this permit. These documents are on file with the Department.

- Application received on February 8, 1999
- Department/ Siting Coordination Office incompleteness letter dated February 11, 1999
- Department/BAR memo to Siting Coordination Office dated March 9, 1999
- Comments and letter from the U. S. Fish and Wildlife Service dated March 19, 1999
- Site Certification and Revised PSD Application received May 10. 1999
- Department/BAR comments on Modeling dated May 20, 1999
- Comments from Hillsborough County EPC dated June 7, 1999
- Response from TEC/ECT received June 10, 1999
- Department's Intent to Issue PSD Permit and Public Notice Package dated June 30, 1999
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this Final Permit.
- Comments from TEC dated August 9, September 10, and 14, 1999.

SECTION II - ADMINISTRATIVE REQUIREMENTS

GENERAL AND ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR). Florida Department of Environmental Protection (FDEP), at 2600 Blairstone Road, Tallahassee, Florida 32399-2400 and phone number (850)488-0114. All documents related to reports, tests, and notifications should be submitted to the DEP Southwest District, 3804 Coconut Palm Drive, Tampa, Fl 33619-8218 and phone number 813/744-6100.
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. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212, F.A.C.]
6. Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)]
7. BACT Determination: In conjunction with extension of the 18 month periods to commence or continue construction, or extension of the December 31, 2002 permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of best available control technology for the source. In accordance with paragraph (4) of 40 CFR 52.21(j) the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a plant conversion. This paragraph states: "For phased construction project, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate

the adequacy of any previous determination of best available control technology for the source." [40 CFR 52.21(j)(4), Rule 62-4.070 F.A.C.]

8. Permit Extension: The permittee, for good cause, may request that this PSD 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 62-4.080, F.A.C.).

9. Application for Title IV Permit: An application for a Title IV Acid Rain Permit, must be submitted to the U.S. Environmental Protection Agency Region IV office in Atlanta, Georgia and a copy to the DEP's Bureau of Air Regulation in Tallahassee 24 months before the date on which a new unit begins serving an electrical generator greater than 25 MW. [40 CFR 72]

10. Application for Title V Permit: An application for a Title V operating permit, pursuant to Chapter 62-213, F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department's Southwest District. [Chapter 62-213, F.A.C.]

11. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

12. Annual Reports: 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 Southwest District by March 1st of each year.

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

14. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1998 version), shall be submitted to the DEP's Southwest District.

SECTION III - EMISSIONS UNIT(S) SPECIFIC CONDITIONS

APPLICABLE STANDARDS AND REGULATIONS:

1. 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, 62-17, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, and 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 52, 60, 72, 73, and 75.

2. 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.]

3. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:

   40CFR60.7, Notification and Recordkeeping
   40CFR60.8, Performance Tests
   40CFR60.11, Compliance with Standards and Maintenance Requirements
   40CFR60.12, Circumvention
   40CFR60.13, Monitoring Requirements
   40CFR60.19, General Notification and Reporting requirements

4. ARMS Emissions Unit 009. Direct Power Generation, consisting of a nominal 165 megawatt simple cycle combustion turbine-electrical generator, shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. 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).

5. ARMS Emissions Unit 010. Direct Power Generation, consisting of a nominal 165 megawatt simple cycle combustion turbine-electrical generator, shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. 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).

6. All notifications and reports required by the above specific conditions shall be submitted to the DEP's Southwest District.

GENERAL OPERATION REQUIREMENTS

7. <u>Fuels</u>: Only pipeline natural gas or maximum 0.05 percent sulfur fuel oil No. 2 or superior grade of distillate fuel oil shall be fired in this unit. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)] {Note: The limitation of this specific condition is more stringent than the NSPS sulfur dioxide limitation and thus assures compliance with 40 CFR 60.333 and 60.334}

8. Combustion Turbine Capacity: The maximum heat input rates, based on the lower heating value (LHV) of each fuel to each unit at ambient conditions of 59°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,600 million Btu per hour (mmBtu/hr) when firing natural gas, nor 1,800 mmBtu/hr when firing No. 2 or superior grade of distillate fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

9. Unconfined Particulate Emissions: 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.

10. 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 DEP Southwest District 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.]

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

12. 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.]

13. Maximum allowable hours of operation for each unit are 4,380 hours per year on natural gas and 750 hours per year on fuel oil. [Rule 62-210.200, F.A.C., (Definitions - Potential Emissions), 62-212.400, F.A.C., (BACT Determination)]

CONTROL TECHNOLOGY

14. Dry Low NO_X (DLN) combustors shall be installed on the stationary combustion turbine to comply with the NO_X emissions limits while firing natural gas. [Design, Rules 62-4.070 and 62-212.400, F.A.C. (BACT Determination)]

15. A water injection system shall be installed for use when firing No. 2 or superior grade distillate fuel oil for control of NO_X emissions. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

16. The permittee shall design these units to accommodate adequate testing and sampling locations for compliance with the applicable emission limits (per each unit) listed in Specific Conditions No. 19 through 24. [Rule 62-4.070 , Rule 62-204.800, F.A.C., and 40 CFR60.40a(b)]

17. The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN and wet injection systems prior to their installation. DLN systems shall each be tuned upon initial operation to optimize emissions reductions consistent with normal operation and maintenance practices and shall be maintained to minimize NOx emissions and CO emissions, consistent with normal operation and maintenance practices. Operation of the DLN systems in the diffusion-firing mode shall be minimized when firing natural gas. [Rule 62-4.070, and 62-210.650, F.A.C.]

EMISSION LIMITS AND STANDARDS

18. Following is a summary of the emission limits and required technology. Values for NO_X are corrected to 15 % O_2 on a dry basis. These limits or their equivalent in terms of lb/hr or NSPS units, as well as the applicable averaging times, are followed by the applicable specific conditions [Rules 62-212.400, 62-204.800(7)(b) (Subpart GG), 62-210.200 (Definitions-Potential Emissions) F.A.C.]

POLLUTANT	CONTROL TECHNOLOGY	EMISSION LIMIT
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	10 Percent Opacity (gas or oil)
VOC	As Above	1.4 ppmvw (Gas) 3.5 ppmvw (FO)
CO	As Above	12 ppmvd (Gas) 20 ppmvd (FO)
SO2 and Sulfuric Acid Mist	Pipeline Natural Gas Low Sulfur Oil	2 gr S/100 ft^3 0.05% S Fuel Oil
NO_X	DLN, WI for F.O., limited fuel oil usage	10.5 ppmvd (DLN) 42 ppmvd (FO)

19. <u>Nitrogen Oxides (NO_X) Emissions:</u>

- <u>While firing Natural Gas</u>: The emission rate of NO_X in the exhaust gas shall not exceed 10.5 ppm @15% O_2 on a 24 hr block average as measured by the continuous emission monitoring system (CEMS). In addition, NO_X emissions calculated as NO_2 shall not exceed 59 pounds per hour (at ISO conditions) and 9 ppmvd @15% O_2 to be demonstrated by the initial "new and clean" GE performance stack test. [Rule 62-212.400, F.A.C.]

  Notwithstanding the applicable NO_X limit during normal operation, reasonable measures shall be implemented to maintain the concentration of NO_X in the exhaust gas at 9 ppmvd at 15% O_2 or lower. Any tuning of the combustors for Dry Low NO_X operation while firing gas shall result in initial subsequent NO_X concentrations of 9 ppmvd @15% O_2 or lower. [Rules 62-212.400 and 62-4.070, F.A.C.]

- While firing Fuel oil: The concentration of NO_X in the exhaust gas shall not exceed 42 ppmvd at 15% O_2 on the basis of a 3-hr average as measured by the continuous emission monitoring system (CEMS). In addition, NO_X emissions calculated as NO_2 shall not exceed 319 lb/hr (at ISO conditions) and 42 ppmvd @15% O_2 to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]

  The permittee shall develop a NOx reduction plan when the hours of oil firing reach the allowable limit of 750 hours per year. This plan shall include a testing protocol designed to establish the maximum water injection rate and the lowest NOx emissions possible without affecting the actual performance of the gas turbine. The testing protocol shall set a range of water injection rates and attempt to quantify the corresponding NOx emissions for each rate and noting any problems with performance. Based on the test results, the plan shall recommend a new NOx emissions limiting standard and shall be submitted to the Department's Bureau of Air Regulation and Compliance Authority for review. If the Department determines that a lower NOx emissions standard is warranted for oil firing, this permit shall be revised. (BACT Determination].

20. Carbon Monoxide (CO) Emissions: During the first 12 months after initial start up, the concentration of CO in the stack exhaust gas shall exceed neither 15 ppmvd nor 48 lb/hr (at ISO conditions) while firing gas and neither 33 ppmvd nor 106 lb/hr (at ISO conditions) while firing oil based on stack test. Thereafter, these limits will be revised and lowered to 12 ppmvd and 38 lb/hr (at ISO conditions) while firing gas and 20 ppmvd and 65 lb/hr (at ISO conditions). The permittee shall demonstrate compliance with these limits by stack test using EPA Method 10. [Rule 62-212.400, F.A.C.]

21. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC in the stack exhaust gas with the combustion turbine operating on natural gas shall exceed neither 1.4 ppmvw nor 2.8 lb/hr (ISO conditions) and neither 3.5 ppmvw nor 7 lb/hr (ISO conditions) while operating on oil to be demonstrated by initial stack test using EPA Method 18, 25 or 25A. [Applicant Request]

22. Sulfur Dioxide (SO_2) emissions: SO_2 emissions shall be limited by firing pipeline natural gas (sulfur content less than 2 grains per 100 standard cubic foot) or by firing No. 2 or superior grade distillate fuel oil with a maximum 0.05 percent sulfur for 750 hours per year per unit. Emissions of SO_2 (at ISO conditions) shall not exceed 9.2 lb/hr (natural gas) and 98.1 lb/hr (fuel oil) as measured by applicable compliance methods described below. [40CFR60 Subpart GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C]

23. Visible Emissions (VE): VE emissions shall serve as a surrogate for PM/PM10 emissions and shall not exceed 10 opacity. Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

EXCESS EMISSIONS

24. Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour

period for other reasons unless specifically authorized by DEP for longer duration. Operation below 50% output shall be limited to 2 hours per unit cycle (breaker closed to breaker open).

25. Excess emissions entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the 24-hr average for NO_X.

26. Excess Emissions Report: If excess emissions occur due to malfunction (for greater than 2 hours in a 24-hr period), the owner or operator shall notify DEP's Southwest District 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. Following the NSPS format, 40 CFR 60.7 Subpart A, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 18 and 19. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1998 version)].

COMPLIANCE DETERMINATION

27. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, 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 (1998 version), and adopted by reference in Chapter 62-204.800, F.A.C.

28. Initial (I) performance tests (for both fuels) shall be performed on each unit while firing natural gas as well as while firing oil. Initial tests shall also be conducted after any modifications (and shake down period not to exceed 100 days after re-starting the CT) of air pollution control equipment such as change or tuning of combustors. Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on each unit as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.

   - EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
   - EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
   - EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40CFR60 Subpart GG and (I, A) short-term NO_X BACT limits (EPA reference Method 7E, "Determination of Nitrogen Oxides Emissions from Stationary Sources" or RATA test data may be used to demonstrate compliance for annual test requirements).

- EPA Reference Method 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.

29. <u>Continuous compliance with the NO_X emission limits</u>: Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 24-hr block average (DLN). Based on CEMS data, a separate compliance determination is conducted at the end of each operating day and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous operating day. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. Valid hourly emission rates shall not include periods of start up, shutdown, or malfunction unless prohibited by 62-210.700 F.A.C. These excess emissions periods shall be reported as required in Conditions 25 and 26. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 40 CFR 75 and BACT]

    - All continuous monitoring systems (CEMS) shall be in continuous operation except for breakdowns, repairs, calibration checks, and zero and span adjustments. These CEMS shall meet minimum frequency of operation requirements: one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data average. [40CFR60.13]

30. <u>Compliance with the SO_2 and PM/PM_{10} emission limits</u>: Not withstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas, is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, ASTM methods D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule or natural gas supplier data 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 in 40 CFR60.335 or 40 CFR75 are used when determination of fuel sulfur content is made. 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) (1998 version).

31. <u>Compliance with CO emission limit</u>: An initial test for CO shall be conducted concurrently with the initial NO_X test, as required. The initial NO_X and CO test results shall be the average of three valid one-hour runs. Annual compliance testing for CO may be conducted at less than capacity when compliance testing is conducted concurrent with the annual RATA testing for the NO_X CEMS required pursuant to 40 CFR 75

32. <u>Compliance with the VOC emission limit:</u> An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, the CO emission limit and periodic tuning data will be employed as surrogate and no annual testing is required.

33. <u>Testing procedures:</u> Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 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 110 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. Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C.

34. Test Notification: The DEP's Southwest District shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance test(s).

35. Special Compliance Tests: The DEP may request a special compliance test pursuant to Rule 62-297.310(7), 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.

36. Test Results: Compliance test results shall be submitted to the DEP's Southwest District no later than 45 days after completion of the last test run. [Rule 62-297.310(8), F.A.C.].

NOTIFICATION, REPORTING, AND RECORDKEEPING

37. Records: All measurements, records, and other data required to be maintained by TEC shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP representatives upon request.

38. Compliance Test Reports: A test report indicating the results of the required compliance tests shall be filed as per Condition No.36 above. 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.

MONITORING REQUIREMENTS

39. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from these units. Upon request from EPA or DEP, the CEMS emission rates for NO_X on these Units shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332. [Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C, 40 CFR 75and 40 CFR 60.7 (1998 version)].

40. CEMS for reporting excess emissions: Excess Emissions and Monitoring System Performance Reports shall be submitted as specified in 40 CFR 60.7(c). CEM monitor downtime shall be

calculated and reported according to the requirements of 40 CFR 60.7(c)(3) and 40CFR 60.7(d)(2). Periods when NO_X emissions (ppmvd @ 15% oxygen) are above the BACT standards, listed in Specific Conditions No 18 and 19, shall be reported to the DEP Southwest District within one working day (verbally) followed up by a written explanation not later than three (3) working days (alternatively by facsimile within one working day).

41. CEMS in lieu of Water to Fuel Ratio: The NO_X CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1998version). The calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) (1998 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS

42. Continuous Monitoring Certification and Quality Assurance Requirements: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. The monitoring plan, consisting of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the DEP Emissions Monitoring Section Administrator and EPA for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62.

43. Natural Gas Monitoring Schedule: A custom fuel monitoring schedule pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2) provided the following requirements are met:

- The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.
- The permittee shall submit a monitoring plan, certified by signature of the Designated Representative, that commits to using a primary fuel of pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant to 40 CFR 75.11(d)(2)).
- Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.

This custom fuel monitoring schedule will only be valid when pipeline natural gas is used as a primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

44. Fuel Oil Monitoring Schedule: The following monitoring schedule for No. 2 or superior grade fuel oil shall be followed: For all bulk shipments of No. 2 fuel oil received at this facility an analysis which reports the sulfur content and 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).

45. Determination of Process Variables:

- 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.
- 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]

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

G.13 This permit also constitutes:

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

G.14 The permittee shall comply with the following:

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

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

c) Records of monitoring information shall include:

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

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

APPENDIX BD

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Polk Power Station Combustion Turbine Project
Tampa Electric Company
PSD-FL-263 and PA92-33
Polk County, Florida

BACKGROUND

The applicant, Tampa Electric Company (TEC), proposes to install two nominal 165 megawatt (MW) General Electric PG 7241 FA combustion turbine-electrical generators at the existing Polk Power Station, located at 9995 State Road 37 South, Polk County. The proposed project will result in "significant increases" with respect to Table 62-212.400-2, Florida Administrative Code (F.A.C.) of emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), nitrogen oxides (NO_X), sulfur dioxide (SO_2), and sulfuric acid mist (SAM). The project is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) in accordance with Rules 62-212.400, F.A.C.

The new units will operate in simple cycle mode and intermittent duty and exhaust through separate 114-foot stacks. TEC proposes to operate these units up to 4380 hours on natural gas and 876 hours on maximum 0.05 percent sulfur distillate fuel oil. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated June 30, 1999, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on February 8, 1999 and included a proposed BACT proposal prepared by the applicant's consultant, Environmental Consulting & Technology (ECT). A revised application and BACT proposal were received on May 10, 1999.

REVIEW GROUP MEMBERS:

A. A. Linero, P.E. and Teresa Heron, Permit Engineer

BACT DETERMINATION REQUESTED BY THE APPLICANT

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Nitrogen Oxides	Dry Low NO_X Combustors Water Injection (Oil)	10.5 ppmvd @ 15% O_2 (gas) 42 ppmvd @ 15% O_2 (oil)
Particulate Matter	Pipeline Natural Gas No. 2 Distillate Oil (876 hr/yr) Combustion Controls	10% Opacity
Carbon Monoxide	As Above	15 ppm (gas, baseload) 33 ppm (oil baseload)
Sulfur Dioxide	As Above	2 gr S/100 scf of natural gas 0.05% S in fuel oil
Sulfuric Acid Mist	As Above	2 gr S/100 scf of natural gas 0.05% S in fuel oil

According to the application, the total maximum annualized emissions from the new units will be approximately 581 tons per year (TPY) of NO_X, 303 TPY of CO, 54 TPY of PM/PM_{10}, 126 TPY of SO_2, 18 TPY of VOC, and 15 TPY of SAM.

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:

- 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.
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- 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 unfeasible 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.

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). The Department adopted subpart GG by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppmvd NO_X @ 15% O_2 (assuming 25 percent efficiency) and 150 ppm SO_2 @ 15% O_2 (or <0.8% sulfur in fuel). The BACT proposed by the TEC is within the NSPS limit, which allows NO_X emissions, over 110 ppmvd for the high efficiency unit to be purchased for the Polk Power Station. No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines.

DETERMINATIONS BY EPA AND STATES:

The following table is based primarily on "F" Class intermittent-duty simple cycle turbines recently permitted or still under review. One project (PREPA) based on smaller units but permitted to operate continuously is included as an example of a simple cycle unit with add-on control equipment. Another continuous-duty project (Lakeland) based on the larger "G" Class is also included. The proposed TEC project is included to facilitate comparison.

VOC determinations are included. However the TEC project does not trigger PSD and a BACT determination is not required for this pollutant.

Project Location	Power Output and Duty	NO_X Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
Lakeland, FL	250 MW SC CON	9/9 – NG (by 2002) 42/15 - No 2 FO	DLN/HSCR WI/HSCR	250 MW WH 501G CT Initially 25 ppm NO_X limit on gas Issued 7/98. 250 hrs on oil
Oleander Cocoa, FL	850 MW SC INT	9 - NG 42 - No 2 FO	DLN WI	5x170 MW GE PG7241FA CTs Draft 4/99 1000 hrs on oil
JEA Baldwin, FL	510 MW SC INT	12 - NG 42 - No 2 FO	DLN WI	3x170 MW GE MS7241FA CTs Application 5/99. 800 hrs on oil
JEA Kennedy, FL	170 MW SC INT	15 - NG 42 - No. 2 FO	DLN WI	170 MW GE MS7241FA CT Issued 2/99. Not PSD/BACT
TEC Polk Power, FL	330 MW SC INT	10 5 – NG 42 – F O	DLN WI	2x165 MW GE MS7241FA CTs Application 2/99. 876 hrs on oil
Dynegy Heard, GA	510 MW SC INT	15 – NG	DLN	3x170 MW WH 501F CTs Application. Gas only
Tenaska Heard, GA	960 MW SC INT	15 - NG 42 - No. 2 FO	DLN WI	6x170 MW GE PG7241FA CTs Issued 12/98. 720 hrs on oil
Thomaston, GA	680 MW SC INT	15 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE PG7241FA CTs Application. 1687 hrs on oil
Dynegy Reidsville, NC	900 MW SC INT	15 – NG (by 2002) 42 – FO	DLN WI	5x180 MW WH 501F CTs Initially 25 ppm NO_X limit on gas Draft 5/98. 1000 hrs on oil.
RockGen Cristiana, WI	525 MW SC INT	15/12 – NG 42 - No 2 FO	DLN WI	3x175 MW GE PG7241FA CTs 15/12 ppm are on 1/24 hr basis Issued 1/99. 800 hrs on oil
SEI Neenah, WI	330 MW SC INT	15/12 - NG 42 - No. 2 FO	DLN WI	2x165 MW GE PG7241FA CTs 15/12 ppm are on 1/24 hr basis Issued 1/99 8760/699 hrs gas/oil
PREPA, PR	248 MW SC CON	10 - No. 2 FO	WI & HSCR	3x83 MW ABB GT11N CTs Issued 12/95.

CON = Continuous | DLN = Dry Low NO_X Combustion | FO = Fuel Oil | GE = General Electric
SC = Simple Cycle | SCR = Selective Catalytic Reduction | ppm = parts per million | WH = Westinghouse
NG = Natural Gas | HSCR = Hot SCR | WI = Water or Steam Injection | ABB = Asea Brown Bovari
INT = Intermittent | CT = Combustion Turbine | MW = megawatts

Project Location	CO - ppm (or as indicated)	VOC - ppm (or as indicated)	PM - lb/hr (or as indicated)	Technology and Comments
Lakeland, FL	25 - NG or 10 by Ox Cat 75 - FO @ 15% O_2	4 – NG 10 – FO	10% Opacity	Clean Fuels Good Combustion
Oleander Cocoa, FL	12 - NG 20 - FO	3 – NG 6 – FO	10% Opacity	Clean Fuels Good Combustion
JEA Baldwin, FL	15 - NG 20/26 (part/full load) - FO	2 8 lb/hr – NG 3 lb/hr – FO	9 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
JEA Kennedy, FL	15 - NG 20 - FO	1 4 – NG 3.5 – FO	9 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
TEC Polk Power, FL	15 - NG 33 - FO	1.6 – NG 4 – FO	10% Opacity	Clean Fuels Good Combustion
Dynegy Heard Co., GA	25 - NG	? – NG	? - NG	Clean Fuels Good Combustion
Tenaska Heard Co , GA	15 - NG 20 - FO	? – NG ? – FO	? - NG ? lb/hr - FO	Clean Fuels Good Combustion
Dynegy Reidsville, NC	25 - NG 50 - FO	6 lb/hr – NG 8 lb/hr – FO	6 lb/hr - NG 23 lb/hr - FO	Clean Fuels Good Combustion
RockGen Cristiana, WI	12@>50% load – NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr – NG 44 lb/hr - FO	Clean Fuels Good Combustion
SEI Neenah, WI	12@>50% load – NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr - NG 41 lb/hr - FO	Clean Fuels Good Combustion
PREPA, PR	9 – FO @15% O_2	11 – FO @15% O_2	0 0171 gr/dscf	Clean Fuels Good Combustion

OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

Besides the information submitted by the applicant and that mentioned above, other information available to the Department consists of:

- Comments from the Fish and Wildlife Service dated March 19, 1999
- DOE website information on Advanced Turbine Systems Project
- Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines
- General Electric 39th Turbine State-of-the-Art Technology Seminar Proceedings
- GE Guarantee for Jacksonville Electric Authority Kennedy Plant Project
- GE Power Generation - Speedtronic™ Mark V Gas Turbine Control System
- GE Combustion Turbine Startup Curves
- TEC Website – www.teco-energy.com
- Goal Line Environmental Technologies Website – www.glet.com
- Catalytica Website – www.catalytica-inc.com

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

Much of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas Turbines. Project-specific information is included where applicable.

Nitrogen Oxides Formation

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO_X forms in the high temperature area of the gas turbine combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of prompt to overall NO_X is relatively small in lean, near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. It is not important for the TEC project because natural gas will be the primary fuel and low sulfur fuel oil will be used only for 876 hours per year.

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2) for small turbines. For large modern turbines, the Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2.

NO_X Control Techniques

Wet Injection

Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. Typical emissions achieved by wet injection are in the range of 15–25 ppmvd when firing gas and 42 ppmvd when firing fuel oil in large combustion turbines. These values often form the basis, particularly in combined cycle turbines, for further reduction to BACT limits by other techniques. Carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines. However steam and (more so) water injection increase emissions of both of these pollutants.

Combustion Controls

The excess air in lean combustion cools the flame and reduces the rate of thermal NO_X formation. Lean premixing of fuel and air prior to combustion can further reduce NO_X emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) that can occur when trying to achieve lean mixing within the combustion zones.

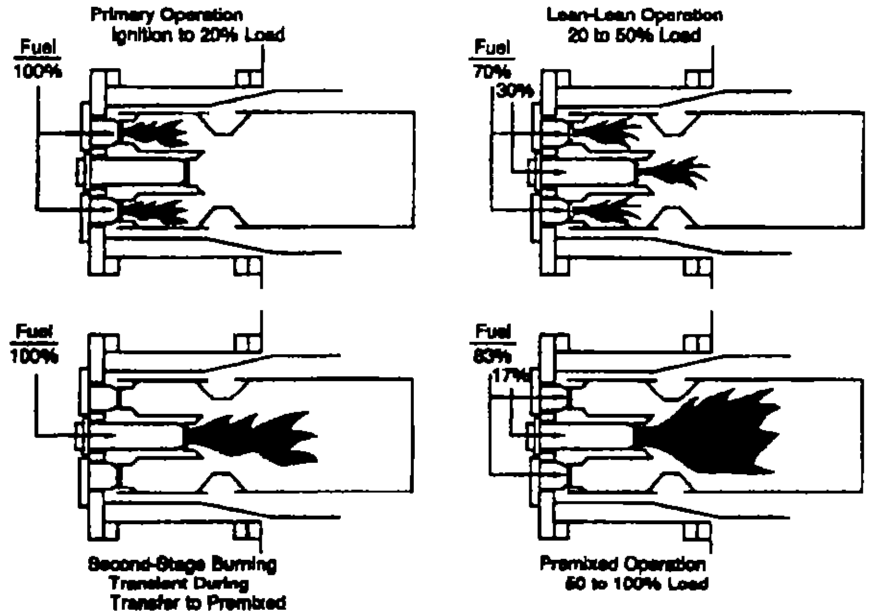
The above principle is depicted in Figure 1 for a General Electric DLN-1 can-annular combustor operating on gas. For ignition, warm-up, and acceleration to approximately 20 percent load, the first stage serves as the complete combustor. Flame is present only in the first stage, which is operated as lean stable combustion will permit. With increasing load, fuel is introduced into the secondary stage, and combustion takes place in both stages. When the load reaches approximately 40 percent, fuel is cut off to the first stage and the flame in this stage is extinguished. The venturi ensures the flame in the second stage cannot propagate upstream to the first stage. When the fuel in the first-stage flame is extinguished (as verified by internal flame detectors), fuel is again introduced into the first stage, which becomes a premixing zone to deliver a lean, unburned, uniform mixture to the second stage. The second stage acts as the complete combustor in this configuration.

To further reduce NO_X emissions, GE developed the DLN-2.0 (cross section shown in Figure 1) wherein air usage (other than for premixing) was minimized. The venturi and the centerbody assembly were eliminated and each combustor has a single burning zone. So-called "quaternary fuel" is introduced through pegs located on the circumference of the outward combustion casing.

GE has made further improvements in the DLN design. The most recent version is the DLN-2.6 (proposed for the TEC project). The combustor is similar to the DLN-2 with the addition of a sixth (center) fuel nozzle. The emission characteristics of the DLN-2.6 combustor while firing natural gas are given in Figure 2 for a unit tuned to meet a 15 ppmvd NO_X limit (by volume, dry corrected to at 15 percent oxygen) at Jacksonville Electric Authority's Kennedy Station.

NO_X concentrations are higher in the exhaust at lower loads because the combustor does not operate in the lean pre-mix mode. Therefore such a combustor emits NO_X at concentrations of 15 parts per million (ppmvd) at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppmvd at less than 50 percent of capacity. Note that VOC comprises a very small amount of the "unburned hydrocarbons" which in turn is mostly non-VOC methane.

The combustor can be tuned differently to achieve emissions as low as 9 ppmvd of NO_X and 9 ppm of CO. Emissions characteristics while firing oil are expected to be similar for the DLN-2.6 as they are for those of the DLN-2.0 shown in Figure 3. Simplified cross sectional views of the totally premixed DLN-2.6 combustor to be installed at the TEC project are shown in Figure 4.



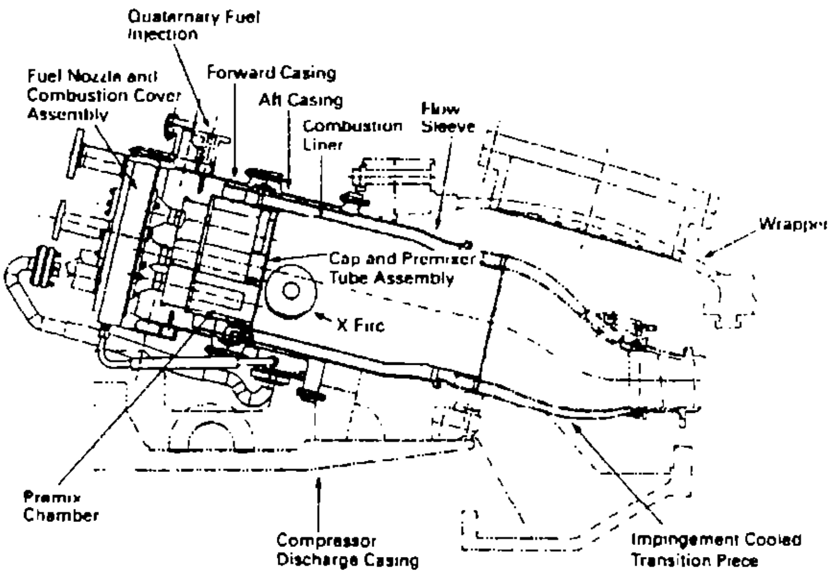


Figure 1 - Dry Low NOx Operating Modes - DLN-1

Cross Section of GE DLN-2

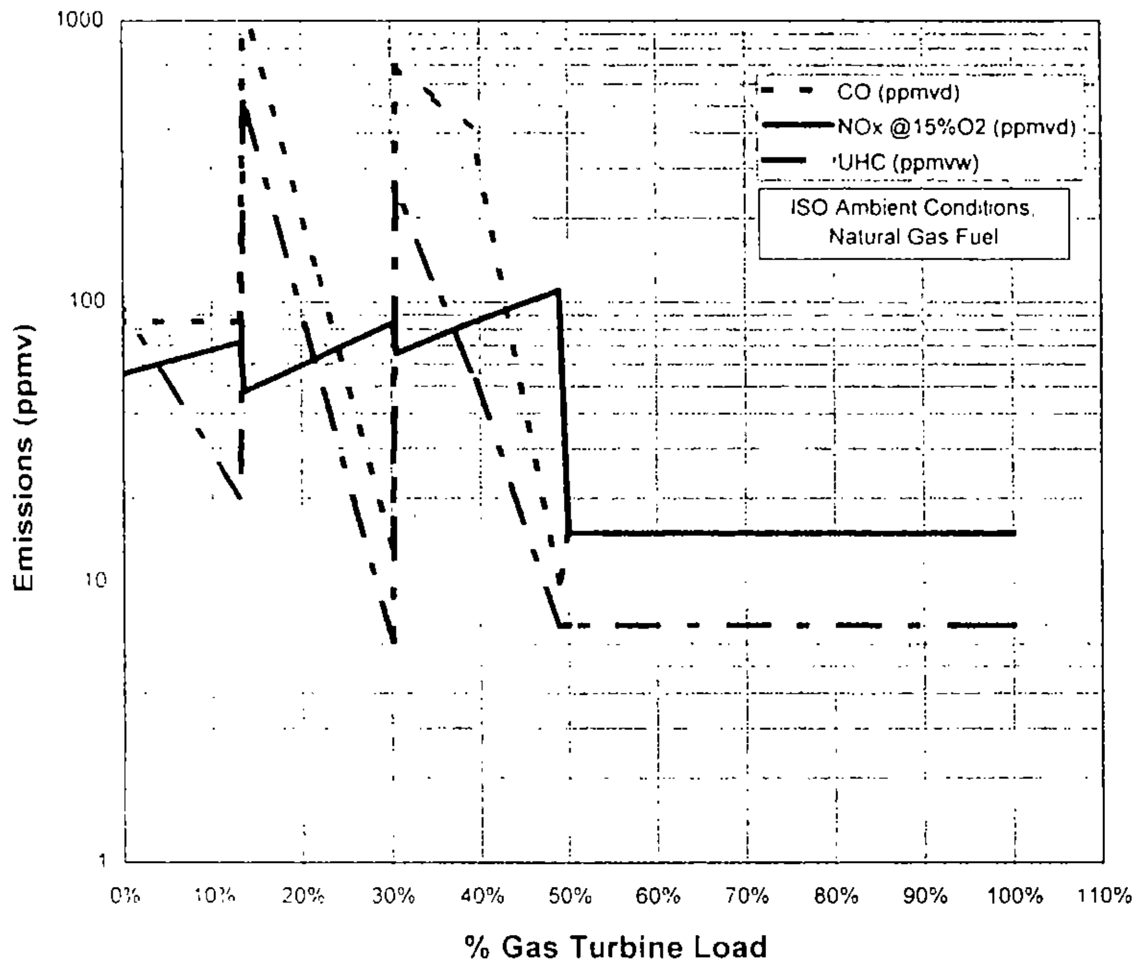


Figure 2 - Emissions Performance Curves for GE DLN-2.6 Combustor

Firing Natural Gas in a Dual Fuel GE 7FA Combustion Turbine

(Simple Cycle, Intermittent Duty - If Tuned to 15 ppm NOx)

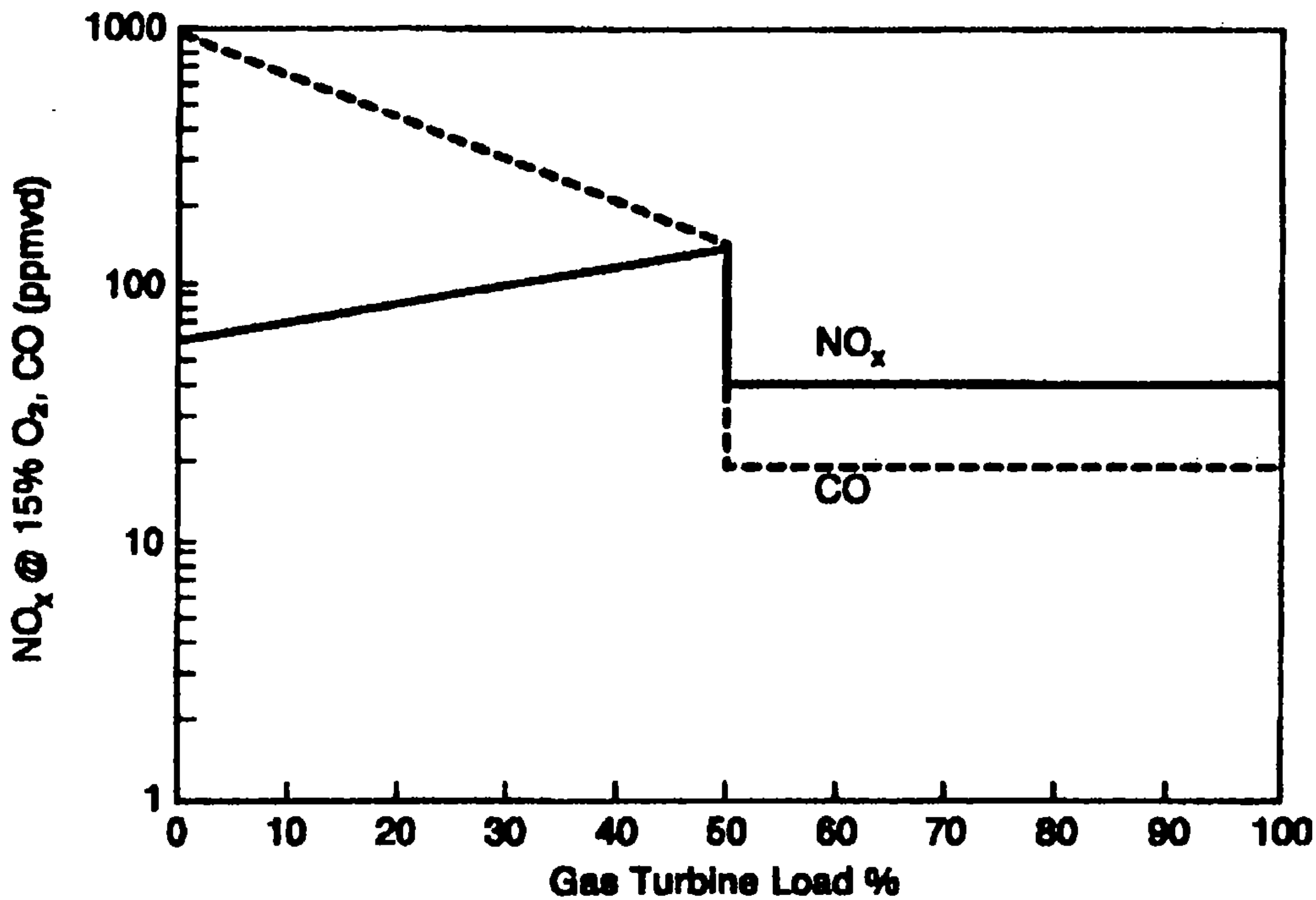


Figure 3 - Emissions Performance for DLN-2 Combustors

Firing Fuel Oil in Dual Fuel GE 7FA Turbine

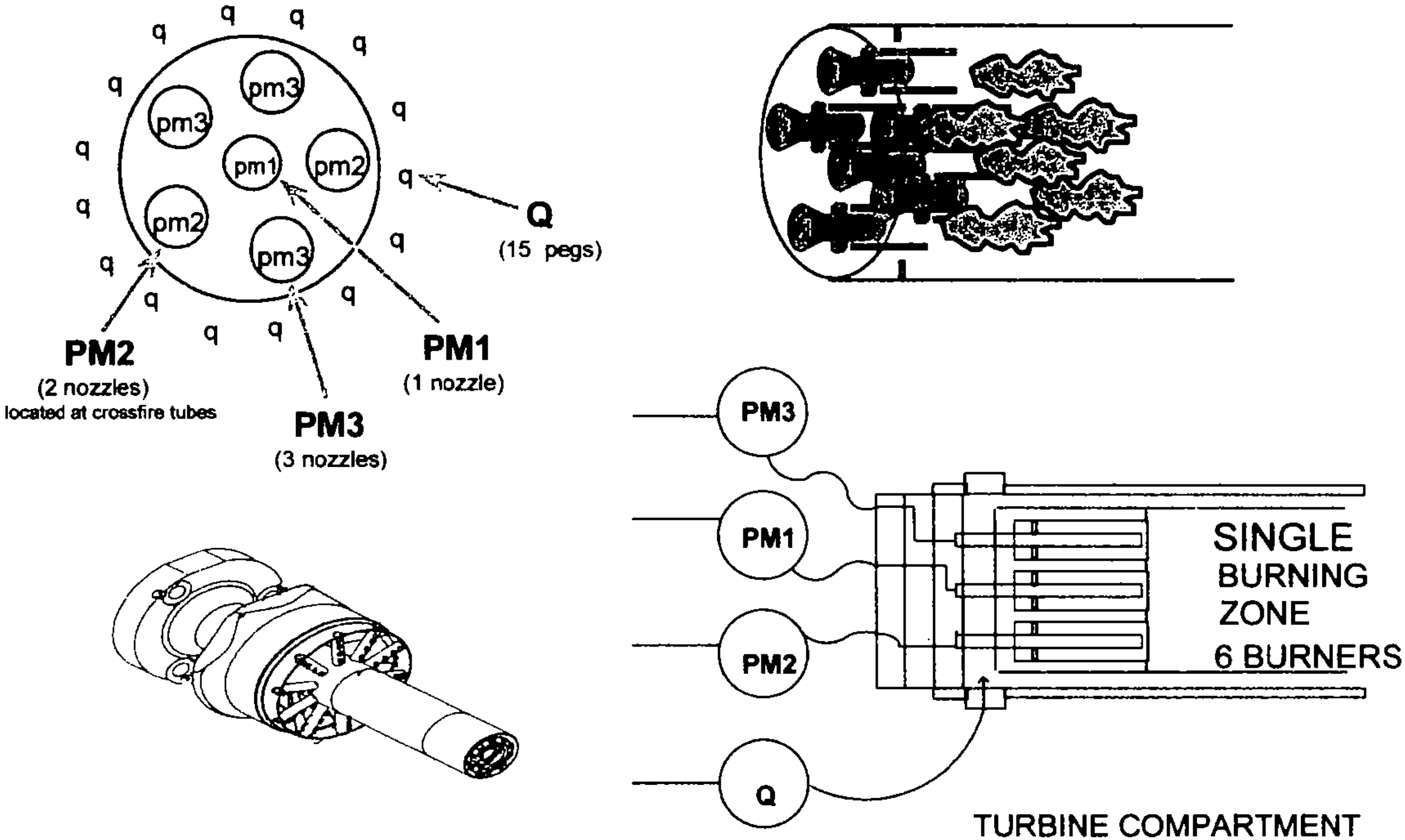


Figure 4 - DLN-2.6 Nozzle and Burner Arrangement

In all but the most recent gas turbine combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_X formation. Cooling is also required to protect the first stage nozzle. When this is accomplished by air cooling, the air is injected into the component and is ejected into the combustion gas stream, causing a further drop in combustion gas temperature. This, in turn, lowers achievable thermal efficiency for the unit.

Larger units, such as the Westinghouse 501 G or the planned General Electric 7H, use steam in a closed loop system to provide much of the cooling. The fluid is circulated through the internal portion of the nozzle component or around the transition piece between the combustor and the nozzle and does not enter the exhaust stream. Instead it is normally sent back to a steam generator. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained.

Another important result of steam cooling is that a higher firing temperature can be attained with no increase in flame temperature. Flame temperatures and NO_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures. At the same time, thermal efficiency should be greater when employing steam cooling. A similar analysis applies to steam cooling around the transition piece between the combustor and first stage nozzle.

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation can be appreciated from Figure 5 which is from a General Electric discussion on these principles. In addition to employing pre-mixing and steam cooling, further reductions are accomplished through design optimization of the burners, testing, further evaluation, etc.

At the present time, emissions achieved by combustion controls are low as 9 ppmvd from gas turbines smaller than 200 MW (simple cycle), such as GE "F Class" units. Even lower NO_X emissions are achieved from certain units smaller than 100 MW, such as the GE 7EA line.

Selective Catalytic Combustion

Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium or titanium oxide and account for almost all installations. For high temperature applications (Hot SCR up to 1100 $^{\circ}$F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date. SCR units are typically used in combination with wet injection or DLN combustion controls.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now available, however, and catalyst formulation improvements have proven effective in resisting performance degradation with fuel oil in Europe and Japan, where conventional SCR catalyst life in excess of 4 to 6 years has been achieved, versus 8 to 10 years with natural gas.

Excessive ammonia use tends to increase emissions of CO, ammonia (slip) and particulate matter (when sulfur bearing fuels are used).

As of early 1992, over 100 gas turbine installations already used SCR in the United States. Per the above table, only one combustion turbine project in Florida (FPC Hines Power Block 1) employs SCR (it is currently being started up). The equipment was installed on a temporary basis because Westinghouse had not yet demonstrated emissions as low as 12 ppmvd by DLN technology at the

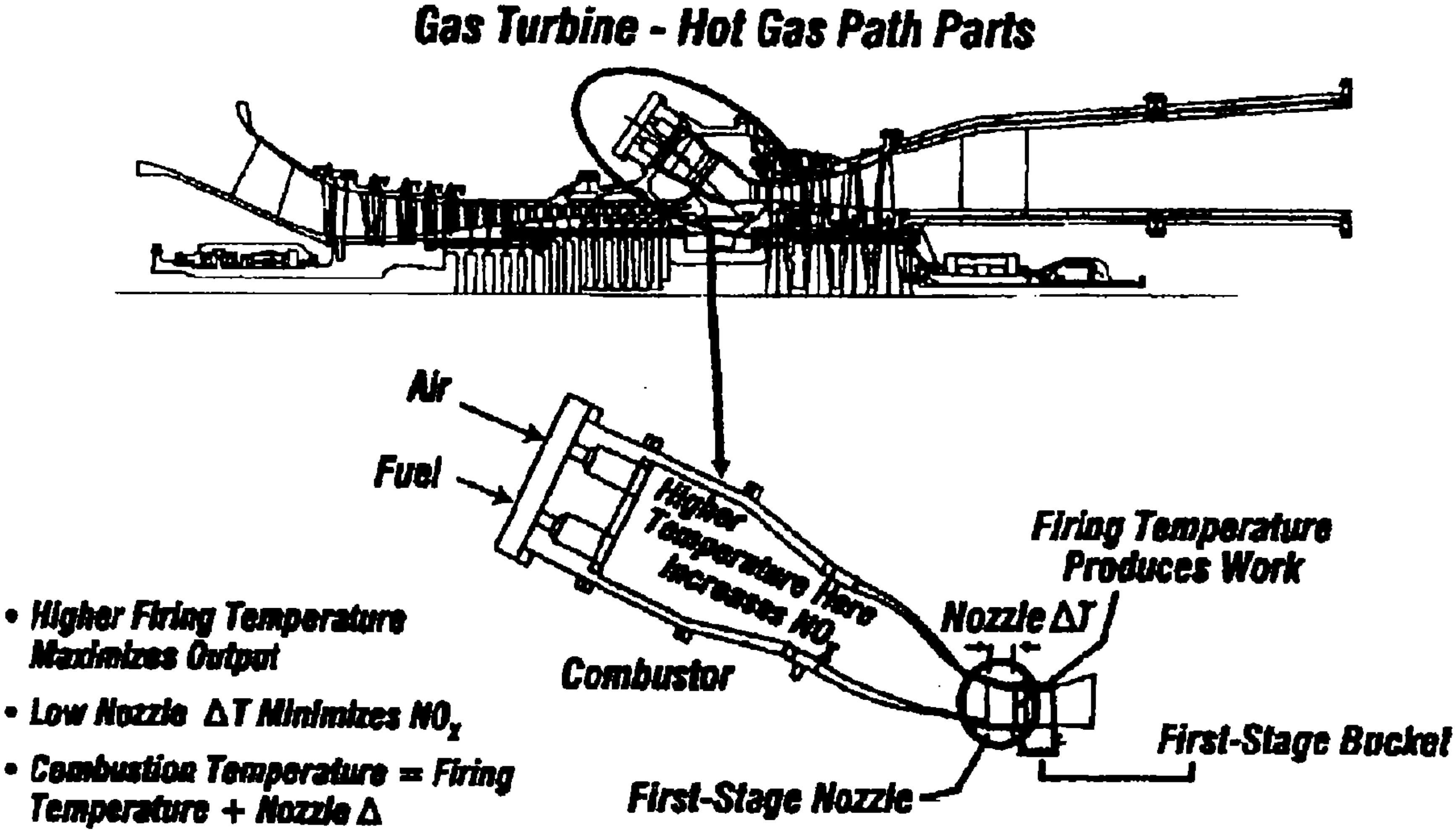


Figure 5 - Relation Between Flame Temperature and Firing Temperature

time the units were to start up in 1998. SCR is also proposed on a permanent basis for the expansion of the FPC Hines Facility (Power Block II). Seminole Electric will install SCR on a previously-permitted 501F unit at the Hardee Unit 3 project. The reasons are similar to those for the FPC Hines Power Block I.

Permit limits as low as 2.25 to 3.5 ppmvd NO_X have been specified using SCR on combined cycle F Class projects throughout the country.

Selective Non-Catalytic Combustion

Selective non-catalytic reduction (SNCR) reduction works on the same principle as SCR. The differences are that it is applicable to hotter streams than conventional or hot SCR, no catalyst is required, and urea can be used as a source of ammonia. No applications have been identified wherein SNCR was applied to a gas turbine because the exhaust temperature of 1100 °F is too low to support the NO_X removal mechanism.

The Department did, however, specify SNCR as one of the available options for the combined cycle Santa Rosa Energy Center. The project will incorporate a large 600 MMBtu/hr duct burner in the heat recovery steam generator (HRSG) and can provide the acceptable temperatures (between 1400 and 2000 °F) and residence times to support the reactions.

Emerging Technologies: SCONOX™ and XONON™

There are at last two technologies on the horizon that will influence BACT determinations. These, as usual, are prompted by the needs specific to non-attainment areas such as Southern California.

The first technology is called $SCONO_X$™ and is a catalytic technology that achieves NO_X control by oxidizing and then absorbing the pollutant onto a honeycomb structure coated with potassium carbonate. The pollutant is then released as harmless molecular nitrogen during a regeneration cycle that requires a dilute hydrogen reducing gas. The technology has been demonstrated on small units in California and has been purchased for a small source in Massachusetts.[1] California regulators and industry sources have stated that the first 250 MW block to install SCONOx ™ will be at U.S. Generating's La Paloma Plant near Bakersfield.[2] The overall project includes several more 250 MW blocks with SCR for control.[3] USEPA has identified an "achieved in practice" BACT value of 2.0 ppmvd over a three-hour rolling average based upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle turbine (without duct burners) equipped with the patented SCONOx™ system

SCONOx™ technology (at 2.0 ppmvd) is considered to represent LAER in non-attainment areas where cost is not a factor in setting an emission limit. It competes with less-expensive SCR in those areas, but has the advantages that it does not cause ammonia emissions in exchange for NO_X reduction. Advantages of the SCONOx ™ process include in addition to the reduction of NO_X, the elimination of ammonia and the control of some CO emissions. SCONOx™ has not been applied on any major sources in ozone attainment areas.

In a letter dated March 23, 1998 to Goal Line Environmental Technologies, the SCONOx™ process was deemed as technically feasible for maintaining NO_X emissions at 2 ppmvd on a combined cycle unit. ABB Environmental was announced on September 10, 1998 as the exclusive licensee for SCONOx™ for United States turbine applications larger than 100 MW. ABB Power Generation has stated that scale up and engineering work will be required before SCONOx™ can be offered with commercial guarantees for large turbines (based upon letter from Kreminski/Broemmelsiek of ABB Power Generation to the Massachusetts Department of Environmental Protection dated November 4, 1998). SCONOx requires a much lower temperature regime that is not available in simple cycle units and is therefore not feasible for this project. Therefore the SCONOx system cannot be considered as achievable or demonstrated in practice for this application.

The second technology is XONON™, which works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO_X combustion) followed by flameless catalytic combustion to further attenuate NO_X formation. The technology has been demonstrated on combustors on the same order of size as $SCONO_X$ ™ has. However GE has teamed with Catalytica to develop a combustor for gas turbines in the 80-90 MW range before continuing with development on a combustor for a larger unit.

XONON™ avoids the emissions of ammonia and the need to generate hydrogen. It is also extremely attractive from a mechanical point of view if it works.

Catalytica Combustion Systems, Inc. develops, manufactures and markets the XONON™ Combustion System. In a press release on October 8, 1998 Catalytica announced the first installation of a gas turbine equipped with the XONON™ Combustion System in a municipally owned utility for the production of electricity. The turbine was started up on that day at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, Calif. The XONON™ Combustion System, deployed for the first time in a commercial setting, is designed to enable turbines to produce environmentally sound power without the need for expensive cleanup solutions. Previously, this XONON™ system had successfully completed over 1,200 hours of extensive full-scale tests which documented its ability to limit emissions of nitrogen oxides, a primary air pollutant, to less than 3 parts per million.

Catalytica's XONON™ system is represented as a powerful technology that essentially eliminates the formation of nitrogen oxides air emissions in gas turbines without impacting the turbine's operating performance. In a definitive agreement signed on November 19, 1998, GE Power Systems and Catalytica agreed to cooperate in the design, application, and commercialization of XONON™ systems for both new and installed GE E-class and F-class turbines used in power generation and mechanical drive applications. This appears to be an up-and-coming technology, the development of which will be watched closely by the Department for future applications. It is not yet available for fuel oil and cycling operation.

REVIEW OF SULFUR DIOXIDE (SO_2) AND SULFURIC ACID MIST (SAM)

SO_2 control processes can be classified into five categories: fuel/material sulfur content limitation, 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 contained in the BACT Clearinghouse shows that the exclusive use of low sulfur fuels constitutes the top control option for SO_2.

For this project, the applicant has proposed as BACT the use of 0.05% sulfur oil and natural gas containing no more than 2 grains of sulfur per 100 standard cubic foot (gr S/100 ft^3). This value is well below the "default" maximum value of 20 gr. S/100 ft^3, but high enough to require a BACT determination. The applicant estimated total emissions for the project at 126 TPY of SO_2 and 15 TPY of SAM. However the Department expects the emissions to be lower because of the limited oil consumption and the typical natural gas in Florida which contains less than 1 gr S/100ft^3.

REVIEW OF PARTICULATE MATTER (PM/PM_{10}) CONTROL TECHNOLOGIES:

Particulate matter is generated by various physical and chemical processes during combustion and will be affected by the design and operation of the NO_X controls. The particulate matter emitted from this unit will mainly be less than 10 microns in diameter (PM_{10}).

Natural gas and 0.05 percent sulfur No. 2 (or superior grade) distillate fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Such fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash The fuel oil to be combusted contains a minimal amount of ash and its use is proposed for only 876 hours per year making any conceivable add-on control technique for PM/PM_{10} either unnecessary or impractical.

A technology review indicated that the top control option for PM/PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air. Total annual emissions of PM_{10} for the project are expected to be approximately 54 tons per year.

REVIEW OF CARBON MONOXIDE(CO) CONTROL TECHNOLOGIES

CO is emitted from combustion turbines due to incomplete fuel combustion. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. The most stringent control technology for CO emissions is the use of an oxidation catalyst.

All combustion turbines using catalytic oxidation appear to be combined cycle units. Among the most recently permitted ones are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millenium in Massachusetts, and Sutter Calpine in California. The permitted CO values of these units are between 3 and 5 ppmvd. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review which would have been required due to increased operation at low load. Seminole Electric recently proposed catalytic oxidation in order to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.[4]

Most combustion turbines incorporate good combustion to minimize emissions of CO. So far this appears to be the only technology proposed at simple cycle turbine projects. These installations typically achieve emissions between 10 and 25 ppm at full load while firing gas. The values of 15 and 33 ppm for gas and oil respectively at baseload proposed in the TEC's original application are within the range of recent determinations for simple cycle CO BACT determinations. By comparison, values of 12 and 20 ppm for gas and oil respectively (at baseload) were proposed for the Oleander's project using identical equipment Values given in GE-based applications are representative of operations between 50 and 100 percent of full load.

REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. There are no viable add-on control techniques as the combustion turbine itself is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC. The limits proposed by TEC for this project are 1.4 and 3.5 ppm for gas and oil firing respectively. According to GE, VOC emissions less than 1.4 ppm were achieved during recent tests of the DLN-2.6 technology when firing natural gas.[5] At such low emission rates, the project does not trigger PSD and a requirement for a VOC BACT determination. Emissions as low as projected by TEC and GE would easily meet BACT requirements based on the above tables.

BACKGROUND ON SELECTED GAS TURBINE

TEC plans the purchase of two 165 MW (nominal) General Electric PG 7241FA simple cycle gas turbines. This is the most recent designation of GE's line of "F" Class units.

The first commercial GE 7F Class unit was installed in a combined cycle project at the Virginia Power Chesterfield Station in 1990.[6] The initial units had a firing temperature of 2300 °F and a combined cycle efficiency exceeding 50 percent. By the mid-90s, the line was improved by higher combustor pressure, a firing temperature of 2400 °F, and a combined cycle efficiency of approximately 56 percent based on a 167 MW combustion turbine. The line was redesignated as the 7FA Class.

The first GE 7F/FA project in Florida was at the FPL Martin Plant in 1993 and entered commercial service in 1994.[7] The units were equipped with DLN-2 combustors with a permitted NO_X limit of 25 ppmvd. These actually achieved emissions of 13-25 ppmvd of NO_X, 0-3 ppm of CO, and 0-0.17 ppm of VOC.[8] The City of Tallahassee recently received approval to install a GE 7FA Class unit at its Purdom Plant.[9] Although permitted emissions are 12 ppmvd of NO_X, the City obtained a performance guarantee from GE of 9 ppmvd.[10] FPL also obtained a guarantee and permit limit of 9 ppmvd NO_X for six GE 7241FA turbines to be installed at the Fort Myers Repowering project.[11] The Santa Rosa Energy Center in Pace, Florida, also received a permit with a 9 ppmvd NO_X limit for a GE 7241 turbine with DLN-2.6 burners.[12]

Most recently, the Department issued draft BACT determinations for the simple cycle Oleander project in Brevard County and the combined cycle projects in Volusia (Duke Energy) and Osceola County (Kissimee Utilities). These three draft permits also include NO_X limits of 9 ppmvd based on the DLN-2.6 technology installed on F Class units.

General Electric has primarily relied on further advancement and refinement of DLN technology to provide sufficient NO_X control for their combined cycle turbines in Florida. Where required by BACT determinations of certain states, General Electric incorporates SCR in combined cycle projects.[13] In its recent permits, Florida has included separate and lower limits in the event that DLN emissions limits are not attainable or the applicant selects a manufacturer that does not provide combustors capable of meeting 9 ppmvd.

GE's approach of progressively refining such technology is a proven one, even on some relatively large units. Recently GE Frame 7FA units met performance guarantees of 9 ppmvd with "DLN-2.6" burners at Fort St. Vrain, Colorado and Clark County, Washington.[14] Although the permitted limit is 15 ppmvd, GE has already achieved emission levels of approximately 6-7 ppmvd on gas at a dual-fuel 7EA (120 MW combined cycle) KUA Cane Island Unit 2.[15] Unit 2 is equipped with DLN-2 combustors. According to GE, similar performance is expected soon on the 7FA line such as the one that will be installed for TEC Polk Power Station Project. Performance guarantees less than 9 ppmvd can be expected using the DLN-2.6 combustors for units delivered in a couple of years.[16]

The 10.5 ppmvd NO_X limit on natural gas requested by TEC is clearly one of the most stringent BACT determinations for simple cycle F Class. In fact, the company obtained a guarantee from GE to achieve 9 ppmvd. However GE's guarantee is for a performance test on a "new and clean unit." The test must be conducted at a steady-state load of 50 to 100 percent and completed within the first 100 fired hours of operation as specified in the GE protocols.

With the frequent start-ups and shutdowns of the unit, TEC is concerned about the ability to maintain the low NO_X values for long periods of time following the performance tests. The Department is not aware of the details of the GE guarantee for Oleander who proposed 9 ppmvd on a simple cycle unit.

However, the Department is aware from discussions with other applicants that a continuing guarantee is available at a substantial cost.[17]

The GE Speedtronic™ Mark V Gas Control System will be used. This control system is designed to fulfill all gas turbine control requirements. These include control of liquid, gas, or both fuels in accordance with the requirements of the speed, load control under part-load conditions, temperature control under maximum capability conditions, or during start-up conditions. Since emissions are controlled utilizing dry low NO_X techniques, fuel staging and combustion mode are also controlled by the Mark V, which also monitors the process. Sequencing of the auxiliaries to allow fully automated start-up, shutdown and cool-down are also handled by the Mark V.[18]

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the TEC project assuming full load. Values for NO_X are corrected to 15% O_2 on a dry volume basis. The emission limits or their equivalents in terms of pounds per hour and NSPS units, as well as the applicable averaging times, are given in the permit Specific Conditions No. 18 through 23.

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	10 Percent Opacity (gas or oil)
VOC	As Above	1.4 ppmvw – Gas (non-BACT) 3.5 ppmvw– Fuel Oil (non-BACT)
CO	As Above	12 ppmvd – Gas 20 ppmvd – Fuel Oil
SO_2/SAM	As Above	2 grains of sulfur per 100 ft^3 gas 0.05 percent sulfur in fuel oil
NO_X	Dry Low NO_X, WI for F.O., limited oil use	10.5 ppmvd – Gas 42 ppmvd – Fuel Oil for 750 hours

RATIONALE FOR DEPARTMENT'S DETERMINATION

- General Electric has provided a "clean and new" guarantee of 9 ppmvd NO_X.
- A level of 9 ppmvd NO_X by DLN has been demonstrated on GE 7FA combustion turbines at Fort St. Vrain, Colorado and Clark County, Washington.
- The proposed 9 ppmvd limit at Oleander while firing natural gas is the lowest known Draft BACT value for an "F" frame combustion turbine operating in simple cycle mode and intermittent duty. The 42 ppmvd limit while firing fuel oil is typical.
- The proposed 10.5 ppmvd limit at TEC while firing natural gas is the next lowest Draft BACT value for an F Class simple cycle, intermittent duty unit. The Department will still require TEC to meet to meet the "clean and new" limit of 9 ppmvd during initial testing.
- The proposed BACT limit of 10.5 ppmvd is about one-tenth of the applicable NSPS limit per 40 CFR 60, Subpart GG for units as efficient as the 7FA.
- Typical permit limits nation-wide for these units while operating in simple cycle mode and intermittent duty are 12-15 ppmvd. Limits as high as 25 ppmvd have been recently proposed by some states. The lower limit at TEC will offset emissions while firing fuel oil. Also TEC will operate fewer hours of operation on oil than Oleander. This will help offset the slightly higher emissions on gas from the TEC project compared to Oleander.

- The units will be operated in simple cycle mode. Therefore control options, which are feasible for combined cycle units, are not applicable. This rules out Low Temperature (conventional) SCR, which achieves 4.5 ppmvd NO_X or lower. It also rules out the possibility of SCONOx. XONON is not available for F Class dual fuel projects.
- The simple cycle "F Class" turbines have very high exhaust temperatures of up to 1200 °F. This is at the higher limit of the present operational temperature of Hot SCR zeolite catalyst (around 1050 °F). The PREPA simple cycle turbines, which use Hot SCR, have exhaust temperatures ranging from 824 to 1024 °F.
- The levelized costs of NO_X removal by Hot SCR for the TEC project were estimated by Environmental Consulting & Technology at $9,717 per ton of NO_X removed assuming 4,380 and 876 hours per year of operation on gas and oil respectively. This cost-effectiveness value assumes a NO_X reduction from 10.5 ppmvd to 3.5 ppmvd @15% O_2 and a <u>3-year performance guarantee</u>.
- Using much of the basic capital cost information developed by the City of Lakeland, The National Park Service estimated the cost of NO_X removal by Hot SCR at $3,802 per ton (excluding the energy penalty) for a *continuous duty* Westinghouse 501 G. A further refinement of the Park Service estimate by including the energy penalty, using the revised catalyst cost data obtained by the Department, and assuming a five year <u>estimated</u> life for the catalyst (per Engelhard's Lakeland quote) would yield a cost-effectiveness closer to $3,500 per ton of NO_X removed for that application. However the cost at the Lakeland project was based on reducing NO_X emissions by 16 ppmvd (from 25 ppmvd to 9 ppmvd). This fact and the difference in hours of operation are the main contributors to the difference in costs between the Lakeland and TEC projects.
- The cost effectiveness for NO_X removal given for the PREPA simple cycle project is $2,200 per ton. This is the only reasonably large project where Hot SCR has actually been installed. The main reason for the relatively low levelized cost is that total costs are applied over a reduction of 40 ppmvd and 8760 hours, whereas the reduction in the TEC case is over a reduction of 7 ppmvd and half the hours. The cost per ton of NO_X removed by Hot SCR at the PREPA project or projected at Lakeland can be re-scaled for the TEC project. This would result in a value on the order of ECT's projections.
- Although the Department does not have a "bright line" cost-effectiveness figure, the values projected by TEC indicate Hot SCR is not cost-effective for this project.
- Comments from the National Park Service on the Oleander project suggested that a reduction in the applicant's proposed NO_X emissions on oil from 42 ppmvd to 25ppmvd is possible based two reported oil-fired units listed in the BACT Clearinghouse. One of the two units cited is a Florida facility that initially had a limit of 25 ppmvd for gas firing. The present limits are 15 ppmvd on gas and 42 ppmvd on oil. The Department has been unable to confirm the report on the second unit. GE has advised that it only offers a 42 ppmvd NO_X guarantee on F Class units when firing oil.

- It is conceivable that NO_X emissions while firing oil from may be reduced from 42 ppmvd by increasing the water injection rate or even by development of a DLN oil burner. In order to address this possibility, a specific condition will be added to conduct appropriate testing and prepare an engineering report. The report will be submitted for the Department's review to ensure that the lowest reliable NO_X emission rates while firing oil are been achieved with the installed technology.
- The Department's overall BACT determination is equivalent to approximately 0.3 lb/MW-hr by Dry Low NO_X. For reference, the new NSPS promulgated on September 3, 1998 requires that new conventional power plants (based on boilers, etc.) meet a limit of 1.6 lb/MW-hr.
- VOC emissions of 1.4 and 3.5 ppm while firing gas or oil proposed by the applicant clearly reflect BACT and, in fact, exempt the project from a BACT determination for VOC.
- The Department will set CO limits achievable by good combustion as 12 ppm (gas) and 20 ppm (oil). These values are equal to the lowest values from permitted or proposed simple cycle units. These limits are equal to those of the Oleander project.
- ECT evaluated the use of an oxidation catalyst with a 90 percent control efficiency and having a three-year catalyst life. The oxidation catalyst control system was estimated to increase the capital cost of the project by $1,921,133 with an annualized cost of $515,433 per year. Levelized costs for CO catalyst control were calculated at $3.652 per ton to control CO emissions to 30.2 TPY (from a baseline of 303 TPY). This figure does not appear to be cost-effective for removal of CO.
- BACT for PM_{10} was determined to be good combustion practices consisting of: inlet air filtering; use of pipeline natural gas; use of clean, low ash, low sulfur fuels, and operation of the unit in accordance with the manufacturer-provided manuals.
- PM_{10} emissions will be very low and difficult to measure. Additionally, the higher emission mode will involve fuel oil firing which will occur only approximately 750 hours per year. It is not practical to require running the turbine on oil, simply to conduct tests. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT for both natural gas and fuel oil firing, consistent with the definition of BACT. Examples of installations with similar VE limits include the City of Lakeland, the City of Tallahassee, Santa Rosa Energy Center, FPL Fort Myers, and the Southern Company Barry projects.

COMPLIANCE PROCEDURES

POLLUTANT	COMPLIANCE PROCEDURE
Visible Emissions	Method 9
Volatile Organic Compounds	Method 18, 25, or 25A (initial tests only)
Carbon Monoxide	Annual Method 10 (can use RATA if at capacity)
NO_X (performance)	Annual Method 20 (can use RATA if at capacity)
NO_X (24-hr average)	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed
SO_2 and SAM	Custom Fuel Monitoring Schedule

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

A. A. Linero, P.E. Administrator, New Source Review Section
Teresa Heron, Review Engineer, New Source Review Section

Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:

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

Date: 10/6/99

Approved By:

Howard L. Rhodes
Howard L. Rhodes, Director
Division of Air Resources Management

Date: 10/6/99

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Florida Department of

Memorandum Environmental Protection

BAR

TO: Howard L. Rhodes

THRU: Clair Fancy

FROM: Al Linero
Teresa Heron T.H.

DATE: September 28, 1999

SUBJECT: TEC Polk Power Station
Two 165 MW Combustion Turbines
DEP File No. PSD-FL-263 and PA 92-32

Attached is the final permit package for construction of two dual-fuel, intermittent duty, simple cycle 165 MW combustion turbines at the TECO Polk Power Station

Nitrogen Oxides (NO_X) emissions from the gas turbine will be controlled by Dry Low NO_X (DLN-2.6). We propose to require that the unit meet the manufacturer's <u>new and clean</u> (one-shot) guarantee of 9 ppm, and a <u>continuous</u> (24-hour averaged) emission limit of 10.5 ppm. However, we will limit use of fuel oil from the 876 hours requested to 750 hours. We can raise the figure to the requested value if TECO subsequently demonstrates continuous operation at 9 ppm instead of 10.5 ppm.

NO_X emissions will be controlled to 42 ppm during the limited fuel oil use. Emissions of carbon monoxide, volatile organic compounds, sulfur dioxide, sulfuric acid mist, and particulate matter (PM/PM_{10}) will be very low because of the inherently clean pipeline quality natural gas, limited fuel oil use and, especially, the design of the GE unit.

Recent simple cycle emission limits in Region IV have typically been at 15 ppm for simple cycle "F Class" units. In fact, North Carolina recently issued a draft BACT to Dynegy for six dual-fuel Westinghouse "F Class" units with limits of 25 ppm. The Dynegy Westinghouse units must meet 15 ppm by early 2002.

For reference, the draft BACT requested by Oleander is a <u>continuous</u> limit of 9 ppm. Oleander will be allowed to operate on fuel oil for 1000 hours instead of the 2000 hours they requested (or the 750 hours to which TECO will be limited). Oleander is either more willing than TECO to take a risk on continuous compliance or more willing to pay for a continuing guarantee. Oleander's parent company, Constellation, included an identical simple cycle project for its planned High Desert Project in California where LAER is required. They undoubtedly tried to get them permitted for the lowest emission rate while avoiding SCR. When they shifted the simple cycle option to the Florida site, they decided to propose 9 ppm.

Our approach is sensible and our limit on fuel oil will provide some equity between the two determinations. It provides some flexibility in the way companies decide to manage the inherent risk in accepting low NO_X limits on simple cycle intermittent duty units when there is no feasible "fall-back" technology alternative (such as conventional SCR for combined cycle units).

We recommend your approval of the attached Intent to Issue.

AAL/th

Attachments

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SENDER:
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- Complete items 3, 4a, and 4b.
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PS Form **3800**, April 1995