Airborne Gypsum Quill #
0040559293 846

RECEIVED

JUN 23 1992

Bureau of
Air Regulation

Florida Power
CORPORATION

June 19, 1992

Mr. C. H. Fancy, P.E., Chief
Bureau of Air Regulation
Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Rd.
Tallahassee, Florida 32399-2400

Re: University of Florida Cogeneration Project
Permit No. AC 01-204652, PSD-FL-181

Dear Mr. Fancy:

On June 8, 1992, Florida Power Corporation (FPC) received the draft air permit for the above referenced facility. Based upon discussions between the Florida Department of Environmental Regulation (FDER) and FPC, it was agreed that a meeting would be held in Tallahassee to discuss several of the draft permit conditions. At your direction, this letter serves to transmit FPC's understanding of the conclusions and agreements reached at our subsequent June 17, 1992 meeting. In addition, please find attached a revision of the draft permit which incorporates FPC's understanding, as discussed in the following paragraphs.

Specific Condition 2. This conditon lists all emission limits, by pollutant and source type, not to be exceeded. Based upon discussions at the June 17, 1992 meeting, the draft permit combustion turbine (CT) SO_2 limits were determined to be inappropriate. Previously, the limit for the turbine was suggested as BACT; however, at the requested emission limit of 0.5 percent sulfur, there will be a net reduction of SO_2 emissions. FDER had accepted the net reduction of SO_2 emissions using 0.5 percent sulfur in their BACT analysis and project description and correctly concluded that PSD review was not applicable.

Second, regarding Boilers 4 and 5, the small fossil fuel steam generator emission limit (FDER Rule 17-2.600(6)F.A.C.) is applicable to new and existing sources with a heat input of less than 250 million BTU/hr unless otherwise specified by rule or by order or permit issued by FDER prior to July 15, 1989. The latter indicates that the rule does not apply if limits are established by permit prior to July 15, 1989. As indicated in conditions of the current air permits for Boilers 4 and 5, a BACT determination was made September 24, 1987 and indicated a 1.5 percent sulfur limit. The requested permit does not indicate any modification of the boilers, except lowering the fuel usage and sulfur content (to 0.5 percent). FPC agrees to accept a limit on Boilers 4 and 5 of 0.5 percent fuel oil sulfur.

The same comments apply for FDER's suggested visible emissions (VE) limit. The turbine VE limit is the same as the recent FDER BACT determinations for the Lake and Pasco Cogen permits. However, while those projects were subject to a BACT determination for particulates and opacity, this project is not. Similarly, as stated above, FPC believes that a BACT determination on opacity for the existing boilers is inappropriate. During our meeting, an agreement was reached allowing 10 percent opacity for the combustion turbine (CT) and boilers while firing natural gas, 20 percent opacity for the CT and boilers while firing fuel oil, and an allowance to 27 percent opacity for the CT and boilers during startups, shutdowns and load swings.

Specific Condition 3. This condition seems inconsistent given the use of heat input (i.e., million BTU) in previous permits. Maximum annual heat inputs for the CT, duct burner, and boilers were provided by FPC to FDER in a revised application submittal dated March 5, 1992. Regarding the footnotes to S.C. 3, FPC had requested the allowance for trading oil operation for natural gas; however, Specific Condition 2 does not provide this allowance. This can be accomplished through limiting the annual emissions in S.C. 2 to the total emissions of the turbine firing natural gas and oil, and the duct burner firing natural gas. In addition, footnotes 3 and 4 have been added to the table in S.C. 3 allowing operating flexibility.

Specific Condition 4. There are no emission limits for Boilers 4 and 5 for either NO_x or CO. Therefore, this reference was removed. Concerning the combustion turbine, FDER practice has allowed testing of 90 percent or greater of permitted capacity in current permits. In order to allow the necessary flexibility for real-world operation and testing conditions, the condition was revised to read:"...between 90 and 100 percent of permitted capacity during compliance testing, as adjusted for ambient temperature."

Specific Condition 6. This condition should be eliminated; such a condition is vague and, to the best of our knowledge, has never been in any previous permits issued by FDER.

Specific Condition 7. There is no requirement in the NSPS to monitor <u>power output</u>. Therefore, this reference was removed.

Specific Condition 8. The reference to NO_x was modified as BACT review for NO_x was not performed. The references for reviewing BACT for CO were modified consistent with that contained in the Lake and Pasco Cogen permits. Further, the CO duct burner limit was revised to be consistent with that proposed in other recent permits for identical machines (0.2 lb/million BTU).

Specific Condition 9. The language in this condition was changed to read: "...cease operation upon receipt of the operating permit for the cogeneration facility."

Regarding the appropriateness of FDER requiring a duct module for NO_x, FDER's authority for establishing specific permit conditions is contained in Rule 17-4.070. In establishing any specific condition, such condition must be "necessary to provide reasonable assurance that department rules can be met" (Rule 17-4.070(3)F.A.C.). The requirement for a duct module must meet this test. FPC believes that reasonable assurance was provided that the proposed limit would be met through manufacturer guarantees. No other permit that is not undergoing BACT has had such a limit. The requirement for a duct module is clearly unreasonable and does not meet the necessary test of the FDER rules.

FPC appreciates the opportunity to present our concerns for discussion and we look forward to issuance of a revised draft permit. As we discussed, FPC would like to submit the revised draft for publication by the end of this month.

Sincerely,

[signature] for

W. Jeffrey Pardue, Manager
Environmental Programs

cc: Preston Lewis, FDER-Tallahassee
J. Reynolds
C. Holladay
A. Kutyna, NE Dist.
J. Harper, EPA
C. Shaver, NPS

SPECIFIC CONDITIONS:

1. Unless otherwise indicated, the construction and operation of the subject cogeneration facility shall be in accordance with the capacities and specifications stated in the application.

2. Emissions from this facility shall not exceed the limits listed below:

Pollu-tant	Source	Fuel	Basis of Limit	lbs./hr	tons/yr.[2]
NOx	Turbine	Gas	EBM[1]:25 ppmvd @ 15% 02	35.0	142.7
	Turbine	Oil	EBM[1]:42 ppmvd @ 15% 02	66.3	7.3
	D.Burner	Gas	EBM[1]:0.1 lb/MMBTU	18.7	24.6
SO2	Turbine	Oil	~~BACT:0.1%~~ Sulfur Max. EBA[1]0.5%	-	-
	Boiler 4	Oil	~~BACT:0.1%~~ Sulfur Max. EBA[1]0.5%	-	-
	Boiler 5	Oil	~~BACT 0.1%~~ Sulfur Max. EBA[1]0.5%	-	-
VE[3]	Turbine	Gas/Oil	Equivalent of mass EBM[1]		~~10% opacity~~ 10%/20% opacity
	D.Burner	Gas	" " "		10% opacity
	Boiler 4	Gas/Oil	" " "		~~10% opacity~~ 10%/20% opacity
	Boiler 5	Gas/Oil	" " "		~~10% opacity~~ 10%/20% opacity
CO	Turbine	Gas	BACT:42 ppmvd	~~38.8~~ 69.5	~~158.0~~ 282.1
	Turbine	Oil	~~EBA[1]~~BACT :75 ppmvd	70.5	7.7
	D.Burner	Gas	BACT:0.2 lb/MMBTU	28.1	36.9

(1) EBM: Established by manufacturer
EBA: Established by applicant

(2) An additional 1.9 hours/yr operation on natural gas will be allowed for each 1.0 hour/yr that fuel oil is not burned (up to 219 x 1.9 hours/yr).

(3) Allowable VE's during startup, shutdown, and load swings is 27%

3. Fuel consumption rates and hours of operation shall not exceed those listed below:

	NATURAL GAS			NO. 2 FUEL OIL		
	Mft.^{3}/hr[1]	MM ft.^{3}/yr	hrs./yr[1]	M gal./hr[1]	M gal./yr	hrs./yr[2]
Turbine	367.9	2997.2[2]	8146.8[2]	2.9	635.1[2]	219.0[2]
Duct Burner	197.7	519.5	2628.00	0	0	
~~Boiler No. 4~~	~~67.0~~	~~10.1~~	~~150.0~~	~~0.5~~	~~7.6~~	~~15.2~~
Boiler No. 4	67.0	20.0[4]	150.0	0.5	15.0[3]	15.2
~~Boiler No. 5~~	~~160.0~~	~~63.4~~	~~396.0~~	~~1.1~~	~~25.3~~	~~23.0~~
Boiler No. 5	160.0	125.0[4]	396.0	1.1	50.0[3]	23.0

(1) Based on maximum firing rates. Units may run at lower rates for more hours within annual fuel limits.

(2) An additional 1.9 hours/yr operation on natural gas will be allowed for each 1.0 hour/yr that fuel oil is not burned (up to 219 x 1.9 hours/yr).

(3) The usage of oil for boilers 4 and 5 may be increased by 0.96 gallons of oil for every gallon not burned in the turbine. The total amount of oil used in the turbine will be reduced by this amount.

(4) The usage of natural gas for boilers 4 and 5 may be increased by 0.34 cubic feet for every cubic foot not burned in the burbine. The total amount of natural gas used in the turbine will be reduced by this amount.

4. Before this construction permit expires, the cogeneration facility ~~and Central Heat Plant (Boilers 4 and 5)~~ stack shall be sampled according to the emission limits in Specific Condition No. 2. Annual compliance tests shall be conducted each year thereafter. ~~Compliance tests shall be run at 100% of permitted capacity.~~ The source shall operate between 90 and 100 percent of permitted capacity during compliance testing as adjusted for ambient temperature. Tests shall be conducted using the following reference methods:

NO_X: EPA Method 20
SO_2: Fuel supplier's sulfur analysis
VE: EPA Method 9
CO: EPA Method 10

5. The DER Northeast District office shall be notified at least 30 days prior to the compliance tests. Compliance test results shall be submitted to the DER Northeast District office and the Bureau of Air Regulation office within 45 days after completion of the tests. Sampling facilities, methods, and reporting shall be in accordance with F.A.C. Rule 17-2.700 and 40 CFR 60, Appendix A.

~~6. Within 60 days of receipt of the compliance test results, the DER Bureau of Air Regulation in Tallahassee will re-evaluate the BACT determination.~~

~~7.~~6. ~~A continuous operations monitoring system shall be installed, operated, and maintained in accordance with 40 CFR 60.334. The natural gas, fuel oil and steam injection flows to the cogeneration turbine along with the power output of the generator shall be metered and continuously recorded.~~ The water/steam to fuel ratio at which compliance is achieved shall be incorporated into the operation permit and shall be continuously monitored. The data shall be logged daily and maintained so that it can be provided to DER upon request.

~~8.~~7. ~~The permittee shall include in the initial construction adequate modules and other provisions necessary for future installation of state-of-the-art catalytic abatement or equivalent CO and NO_x control systems. Following receipt of the initial compliance test results, the Department may make a revised determination of Best Available Control Technology and may require installation of such technology~~. Combustion control shall be utilized for CO control. Due to the lack of operational experience with the LM6000 and the uncertainty of actual CO emissions, the permittee shall leave a space suitable for future installation of an oxidation catalyst. If compliance testing indicates that the applicant is unable to meet the CO limits established in Table 2, the decision to require an oxidation catalyst will be based on a cost/benefit analysis of using such control.

8. The Department will not require the applicant to provide modular space for a NO_x post-combustion abatement system, nor provide for the system itself. However, if the permittee is subject to future new source review requirements, the additional retrofit costs associated with not providing space during the initial project construction cannot be factored into the NO_x control cost-effectiveness analysis.

9. Boilers Nos. 1, 2 and 3 shall permanently cease operation ~~prior to the startup of~~ upon receipt of the operating permit for the cogeneration facility.

10. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (F.A.C. Rule 17-3.090).

11. An application for an operation permit must be submitted to the Northeast District office at least 90 days prior to the expiration date of this construction permit. To properly apply for an operation permit, the applicant shall submit the appropriate application form, fee, certification that construction was completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit (F.A.C. Rules 17-4.055 and 17-4.220).

Best Available Control Technology (BACT) Determination
University of Florida Cogeneration Project
Alachua County

The applicant proposes to install a 43 MW cogeneration facility to replace existing boiler capacity at the University of Florida - Gainesville campus in Alachua County. The facility will consist of a General Electric LM-6000 Gas Turbine Generator exhausting through a duct-fired heat recovery steam generator which will produce steam for the University campus. The turbine and duct burner will be fired by natural gas with No. 2 fuel oil being used only as a backup fuel for the turbine.

A BACT determination is required for all regulated air pollutants emitted in amounts equal to or greater than the significant emission rates listed in Table 500-2 of Florida Administrative Code (F.A.C.) Rule 17-2.500.

Maximum annual emissions from the proposed project are listed below in tons per year:

	Gas Turbine		Duct Burner	Total	Offsets	Increase	PSD
	NG	Oil	NG				
NO_x	142.7	7.3	24.6	174.6	134.9	39.7	40.0
SO_2	4.3	21.6	0.7	26.6	36.1	-9.5	40.0
PM/PM_{10}	10.2	1.1	2.5	13.8	3.4	10.4	25/15
CO	158.0	7.7	24.6	190.3	20.4	169.9	100.0
VOC	6.5	0.4	10.6	17.5	1.1	16.4	40.0
H_2SO_4	0.3	2.0	0.1	2.4	0.8	1.6	7.0

Emissions are based on firing natural gas in the turbine for 8,147 hours/yr at 348 MMBTU/hr and natural gas in the duct burner for 2,628 hours/yr at 187 MMBTU/hr. Oil firing in the turbine is based on 219 hours/yr at 382.6 MMBTU/hr. Regarding the turbine operation, an additional 1.9 hours/yr operation on natural gas will be allowed for each 1.0 hour/yr that fuel oil is not burned (up to 219 x 1.9 hours/yr).

The usage of oil for boilers 4 and 5 may be increased by 0.96 gallons of oil for every gallon not burned in the turbine. The total amount of oil used in the turbine will be reduced by this amount. The usage of natural gas for boilers 4 and 5 may be increased by 0.34 cubic feet for every cubic foot not burned in the turbine. The total amount of natural gas used in the turbine will be reduced by this amount.

Calculation for Boiler 4 and 5 Oil Tradeoff:

- NO_x Emissions from turbine on oil:

  $66.3 \text{ lb/hour} \div 382.6 \times 10^6 \text{ BTU/hr} = 0.1733 \text{ lb}/10^6 \text{ BTU}$

- NO_x Emissions from Boilers 4 and 5:

  $24 \text{ lb } NO_x / 10^3 \text{ gal.} \times \text{gal.}/7.2 \text{ lb} \times \text{lb}/18{,}400 \text{ BTU} =$
  $0.1812 \text{ lb } NO_x/10^6 \text{BTU}$

(Highest emissions from Boiler 5 were used)

- Oil Tradeoff Ratio = 0.1733 lb/10^6 BTU ÷ 0.1812lb/10^6 BTU = 0.96

Notes:
1) Turbine and boilers will use same fuel. Therefore, BTU equivalents and gallons will be the same.
2) Emissions of other pollutants such as SO_2 will virtually be the same from turbine and boiler.

Calculation of Boiler 4 and 5 Natural Gas Tradeoff:

- NO_x Emissions from turbine on natural gas:

  35.0 lb/hr ÷ 348 x 10^6 BTU/hr = 0.1006 lb/10^6 BTU

- No_x Emissions from Boilers 4 and 5 on natural gas:

  281.2 lb NO_x/MMscf x MMscf/946 x 10^6 BTU = 0.2973 lb/10^6 BTU

  (Highest emissions from Boiler 5 were used)

- Natural Gas Trade-Off Ratio = 0.1006 lb/10^6 BTU ÷ 0.2973 lb/10^6 BTU = 0.34

Notes:
1) Turbine and boilers will use the same fuel, therefore, BTU equivalents and cubic feet will be the same.
2) Emissions of other pollutants such as SO_2 will virtually be the same from the turbine and the boilers.

<u>Date of Receipt of a Complete Application</u>

March 6, 1992

<u>BACT Determination Requested by Applicant</u>

Control Technology: Combustion efficiency for cogeneration CO control.

Emission Limits: 75 ppmvd CO (natural gas or No. 2 oil - 0.5% sulfur max.)
(No request made for Boilers 4 and 5)

<u>BACT Determined by the Department</u>

Control Technology: Combustion efficiency for cogeneration CO control with provision for future installation of an oxidation catalyst system. Once performance testing has been completed and the applicant has failed to meet the CO limits established in Table 2, the decision to require an oxidation catalyst will be based on a cost/benefit analysis of using such control.

Emission Limits:	Turbine - natural gas firing:	42 ppmvd CO
	Turbine - No. 2 oil firing:	75 ppmvd CO
	Boilers 4 & 5 - Max. % S:	~~0.1% S~~ 0.5% S
	Duct Burner - Natural gas:	~~0.1 lb CO/MMBTU~~
		0.2 lb CO/MMBTU
	Boilers 4 & 5 (Gas/Oil):	10%/20% opacity

<u>BACT Determination Procedure</u>

In accordance with F.A.C. Chapter 17-2, this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the 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 control methods, systems and techniques. In addition, the regulations require that in making the BACT determination the Department shall give consideration to:

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

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

(c) The emission limiting standards or BACT determinations of any other State.

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

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine for the emission source in question the most stringent control available for a similar or identical source or source category. If it is shown that this level of control is technically or economically infeasible for the source 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.

A review of EPA's BACT/LAER Clearinghouse indicates that catalytic oxidation is the most stringent control technique. An oxidation catalyst control system allows unburned CO to react with oxygen at the surface of a precious metal catalyst such as platinum. Combustion of CO starts at about 300°F and reaches near completion (above 90%) at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than for thermal oxidation thus reducing the thermal energy required. The oxidation catalyst is typically located directly after the turbine or as an integral part of the steam generator. Catalyst size depends on the exhaust flow, temperature, and desired efficiency.

Catalytic oxidation for CO control has been employed in nonattainment areas and is considered to be LAER technology capable of reducing CO emissions to the 10 ppm range. Due to economics, applications of catalytic oxidation technology have thus far been limited to small cogeneration facilities burning natural gas. Oxidation catalysts have not been used on base-loaded fuel oil-fired turbines in simple cycle or combined cycle facilities since extended use of sulfur-containing fuel would result in increased corrosion. Also, trace metals in the fuel could poison catalysts during prolonged fuel oil firing. ~~For these reasons, if catalytic oxidation is required upon re-evaluation of the BACT, the permit will be amended to allow natural gas firing only.~~

Using the applicant's proposed CO emission level of 75 ppmvd, the total annualized cost of CO catalytic oxidation for this project is $508,156 with a cost effectiveness of about $1,970/ton of CO removed. The cost effectiveness is based on 87% efficiency (75 ppmvd to 10 ppmvd) and includes a heat rate penalty of 0.2% based on an energy loss of $50/MW associated with pressure drop across the catalyst. A review of previous BACT determinations indicates that $1,970/ton would not be prohibitive. However, since the applicant is required to provide space for an oxidation catalyst retrofit the decision to require catalytic oxidation should be based on a cost/benefit analysis once compliance testing has been ~~done~~completed and if the applicant is unable to meet the CO emission limits established in Table 2. ~~with the provision for future installation being made a condition of the original construction permit~~. Therefore, the Department will propose initial BACT emission limits for CO consistent with recent BACT determinations for similar sources. These limits are to be revised, ~~if necessary, upon evaluation of the compliance test data~~ if installation of an oxidation catalyst is warranted. The turbine limit proposed by the applicant for fuel oil operation (75 ppmvd) is more stringent than a recent BACT determination for similar sources (78 ppmvd).

Other Air Pollutants Not Subject to BACT Determination

The application indicates that emissions of other pollutants will not be subject to a BACT determination. ~~Since the applicant narrowly escaped PSD review for NO_X by lowering firing rates, and since increased firing rates may be requested at some future date, the Department will require that the applicant make provisions for future installation of state of the art catalytic abatement technology for control of NO_X emissions, such as would presently be required if the source was subject to a NO_X BACT determination.~~

Details of the Analysis May be Obtained by Contacting:

Preston Lewis, P.E., BACT Coordinator
Department of Environmental Regulation
Bureau of Air Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET, N.E.
ATLANTA, GEORGIA 30365

JUN 16 1992

RECEIVED
JUN 19 1992
Division of Air
Resources Management

4APT-AEB

Mr. Clair H. Fancy, P.E., Chief
Bureau of Air Regulation
Florida Department of Environmental
Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: Florida Power Corp. - U of F Project (PSD-FL-181)

Dear Mr. Fancy:

This is to acknowledge receipt of your preliminary determination and draft Prevention of Significant Deterioration (PSD) permit for the above referenced facility by letter dated June 2, 1992. The proposed modification involves the shutdown of three existing boilers and the construction of a combined cycle combustion turbine (GE LM 6000 model). As a result of the shutdowns, the modification will have a significant increase in emissions for CO only.

We have reviewed the package as requested and have no adverse comments. If you have any questions or comments on this project, please contact Mr. Gregg Worley of my staff at (404) 347-5014.

Sincerely yours,

Jewell A. Harper, Chief
Air Enforcement Branch
Air, Pesticides, and Toxics
Management Division

cc: J. Reynolds
C. Holladay
A. Kutyna, NE Dist
C. Shaver NPS
K. Kosky, KBN
CHF/PL

Printed on Recycled Paper

Florida Power CORPORATION

RECEIVED

JUN 18 1992

Division of Air Resources Management

June 15, 1992

Mr. Richard Donelan, Esq.
Office of General Counsel
Florida Department of Environmental Regulation
2600 Blairstone Rd.
Tallahassee, Florida 32399-2400

Dear Mr. Donelan:

Re: Florida Power Corporation/University of Florida Cogeneration Project Permit No. AC 01-204652, PSD-FL-181

On June 8, 1992, Florida Power Corporation (FPC) received the Technical Evaluation and Preliminary Determination and proposed air construction permit for the above referenced facility. A review of the permit conditions has revealed that several issues remain to be resolved. I have had conversations with Mr. Clair Fancy of FDER and he has agreed that an extention of time to discuss these issues is appropriate. Therefore, based upon Mr. Fancy's recommendation and pursuant to Section 17-120.070, FAC, FPC respectfully requests an extension of time in which to file a petition for an administrative hearing under Section 120.57 FS, up to and including June 24, 1992.

If you should have any questions, please contact Mr. Scott Osbourn at (813) 866-5158.

Sincerely,

W. Jeffrey Pardue, Manager
Environmental Programs

cc: C. Fancy, FDER-Tallahassee

M.A.C. H2G
POST OFFICE BOX 14042, ST. PETERSBURG, FLORIDA 33733

Florida Power
CORPORATION

Mr. C. Fancy
Florida Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

951 675(S)