State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

INTEROFFICE MEMORANDUM

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From: S. Smallwood	Date: 6/26/78

TO: J. P. Subramani

FROM: Steve Smallwood Steve Smallwood

DATE: June 14, 1978

SUBJECT: BACT RECOMMENDATION
Four (4) Stationary Gas Turbines
Florida Power Company, Suwannee Plant Site
Suwannee County, Florida

This report provides background information and recommended BACT for four (4) new distillate oil fired, 63 megawatt (each) stationary gas turbines which Florida Power Company (FPC) proposes to install at their Suwannee River plant to provide peaking power.

SUMMARY

There are no emission limiting standards currently included in the Florida Air Pollution Control Regulations (17-2) which directly apply to stationary gas turbines. The rule therefore requires that the allowable emission standard be based on a determination of emission level achievable through the application of Best Available Control Technology (BACT).

At the present time the BACT for reducing air pollutant emissions resulting from the operation of large stationary gas turbines of the type proposed by FPC is the use of water or steam injection to control nitrogen oxide (NO_2) emissions, the use of low sulfur fuels to reduce sulfur dioxide (SO_2) emissions, and the use of more efficient fuel combustors (cannisters) to reduce smoke, hydrocarbon (HC) and carbon monoxide (CO) emissions.

Using this technology, NO_2 emissions can be reduced to below 75 ppm corrected to 15% Oxygen (O_2) in the exhaust gas, adjusted for the effects of turbine efficiency, nitrogen content of the fuel, and atmospheric conditions.

SO_2 can be limited to 150 ppm corrected to 15% oxygen by using #2 distillate oil, or to lower levels by using cleaner fuels if they are available.

Smoke, HC, and CO emission can be kept at acceptable levels by requiring the discharge gas to have an opacity of less than 20%, which is achievable.

Background information on FPC's proposed installation is included under DISCUSSION. Supporting information for the BACT recommendation is included under BACT and RECOMMENDED EMISSION STANDARDS. The proposed federal test method for stationary gas turbines is included as an attachment. Notes on several questions concerning FPC's proposal that are not fully answered by the information provided in their BACT application plus notes on several related issues are included under COMMENTS.

DISCUSSION

Florida Power Company plans to install four (4) stationary gas turbines at their Suwannee River Plant site. They propose to fire each unit with a maximum of 37,910 #/hr of distillate fuel oil (6.8 #/gal, 19,494 BTU/lb). Each unit is to be composed of two parallel jet engines, the exhausts from which will drive a power turbine. Each unit (pair of engines plus power turbine) is to be capable of generating 63 megawatts of electrical energy at peak load. Each megawatt-hr. of power output is equivalent to 3,413,000 BTU of energy. Total maximum hourly design peak output is then 215.019 MMBTU resulting from a total heat input of 739 MMBTU: a thermal efficienty or 'heat rate' of 29.1% (215/739).

Stationary gas turbines emit nitrogen oxides (NO, NO_2), sulfur dioxide (SO_2), hydrocarbons (HC), carbon monoxide (CO), fine particulate (PM), and smoke. Stationary turbines used for electrical power production are normally operated at or near rated capacity. They are usually operated for approximately five (5) hours per day to handle peak load electrical demand. Some companies will operate their turbines for short periods of time at no load conditions in anticipation of any rapid surge in power demand. This is referred to as "spinning reserve." The write-up in EPA's "Compilation of Air Pollutant Emission Factors", (AP-42, third edition, August 1977), on stationary gas turbines states that a 'typical' turbine operates 1200 hours per year, for 250 starts, operating 4.8 hours per start. The emission factors (#/hr per rated capacity-megawatts) for stationary gas turbines (AP-42, 3rd edition, section 3.3.1) are based on the following assumed load conditions:

15% @ zero load (spinning reserve)
2% @ 25% load
2% @ 50% load
2% @ 75% load
60% @ 100% load (rated)
19% @ 125% load (peak)

Based on these conditions and the AP-42 emission factors, each FPC gas turbine would be expected to have the following annual uncontrolled emissions:

MW (rated) X EF X hr/yr X T/lb = Tons/yr

NO_x: 50.4 X 9.60 X $\overset{250\times4.8}{1200}$/2000 = 290

SO_2: 50.4 X 0.50 X 1200/2000 = 15

HC: 50.4 X 0.79 X 1200/2000 = 24

CO: 50.4 X 2.18 X 1200/2000 = 66

PM: 50.4 X 0.71 X 1200/2000 = 21

(Note: FPC listed 63 MW* as the peak load in their BACT application. Peak capacity is assumed to be 125% of rated continuous basis: 63 ÷ 1.25 = 50.4) The SO_2 emissions will vary directly with the sulfur content of the fuel used. The sulfur content assumed for the emission factor was not specified in AP-42. Typical sulfur content for distillate oil is approximately 0.5% with a maximum of 0.7%.

In their BACT application FPC listed each turbine as operating 1500 hours per year at four hours operation per start for 375 starts per year. These units are to operate daytime and early evening to provide peaking power. FPC estimates the actual

* See COMMENTS - #1

maximum discharge rate for each turbine as follows (from BACT application):

NO_x	:	187.5	Tons per year
SO_2	:	284	Tons per year
HC	:	6.75	Tons per year
CO	:	64.5	Tons per year
PM	:	28.5	Tons per year

These estimated emissions are to be discharged through a stack listed as having a minimum height of 22 ft. with a cross-sectional area of 130 sq. ft. (rectangular). The exit gas volume is listed at 1,255,500 ACFM at 726° - 800° F for an exit gas speed of 153 FPS. (At the listed exit volumetric flow rate and cross-sectional area the exit gas speed should be 160 FPS).

FPC lists the distillate oil as having a maximum sulfur content of 0.5%. If all sulfur in the fuel is converted to SO_2, the maximum annual SO_2 emissions based on their listed fuel use rate would be:

Fuel (#/hr) X % S/100 X 2(SO_2/S) X hr/yr ÷ 2000 = Tons/yr
37,910 X 0.005 X 2 X 1500/2000 = 284

which is in agreement with the FPC SO_2 estimate. The AP-42 emission factor for SO_2 for stationary gas turbines fired with oil is equivalent to burning an oil with a sulfur content of approximately 0.025%. This appears to be a technical or typographical error, and the emission factor should not be used. The FPC estimate is based on maximum sulfur content and continuous peak load operation for 1500 hours per year. Their actual average load can be expected to be in the range of 85-90%, therefore, actual annual SO_2 emissions can be expected to be approximately 200 Ton/yr (assuming 88% average load, and 0.4% average sulfur).

Both the AP-42 and FPC particulate emission estimates appear to be in a reasonable range.

Spinning reserve operation results in inefficient fuel combustion which can increase emissions of unburned carbon particles, hydrocarbons and carbon monoxide. In their BACT application FPC did not specify the percent of time that they expect to operate these units in spinning reserve.

The FPC and AP-42 carbon monoxide estimates are essentially the same, however the FPC hydrocarbon estimate is considerably less than the AP-42 estimate. Hydrocarbons generally will be burned to CO_2, CO, and water before CO is oxidized to CO_2. The amount of hydrocarbons emitted will depend upon the combustion efficiency, which will depend upon how the units are operated and maintained. At low load conditions and/or very low fuel to air ratios, hydrocarbon and CO emission can increase by a factor of 10. The FPC HC and CO estimates suggest that they expect to operate these turbines at moderate fuel to air ratios and at moderate to full load conditions during most of the time they are in operation, but a specific statement to this effect has not been included in the BACT application.

The NO_x emission estimates listed by FPC on their BACT application represent emissions after control. The control technology they propose (water injection to the gas turbine combustion chambers-cannisters) would reduce NO_x emission, but would have little effect on the other air pollutant emissions. The AP-42 emission estimates are for uncontrolled emissions.

US EPA published the results of their investigation of stationary gas turbine emissions in September 1977. In that report "Standards Support and Environmental Impact Statement, Volume 1: Proposed Standards of Performance for Stationary Gas Turbines" (EPA-450/2-77-017a), EPA included a table on page 3-46 of that document that summarized the air pollutant test results of several gas turbines produced by different manufactures. Below is a partial listing of that data for turbines of a size and type (simple cycle turbines) similar to those proposed for the Suwannee River Plant site.

Manufacturer & Engine No.	Type Fuel	Base Load MV	Plume Opacity	#/hr		
				NO_2	CO	SO_2*
General Electric						
M57001B	DF-2	59.4	-	371	0	355
M57001C	DF-2	66.2	<10%	531	4	401
Turbodyne						
11C	DF-2	51.7^k	8%	319	47.2	332
Westinghouse						
N501B4	DF-2	88.85^k	<20%	925	43.9	485
k - peak rate			* at 0.5% sulfur			

2667

2145

From where?

Assuming that peak rates are about 1.25 times base load rates, the average #/hr of NO_2 per megawatt (base load design) is 8.75 with a standard deviation of 2.9 or 34% of the mean value. This data compares fairly well with the 9.6 #/hr factor listed in AP-42. Therefore FPC is proposing to reduce NO_2 emissions from their new gas turbines by approximately 49%: (363-187)/363*= 0.485.

The operation of the four (4) stationary gas turbines at the Suwannee River plant site would result in the following estimated actual annual emissions based on 1500 hr of operation for each turbine, a minimum of spinning reserve operation, the use of 0.3-0.5 % S distillate fuel oil (#1), an average load of 88%, and the uses of water injection to reduce NO_2 emission by approximately 50% from uncontrolled emission levels.

NO_2 : 140-190 Ton/yr

SO_2 : 200-270 Ton/yr

HC : 10-20 Ton/yr

CO : 50-60 Ton/yr

PM : 20-30 Ton/yr

Smoke : <20% opacity

In the SSEIS document mentioned above, EPA presented the results of some modified diffusion modeling based on the CRSTER single source model. Three modifications were made to the model: 1) Briggs bouyant plume rise model is used to account for the expectation that the maximum ground level concentration will occur at a distance closer in to the source than the distance at which the plume reaches its maximum height; 2) The plume rise height used in the Single Source Model (CRSTER) is 70% of that estimated in (1) above. This is to account for the loss of plume rise observed due to strong wind shear and increased mechanical turbulance due to nearby buildings and the relatively low discharge height of turbine stacks (usually less than 10 meters). 3) The plume height at two building heights down wind of the turbine structure is calculated. If the plume centerline is less than 2.5 times the height of nearby structures, the vertical dispersion parameters are enhanced (increase indicated stability class).

The results of this modeling (Ch. 6 SSEIS document) suggests that the maximum ground level impact of the emissions from each of FPC's four turbines would be as follows:

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* 290 (1500/1200) - The AP-42 estimate was based on 1200 hr. operation, the FPC estimate is based on 1500 hr. of operation.

Emissions:		GLC: ug/m^3 for each turbine			
gm/sec		3 hr	8 hr	24 hr	Annual
31.5	NO_2:	(250)	-	-	0.3
47.8	SO_2:	380	-	110	0.6
1.3	HC :	(10)			
10.8	CO :		0.2*		
4.8	TSP PM :			(10)	(0.1)

* mg/m^3

Note: Numbers in parenthesis were estimated by comparison with other data included in the Table on page 6-22 SSEIS document.

While these estimates should be considered only rough approximations, they do indicate that neither HC, CO or particulate emissions from these turbines can be expected to have a significant impact on the surrounding ambient air quality, if the estimated emission rates are approximately correct.

However NO_2 and SO_2 emissions may have a significant impact.

If all four turbines were operated at the same time, on a windy day, a maximum ground level impact in the range 1200-1500 ug/m^3 SO_2 could possibly occur within one half kilometer downwind of the turbines. The three hour SO_2 air quality standard is 1300 ug/m^3, not to be exceeded more than once per year. Although the NO_2 emissions do not appear to be a direct threat to the annual average NO_2 standard, the Congress has directed EPA to establish a short term NO_2 standard. Unless this new standard has a numerical value significantly greater than 1000 ug/m^3 (and it probably won't), short-term ground level impact of NO_2 emissions from these stationary gas turbines may also reach levels near the new NO_2 ambient air quality standard.

BACT

Currently the best available control technology for this size and type of stationary gas turbine is:

1) Steam or water injection into the primary combustion zone of the gas turbine combustion cannisters at the rate of approximately 0.4-1.2 lbs water per lb of fuel to reduce peak combustion flame temperatures thus reducing thermally formed NO_x emission. Reduction of up to 80% can be achieved.

2) The use of lower sulfur distillate fuel oil to reduce SO_2 emission. Residual oil could be used, but generally is not.[2] It requires heating, special handling, and is usually high in sulfur content. Natural gas can be and is used, along with other very low sulfur fuels, such as kerosene and methanol, but they are not generally available in the quantities needed, at this time.

3) The use of improved combustion cannisters, that provide additional oxygen and turbulence in the primary combustion zone of the cannisters without excessively reducing the local combustion temperature, to minimize the formation and emission of smoke, HC, and CO particularly at low load conditions.

There are a variety of other technologies that could be used. But they have various characteristics which discourage their use at the present time.

For controlling any of these emissions, tail end clean-up such as lime or soda scrubbing for SO_2 removal or ammonia scrubbing for NO_2 removal are prohibitively expensive: two to three times the cost of the gas turbine.

There is a group of turbine combustion design changes, usually called 'dry controls' which on prototype gas turbines have resulted in NO_2 reduction as great as that achieved with water injection. But these techniques have not been fully demonstrated in commercial operation. Such techniques include catalytic combustion, pre-mixing and vaporizing air and fuel, improved fuel injection (atomization), variable combustion chamber geometry to improve turbulence, smooth out combustion chamber temperature profiles, and reduce residence time in the primary combustion zone (50% of the NO_x is formed within the first 0.5 milliseconds of combustion time; 100% within 3 milliseconds), exhaust gas recirculation (however the exhaust must be cooled to prevent engine malfunction), and off-stoichiometric combustion. Many of these techniques look promising and some combination of them will probably become the best technology, at least for smaller gas turbines, within the next 3-5 year.

RECOMMENDED EMISSION STANDARDS

In applying this technology the degree of emission reduction recommended is not as much a matter of what what is technically feasible as it is a matter of what is economically reasonable within the constraint of what is needed to meet the applicable ambient air quality standards.

By using more water, NO_2 emissions can be reduced to very low levels, but at water to fuel ratios above about 1.4 the water injection begins to significantly interfere with efficient turbine operation. Cleaner fuels than #2 distillate fuel oil can be used but they are more costly and generally less available than #2 oil. # 2 distillate oil has an upper sulfur content limit of 0.7% however 0.3 - 0.5% S oil is generally available, and 0.1% sulfur distillate oil can be purchased, but at a higher cost.

Considering these factors, EPA has proposed the following as NSPS for stationary gas turbines:

> The numerical emission limit for NO_x is to be 75 ppm by volume corrected to 15 percent oxygen and ISO ambient atmosphere conditions. The proposed standard would also include an adjustment factor for gas turbine efficiency and a fuel-bound nitrogen allowance. NO_x emissions from gas turbines, therefore, would be limited according to the following equation:
>
> $$STD = (0.0075\ E) + F$$
>
> where:
>
> STD = allowable NO_x emissions (percent by volume at 15 percent oxygen)
>
> E = efficiency adjustment factor:
>
> $$\frac{14.4 \text{ kilojoules/watt} \cdot \text{hr}}{\text{Actual ISO heat rate}}$$
>
> F = fuel-bound nitrogen allowance:

Fuel-Bound Nitrogen (percent by weight)	F (NO_x - percent by volume)
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	0.04(N)
$0.1 < N \leq 0.25$?	0.004 + 0.0067 (N-0.1)
$N > 0.25$	0.005

During performance tests to determine compliance with the proposed standard, measured NO_x emissions at 15 percent oxygen would be adjusted to ISO ambient atmospheric conditions by the following correction factor:

$$NO_x = (NO_{x_{obs}}) \left(\frac{P_{ref}}{P_{obs}}\right)^{0.5} e^{19(H_{obs}-0.00633)}$$

Where:

NO_x = emissions of NO_x at 15 percent oxygen and ISO standard ambient conditions.

$NO_{x_{obs}}$ = Measured NO_x emissions at 15 percent oxygen, ppmv.

P_{ref} = Reference combustor inlet absolute pressure at

101.3 kilopascals (1 atmosphere) ambient pressure.

P_{obs} = Measured combustor inlet absolute pressure.

H_{obs} = Specific humidity of ambient air.

e = Transcendental constant (2.718)

The numerical emission limit for SO_2 would be 150 ppm by volume corrected to 15 percent oxygen or a fuel sulfur content limit of 0.8 percent by weight. There would be no efficiency adjustment factor or ambient condition correction factor for SO_2 emissions, since SO_2 emissions are not affected by gas turbine efficiency or ambient atmospheric conditions.

Higher efficiencies are normally achieved by increasing combustor operating pressures and temperatures and NO_x formation generally increases exponentially with increased pressure and temperature. High efficiency turbines, therefore, generally discharge gases with higher NO_x concentrations than low efficiency turbines. A concentration standard based on low efficiency turbines could restrict the use of some high efficiency turbines. Conversely, a concentration standard based on high efficiency turbines could allow such high NO_x concentrations that low efficiency turbines would require no controls. Consequently, having selected a concentration format for standards of performance, an efficiency adjustment factor needs to be selected to permit higher NO_x emissions from high efficiency gas turbines.

As mentioned above, NO_x emissions tend to increase exponentially with increased efficiency. It is not reasonable from an emission control viewpoint, however, to select an exponential efficiency adjustment factor. Such an adjustment would at some point allow very large increases in emissions for very small increases in efficiency. The objective of an efficiency adjustment factor should be to give an emissions credit for the lower fuel consumption of high efficiency gas turbines. Since the relative fuel consumption of gas turbines varies linearly with efficiency, a linear efficiency adjustment factor is selected to permit increased NO_x emissions from high efficiency gas turbines. A linear efficiency adjustment factor also effectively limits NO_x emissions to a constant mass emission rate per unit of power output.

The efficiency adjustment factor needs to be referenced to a baseline efficiency. Since most existing simple cycle gas turbines fall in the range of 20 to 30 percent efficiency, 25 percent is selected as the baseline efficiency. The efficiency of stationary gas turbines is usually expressed in terms of heat rate which is the ratio of heat input, based on lower heating value (LHV) of the fuel, to the mechanical power output. The heat rate of a gas turbine operating at 25 percent efficiency is 14.4 kilojoules per watt-hr (10,180 Btu per hp·hr). Thus, the following linear adjustment factor is selected to permit increased NO_x emissions from high efficiency stationary gas turbines:

$$x_a = x \frac{14.4}{Y}$$

where:

x_a = adjusted NO_x emissions permitted at 15 percent oxygen and ISO conditions, ppmv.

x = NO_x emission limit specified in the standards at 15 percent oxygen and ISO conditions, (i.e. 75 ppmv).

Y = LHV heat input per unit of power output (kilojoules/watt·hr).

NOTE: ISO conditions refers to standard atmospheric conditions of 760 mm mercury, 288° Kelvin and 60 percent relative humidity.

15°C

The only intent of this efficiency adjustment factor is to permit a linear increase in NO_x emissions with increased efficiencies above 25 percent. Consequently, the adjustment factor would not be used to adjust the emission limit downward for gas turbines with efficiencies of less than 25 percent.

In the event of future limited distillate oil supplies, many new gas turbines would probably be designed to fire residual or heavy fuel oils. Consequently, in order to provide gas turbine owners and operators the flexibility to fire either premium or heavy and residual fuel oils, but to ensure that standards of performance add no impetus toward the firing of heavy fuel oils as a means of evading standards, a fuel bound nitrogen allowance is proposed for the standard of performance limiting NO_x emissions from stationary gas turbines.

An allowance in the NO_x emission limit dependent on fuel-bound nitrogen level with no upper limit on emissions, however, could permit extremely high NO_x emissions when firing some very high nitrogen-containing fuels. Thus, it is essential that restraints be placed on such an emission allowance. A fuel-bound nitrogen allowance has been developed that allows approximately 50 percent use of the heavy fuel oils such as #6 fuel oil (desulfurized). This corresponds to a fuel-bound nitrogen content of about 0.25 weight percent. Firing a fuel with 0.25 weight percent fuel-bound nitrogen increases controlled NO_x emissions by about 50 ppm. Consequently, a fuel-bound nitrogen NO_x emission allowance based on a straight line approximation of the relationship between total NO_x emissions and fuel-bound nitrogen content with a maximum allowance of 50 ppm, due to fuel bound nitrogen is selected for the standard of performance.

The effect of ambient atmospheric conditions on NO_x emissions from stationary gas turbines is substantial. Large changes in relative humidity, for example, can cause NO_x emissions to vary by a factor of 2 or more. In order to insure that standards of performance are enforced uniformly, therefore, the effect of ambient atmospheric conditions on NO_x emission levels needs to be taken into account. The equation presented above to correct measured NO_x emissions to ISO ambient atmospheric conditions was derived by extracting the common elements from several ambient correction factors proposed by gas turbine manufacturers. This correction factor, therefore, represents the general effect of ambient atmospheric conditions on NO_x emissions. Consequently, the correction factor listed above, or an alternative factor as discussed below, is to be used to adjust measured NO_x emissions during any performance test to determine compliance with the numerical emission limit.

As an alternative, gas turbine manufacturers may elect to develop custom correction factors for adjusting measured NO_x emissions from particular gas turbine models. Some gas turbine manufacturers have proposed ambient correction factors which include variables such as fuel-to-air ratios and combustor temperatures. These variables are difficult to measure and are operating parameters which may vary widely due to factors other than atmospheric conditions.

Correction factors to adjust NO_x emissions to a reference humidity and pressure are recommended. If a manufacturer develops a correction factor for humidity and pressure specifically for his model of turbine, he may use those correction factors after submittal of substantiating data to EPA and approval by EPA. Correction factors for temperature are optional and, if used, must be developed by the manufacturer for the specific model. The International Standards Organization (ISO) standard day conditions of one atmosphere, 59°F and 60 percent relative humidity are chosen as the reference conditions. Since the existing correction factors were developed by manufacturers for turbines which use conventional combustors operating at, or near, stoichiometric conditions, they cannot be applied to turbines which use emerging technology combustors such as the low emission lean-burn types which operate at off-stoichiometric conditions. Correction factors for turbines which use non-conventional combustors must be developed by the manufacturer and approved by EPA for each specific turbine model.

For large gas turbines used to generate peaking power and burning distillate fuel oil, such as the FPC proposed turbines, the rate of efficiency decrease can be expected to be about 1 percent per year, due to degradation of the combustors, and errosion and/or deposits on the compressor or turbine blades. Deposits are usually removed by steam cleaning or by introducing crushed walnut shells or rice hulls into the air intake. Combustor life can be estimated so that maintenance activities and compliance tests can be scheduled accordingly. Decrease in efficiency can be monitored by standard process instrumentation, by measuring such things as pressure ratios, exhaust temperatures, and fuel flow. Turbines equipped with water injection should have equipment to continuously measure the water/fuel ratio. Compliance test should be conducted after each major turbine repair and when combustor sections are modified or replaced using EPA Test Method 20- Determination of NO_x, SO_2, and O_2 emissions from Stationary Gas Turbines, a copy of which is attached. Tests should be conducted at full load conditions, using the highest sulfur content fuel normally used, with the turbine operated at the A/F ratio normally used, with the water injection/fuel ratio typically used.

The reason for selecting a concentration standard is the fact that the high turbulence of turbine exhaust gas makes the determination of exhaust flow rates subject to considerable error. Concentration measurements will generally be more accurate and less expensive. To prevent circumvention of the standard by adding dilution air the concentration standard is tied to a specified oxygen content in the exhaust gas: 15% by volume which approximately corresponds to the normal amount of excess air used to properly operate such turbines.

Since SO_2 emissions are directly related to the amount of sulfur in the fuel, SO_2 emissions can be determined from a fuel quality analysis and measurements of fuel use.

Opacity can be determined by a trained observer using standard observation procedures based on a six minute average opacity - one observation each 15 seconds.

If we were to consider large stationary gas turbines as a class, I would recommend the adoption of the US EPA proposed NSPS with the addition of an opacity standard and a tighter SO_2 standard, in the range of 100-125 ppmv.

Considering the four (4) large turbines proposed by FPC as individual units, I recommend that NO_2 emission be limited to no more than 75 ppmv adjusted and corrected as in the EPA proposal; SO_2 be limited to no more than 100 ppmv; with an opacity standard of no more than 20%. I think that in this particular case it might be reasonable to require a tighter set of standards such as 60 ppmv NO_2, 80 ppmv SO_2, and 10% opacity. Such a set of standards are achievable, particularly if FPC intends to use and has a long term supply of high quality distillate oil (#1 oil), but their BACT application does not provide information on which to base an economic analysis of this alternative vs. their proposal of 75 ppmv NO_2, 95 ppmv SO_2, and 20% opacity.

Before making a final determination on BACT for these specific turbines, you may wish to consider some of the points raised in the next section.

COMMENTS

1. On the BACT application forms, FPC listed each turbine as generating 63,000 MW at peak load. This is a typographical error. They apparently meant 63 MW. In an attachment to the application, each unit was listed as 63,000 KW peak load, with the whole installation rated at 200 MW base load. This agrees with the AP-42 assumption of peak load being 1.25 times base load. One of the largest coal-fired steam-electric units in the country generates only 1300 MW. (the whole plant, which consists of three units, generates 2900 MW.)

2. FPC lists the specification for the distillate oil they plan to burn as 6.8 #/gal, 19,494 BTU/lb, with a maximum sulfur content of 0.5%. These are approximately the specifications for #1 distillate oil. #2 oil specifications are: 7.3 #/gal, 19,420 BTU/lb, with a maximum sulfur content of 0.7%. Both #1 and #2 oil are to have a water and sediment content of less than 0.1%. These standard specifications are based on the National Oil Fuel Institute's publication No. 68-101 "Fuel Oil Specifications".

3. In some cases steam injection appears to be more effective in reducing NO_x. In other cases water injection seems to work best. The difference appears to be related to specific design of the various machines tested and the way in which the injection is accomplished. Either steam or water injection are acceptable control techniques for NO_x.

4. Gas turbines are less fuel efficient than reciprocating engines, but they generally release lesser amounts of air pollutants. Diesel engines of comparable size to the turbines proposed by FPC, to my knowledge, do not exist.

5. Per pound of gas or oil burned, gas turbines, generally emit more HC, CO, and NO_x than external combustion boilers.

6. Feed water for the water injection system should be filtered and demineralized (less than 1% sodium) but it does not need to be of boiler feedwater purity.

1ppm

7. In an attachment to their application (Exhibit B) FPC indicated that at a 1 to 1 water to fuel ratio turbine efficiency would be reduced by 6.95%. This was based on assuming that all of the heat used to vaporize the water and raise this vapor to 726°F (the stack gas exit temperature) was lost. Therefore, the 700 BTU's per lb for vaporation plus the 656 BTU/lb to raise the vapor temperature to 726°F was lost. Hence (1356/19,500) 6.95% of the heat input value of the fuel would be unavailable for producing work output.

970
@212

The overall efficiency of a heat engine is a function of the total heat input and the usable heat or work output. The heat rejected to the stack is lost whether it is transported by dry stack gas or by water vapor. In the engine, the water vapor absorbs and transfers usable energy. The real loss due to water injection is the unrecoverable heat used to convert liquid water to vapor, approximately 700 BTU/lb, about a 3.6% decrease in available heat input energy. If the turbine was 30% efficient without water injection, each BTU heat input would produce 0.30 BTU of work or electric energy output. A 3.6 decrease in available input energy would decrease output energy by the same amount. Thus the output would drop to 0.289 BTU's output, or an overall 1 percent decrease in thermal efficiency. The primary reason for low efficiency for gas turbines is the large amount of heat rejected to the stack. However, even if the turbine was a perfect thermal machine operating at a temperature of 3000°F (3460°R), with an ambient air temperature of 70°F (530°R) the highest thermal efficiency possible, due to thermodynamic considerations, would be 85% (3460-530)/3460. If such a machine rejected heat at 726°F (1186°R) its maximum possible efficiency would be 65%.

970 = hvap water @212
386
Δh water

8. Table 4.2 on page 4-28 of EPA's SSEIS document for stationary gas turbines list 58 turbine installations which are currently on order or in operation with either water or steam injection. Seven installations were listed for Florida: One GE unit on order for the City of Jacksonville. One Westinghouse unit with 857 hours of operation owned by Jacksonville Electric; Four Westinghouse units owned by Florida Power and Light with water injection systems available, but not being used; one Westinghouse unit owned by Florida Power Company, located at Enterprise, Florida, with 718 hours of operation. Enterprise is in Volusia County, near Sanford.

9. The following is an analysis of the relationships among the data provided by FPC for each gas turbine.

Each turbine is to burn a maximum of 37,910 #/hr of light distillate fuel oil. Theoretical Air calculations indicate that about 14.5 lbs of air per lb of fuel is required for stoichiometric combustion. This results in 589,121 lbs/hr of exhaust or approximately 133,406 scfm of exhaust. Atmospheric moisture at 80°F would add about 2600 scfm. If a 1:1 water-fuel ratio is used for water injection the water would add about 14,000 scfm.At 15% oxygen there would be approximately 270% excess air, for a total dry volume of 470,420 scfm. FPC lists the exit gas volume for each turbine as 1,255,500 ACFM @ 726°F. It was not specified whether this was wet or dry volume. This would be a standard volume (at 60°F, latm) of 550,472 scfm. Assuming that this is meant to be wet or total volume including moisture , the turbine would be operated at 320% excess air which would correspond to 15.75% oxygen in the exit gas. Neither excess air or percent oxygen was specified in the application. Note the considerable change in indicated excess air for a small change in percent oxygen. This underscores the need for accurate O_2 measurements when conducting compliance tests.

Basing the 75 ppmv NO_2 standard on dry gas volume (Test Method 20 attached), and using the previously calculated dry volume of 470,420 scfm, the standard for these turbines is equivalent to 248 lb/hr emission, which agrees with FPC's estimate of 250 #/hr.

Using the same volume estimates, and FPC's recommended standard of 95 ppmv SO_2, I estimate an emission rate of 437 lb/hr, which corresponds to 0.575% S Fuel oil. FPC listed their maximum sulfur content at 0.5% S which is approximately equivalent to 80 ppmv. However, note that a small change in either exit volume due to a small change in theoretical air required, or sulfur content, or fuel heating value could result in 0.5 sulfur fuel being equivalent to 90-100 ppmv. Burning 0.5% sulfur light fuel oil results in SO_2 emissions of approximately 0.51 lbs/MMBTU. EPA's SSEIS document on gas turbines says that 150 ppmv is approximately equivalent to 0.8% S in fuel oil, which would imply that 95 ppmv is roughly equivalent to 0.5% sulfur.

10. There are several questions which I have noted in this report which you may wish to obtain more information on, before declaring BACT for these turbines, or before a Construction Permit is issued, whichever is appropriate.

Is an economic analysis of an alternate set of standards, such as 60 ppmv NO_2, 80 ppmv SO_2 and 10% opacity appropriate or necessary? If so additional information is needed.

What amount of "spinning reserve" is planned for these turbines?

What is the possibility of all four turbines operating at full load at the same time? It might affect the PSD review.

What other SO_2 sources are located near this site? An attachment to the BACT application indicated that there are existing fossil-fuel fired units at this site.

What bearing does EPA's development of a short term NO_2 standard have on the permit review for this facility?

What is the Air/fuel ratio for maximum load operation? What is the excess air? Is the exit volume listed on a total or dry basis? What is the planned water to fuel ratio? What has been FPC's experience with water injection at their Enterprise plant? What is the possibility of increasing the stack height to, say, 45 feet? What is the source of their fuel oil supply, and how certain is FPC that they can continue to obtain high grade light fuel oil for gas turbine fuel?

Many of these questions do not necessarily need to be answered prior to making the BACT determination, but they probably should be answered before a construction permit is issued.

11. If the nominal 75 ppmv NO_x emission standard is applied, the FPC turbines would actually be allowed an emission rate of 87 ppmv due to the efficiency adjustment factor, which would increase all of the NO_2 emission estimates included in FPC BACT application and this report by 16.4% (29.1/25.0). 25% is the base efficiency for the adjustment factor. Typical gas turbine thermal efficiencies range from 20-30%.

SS/ca

Attachments
Turbine pictorial
EPA Test Method 20

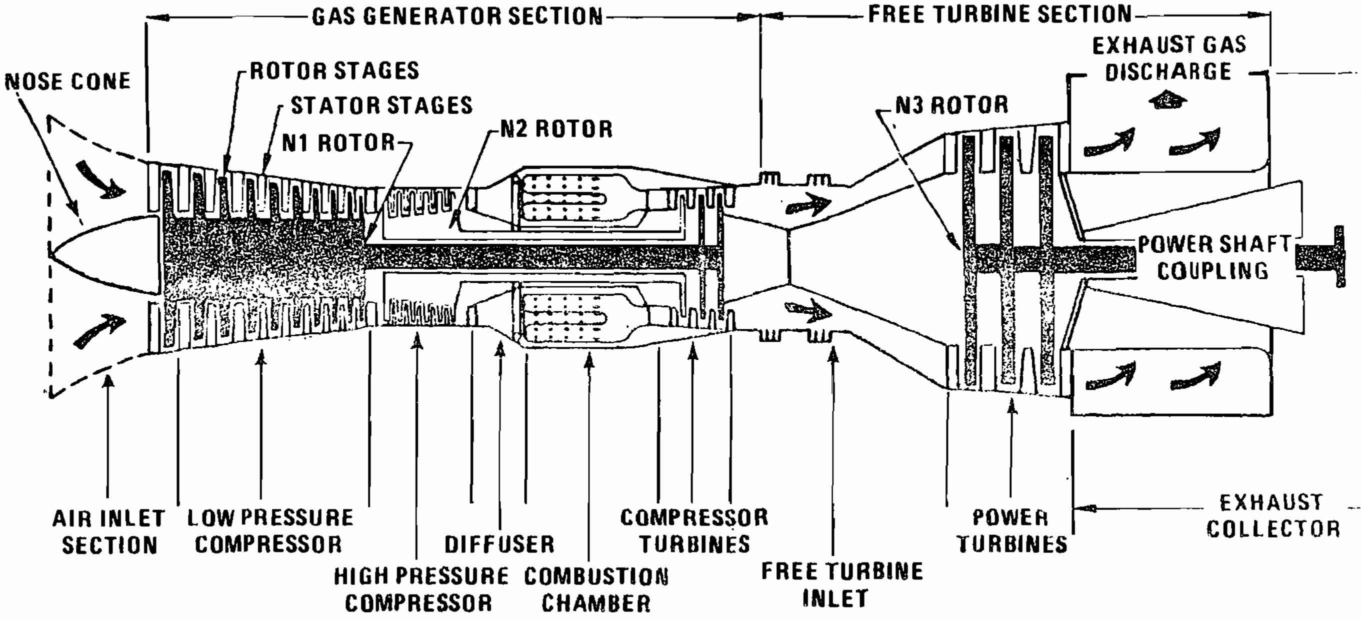

Figure 3-6. Cut-away view of a typical simple cycle gas turbine.

APPENDIX - G

METHOD 20--DETERMINATION OF NITROGEN OXIDES, SULFUR DIOXIDE, AND OXYGEN EMISSIONS FROM STATIONARY GAS TURBINES

1. Principle and Applicability

1.1 Principle. A gas sample is continuously extracted from the exhaust stream of a stationary gas turbine; a portion of the sample stream is conveyed to instrumental analyzers for determination of nitrogen oxides (NO_x) and oxygen (O_2) content. During each NO_x and O_2 determination, a separate measurement of sulfur dioxide (SO_2) emissions is made, using Method 6, or its equivalent. The O_2 determination is used to adjust the NO_x and SO_2 to a reference condition.

1.2 Applicability. This method is applicable for the determination of nitrogen oxide, sulfur dioxide, and oxygen emissions from stationary gas turbines. For the NO_x and O_2 determinations, this method includes: (1) measurement system design criteria, (2) analyzer performance specifications and performance test procedures; and (3) procedures for emission testing.

2. Apparatus and Reagents

2.1 Measurement System. The equipment required to extract, transport, and analyze the gas sample constitutes the "measurement system." A schematic of the measurement system is shown in Figure 20-1. (Measurement system performance specifications are described in detail in Section 3.) The essential components of the measurement system are described below.

2.1.1 Probe. Stainless steel type 316 or equivalent, to transport gas from stack.

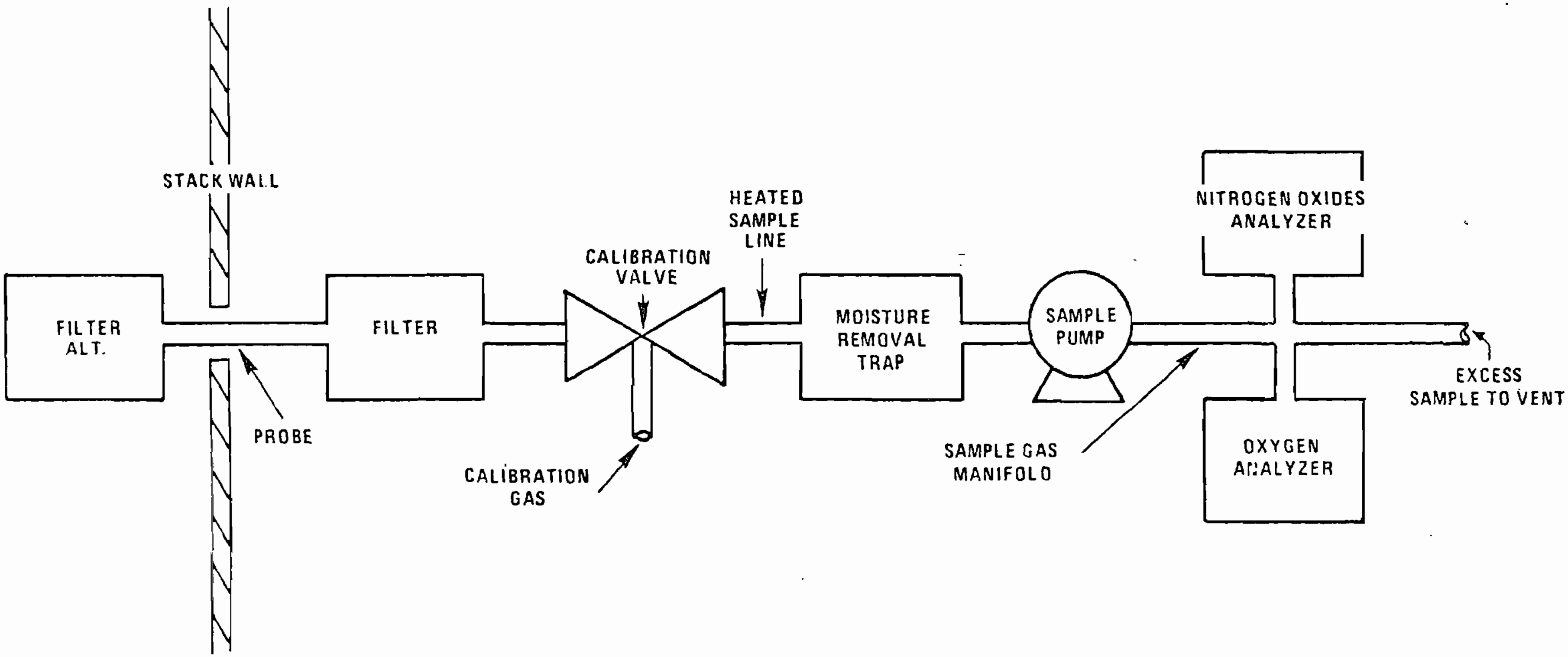

Figure 20.1 Measurement system design for stationary gas turbine tests.

2.1.2 Particulate Filter. A filter is used to remove particulates ahead of the calibration valve assembly. In most cases, either in-stack or out-stack filter location is acceptable; however, out-stack filtration is required when the sample gas temperature is above 500°C (930°F). The filtration temperature shall be at least 120°C (250°F) to prevent moisture condensation. Glass fiber filters, of the type specified in EPA Method 5, or equivalent, are recommended.

2.1.3 Calibration Valve Assembly. A three-way valve assembly is used to direct the zero and span calibration gases to the analyzers. This assembly shall be located directly behind the probe and filter and shall be capable of blocking the sample gas flow and introducing the span and zero gases when the system is in the calibration mode.

2.1.4 Calibration Gases. Calibration gases are used to perform zero, span and calibration checks of the analyzers during each test run. The concentrations and specifications of these gases are described in detail in Sections 2.2 and 6.2.

2.1.5 Heated Sample Line. A FEP fluorocarbon or stainless steel (type 316 or equivalent) sample line is used to transport the gases to the sample conditioner and analyzers. The sample gas shall be maintained at least 5°C (10°F) above the stack gas dew point to prevent moisture condensation.

2.1.6 Moisture Trap. A moisture trap, designed to reduce the dew point of the sample gas to 3°C (37°F) or less, is used. For instruments not affected by water vapor, this device is not required; however, the moisture content shall be determined using methods subject to the approval of the Administrator and the NO_x and O_2 concentrations shall be corrected to a dry gas basis.

2.1.7 Pump. A nonreactive leak-free sample pump is used to pull the sample gas through the system at a flow rate sufficient to minimize transport delay. The pump shall be made from or coated with nonreactive material (FEP fluorocarbon or type 316 stainless steel).

2.1.8 Sample Gas Manifold. A sample gas manifold is recommended for diverting portions of the sample gas stream to the analyzers. The manifold may be constructed of glass, FEP fluorocarbon, or stainless steel (type 316 or equivalent). Instead of using the manifold, separate sample lines may be connected to each analyzer.

2.1.9 Oxygen Analyzer. An oxygen analyzer is used to determine the oxygen concentration (percent O_2) of the sample gas stream.

2.1.10 Nitrogen Oxides Analyzer. A NO_x analyzer is used to determine the ppm concentration of nitrogen oxides in the sample gas stream.

2.1.11 Sulfur Dioxide Analysis. Method 6 apparatus, or equivalent, is required for sulfur dioxide determination.

2.2 Calibration Gas Specifications.

2.2.1 Zero Gas. Prepurified nitrogen is used.

2.2.2 Nitrogen Oxide Calibration Gases. Mixtures of known concentrations of NO in nitrogen are required. Nominal NO concentrations of 25, 50, and 90 percent of the instrument full scale range are needed. The 90 percent gas mixture is used to set and check the instrument span and is referred to as span gas. The 25 and 50 percent gas mixtures shall be used to validate the analyzer calibration, prior to each test.

2.2.3 Oxygen Calibration Gases. Ambient air at 20.9 percent oxygen shall be used as the span gas (high range concentration gas). A midscale calibration gas (approximately 13 percent O_2 in nitrogen) shall be used to validate the analyzer calibration prior to each test.

2.2.4 Concentration Validation. Within one month prior to test use, calibration gases shall be analyzed, by the appropriate test method specified in Section 6.2, to determine their true concentration levels. Gas concentrations that are traceable to the National Bureau of Standards and which can be demonstrated to be stable are exempted from the analysis requirements.

3. Measurement System Performance Specifications and Performance Test Procedures

3.1 Analyzer. "Span" is defined as the concentration range (specified by manufacturer) over which an analyzer will give valid readings. The spans for the analyzers used in this method shall be as follows:

3.1.1 Oxygen Analyzer: 0 to 25% O_2

3.1.2 NO_x Analyzer: 0 to 120 ppm

3.2 Analyzer Interferences and Interference Response. The "interference response" of an analyzer is defined as the output response to a component in the sample gas stream, other than the gas component being analyzed; the analyzers used in this method shall not have a total interference response of more than ±2 percent of span.

Particulate matter and water vapor are the primary interfering species for most instrumental analyzers, but these may be removed physically by using filters and condensers. Other possible specific interferents found in turbine exhaust streams include carbon monoxide, carbon dioxide, nitrogen oxides, sulfur dioxide and hydrocarbons. Each analyzing instrument may respond to one or more of these interferents in ways that alter the desired measurement.

The interference response of an analyzer is determined by measuring the total analyzer response to the gaseous components (or mixtures) listed in Table 20.1; these gases may either be introduced into the analyzer separately, or as a single gas mixture. The total interference output response of the analyzer to these components, if any, shall be determined (in concentration units). The values obtained in an interference response test shall be recorded on a form similar to Figure 20.2. If the sum of the interference responses of the test gases is greater than 2 percent of the instrument span, the analyzer shall not be used in the measurement system of this method.

An interference response test of each analyzer shall be conducted prior to its initial use in the field. Thereafter, if changes are made in the instrumentation which could alter the interference response, e.g., changes in the type of gas detector, the instruments shall be retested.

In lieu of conducting the interference response test, instrument vendor data, which demonstrate that for the test gases of Table 20.1 the interference performance specification is not exceeded, are acceptable. If these data are not available, the tests shall be made.

TABLE 20.1 INTERFERENCE TEST GAS CONCENTRATIONS

CO	500 ppm
SO_2	200 ppm
NO/NO_2	200 ppm
CO_2	10%
O_2	20.9% (Air)

FIGURE 20.2 INTERFERENCE RESPONSE

Date of Test:____________________

Analyzer Type:____________________ S/N____________

Test Gas Type	Conc.	Analyzer Output Response	% of Span

$$\% \text{ of Span} = \frac{\text{Analyzer Output Response}}{\text{Instrument Span}} \times 100$$

3.3 Analyzer Response Time. When a change in pollutant concentration occurs at the inlet of the measurement system (i.e., at probe), the change is not immediately registered by the analyzer; "response time" is defined as the amount of time that it takes for the analyzer to register a concentration value within 5 percent of the new inlet concentration. The maximum response time for the analyzers used in this method is three minutes.

To determine response time, first introduce zero gas into the system until all readings are stable; then, introduce span gas into the system. The amount of time that it takes for the analyzer to register 95 percent of the final span gas concentration is the upscale response time. Next, reintroduce zero gas into the system; the length of time that it takes for the analyzer output to come within 5 percent of the final reading is the downscale response time. The upscale and downscale response times shall each be measured three times. The readings shall be averaged, and the average upscale or downscale response time, whichever is greater, shall be reported as the "response time" for the analyzer. Response time data are recorded on a form similar to Figure 20.3. A response time test shall be conducted prior to the initial field use of the measurement system, and shall be repeated if changes are made in the measurement system.

3.4 Zero Drift. "Zero drift" is the change in analyzer output during a turbine performance test, when the input to the measurement system is a pure grade of nitrogen (zero gas). The maximum allowable

RESPONSE TIME

Date of Test ____________________

Analyzer Type ____________________ S/N ____________________

Span Gas Concentration ____________ ppm

Analyzer Span Setting ____________ ppm

1 ____________ seconds

Upscale 2 ____________ seconds

3 ____________ seconds

Average upscale response ________ seconds

1 ____________ seconds

Downscale 2 ____________ seconds

3 ____________ seconds

Average downscale response ________ seconds

System response time = slower average time = ________ seconds.

Figure 20.3

zero drift for the analyzers used in this method is ±2 percent of the specified instrument span. The zero drift calculation is made for each gas for each turbine test run; this is done by taking the difference of the zero gas concentration values measured at the start and finish of the test (see Section 6.1). The zero drift is recorded (as a percentage of the instrument span) on a form similar to Figure 20.4.

3.5 Span Drift. "Span drift" is the change in the analyzer output during a turbine performance test, when the input to the measurement system is span gas. The maximum allowable span drift for the analyzers used in this method is ±2 percent of the specified instrument span. The span drift calculation is to be made for each gas for each turbine test run; this is done by taking the difference between the span gas concentration values measured at the beginning and end of the test. Span drift is recorded (as a percentage of instrument span) on a form similar to Figure 20.4. Span drift must be corrected for any zero drift that occurred during the test period (see Figure 20.4).

4. Procedure for Field Sampling

4.1 Selection of a Sampling Site and the Minimum Number of Traverse Points.

4.1.1 Select a sampling site as close as practical to the exhaust of the turbine. Turbine geometry, stack configuration, internal baffling, and point of introduction of dilution air will vary for different turbine designs. Thus, each of these factors must be given special consideration in order to obtain a representative sample. Whenever possible, the sampling site shall be located upstream of the

Zero and Span Drift Data

Turbine Type ______________________ S/N ______________________

Date: ______________________

Test No.: ______________________

Analyzer: Type ______________________ S/N ______________________

	Initial Calibration ppm or %	Final Calibration ppm-or %	Difference Initial-Final ppm or %	% of Span
Zero Gas				
High Calibration Gas (Span Gas)			*	

$$\% \text{ of Span} = \frac{\text{Absolute Value of Difference}}{\text{Instrument Span}} \times 100$$

*Corrected for zero drift, i.e., if zero drift over test period is +2 ppm then 2 ppm shall be subtracted from the difference between the initial and final readings.

Figure 20.4

point of introduction of dilution air into the duct. Sample ports may be located before or after the upturn elbow, in order to accommodate the configuration of the turning vanes and baffles and to permit a complete, unobstructed traverse of the stack. The sample ports shall not be located within 5 feet or 2 diameters (whichever is less) of the gas discharge to atmosphere. For supplementary-fired, combined-cycle plants, the sampling site shall be located between the gas turbine and the boiler.

4.1.2 The minimum diameter of the sample ports shall be 3-inch nominal pipe size (NPS).

4.1.3 The minimum number of points for the preliminary O_2 sampling (Section 8.3.2) shall be as follows: (1) eight, for stacks having cross-sectional areas less than 1.5 m^2 (16.1 ft^2); (2) one sample point for each 0.2 m^2 (2.2 ft^2) of area, for stacks of 1.5 m^2 to 10.0 m^2 (16.1 - 107.6 ft^2) in cross-sectional area; and (3) one sample point for each 0.4 m^2 (4.4 ft^2) of area, for stacks greater than 10.0 m^2 (107.6 ft^2) in cross-sectional area. Note that for circular ducts, the number of sample points must be a multiple of 4, and for rectangular ducts, the number of points must be one of those listed in Table 20.2; therefore, round off the number of points (upward), when appropriate.

4.2 Cross-sectional Layout and Location of Traverse Points. After the number of traverse points for the preliminary O_2 sampling has been determined, use Method 1 to locate the traverse points.

TABLE 20.2 CROSS-SECTIONAL LAYOUT FOR RECTANGULAR STACKS

No. of traverse points	Matrix layout
9	3 x 3
12	4 x 3
16	4 x 4
20	5 x 4
25	5 x 5
30	6 x 5
36	6 x 6
42	7 x 6
49	7 x 7

4.3 Measurement System Operation.

4.3.1 Preliminaries.

4.3.1.1 Prior to the turbine test, the measurement system shall have been demonstrated to have met the performance specifications for interference response and response time described in Sections 3.2 and 3.3.

4.3.1.2 Turn on the sample pump and instruments; allow the normal warmup time required for stable instrument operation.

4.3.1.3 After the instruments have stabilized, the measurement system shall be calibrated using the procedures detailed in Section 6.1. Transfer the zero and span gas calibration data from Figure 20.5 to a form similar to Figure 20.4.

4.3.1.4 At the beginning of each NO_x test run and, as applicable, during the run, record turbine data as indicated in Figure 20.6 Also, record the location and number of the traverse points on a diagram.

4.3.2 Preliminary Oxygen Sampling.

4.3.2.1 At the start of a 3-run sample sequence, position the probe at the first traverse point and begin sampling. The minimum sampling time at each point shall be 1 minute plus the average system response time. Determine the average steady-state concentration of O_2 at each point and record the data on Figure 20.7.

4.3.2.2 Select the eight sample points at which the lowest oxygen concentrations were obtained. These same points shall be used for all three runs which comprise the emission test. More points may be used, if desired.

Figure 20.5

CALIBRATION DATA

Date____________________

Analyzer Type____________________ S/N____________________

High Range Gas Conc._______________ % Full Scale_______________

Mid Range Gas Conc._______________ % Full Scale_______________

Low Range Gas Conc._______________ % Full Scale_______________

Zero Gas____________________ % Full Scale_______________

Figure 20.6

STATIONARY GAS TURBINE

TURBINE OPERATION RECORD

Test Operator ____________________

Turbine ID Type ____________________

S/N ____________________

Location Plant ____________________

City ____________________

Ambient Temperature ____________________

Ambient Humidity ____________________

Test Time Start ____________________

Test Time Finish ____________________

Fuel Flow Rate ____________________ *

Water or Steam Flow Rate ____________________ *

Ambient Pressure ____________________

Date ____________________

Ultimate Fuel Analysis
C ____________________
H ____________________
O ____________________
N ____________________
S ____________________
Ash ____________________
H_2O ____________________

Trace Metals
____
Na ____________________
Va ____________________
K ____________________
etc.** ____________________

Operating Load ____________________

*Describe measurement method, i.e., continuous flow meter, start finish volumes, etc.

**i.e., Additional elements added for smoke suppression.

FIGURE 20.7

Preliminary Oxygen Traverse

Location ______________ Date ____________

Plant ______________________

City, State __________________________

Turbine ID

Mfg. _______________________

Model, serial number __________________________

Sample Point	Oxygen Concentration

4.3.3 Emission Sampling.

4.3.3.1 Position the probe at the first point determined in the preceding section and begin sampling. The minimum sampling time at each point shall be 3 minutes plus the average system response time. Determine the average steady-state concentration of O_2 and NO_x at each point and record the data on Figure 20.8.

4.3.2.2 After sampling the last point, conclude the test run by recording the final turbine operating parameters and by determining the zero and span drift, as described in Sections 3.4 and 3.5. If the zero and/or span drift exceed ±2.0 percent the run may be considered invalid, or may be accepted provided the calibration data which results in the highest corrected emission concentration is used.

4.3.2.3 If additional turbine runs are conducted within 4 hours of the previous run, an initial calibration of the measurement system is not required. If more than 4 hours have elapsed between runs, the pretest calibration shall be done.

4.4 An SO_2 determination shall be made (using Method 6, or equivalent) during the test. A minimum of six total points, selected from those required for the NO_x measurement, shall be sampled; two points shall be used for each sample run. The sample time at each point shall be at least 10 minutes. The oxygen readings taken during the NO_x test runs corresponding to the SO_2 traverse points (see Section 4.3.3.1) shall be averaged, and this average oxygen concentration shall be used to correct the integrated SO_2 concentration obtained by Method 6 to 15 percent O_2 (see Equation 20-1).

Figure 20.8

STATIONARY GAS TURBINE
GAS SAMPLE POINT RECORD

Turbine ID

Mfg.____________________

Model & S/N____________________

Plant____________________

Location

City____________________

State____________________

Ambient Temp.____________________

Ambient Press____________________

Ambient Humidity____________________

Date____________________

Test Time Start____________________

Test Time Finish____________________

Test Operator Name____________________

O_2 Instrument Type____________ S/N____________

NO_x Instrument Type____________ S/N____________

Sample Point	Time (Min)	O_2* (%)	NO_x* (ppm)
1	0		

*Average steady state value from recorder or instrument readout.

5. Emission Calculations

5.1 Correction to 15 Percent Oxygen. Using Equation 20-1, calculate the NO_x and SO_2 concentrations (adjusted to 15 percent O_2). The correction to 15 percent oxygen is sensitive to the accuracy of the oxygen measurement. At the level of analyzer drift specified in the method ($\pm$2 percent of full scale), the change in the oxygen concentration correction can exceed 10 percent when the oxygen content of the exhaust is above 16 percent O_2. Therefore O_2 analyzer stability and careful calibration are necessary.

$$\begin{array}{c}\text{Actual Pollutant}\\ \text{Concentration}\\ (NO_x \text{ or } SO_2)\end{array} \times \frac{5.9\%}{20.9\% - O_2\% \text{ actual}} = \begin{array}{c}\text{Pollutant concentration}\\ \text{adjusted to } 15\%\ O_2\end{array}$$

Equation 20-1

where:

5.9% is 20.9% - 15% (the defined concentration basis)

O_2 actual is the sample point oxygen concentration for NO_x calculation, and the average O_2 concentration for SO_2 calculation.

5.2 Calculate the average adjusted NO_x concentration by summing the point values and dividing by the number of sample points.

6. Calibration

6.1 Measurement System. Prior to each turbine test, the measurement system shall be calibrated according to the procedures described below. The manufacturer's operation and calibration instructions are also to be followed as required for each specific analyzer.

6.1.1 Turn on all measurement system components and allow them to warm up until stable conditions are achieved. Next, introduce zero gas and each of the calibration gases described in Section 6.2, one at a time, into the inlet of the probe. The responses of the analyzer to these gases shall be used to establish a calibration curve or to verify the manufacturers calibration curve. The data obtained in these procedures shall be recorded on a form similar to Figure 20.4. If, for the mid-scale gases, the accuracy of the manufacturer's calibration curve or the expected response curve cannot be shown to be ±2 percent of full scale (or better), the calibration shall be considered invalid and corrective measures on the instrument shall be taken. The calibration procedure shall be repeated, using only zero gas and span gas, at the conclusion of test; this allows calculation of zero and span drift (Sections 3.2 and 3.3).

6.2 Calibration Gas Mixtures.

6.2.1 Within one month prior to the turbine test, the NO_x calibration gas mixtures shall be analyzed, using the phenoldisulfonic acid procedure (Method 7) for nitrogen oxides. A minimum of three analyses shall be done, and the average concentration of each gas shall be reported as the true calibration gas value (see Figure 20.9). Alternate procedures may be employed, subject to the approval of the Administrator, to determine the calibration gas concentration.

Note: The NO_x calibration gas mixtures shall contain nitric oxide (NO) in nitrogen. Instruments which require conversion of one nitrogen

Figure 20.9

ANALYSIS OF CALIBRATION GAS MIXTURES

CYLINDER GAS COMPOSITION

Reference Method Used________

Date:______________________________

Low Range Calibration Gas Mixture

Sample 1____________ppm

Sample 2____________ppm

Sample 3____________ppm

Average_____________ppm

Mid Range Calibration Gas Mixture

Sample 1____________ppm

Sample 2____________ppm

Sample 3____________ppm

Average_____________ppm

High Range (span) Calibration Gas Mixture

Sample 1____________ppm

Sample 2____________ppm

Sample 3____________ppm

Average_____________ppm

oxide component to another for total NO_x measurement shall be checked to ensure that this conversion is complete and reproducible, as specified by the manufacturer.

6.2.2 Ambient air may be used as the oxygen span gas. The mid-scale calibration gas concentration shall be certified (by vendor) as being within ±2 percent of the indicated concentration.

• U.S. GOVERNMENT PRINTING OFFICE: 1977--740-261 /326 Region No. 4

Ella Complete attachments to

MODIFIED ORIGINAL

for Suwanee River gas turbines

ATTACHMENT A

COMPLETE BACT APPLICATION

Unit P-1

ST. JOHNS RIVER
RECEIVED
MAY 13 1978
SUB DISTRICT
GAINESVILLE BRANCH

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION
APPLICATION FOR DETERMINATION OF BEST AVAILABLE CONTROL TECHNOLOGY FOR AIR POLLUTION SOURCES

SOURCE STATUS: (X) New ( ) Modification

Company Name: FLORIDA POWER CORPORATION County: Suwannee

Source Identification: Suwannee River Plant Peaking Unit Addition

Source Location: Street: Suwannee River Plant Site City:

UTM: East: 503,673 North: 2,415,157 (coordinates of existing center stack)

Appl. Name and Title: J. T. Rodgers, Assistant Vice President

Appl. Address: P. O. Box 14042, St. Petersburg, FL 33733

Appl. Phone: 813/866-4765

DEPARTMENT USE ONLY

Date Appl. Received: May 12, 1978

Notice of Receipt:

Newspaper: Florida Times Union Date: June 30, 1978

Florida Administrative Weekly Date: June 23, 1978

BACT Determination:

Declared by Secretary: Date:

BACT:

NOTICE OF DETERMINATION

Newspaper: Date:

Florida Administrative Weekly Date:

NOTE: All data is for one (1) gas turbine unit operating at a peak load of 63,000 MW at an ambient temperature of 59°F.

I. DETAILED DESCRIPTION OF SOURCE

A. Describe The Manufacturing Process at the Facility and the Unit Operation to be Controlled. Discuss the Source of Emissions, Existing Control Devices, the Expected Improvement in Performance, With Ambient Ambient Air Quality Standards or Applicable PSD Increments. Attach Additional Sheet If Necessary.

See attached Exhibit A

B. For This Source Indicate Any Previous DER Permits, Order and Notices; Including Issuance Dates and Expiration Dates.
None

C. Raw Materials, Fuels, and Chemicals Used:

DESCRIPTION	HOURLY USE	CONTAMINANT		RELATION
		TYPE	%WT.	TO FLOW DIAGRAM
Distillate Fuel Oil	37,910#/hr	Ash	0.1% Max	(2)
		Sulfur	0.5% Max	
Air	2,196,000#/hr			(1)

D. Process Rate

1. Total Process Input Rate: 2,235,000#/hr (Air and Fuel)
2. Produce Output Rate: 2,235,000#/hr (Exhaust Gas)
3. Operation Time: 1,500 Hrs/yr
   - a. ~~Hrs/Day:~~ b. ~~Days/Wk~~ c. XXXXXXXXX
   - d. Seansons: Operate daytime and early evenings to supply power during periods of high system electrical load for a range of 4 hours per run and during emergency conditions.

II. BEST AVAILABLE CONTROL TECHNOLOGY DATA

A. Emission Limitations For Any Pollutants Emitted From The Source Pursuant To 17-2, F.A.C.?

Yes (X) No ( )

CONTAMINANT	FOR CLASS II AREA MAXIMUM ALLOWABLE INCREASE IN CONCENTRATIONS RATE OR CONCENTRATION
Particulate	Annual geometric mean: 19 ug/m^3 24 hr max 37 ug/m^3
SO_x as SO_2	Annual arithmetic mean: 20 ug/m^3 24 hr max: 91 ug/m^3 3 hr max: 512 ug/m^3
NO_x as NO_2	-------
HC as (H_4)	--------
CO	--------
Visible emissions & opacity	Less than 20%

B. Are Standards Of Performance For New Stationary Sources Pursuant To 40 C.F.R. Part 60 Applicable To The Source?

Yes ( ) No (X) However standards are proposed for SO_x and NO_x see below and footnote.

CONTAMINANT	RATE OR CONCENTRATION
Particulate	*Not Applicable
SO_x as SO_2	*150 ppm by volume
NO_x as NO_2	** 75 ppm by volume STD (Allowable emission)
HC as (H_4)	*Not Applicable
CO	*Not Applicable

C. Has EPA Declared The Best Available Control Technology For This Class Of Sources? (If Yes Attach Copy)

Yes ( ) No (X)

CONTAMINANT	RATE OR CONCENTRATION

*Reference is made to page 53783, Selection of Pollutants, Federal Register, Vol. 42, No. 191, Monday, October 3, 1977.

**The actual NO_x Emission Rate is adjusted according to the requirements on Page 53789 of the above referenced Federal Register.

D. What Emission Levels Do You Propose As Best Available Control Technology? Also see D continued at bottom of page.

CONTAMINANT	(ACTUAL ESTIMATED EMISSIONS) RATE OR CONCENTRATION Lbs/Hr	T/Yr
Particulate	38	28.5
SO_X as SO_2	379	284
NO_X as NO_2	250	187.5
HC as (H_4)	9	6.75
CO	86	64.5

E. Describe The Existing Control and Treatment Technology (If Any) N/A

1. Control Device:

2. Operating Principles:

3. Efficiency*:

4. Capital Costs:

5. Useful Life:

6. Operating Costs:

7. Energy:

8. Maintenance Cost:

9. Emissions :

CONTAMINANT	RATE OR CONCENTRATION Before Device	After Device

10. Stack Parameters

a. Height: Ft.

b. Diameter: Ft.

c. Flow Rate: ACFM

d. Temperature: °F

e. Velocity: FPS

D. (Continued)

CONTAMINATE	RATE OR CONCENTRATION
SO_X as SO_2	95 ppm by volume
NO_X as NO_2	**75 ppm by volume STD (Allowable Emission)
Opacity	Less than 20%

F. Describe The Control and Treatment Technology Available
(As Many Types As Applicable Use Additional Pages If Necessary)

1. NO_2 Control and Treatment Technology (Wet Method) See Exhibit B

a. Control Device:

b. Operating Principles:

c. Efficiency: (See Footnote) d. Capital Cost: $945,000.

e. Life: 20 years f. Operating Cost: $759,000 per year

g. *Energy: 375,000 KWHR h. Maintenance Cost: Significant informatio is presently unavailable to determine maintenanc Cost

i. Availability of Construction Material and Process Chemicals: Equipment is available and demineralized water will be used for the control process

j. Applicability to Manufacturing Processes: The control strategy is well adapted to the process and is currently available

k. Ability to Construct with Control Device, Install In Available Space, and Operate within Proposed Levels: The plant site has adequate space to install the necessary water treatment and storage facility for the NO_x control.

2. NO_2 Control and Treatment Technology (Dry Method) See Exhibit B

a. Control Device: Insufficient information is available from manufacturers on dry NO_x control to complete this section, since the equipment is not commercially available at the present time. The Company cannot indicate that dry NO_x control is a practical control method at the present time. However, the Company is leaving the option open in that this control methodology may be demonstrated soon by manufacturer's test programs.

b. Operating Principles:

c. Efficiency: d. Capital Cost:

e. Life: f. Operating Cost:

g. Energy: h. Maintenance Cost:

i. Availability of Construction Materials and Process Chemicals:

j. Applicability to Manufacturing Processes:

k. Ability to Construct with Control Device, Install In Available Space, and Operate within Proposed Levels;

* Energy to be Reported in Units of Electrical Power - KWH Design Rate.

F. 1. (c) Efficiency: Description of NO_x control will be in accordance with specifications of a particular manufacturer. Use of steam is not contemplated since boilers will not be installed on site. Water injection will be used with expected efficiency - adequate to reduce the NO_x emission level to 75 ppm by volume (Standard) (Allowable Emission)**

3. SO_2 Control and Treatment Technology

a. **Control Device:** Distillate fuel will not exceed .5% sulfur by weight

b. **Operating Principles:**

c. **Efficiency:** (See Footnote Below)

d. **Capital Cost:** The capital cost is lower when using distillate fuel when compared to a higher

e. **Life:**

f. **Operating Cost:** sulfur less expensive fuel.

g. **Energy:**

h. **Maintenance Cost:**

i. **Availability of Construction Materials and Process Chemicals:**

j. **Applicability to Manufacturing Processes:**

The control strategy is well suited to the process.

k. **Ability to Construct with Control Device, Install In Available Space, and Operate within Proposed Levels:** It is anticipated that no difficulties will be realized in acquiring the low sulfur fuel to meet the aforementioned control technology for SO_2. Appropriate contract(s) would be secured subsequent to acquiring all necessary governmental licensing for the project.

4.

a. **Control Device:**

b. **Operating Principles:**

c. **Efficiency:**

d. **Capital Cost:**

e. **Life:**

f. **Operating Cost:**

g. **Energy:**

h. **Maintenance Cost:**

i. **Availability of Construction Materials and Process Chemicals:**

j. **Applicability to Manufacturing Processes:**

k. **Ability to Construct with Control Device, Install in Available Space, and Operate within Proposed Levels:**

3 (c). Efficiency: For peaking unit installations, low sulfur distillate fuel is normally used to provide maximum reliability.
There is no feasible control device for removing SO_2 from a combustion turbine exhaust gas when high sulfur fuel is used. (High sulfur fuel is defined as that with a sulfur content over 0.8% which would exceed the EPA proposed emission limits).

G. Describe the Control Technology Selected: SO_2 Control will be Distillate Fuel Oil, NO_X Control: Wet or Dry Method. See Para. 10, REASONS FOR SELECTION AND DESCRIPTION OF SYSTEMS and attached Exhibit B. Also refer to F1, 2, & 3 on the preceding two pages.

1. Control Device:

2. Efficiency:

3. Capital Cost:

4. Life:

5. Operating Cost:

6. Energy:

7. Maintenance Cost:

8. Manufacturer: General Electric Co., Westinghouse Corp., Brown Boveri, United Technologies.

9. Other locations Where Employed on Similar Processes: Presently is not employed at any FPC facility

a.

(1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:

CONTAMINANT	RATE OR CONCENTRATION

(8) Process Rate:

b.

(1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:

CONTAMINANT	RATE OR CONCENTRATION

(8) Process Rate:

c.

(1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:

CONTAMINANT	RATE OR CONCENTRATION

(8) Process Rate:

d.

(1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:

CONTAMINANT	RATE OR CONCENTRATION

d. (7) Emissions: (continued)

CONTAMINANT	RATE OR CONCENTRATION

(8) Process Rate:

c.

(1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:

CONTAMINANT	RATE OR CONCENTRATION

(8) Process Rate:

10. **Reason For Selection and Description of Systems:** NO_X Control - recommendation from manufacturer to be requested in Specs. Methodology availabl Wet & Dry Method, See Exhibit B. Specifications will require compliance with Federal and State regulations on NO_X Control.
SO_2 Control - Fuel - Reason: Only existing feasible control technology availabl for SO_2.

11. **Emissions:**

CONTAMINANT	ACTUAL ESTIMATED MAXIMUM DISCHARGE RATE OR CONCENTRATION Lbs/Hr	T/Hr
Particulate	38	28.5
SO_X as SO_2	379	284
NO_X as NO_2	250	187.5
HC as (H_4)	9	6.75
CO	86	64.5

12. **Stack Parameters:****

a. HEIGHT: 22 Ft. Minimum

b. Cross sectional area 130 sq. ft. (Rectangular)

c. Gas Flow Rate: 1,255,500 ACFM

d. Gas Exit Temperature: 726°F to 800°F

e. Velocity: 153 FPS

** Depending on the selection of a manufacturer, there will be one or two stacks per unit.

13. Fuels:

TYPE	HOURLY USE*		HOURLY HEAT INPUT MILLION BTU/HR.	
	AVG.	MAX.	AVG.	MAX.
Distillate Fuel Oil	Varies	37,910	Varies	739 X 10^6 BTU/Hr.

NOTE; Fuel consumption will vary with load and ambient temperature. The consumption listed is for one (1) gas turbine unit operating at peak load at 59°F ambient temperature.

TYPE	DENSITY	%S Maximum by % Weight	%N	%ASH Maximum
Distillate Fuel Oil	6.8 Lb/Gal	0.5%		0.1%

*Gaseous Cu. Ft./Hr. Liquid & Solid: Lbs./Hr.

14. **Wates Generated, Disposal Method, Cost of Disposal:** Waste water due to water demineralization plant may be disposed of in existing percolation pond. Appropriate licensing will be acquired from the DER if wet method of NO_x Control is choosen.

H. **Discuss the Social Impact of the Selected Technology Versus Other Applicable Technologies. (i.e. Jobs, Payroll, Production, Taxes, Energy, Etc.)**
Include Assessment of the Environmental Impact of the Sources

Social Impacts: See Exhibit C

Environmental Impacts: See Exhibit D

III. ADDITIONAL ATTACHED INFORMATION.

A. Show Derivation of Total Process Input Rate and Product Weight.

B. Show Derivation of Efficiency Estimation. See B below.

C. An 8½"x 11" Flow Diagram Which Will, Without Revealing Trade Secrets, Identify the Individual Operations and/or Processes. Indicate Where Raw Materials Enter, Where Solid and Liquid Waste Exist, Where Gaseous Emissions and/or Airborne Particles Are Evolved and Where Finished Products Are Obtained.
See Dwg. No. SRP-L3-A-0

D. An 8½"x 11" Plot Plan Showing the Exact Location of Manufacturing Processes and Outlets for Airborne Emissions. Relate All Flows to the Flow Diagram.
See Dwg. No. SRP-L1-A-0

E. An 8½"x 11" Plot Plan Showing the Exact Location of the Establishment, and Points of Airborne Emissions In Relation to the Surrounding Area, Residences and Other Permanent Structures and Roadways.
See Dwg. No. SRP-L2-A-0

F. Attach All Scientific, Engineering, and Technical Material, Reports, Publications, Journals, and Other Competent Relevant Information Describing the Theory and Appplication of the Requested Best Available Control Technology.

B. Heat Rate 11,734 BTU/KW-HR. (Higher Heating Value)

1 KW - HR = 3413 BTU

$$\frac{3413}{11,734} = 29\%$$

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

INTEROFFICE MEMORANDUM

For Routing To District Offices
And/Or To Other Than The Addressee

To: ______________ Loctn.: ______________
To: ______________ Loctn.: ______________
To: ______________ Loctn.: ______________
From: ______________ Date: ______________

TO: Walter Starnes

FROM: Victoria Martinez V.M.

DATE: August 11, 1978

SUBJECT: BACT Determination for FPC Gas Turbines Suwannee River Plant Site - Suwannee County

The study group recommendations considered the four criteria given in the BACT rule: (a) EPA's determinations, (b) technical material available, (c) other state's BACT determinations, and (d) social, economic and energy impacts.

As regards criteria (a) EPA proposed in October, 1977, applicable NSPS for gas turbines. These standards are expected to be promulgated as proposed, in January, 1979. The proposed standards would limit the concentration of nitrogen oxides (NO_x) in the exhaust gases from stationary gas turbines to .0075 percent by volumes (75 ppm) at 15 percent oxygen on a dry basis. The standard would include an upward adjustment factor for gas turbines with thermal efficiencies greater than 25 percent, and also an upward adjustment factor for turbines burning fuels with a nitrogen content greater than .15 percent by weight. Measured NO_x levels would be adjusted to ISO reference conditions (see attached FR).

In addition, the proposed standards would limit the SO_2 emission to 150 ppm by volume corrected to 15 percent oxygen or a fuel content limit of .8 percent by weight. There would be no efficiency adjustment factor or ambient condition correction factor for SO_2 emission, since SO_2 emissions are not affected by gas turbine efficiency or ambient atmospheric conditions (see attached FR).

With respect to criteria (b), the study group relied mainly on the information in the BACT application. Steve Smallwood and the BACT coordinator had the benefit of EPA's (SSEIS) document on gas turbines, EPA 450/2-77-017. Ray Dinardo quoted the February 1977, volume of the APCA Journal on control strategies for emission reductions for gas turbines.

H6 - Rev 7/76

In reference to criteria (c), no other state's BACT's for gas turbines have been reported to EPA's BACT Clearinghouse in Research Trinagle Park.

With respect to criteria (d), the applicant provided information only on the economics of the wet method for NO_x control. The dry method also described is not commercially available. The only control technology listed for SO_2 was distillate fuel not exceeding .5% by weight. The comparative economic impact of other technologies such as lime or soda scrubbing for SO_2 removal or ammonia scrubbing for NO_2 removal were not discussed by the applicant, probably because they are prohibitively expensive.

The study group and the applicant's proposed BACT's are attached.

After carefully examining the study group's recommendations and EPA's proposed standards, I suggest we determine BACT as follows:

NO_x

Emission to be limited according to EPA's proposed NSPS. The emission limit would be 75 ppm by volume corrected to 15 percent oxygen and ISO ambient atmospheric conditions. The standard includes an upward adjustment factor for turbine efficiencies greater than 25% and another for fuel bound nitrogen. NO_x emissions would be limited according to the following equation given in EPA's proposed NSPS,

$$STP = (.0075\ E) + F$$

where:

STP= allowable NO_x emissions (percent by volume at 15 percent oxygen)

$$E = \text{efficiency adjustment factor} = \frac{14.4 \text{ kilo joules/watt} \cdot \text{hr}}{\text{Actual ISO heat rate}}$$

The high efficiencies normally achieved by increasing combustor operating pressure and temperature are accompanied by exponential increases in NO_x. However, as explained in detail on page 10 of Steve Smallwood's recommendation, it is not reasonable to select an exponential efficiency adjustment factor since it would allow for very large increases in NO_x emission for small increases in efficiency, thus the EPA's linear adjustment factor given above. The 14.4 kilojoules per watt-hr corresponds to the heat rate of a gas turbine operating at 25% efficiency.

F = Fuel-bound nitrogen allowance

Fuel-Bound Nitrogen (percent by weight)	F (NO_x - percent by volume)
N 0.015	0
0.015 N 0.1	0.04 (N)
0.1 N 0.25	0.004 + 0.0067 (N -0.1)
N 0.25	0.005

The fuel bound nitrogen allowance was included in EPA's NO_x NSPS to provide gas turbine owners the flexibility to fire either premimum or heavy and residual fuel oils. However, unlimited allowance in the NO_x emission limit dependent on fuel-bound nitrogen level could permit extremely high NO_x emissions when firing high nitrogen-containing fuels. Thus EPA had developed the above fuel bound nitrogen allowance which allows a maximum of 50 ppm for fuel with .25 percent nitrogen by weight or above. To adjust measured NO_x emissions at 15 percent oxygen to ISO ambient atmospheric conditions, EPA gives the following correction factor.

$$NO_x = (NO_{x_{obs}}) \left(\frac{P_{ref}}{P_{obs}} \right)^{0.5} e^{19(H_{obs} - 0.00633)}$$

Where:

NO_x = emissions of NO_x at 15 percent oxygen and ISO standard ambient conditions.

$NO_{x_{obs}}$ = Measured NO_x emissions at 15 percent oxygen, ppmv.

P_{ref} = Reference combustor inlet absolute pressure at 101.3 kilopascals (1 atmosphere) ambient pressure

P_{obs} = Measured combustor inlet absolute pressure.

H_{obs} = Specific humidity of ambient air.

e = Transcendental constant (2.718)

Walt Starnes

State of Florida

DEPARTMENT OF ENVIRONMENTAL REGULATION

INTEROFFICE MEMORANDUM

For Routing To District Offices And/Or To Other Than The Addressee	
To:	Loctn.:
To:	Loctn.:
To:	Loctn.:
From:	Date:

TO: J.P. Subramani

FROM: Albert W. Townsend

DATE: June 19, 1978

SUBJECT: Application for Determination of Best Available Control Technology (BACT) for Gas Turbines

The subject application left quite a bit to be desired. No test data was supplied with the package; therefore, there is nothing to base an emission limiting standard on for SO_2 or NO_x emissions.

There was only one (1) method proposed to control SO_2 emissions; i.e., low sulfur fuel. Therefore, based on the application this would have to be considered BACT.

Two (2) methods were proposed for the control of NO_x. One method isn't commercially available; therefore, the wet method would have to be considered BACT.

I feel that all future BACT applications should be screened to insure that there is enough information and alternatives so that the reviewing engineer will have a choice. For instance, there is more than one way to reduce SO_2 emissions besides low sulfur fuel; i.e., limestone scrubbing, magnesium-oxide scrubbing, Wellman-Lord.

It is a waste of our time to attempt to analyze an incomplete application. It is suggested that no distribution for BACT determination be made until the application is complete and then a complete application should be sent to the appropriate parties.

If you have any questions please contact me, SUNCOM 451-5005.

AWT:fs

cc: Warren G. Strahm

JUN 1978
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BUREAU
AQM

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Tech Talk

PUBLISHED [illegible]
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Principal Contaminants

Air pollution has been a product of man's progress since his earliest days on this continent. However, this has been of little concern until the present day when suddenly the cry is to "end all pollution." Air pollution is usually the unintentional result of some activity which emits undesirable substances into the air in either one or a combination of the following physical states:

(1) liquid or solid particles capable of remaining air-borne either permanently or for significantly long periods of time, or (2) gaseous contaminants which expand and mix with the gases of the atmosphere. The diameter of contaminant particles emitted from man-made sources varies greatly in size, from about 1000 microns (near the size of raindrops), to particles substantially less than one micron.

Particulates are considered to be particles generally larger than 50 microns, at which size they settle out of the atmosphere. Aerosols are usually particulates which range in size from 50 microns to something less than 0.01 microns. Most aerosols are considered to be less than 1 micron in diameter. The gases significant in air pollution represent a wide range of organic and inorganic compounds, as shown in Figure 1.

Power generating plants have been considered to be one of the major polluters of the environment but they actually account for approximately one-eighth of the total man-made air pollution within the United States. Gas turbines now used for power generation contribute an insignificant amount of this contamination. The principal contaminants emitted from gas turbines operating on distillate fuel are unburned hydrocarbons, carbon monoxide, oxides of nitrogen, sulfur dioxide, smoke and particulates. The magnitude of emissions from gas turbines varies with the operating power of the unit. Carbon monoxide and unburned hydrocarbons are only significant at starting and at low power operation such as idle, whereas oxides of nitrogen, smoke, particulates and sulfur dioxide become more significant at peak power.

The presence of carbon monoxide and unburned hydrocarbons at low power levels is primarily due to lower combustion efficiency that might be caused by poor fuel atomization, poor mixing of fuel and air or an inadequate zone burning rate. Oxides of nitrogen (NOx) formations are fixed primarily by the rate of formation and residence time in the hot reaction zones of the combustor. Smoke is formed by carbon generated in a rich primary combustion zone or through quenching in the secondary burning zone. Particulate matter is a function of the fuel quality being consumed. Sulfur dioxide is fixed by the sulfur content in the distillate fuel being burned.

MAJOR CLASSES OF AIR CONTAMINANTS	SUBCLASSES OF AIR CONTAMINANTS	TYPICAL MEMBERS OF SUBCLASSES
Organic Gases	Hydrocarbons	Hexane, Benzene, Ethylene, Methane, Butane, Butadiene,
	Aldehydes and Ketones	Formaldehyde, Acetone.
	Other Organics	Chlorinated Hydrocarbons, Alcohols.
Inorganic Gases	Oxides of Nitrogen	Nitrogen Dioxide, Nitric Oxide.
	Oxides of Sulfur	Sulfur Dioxide, Sulfur Trioxide.
	Carbon Monoxide	Carbon Monoxide.
	Other Inorganics	Hydrogen Sulfide. Ammonia, Chlorine.
Aerosols	Solid Particulate Matter	Dusts, Smoke, Fumes.
	Liquid Particulate	Oil Mists, Entrained Liquid Droplets.

Figure 1

Diffusion of Pollutants

After the pollutants have been released it is necessary to determine how they are transported to a measuring instrument or receptor, and in what concentrations they arrive.

When a concentrated puff of pollutant is released from a source, it tends to expand due to the dynamic action of the atmosphere, and as the same amount of pollutant is now contained in a bigger volume of air, the concentration is decreased. This process of moving from a higher to a lower concentration is the process of diffusion and is accomplished within the atmosphere mainly by two agents, the wind speed and the turbulent motion of the air. The wind speed acts directly to reduce concentration as the effluent leaves the stack, that is, doubling the wind speed will halve the concentrations. Turbulence is generated primarily by the structure of the atmospheric temperature variation with height, and wind flow over surface roughness that acts to mix the pollutant with the ambient air. Source measurements can be made at existing sites whereas a mathematical dispersion model is used to estimate concentrations for future installations.

The most widely used model represents diffusion of the plume as a two phase problem. The first phase is the initial rise of the plume by virtue of its kinetic and thermal energy. The second phase is its diffusion downwind with an assumed vertical and horizontal distribution of concentration based on statistical reasoning.

Expressions defining the concentrations of pollutants have been established by several workers; TPM utilizes formulae for dispersion estimates (under varied atmospheric conditions) that have been compiled by the Environmental Protection Agency.

Regulatory Standards

It should be noted that the EPA has not, as of this date, provided air pollution regulations specifically for gas turbines.

Some states have used the EPA steam regulations as a guideline in establishing gas turbine exhaust emission standards.

Figure 2 lists the environmental standards most well known i.e., Los Angeles Rule 67, San Diego Rule 68 and the EPA Steam Regulations.

The FT4 gas turbine emission control program being conducted by TPM has had a goal of compliance with Los Angeles County Air Pollution Control District (LACAPCD) Rule 67 under all power conditions.

Requirements

	LACAPCD Rule 67		SDAPCD Rule 68		EPA Steam Reg.	
	Gas	Liquid	Gas	Liquid	Gas	Liquid
NOx — Lb/Hr	140	140				
NOx — Lb/MBTU					0.2	0.3
NOx — PPM Corr. 3% O_2			125	225		
Smoke — Ringelmann		1.0		1.0		1.0
SO_2 — Lb/Hr 0.3% S Fuel		200		200		
SO_2 — Lb/MBTU						.8
Part. — Lb/Hr		10		10		
Part. — Lb/MBTU						0.1

Figure 2

MAXIMUM PERMISSIBLE NITROGEN OXIDE EMISSIONS

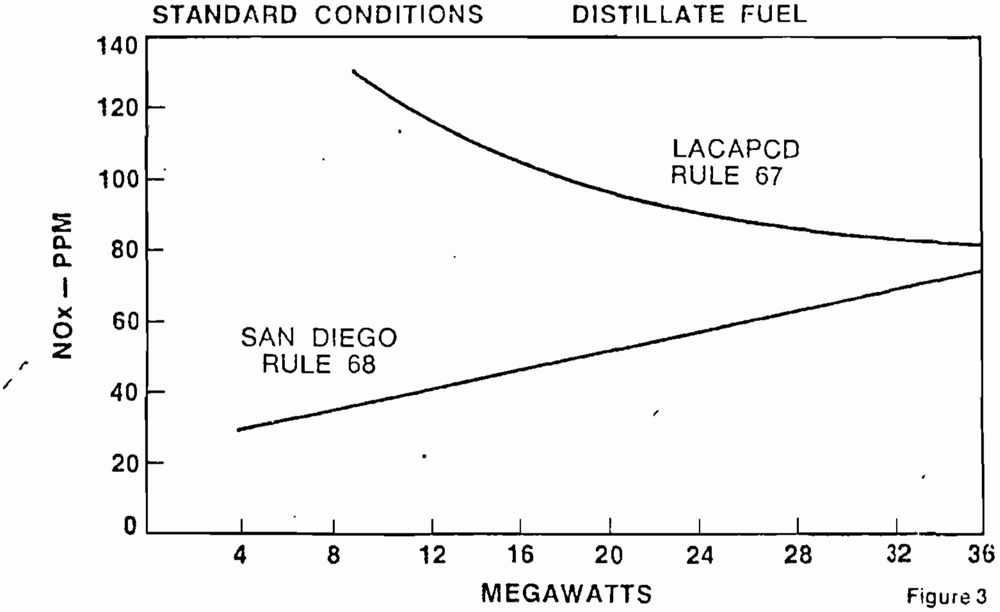


Figure 3

Figure 3 shows the maximum allowable NOx emission (in parts per million) as a function of power output for LACAPCD Rule 67 and San Diego Rule 68.

FT4 Smoke Reduction

In 1969, production was started on a smoke reduction burner can. The new burner can included the use of 1) swirl cups and vanes which surround the six fuel nozzles of each of the eight combustion chambers. Swirl is imparted to the air entering the chamber to improve fuel atomization in the fuel spray pattern; 2) nozzle nuts with tangential air cooling slots to improve fuel atomization; 3) airflow distribution into the burner charged through a series of holes in the head to lean the fuel-air ratio in the primary combustion zone. Figure 4 shows the construction of the smoke-reducing burner can.

The initial goal was to reduce the visible emission from the FT4 gas turbine to a Von Brand Reflectance level of 95 or better which is acceptable to all known air pollution codes.

FT4 SMOKE REDUCING BURNER CAN

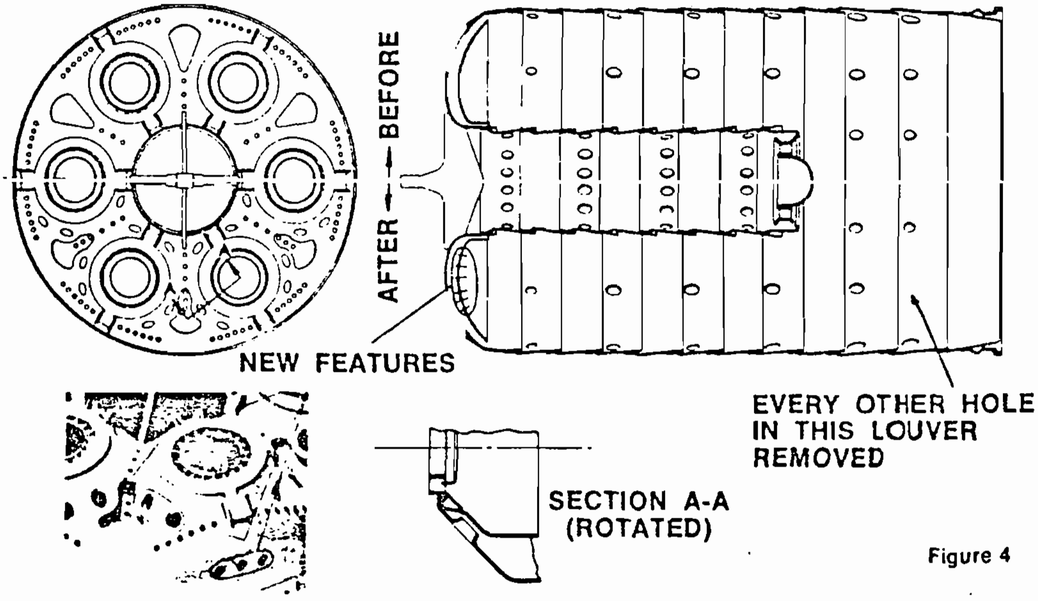


Figure 4

Von Brand Reflectance, Bacharach Smoke Number, and Ringelmann Numbers are different terms used to describe smoke from exhaust stacks. Figure 5 shows the Exhaust Smoke Measurement comparisons between Von Brand Reflectance, Bacharach and Ringelmann. Comparison of Von Brand Reflectance Numbers to visual observations is also shown.

The Von Brand Reflectance is most often used by TPM since it has been accepted by the industry as the most accurate method of determining smoke. A Von Brand instrument collects samples of particulate matter and aerosols on a continuous moving filter paper tape for subsequent analysis. Exhaust gas under test is sampled at a uniform rate by means of a probe positioned in the gas stream at a point of approximate average flow with the gas pulled thru the filter tape by means of a motor-driven pump or other vacuum source. Evaluation of the smoke stain is accomplished with a Photovolt Reflectometer which compares the reflectance of the smoke stain to a clean piece of filter tape. Clean is one hundred while a stain would read an amount less than 100.

The Bacharach Smoke Number, used by some power companies and state agencies, is obtained by drawing a specific volume of gas from the exhaust thru a spot filter over a normal period of approximately two minutes. The spot is then classified by comparing it with the Bacharach Smoke Scale which has ten standard graduated spots from 0 to 9, white to black.

EXHAUST SMOKE MEASUREMENT COMPARISONS

Von Brand Reflectance At 0.216 SCFM	Bacharach	Ringelmann	Color
100	0	0	Clear
99	1		
97	2		
94	3		
89	4		
85		1	
83	5		
75	6	2	
66	7		
60		3	
56	8		
45	9		
40		4	
20		5	Black

The following table can be used as a guide for comparing Von Brand Reflectance numbers to visual observations.

Appearance	Von Brand Reflectance Numbers
Clean Air	100
Clear — Heat Waves	95
Heat Waves with Faint Wisps	93
Slightly Visible	90
Visible Emission	85
Darker Smoke — Becoming Objectionable	80
Dark Smoke	75
Objectionable Smoke	70

Figure 5

The third method utilizes Ringelmann Numbers which are based on visual observation and is therefore quite subjective. It is expressed in degree of blackness in numbers from 0 to 5, with each number representing a 20% difference in opacity from clean to black. Here again interpolation can be made between numbers. This method has been used extensively by federal and state air pollution control agencies.

TPM is currently conducting a program to reduce further the smoke emission level of FT4 engines while burning distillate fuel by improving the fuel nozzles. This includes the use of aerating nozzles that atomize the fuel through the use of turbine compressor air introduced into the fuel spray at the nozzle outlet.

It is anticipated that these improved nozzles, which will be available in 1973 production gas turbines, will meet all known regulations. The expected smoke level will exceed Ringelmann No. 0.5 or Von Brand Reflectance No. 95. It should also be noted that the type of fuel used affects the smoke level as illustrated by Figure 6.

Sulphur Oxides

Sulphur oxides in exhaust gases, (chiefly sulphur dioxide, SO_2, with a trace of sulphur trioxide, SO_3), result from oxidation of essentially all of the sulphur in the fuel being burned. The higher the sulphur content, the more SOx produced. The high temperatures and flows encountered in gas turbine exhausts make SO_2 removal impractical. The only economical way to limit SO_2 is through the use of low sulphur content fuels.

SO_2 in sufficient concentration is known to be irritating to eyes and skin and is purported to contribute to respiratory disorders. There is some disagreement among experts as to whether SO_2 is harmful or beneficial to plant life over a long term.

Because of the irritating effects on humans, regulatory agencies will be increasingly vigilant in measuring SO_2 levels in the ambient air. In order to minimize the ambient concentrations, the EPA has established SO_2 limits for steam power plants of 0.8 pounds per million BTU of fuel input. Most gas turbine liquid fuels contain less than 0.5% sulphur, which will produce less than 0.5 pounds per million BTU SO_2.

SO_2 can be measured by one of several batch sampling systems, such as the "West-Goeke" method, which uses a self-contained automatic chemical process to determine and read out SO_2 concentrations.

EFFECT OF FUEL TYPE ON SMOKE LEVELS — FT4C ENGINE

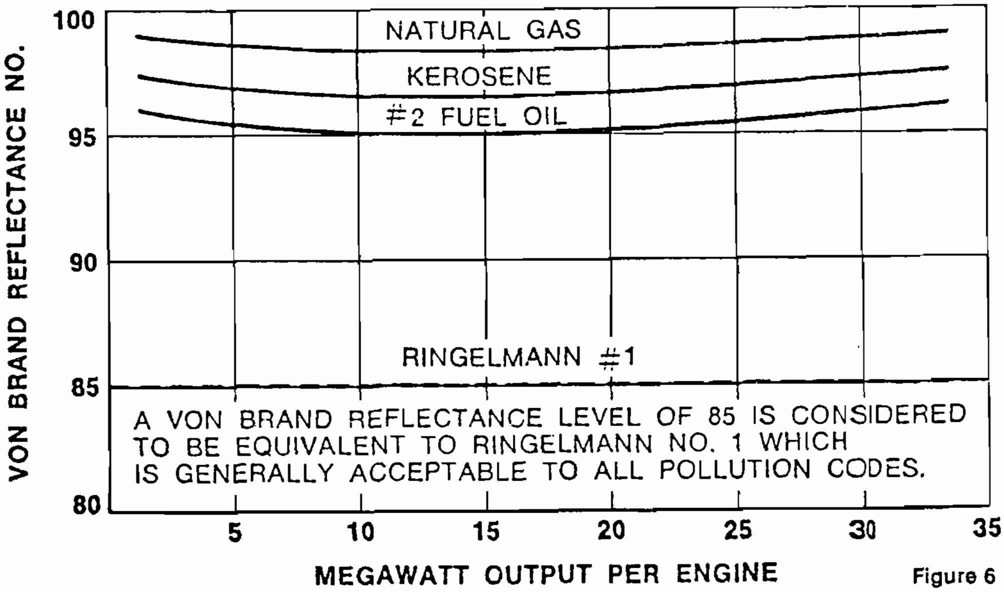


Figure 6

Particulates

Exhaust particulates are generally defined as any solids or condensibles, other than water, in the exhaust stream. In gas turbines burning liquid fuel,particulate emissions usually consist of dirt carried in by the inlet air; metallic ash from fuel contaminants; carbon from incomplete combustion; and condensible sulphur compounds, mostly H_2SO_3. The particle size and quantity will vary with air and fuel quality.

Gas exhaust particulates can be reduced by filtering the gas turbine inlet air, and by using fuels with low metal and sulphur levels. Further reduction is possible through improved combustor design to minimize unburned hydrocarbons.

Both LACAPCD Rule 67 and SDAPCD Rule 68 limit particulate emission to 10 pounds per hour. The EPA guidelines for steam plants, which many states are applying to all stationary power plants, has a limit of 0.1 pounds per million BTU of energy input. TPM FT4 gas turbines currently in service produce particulate levels of approximately 0.09 lb/MBTU.

Particulates are normally measured by taking a sample of the gas by means of a vacuum probe, passing it through either liquid baths or dry filter pads, and weighing the residue.

Oxides of Nitrogen

Combustion research has shown that oxides of nitrogen (NOx) levels are fixed primarily by the rate of formation and residence time in the hot reaction zones of the combustor. Factors controlling the final NOx emission levels are:

1. Temperature in both the combustion reaction and dilution zones.
2. Residence times in both zones.
3. Mixing of fuel, air and combustion products.
4. Fuel vaporization.
5. Combustor inlet temperature and pressure.

It has been demonstrated that slow mixing, in conjunction with rich or heterogeneous mixtures, leads to high combustion temperatures and therefore high NOx levels.

A NOx reduction program was initiated for the FT4 gas turbine in early 1971 with a goal to meet the requirements of LACAPCD Rule 67.

A three-prong approach was used in order to accomplish this goal. This included 1) burner rig tests to verify burner design for obtaining the desired emission reduction, 2) flame rig tests for applied research in determining combustion characteristics, and 3) mathematical models or analytical prediction for burner modifications.

It was determined that water or steam injected directly into the primary zone of combustion served to reduce the flame temperature and promote mixing. Burner rig tests confirmed this reduction (Figure 7).

FT4 BURNER RIG RESULTS WITH WATER INJECTION

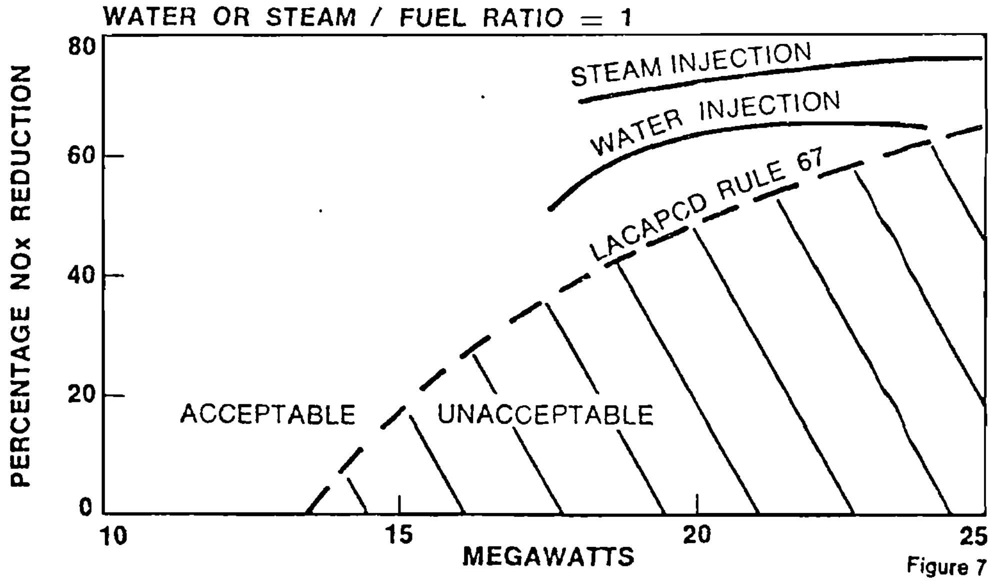


Figure 7

The test results showed a 65% NOx reduction while injecting water into the chamber and a 75% reduction while injecting steam. Steam injection was found to be more effective in reducing NOx than water injection on a pound for pound basis, in spite of the greater potential thermal effect of water. The latent heat of vaporization of water is not fully realized because of poor mixing and the slow vaporization rate of the water relative to fuel vaporization and combustion times.

The fact that water injection reduced NOx emission from gas turbines was further confirmed through full scale engine testing at a TPM field installation in southern California burning natural gas. The water flow rates were varied, NOx reductions were recorded, and the results are plotted in Figure 8.

Probing within a standard combustion chamber determined temperature and NOx formation in the can at various stations along its axis. Figure 9 shows the temperatures and NOx measured across the chamber in the primary flame zone. This supports the theory that NOx formation is primarily a function of temperature and residence time. Fifty percent of NOx formation occurred within 0.5 milliseconds after combustion and production was terminated by 3 milliseconds. Probing the same combustion chamber with steam injected into the primary zone shows a reduction of peak temperatures as shown in Figure 10. NOx levels were significantly reduced by steam injection since the peak temperatures were reduced below the level required for high NOx formation.

H_2O INJECTION

ENGINE DEMONSTRATED REDUCTION

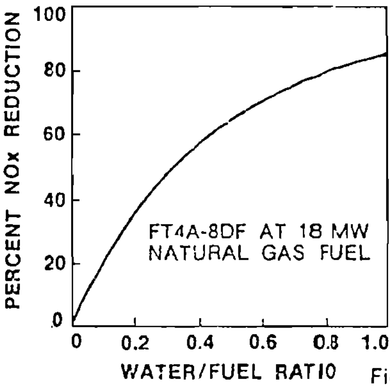


Figure 8

FT4 BURNER CAN TEMPERATURE & NOx TRAVERSE

EIGHT INCHES DOWNSTREAM OF NOZZLE

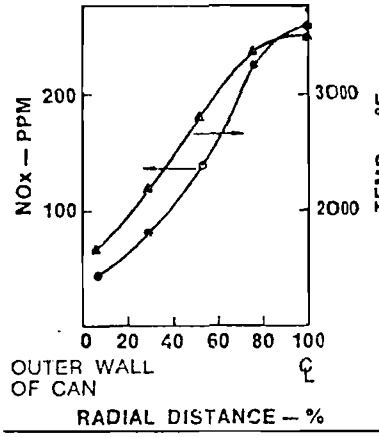


Figure 9

FT4 BURNER CAN TEMPERATURE & NOx TRAVERSE

EIGHT INCHES DOWNSTREAM OF NOZZLE
STEAM INJECTION — 1.4 LBS / LBS FUEL

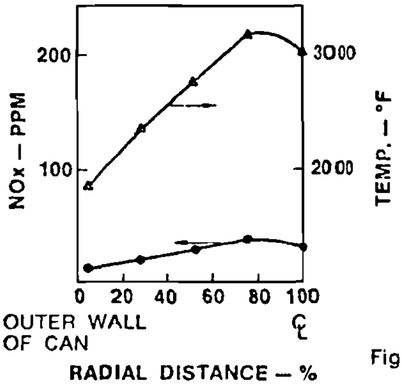


Figure 10

FT4 BURNER RIG NEW COMBUSTION PROGRAM RESULTS

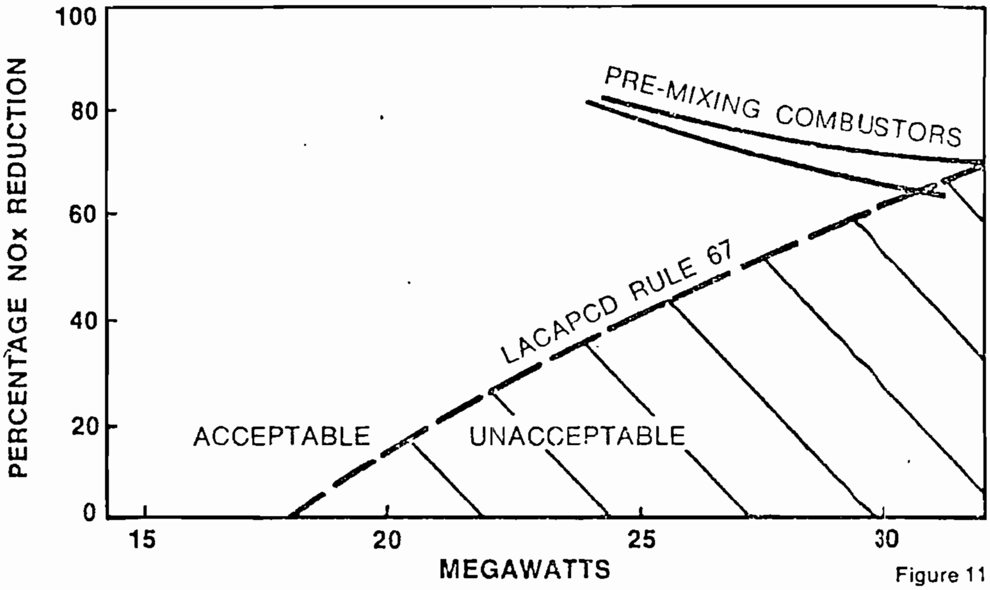


Figure 11

To eliminate the requirement for water or steam injection a new approach is being investigated through premixing and prevaporizing the fuel prior to combustion. Combustion rig tests using these techniques shown in Figure 11 have demonstrated that NOx emission levels are substantially below Rule 67 requirements. This "dry fix" enables the utility to meet existing and anticipated NOx requirements and at the same time retain the gas turbine remote siting capability by precluding the need for a major demineralized water or steam source. Plans are being implemented to make "dry fix" burner cans available in 1974 production engines.

Conversion Equations

Sometimes it is convenient to express NOx exhaust emissions in parts per million (ppm), pounds per hour (#/Hr.) or pounds per million BTU (#/10⁶BTU). The three equations shown in Figure 12 may be useful.

To find NOx (ppm)

$$\text{NOx (ppm)} = \frac{\text{NOx (\#/Hr)}}{\text{Wg (\#/Hr)}} \times \frac{\text{MOL WT AIR}}{\text{MOL WT NOx}} =$$

$$\frac{\text{NOx (\#/}10^6\text{BTU)}}{\text{Wg (\#/Hr)}} \times \frac{\text{HR (BTU/KwHr)}}{10^6} \times \text{OUTPUT (Kw)} \times \frac{\text{MOL WT Air}}{\text{MOL WT NOx}}$$

To find NOx (#/Hr)

$$\text{NOx (\#/Hr)} = \text{NOx (ppm)} \times \frac{\text{MOL WT NOx}}{\text{MOL WT Air}} \times \text{Wg (\#/Hr)} =$$

$$\frac{\frac{\text{NOx (\#}\quad\text{)}}{10^6\text{BTU}} \times \text{HR (BTU/KwHr)} \times \text{OUTPUT (Kw)}}{10^6}$$

To find NOx (#/10⁶BTU)

$$\text{NOx (\#/}10^6\text{BTU)} = \frac{\text{NOx (\#/Hr)} \times 10^6}{\text{Hr (BTU/KwHr)} \times \text{OUTPUT (Kw)}} =$$

$$\frac{\text{NOx (ppm)}}{\text{Hr (BTU/KwHr)}} \times \frac{\text{MOL WT NOx}}{\text{MOL WT Air}} \times \frac{\text{Wg (\#/Hr)} \times 10^6}{\text{OUTPUT (Kw)}}$$

NOx is calculated as NO_2, Mol Wt = 46; Mol Wt Air = 29

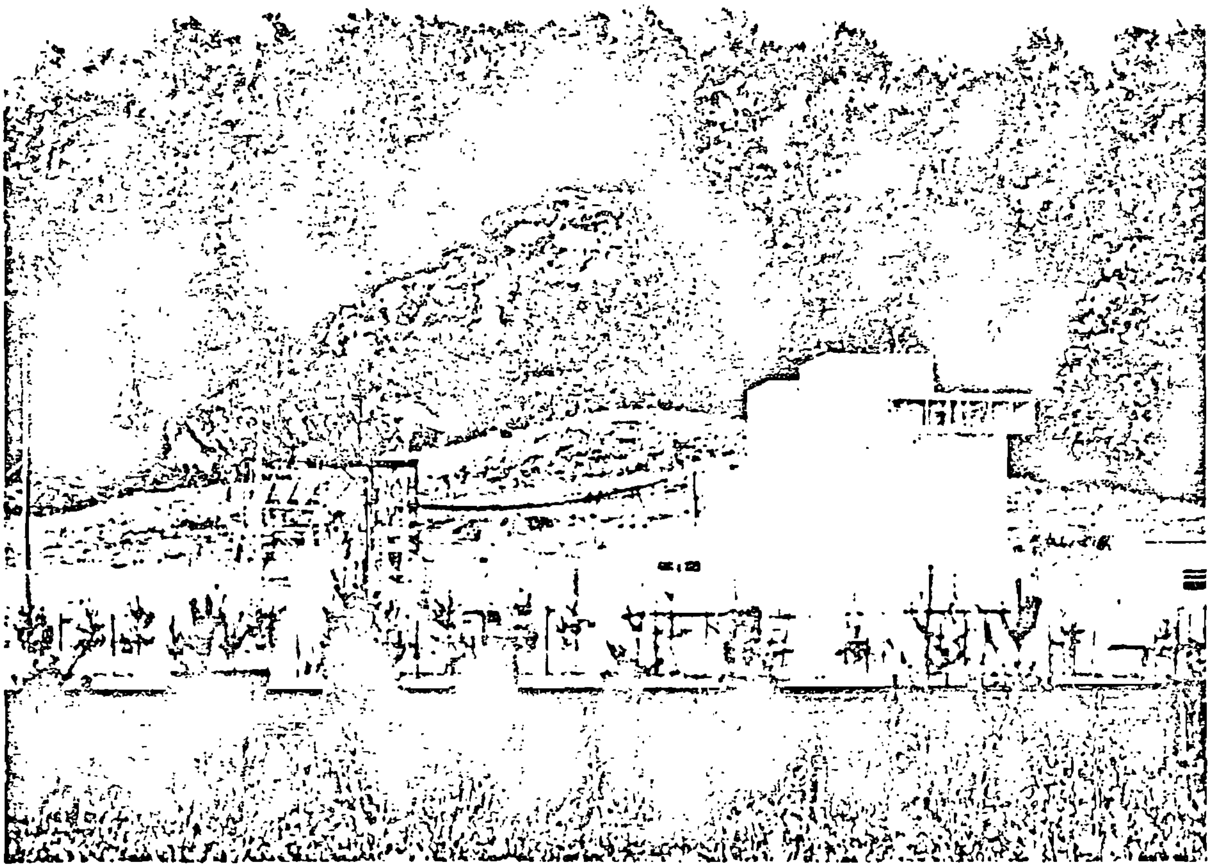
Figure 12

Summary

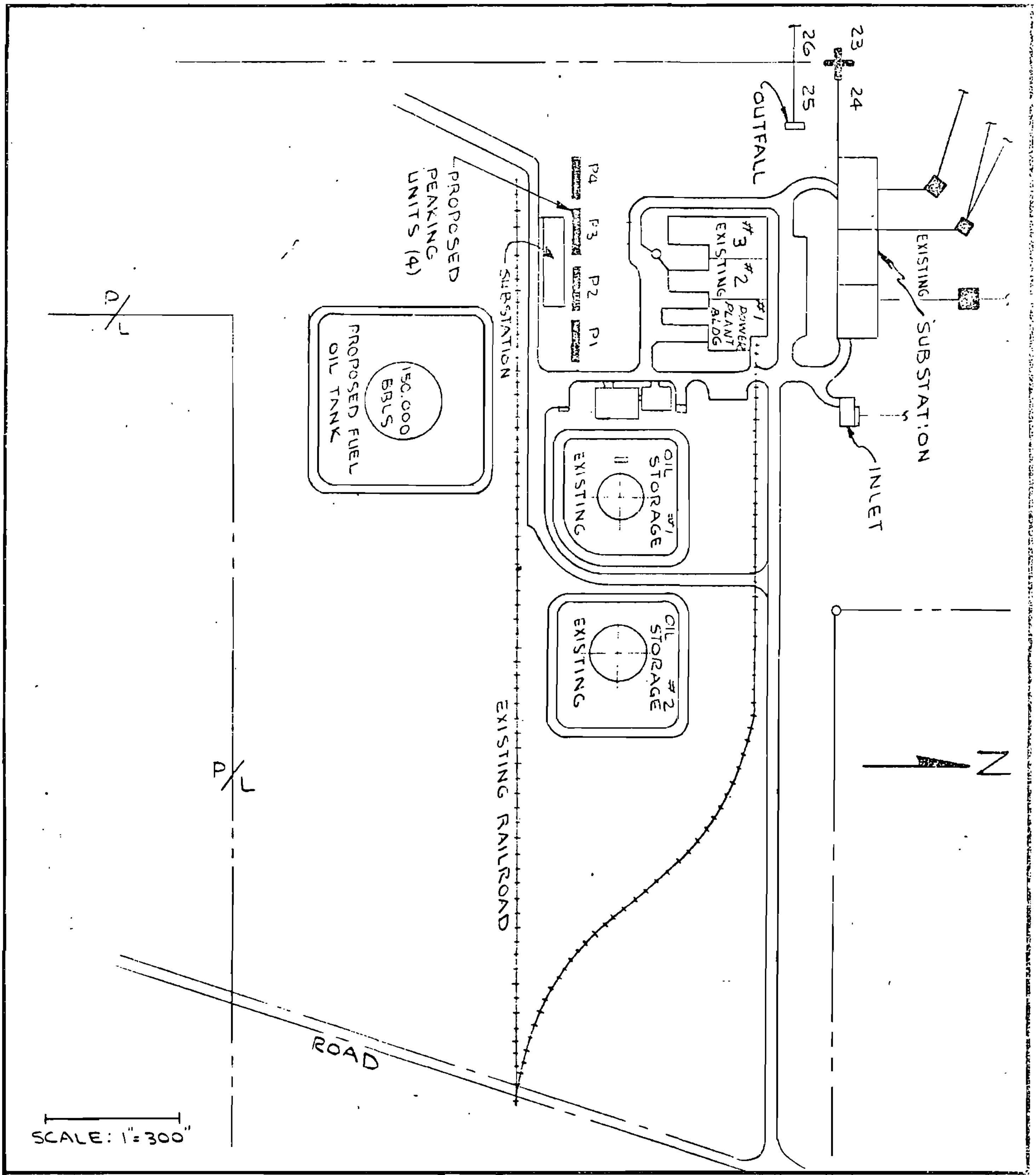
TPM recognizes the importance of clean air and will continue its intensive emission reduction program to keep abreast of and meet federal, state, and local regulatory standards. Actual rig and engine tests have demonstrated that the FT4C-1 engine can limit NOx emissions to meet known regulations by using water injection, steam injection, or the "dry fix".

The water or steam injection systems require provision of a demineralized water or steam source which is an added item of cost in most installations. Although TPM is prepared to provide such systems where they make economic sense, the "dry fix" approach appears to be the more desirable. The "dry fix" burner cans enable the customers to meet known NOx emission requirements without additional equipment or expense. This is particularly important in areas where water is scarce or unavailable. A demineralized water or steam source, which must be available for combined cycle plants, does not become a necessity for a TPM simple cycle gas turbine unit. This offers the customer maximum equipment selection flexibility when considering a TPM installation.

Typical TPM simple-cycle FT4 Twin Pac installation.



FLORIDA POWER CORPORATION
SYSTEM ENGINEERING DEPARTMENT

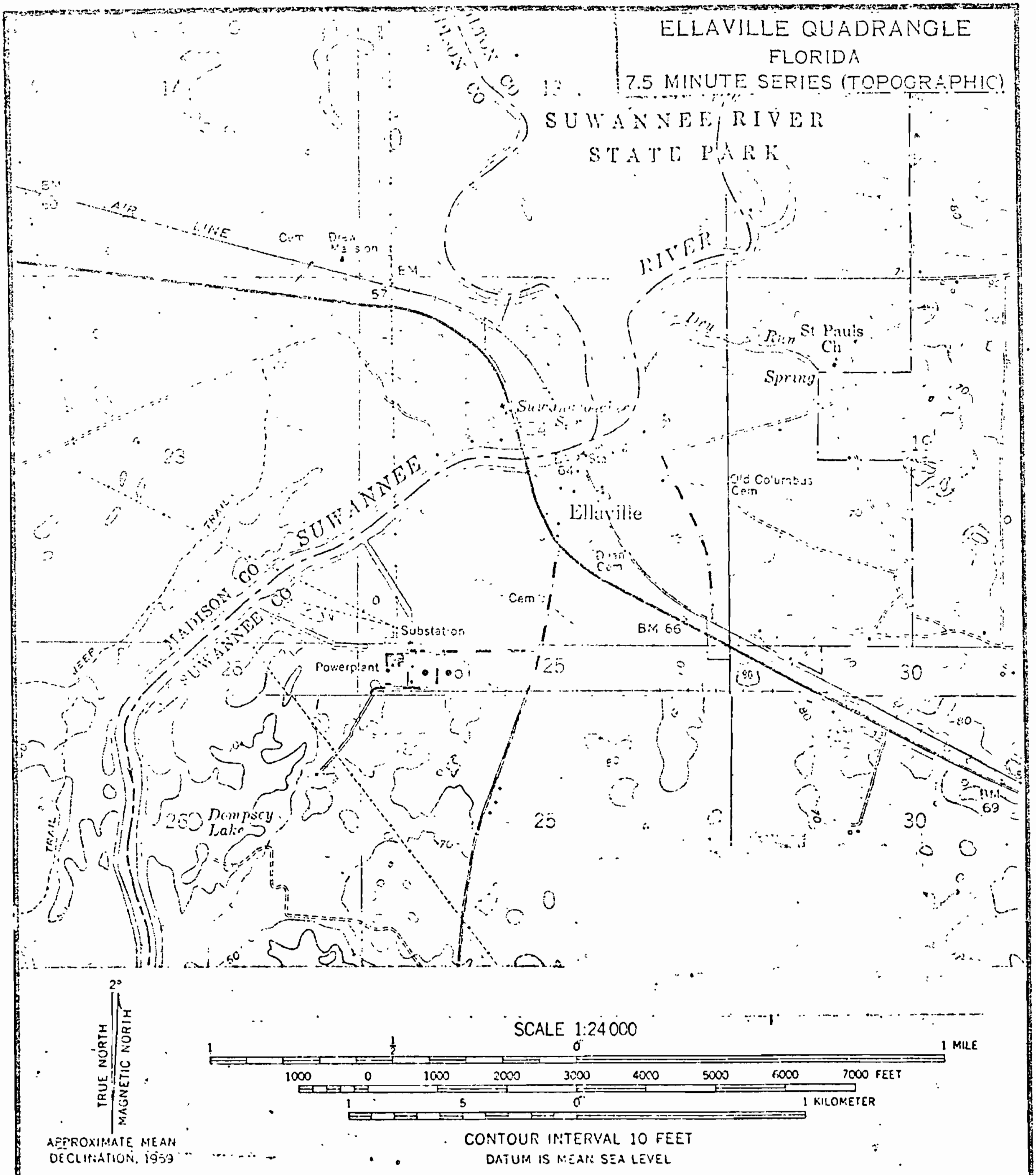


REVISIONS	
NO DATE	

SITE PLAN FOR
PROPOSED SUWANNEE
RIVER PEAKERS

DRAWN BY MWP
DATE 2-2-78
CHECKED
APPROVED R. O. [illegible]
SCALE 1" = 300'

SRP-L1-A-0



NO.	DATE	REVISION	BY	CK.	APP.

DATE 2-2-78 SCALE AS NOTED BY MWP CK. [illegible] APP. [illegible]

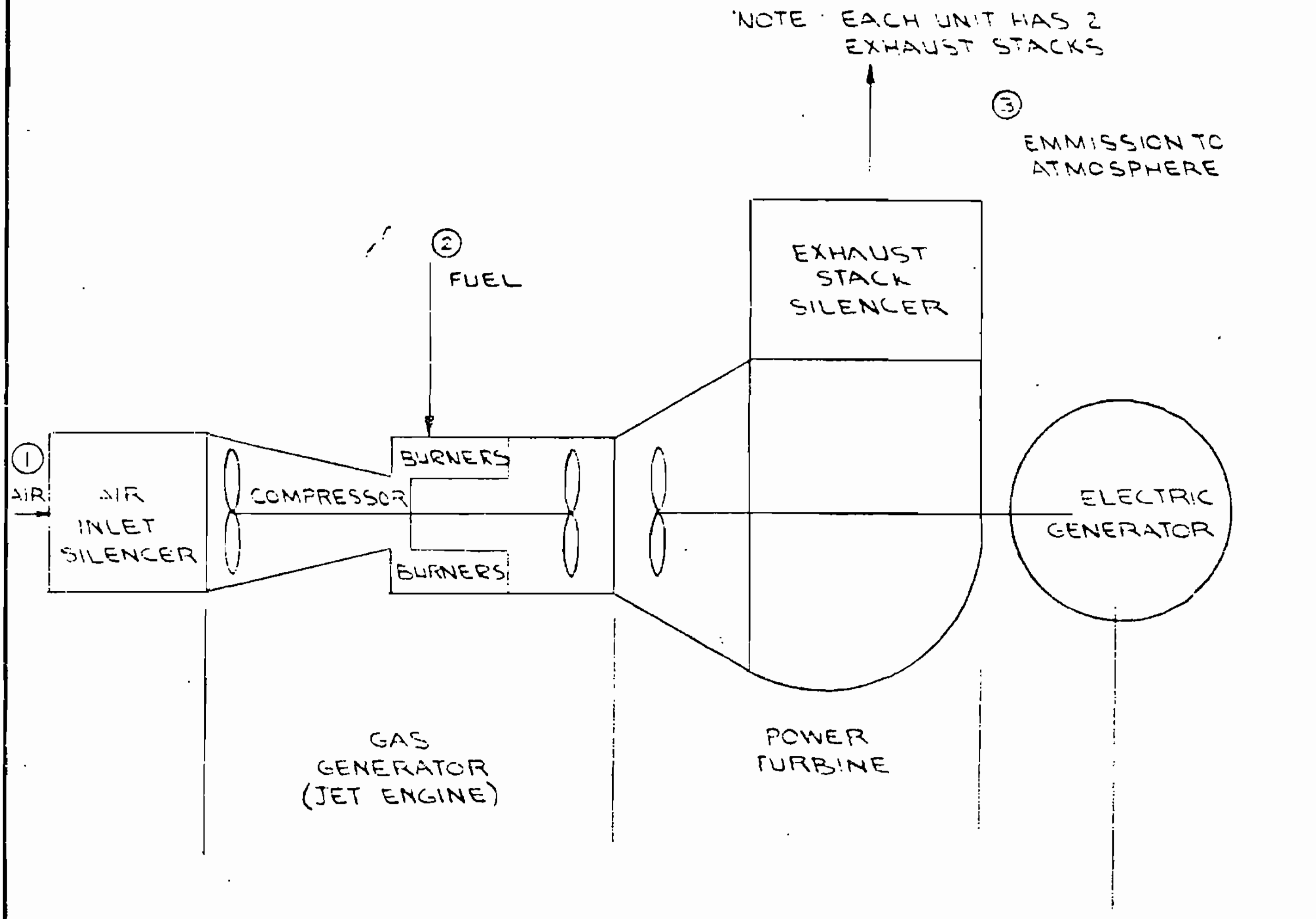
GENERAL AREA LOCATION MAP

PROJECT SUWANNEE R. GAS TURB. UNITS

FLORIDA POWER CORPORATION
ST. PETERSBURG, FLORIDA

DRAWING NO. SRP-L2 -A-O

FLORIDA POWER CORPORATION
SYSTEM ENGINEERING DEPARTMENT



NOTE: EACH UNIT CONSISTS OF
1 ELECTRIC GENERATOR
AND 2 JET ENGINES

NOTE: UNIT IS SYMETRICAL
ABOUT ℄

REVISIONS	
NO.	DATE

FLOW DIAGRAM
SUWANNEE RIVER PEAKERS

DRAWN BY
DATE 2/6/75
CHECKED
APPROVED
SCALE

DWG NO. SRP-L3-A-0

EXHIBIT A

DESCRIPTION OF FLORIDA POWER CORPORATION GAS TURBINE GENERATING UNITS TO BE LOCATED AT THE COMPANY SUWANNEE RIVER POWER PLANT SITE

Four (4) 63,000 KW gas turbine electric generating units are intended to be constructed for Florida Power Corporation. The units are planned for installation at the Florida Power Corporation Suwannee River Power Plant site. The units are scheduled for commercial operation in October 1980, and will be known as Suwannee River Peaking Units 1 through 4.

The gas turbine electric generating units are individually housed and are completely automated facilities. The units will be operated by remote control and no water is utilized for cooling purposes.

The plants are to be used for peaking purposes (intermittent operation) and will normally be run in the daytime and early evening during periods of peak electrical load. These units will be run at night only during emergencies.

At the peak power level of 63,000 KW, occurring at an ambient air temperature of 59°F, each unit will burn approximately 632 pounds of liquid fuel per minute. The exhaust gas flow at this rating will be 1,255,500 ACFM at an approximate temperature of 726°F. Clean burning fuel which will have a maximum sulfur content of 0.5% will be used. The output of the gas turbines will vary with the ambient air temperature and the maximum plant electrical output will vary accordingly.

Since the gas turbines utilize low sulfur fuel oil, causing an essentially clear exhaust discharge, the process is considered to be an extremely low pollution source. The smoke density is less than a Ringleman #1 during all modes of operation and the visible emissions shall be less than 20% opacity.

EXHIBIT B

WET METHOD

The present day available (state of the art) control device for reducing NO_X emissions formed in combustion turbines is injection of water with the fuel in the gas turbine burner chambers. Various types of burners are used by the major manufacturers and therefore the quantity of water injected will vary according to the particular manufacturer. In general the amount of water injection required to meet the allowable emission level (75 PPM NO_X by volume) will run from 50% to 100% of the total weight of fuel burned.

The water injection cools the flame which lowers the temperature which is the mechanism by which NO_X is formed in the combustion process.

To prevent high temperature corrosion of the turbine blades, only demineralized water can be used for the water injection (with Sodium content of 1 PPM or less). There is an efficiency loss in the combustion turbine due to water injection as follows:

Assume 1# of water need per 1# of fuel fired.

$$\Delta h \begin{pmatrix}\text{Heat required to vaporize 1\# of water at 70°F} \\ \text{to 726°F exhaust temperature}\end{pmatrix} = 1{,}356 \text{ BTU/\#}$$

Heating Value of fuel = 19,500 BTU/#

$$\text{Gross Loss in Thermal Efficiency} = \frac{\Delta h \text{ injection water}}{19{,}500} = \frac{1{,}356}{19{,}500} = 6.95\%$$

DRY METHOD

As an alternate, most manufacturers are developing burner chambers that will reduce NO_X emissions to the allowable level by staging the fuel combustion in various zones of the burner chambers to lower the overall burner temperatures and NO_X formation conditions. Presently this type of control is not available commercially for a gas turbine plant, but it is possible that due to rapid development, the "dry" NO_X burner chambers will be available at the time or soon after the new generating units will be operational (October 1980).

There is no loss in thermal efficiency when using the dry type emission control method and consequently it is the preferred method.

EXHIBIT C

SOCIAL ECONOMIC IMPACT

A fundamental social economic benefit is derived from the adequacy of electric supply to meet society's demand for energy. The proposed installation of 200 MW of gas turbine capability at Suwannee River Plant is part of a strategic generation expansion plan that has been evaluated as the economic optimum choice from a set of alternative plans. This selected strategy considers state wide coordination, including purchase power agreements and joint venture projects.

The construction of a four unit project will employ a peak construction work force and supervisory staff of approximately 125 people. Capitalized construction costs of each individual unit is estimated at approximately $10.5 million, including state sales taxes of approximately $275,000. Construction payroll will impact the local community with expected average monthly payroll for the project of $100,000 over the 18 month period. This represents a benefit to employment and the local economy relative to the subsistence needs of these local and transient workers. In addition to labor payroll, construction materials and supplies will be purchased from local businesses. Additional sales taxes will be derived from partial expenditure of this payroll by the construction labor force.

The unit will become operational in October 1980. The social economic impact of the operation of the plant can be best analyzed on a total project basis, as opposed to individual unit price and the resulting economic benefit could theoretically be allocated in proportionate shares to each unit.

This project will create an estimated eleven new permanent jobs to operate, maintain and manage the facilities, with an estimated new annual payroll of $275,000. These people will be residents of the local area and their income will stimulate the local economy, by the construction of homes and the consumption of goods and services to meet their living needs. State sales taxes and local property taxes will also be impacted by the presence of these plant personnel.

Production of energy from this plant will represent a vital part of the state's energy needs during peak load requirements. The role of these facilities in the overall configuration of Florida Power's generation plans is expected not to exceed 1500 hours per year, to supply peak load requirements. The characteristic low capital cost of these facilities, in spite of their higher fuel costs, results in an economic contribution to the energy supply for our system and for the state. The fuel oil consumed by these units is minimal because of the limited hours a year of operation during peak load requirements only.

The supply of fuel and the supply of outside materials and services to operate and maintain these facilities represents additional social economic benefit. The social economic costs of the presence of these facilities is represented by the added stress on socio-eco systems, including traffic congestion and other problems associated with higher population density - particularly during the construction phase.

EXHIBIT D

ASSESSMENT OF THE ENVIRONMENTAL IMPACT OF THE SOURCES

The site selected for the proposed combustion turbines is immediately adjacent to the existing fossil-fueled units of the Suwannee River Generating Facility. Because these new units will be built on already cleared and partially compacted land, no impact to natural vegetation or wildlife is anticipated. No alteration to the local hydrology is expected, and storm water runoff patterns will not be altered.

Any waste waters generated will be conveyed to the existing evaporation/percolation ponds. The noise generated during construction should be antenuated before it reaches the property boundaries.

The only potential environmental impact is alteration of the ambient air quality. This impact will be discussed in the Prevention of Significant Deterioration permit application.

ATTACHMENT B

STUDY GROUP RECOMMENDATIONS

State of Florida

DEPARTMENT OF ENVIRONMENTAL REGULATION

INTEROFFICE MEMORANDUM

For Routing To District Offices And/Or To Other Than The Addressee	
To:	Loctn.:
To:	Loctn.:
To:	Loctn.:
From:	Date:

TO: Al Townsend, Bob Kappelmann, Steve Smallwood and Frank Darabi

FROM: J. P. Subramani

DATE: May 22, 1978

SUBJECT: Florida Power Corporation BACT application for 4 stationary gas turbines to be constructed at the Suwannee River Plant site, Suwannee County, Florida.

The above referenced source will be considered for BACT determination when the BACT rule becomes effective about June 9, 1978.

You have been selected to participate in the BACT determination for this source. Enclosed for your review and evaluation is the complete application for BACT determination.

Your responding by June 16, 1978 will be appreciated.

JPS/VM/es

Enclosure

Walt Starnes

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

INTEROFFICE MEMORANDUM

For Routing To District Offices
And/Or To Other Than The Addressee
To: ______ Loctn.: ______
To: ______ Loctn.: ______
To: ______ Loctn.: ______
From: ______ Date: ______

TO: J.P. Subramani

FROM: Albert W. Townsend

DATE: June 19, 1978

SUBJECT: Application for Determination of Best Available Control Technology (BACT) for Gas Turbines

The subject application left quite a bit to be desired. No test data was supplied with the package; therefore, there is nothing to base an emission limiting standard on for SO_2 or NO_x emissions.

There was only one (1) method proposed to control SO_2 emissions; i.e., low sulfur fuel. Therefore, based on the application this would have to be considered BACT.

Two (2) methods were proposed for the control of NO_x. One method isn't commercially available; therefore, the wet method would have to be considered BACT.

I feel that all future BACT applications should be screened to insure that there is enough information and alternatives so that the reviewing engineer will have a choice. For instance, there is more than one way to reduce SO_2 emissions besides low sulfur fuel; i.e., limestone scrubbing, magnesium-oxide scrubbing, Wellman-Lord.

It is a waste of our time to attempt to analyze an incomplete application. It is suggested that no distribution for BACT determination be made until the application is complete and then a complete application should be sent to the appropriate parties.

If you have any questions please contact me, SUNCOM 451-5005.

AWT:fs

cc: Warren G. Strahm

H6 - Rev 7/76

DEPARTMENT OF HEALTH, WELFARE
& BIO-ENVIRONMENTAL SERVICES
Bio-Environmental Services Division
Air and Water Pollution Control

CITY OF JACKSONVILLE, FLORIDA

June 23, 1978

Dr. J.P. Subramani, Chief
Bureau of Air Quality Management
2600 Blair Stone Road
Tallahassee, FL. 32301

SUBJECT: BACT APPLICATIONS FOR FLORIDA POWER CORPORATION GAS TURBINES-SUWANNEE RIVER PLANT SITE

Dear Dr. Subramani:

I have reviewed the above mentioned applications and feel adequate data was not made available to form a sound judgement on what BACT for this type source should be. Specifically, question G9 is critical in finding out in fact how the proposed technology is working in practice. However, the following is offered based on the data supplied by the applicant and our own experience with gas turbines.

BACT should specify an emission rate as well as the equipment and/or procedures used for control. For example, low sulfur fuel is BACT for SO_2 for this source but to be effective, maximum sulfur content must be specified. This is also true with ash content.

Based on current fuel availability, BACT should require a fuel sulfur content of no greater than 0.3%. Ash content should be limited to less than .01% since 0.005% ash in this type fuel is available. Opacity should be limited to 10% or less except for start up. NOx control should be by water or steam injection. Steam should be specified unless a ready source of steam is not available. A water or steam to fuel ratio should be specified as well as a maximum ppm of NOx. Fifty (50) ppm NOx limit is possible at water or steam to fuel ratio of about 1.4. Particulate should be adequately controlled by specifying sulfur and ash content of the fuel and with a 10% opacity limit.

The above mentioned BACT limits are based on what should be readily available commercially. Even more restrictive limits are possible but the economics of greater cost with a minimal improvement in air quality must be considered.

Again my remarks are based on the data supplied. Deficiencies in the applications are numerous and seriously jeopardize the applicants ability to justify his requested BACT limits. I feel a workshop with the affected parties would be beneficial.

Sincerely,

Robert L. Kappelmann, P.E.
Air Pollution Control Engineer

RLK/dl

12.9.17.2

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

INTEROFFICE MEMORANDUM

For Routing To District Offices
And/Or To Other Than The Addressee

To:	Loctn.:
To:	Loctn.:
To:	Loctn.:
From:	Date:

TO: J. P. Subramani

FROM: Steve Smallwood

DATE: June 14, 1978

SUBJECT: BACT RECOMMENDATION
Four (4) Stationary Gas Turbines
Florida Power Company, Suwannee Plant Site
Suwannee County, Florida

This report provides background information and recommended BACT for four (4) new distillate oil fired, 63 megawatt (each) stationary gas turbines which Florida Power Company (FPC) proposes to install at their Suwannee River plant to provide peaking power.

SUMMARY

There are no emission limiting standards currently included in the Florida Air Pollution Control Regulations (17-2) which directly apply to stationary gas turbines. The rule therefore requires that the allowable emission standard be based on a determination of emission level achievable through the application of Best Available Control Technology (BACT).

At the present time the BACT for reducing air pollutant emissions resulting from the operation of large stationary gas turbines of the type proposed by FPC is the use of water or steam

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injection to control nitrogen oxide (NO_2) emissions, the use of low sulfur fuels to reduce sulfur dioxide (SO_2) emissions, and the use of more efficient fuel combustors (cannisters) to reduce smoke, hydrocarbon (HC) and carbon monoxide (CO) emissions.

Using this technology, NO_2 emissions can be reduced to below 75 ppm corrected to 15% Oxygen (O_2) in the exhaust gas, adjusted for the effects of turbine efficiency, nitrogen content of the fuel, and atmospheric conditions.

SO_2 can be limited to 150 ppm corrected to 15% oxygen by using #2 distillate oil, or to lower levels by using cleaner fuels if they are available.

Smoke, HC, and CO emission can be kept at acceptable levels by requiring the discharge gas to have an opacity of less than 20%, which is achievable.

Background information on FPC's proposed installation is included under DISCUSSION. Supporting information for the BACT recommendation is included under BACT and RECOMMENDED EMISSION STANDARDS. The proposed federal test method for stationary gas turbines is included as an attachment. Notes on several questions concerning FPC's proposal that are not fully answered by the information provided in their BACT application plus notes on several related issues are included under COMMENTS.

DISCUSSION

Florida Power Company plans to install four (4) stationary gas turbines at their Suwannee River Plant site. They propose to fire each unit with a maximum of 37,910 #/hr of distillate fuel oil (6.8 #/gal, 19,494 BTU/lb). Each unit is to be composed of two parallel jet engines, the exhausts from which will drive a power turbine. Each unit (pair of engines plus power turbine) is to be capable of generating 63 megawatts of electrical energy at peak load. Each megawatt-hr. of power output is equivalent to 3,413,000✓ BTU of energy. Total maximum hourly design peak output is then 215.019✓ MMBTU resulting from a total heat input of 739 MMBTU: a thermal efficienty or 'heat rate' of 29.1% (215/739)✓. each unit

Stationary gas turbines emit nitrogen oxides (NO, NO_2), sulfur dioxide (SO_2), hydrocarbons (HC), carbon monoxide (CO), fine particulate (PM), and smoke. Stationary turbines used for electrical power production are normally operated at or near rated capacity. They are usually operated for approximately five (5) hours per day to handle peak load electrical demand. Some companies will operate their turbines for short periods of time at no load conditions in anticipation of any rapid surge in power demand. This is referred to as "spinning reserve." The write-up in EPA's "Compilation of Air Pollutant Emission Factors", (AP-42, third edition, August 1977), on stationary gas turbines states that a 'typical' turbine operates 1200 hours per year, for 250 starts, operating 4.8 hours per start. The emission factors (#/hr per rated capacity-megawatts) for stationary gas turbines (AP-42, 3rd edition, section 3.3.1) are based on the following assumed load conditions:

15% @ zero load (spinning reserve)
2% @ 25% load
2% @ 50% load
2% @ 75% load
60% @ 100% load (rated)
19% @ 125% load (peak)

Based on these conditions and the AP-42 emission factors, each FPC gas turbine would be expected to have the following annual uncontrolled emissions:

MW (rated) X EF X (hr/yr X (T/lb) = Tons/yr

NO_x: 50.4 X 9.60 X 1200/2000 = 290

SO_2: 50.4 X 0.50 X 1200/2000 = 15

HC: 50.4 X 0.79 X 1200/2000 = 24

CO: 50.4 X 2.18 X 1200/2000 = 66

PM: 50.4 X 0.71 X 1200/2000 = 21

(Note: FPC listed 63 MW* as the peak load in their BACT application. Peak capacity is assumed to be 125% of rated continuous basis: 63 ÷ 1.25 = 50.4) The SO_2 emissions will vary directly with the sulfur content of the fuel used. The sulfur content assumed for the emission factor was not specified in AP-42. Typical sulfur content for distillate oil is approximately 0.5% with a maximum of 0.7%.

In their BACT application FPC listed each turbine as operating 1500 hours per year at four hours operation per start for 375 starts per year. These units are to operate daytime and early evening to provide peaking power. FPC estimates the actual

* See COMMENTS - #1

maximum discharge rate for each turbine as follows (from BACT application):

NO_x : 187.5 Tons per year

SO_2 : 284 Tons per year

HC : 6.75 Tons per year

CO : 64.5 Tons per year

PM : 28.5 Tons per year

These estimated emissions are to be discharged through a stack listed as having a minimum height of 22 ft. with a cross-sectional area of 130 sq. ft. (rectangular). The exit gas volume is listed at 1,255,500 ACFM at 726° - 800° F for an exit gas speed of 153 FPS. (At the listed exit volumetric flow rate and cross-sectional area the exit gas speed should be 160 FPS).

FPC lists the distillate oil as having a maximum sulfur content of 0.5%. If all sulfur in the fuel is converted to SO_2, the maximum annual SO_2 emissions based on their listed fuel use rate would be:

Fuel (#/hr) X % S/100 X 2(SO_2/S) X hr/yr ÷ 2000 = Tons/yr
37,910 X 0.005 X 2 X 1500/2000 = 284

which is in agreement with the FPC SO_2 estimate. The AP-42 emission factor for SO_2 for stationary gas turbines fired with oil is equivalent to burning an oil with a sulfur content of approximately 0.025%. This appears to be a technical or typographical error, and the emission factor should not be used. The FPC estimate is based on maximum sulfur content and continuous peak load operation for 1500 hours per year. Their actual average load can be expected to be in the range of 85-90%, therefore, actual annual SO_2 emissions can be expected to be approximately 200 Ton/yr (assuming 88% average load, and 0.4% average sulfur).

Both the AP-42 and FPC particulate emission estimates appear to be in a reasonable range.

Spinning reserve operation results in inefficient fuel combustion which can increase emissions of unburned carbon particles, hydrocarbons and carbon monoxide. In their BACT application FPC did not specify the percent of time that they expect to operate these units in spinning reserve.

The FPC and AP-42 carbon monoxide estimates are essentially the same, however the FPC hydrocarbon estimate is considerably less than the AP-42 estimate. Hydrocarbons generally will be burned to CO_2, CO, and water before CO is oxidized to CO_2. The amount of hydrocarbons emitted will depend upon the combustion efficiency, which will depend upon how the units are operated and maintained. At low load conditions and/or very low fuel to air ratios, hydrocarbon and CO emission can increase by a factor of 10. The FPC HC and CO estimates suggest that they expect to operate these turbines at moderate fuel to air ratios and at moderate to full load conditions during most of the time they are in operation, but a specific statement to this effect has not been included in the BACT application.

The NO_x emission estimates listed by FPC on their BACT application represent emissions after control. The control technology they propose (water injection to the gas turbine combustion chambers-cannisters) would reduce NO_x emission, but would have little effect on the other air pollutant emissions. The AP-42 emission estimates are for uncontrolled emissions.

US EPA published the results of their investigation of stationary gas turbine emissions in September 1977. In that report "Standards Support and Environmental Impact Statement, Volume 1: Proposed Standards of Performance for Stationary Gas Turbines" (EPA-450/2-77-017a), EPA included a table on page 3-46 of that document that summarized the air pollutant test results of several gas turbines produced by different manufactures. Below is a partial listing of that data for turbines of a size and type (simple cycle turbines) similar to those proposed for the Suwannee River Plant site.

Manufacturer & Engine No.	Type Fuel	Base Load MV	Plume Opacity	#/hr		
				NO_2	CO	SO_2*
General Electric						
M57001B	DF-2	59.4	-	371	0	355
M57001C	DF-2	66.2	<10%	531	4	401
Turbodyne 11C	DF-2	51.7^k	8%	319	47.2	332
Westinghouse N501B4	DF-2	88.85^k	< 20%	925	43.9	485

k - peak rate

* at 0.5% sulfur

Assuming that peak rates are about 1.25 times base load rates, the average #/hr of NO_2 per megawatt (base load design) is 8.75 with a standard deviation of 2.9 or 34% of the mean value. This data compares fairly well with the 9.6 #/hr factor listed in AP-42. Therefore FPC is proposing to reduce NO_2 emissions from their new gas turbines by approximately 49%: (363-187)/363*= 0.485.

The operation of the four (4) stationary gas turbines at the Suwannee River plant site would result in the following estimated actual annual emissions based on 1500 hr of operation for each turbine, a minimum of spinning reserve operation, the use of 0.3-0.5 % S distillate fuel oil (#1), an average load of 88%, and the uses of water injection to reduce NO_2 emission by approximately 50% from uncontrolled emission levels.

NO_2	:	140-190 Ton/yr
SO_2	:	200-270 Ton/yr
HC	:	10-20 Ton/yr
CO	:	50-60 Ton/yr
PM	:	20-30 Ton/yr
Smoke	:	<20% opacity

In the SSEIS document mentioned above, EPA presented the results of some modified diffusion modeling based on the CRSTER single source model. Three modifications were made to the model:
1) Briggs bouyant plume rise model is used to account for the expectation that the maximum ground level concentration will occur at a distance closer in to the source than the distance at which the plume reaches its maximum height; 2) The plume rise height used in the Single Source Model (CRSTER) is 70% of that estimated in (1) above. This is to account for the loss of plume rise observed due to strong wind shear and increased mechanical turbulance due to nearby buildings and the relatively low discharge height of turbine stacks (usually less than 10 meters). 3) The plume height at two building heights down wind of the turbine structure is calculated. If the plume centerline is less than 2.5 times the height of nearby structures, the vertical dispersion parameters are enhanced (increase indicated stability class).

The results of this modeling (Ch. 6 SSEIS document) suggests that the maximum ground level impact of the emissions from each of FPC's four turbines would be as follows:

* 290 (1500/1200) - The AP-42 estimate was based on 1200 hr. operation, the FPC estimate is based on 1500 hr. of operation.

Emissions: GLC: ug/m^3 for each turbine

gm/sec		3 hr	8 hr	24 hr	Annual
31.5	NO$_2$:	(250)	-	-	0.3
47.8	SO$_2$:	380	-	110	0.6
1.3	HC :	(10)			
10.8	CO :		0.2*		
4.8	PM :			(10)	(0.1)

* mg/m^3

Note: Numbers in parenthesis were estimated by comparison with other data included in the Table on page 6-22 SSEIS document.

While these estimates should be considered only rough approximations, they do indicate that neither HC, CO or particulate emissions from these turbines can be expected to have a significant impact on the surrounding ambient air quality, if the estimated emission rates are approximately correct.

However NO$_2$ and SO$_2$ emissions may have a significant impact.

If all four turbines were operated at the same time, on a windy day, a maximum ground level impact in the range 1200-1500 ug/m^3 SO$_2$ could possibly occur within one half kilometer downwind of the turbines. The three hour SO$_2$ air quality standard is 1300 ug/m^3, not to be exceeded more than once per year. Although the NO$_2$ emissions do not appear to be a direct threat to the annual average NO$_2$ standard, the Congress has directed EPA to establish a short term NO$_2$ standard. Unless this new standard has a numerical value significantly greater than 1000 ug/m^3 (and it probably won't), short-term ground level impact of NO$_2$ emissions from these stationary gas turbines may also reach levels near the new NO$_2$ ambient air quality standard.

BACT

Currently the best available control technology for this size and type of stationary gas turbine is:

1) Steam or water injection into the primary combustion zone of the gas turbine combustion cannisters at the rate of approximately 0.4-1.2 lbs water per lb of fuel to reduce peak combustion flame temperatures thus reducing thermally formed NO$_x$ emission. Reduction of up to 80% can be achieved.

2) The use of lower sulfur distillate fuel oil to reduce SO_2 emission. Residual oil could be used, but generally is not. It requires heating, special handling, and is usually high in sulfur content. Natural gas can be and is used, along with other very low sulfur fuels, such as kerosene and methanol, but they are not generally available in the quantities needed, at this time.

3) The use of improved combustion cannisters, that provide additional oxygen and turbulence in the primary combustion zone of the cannisters without excessively reducing the local combustion temperature, to minimize the formation and emission of smoke, HC, and CO particularly at low load conditions.

There are a variety of other technologies that could be used. But they have various characteristics which discourage their use at the present time.

For controlling any of these emissions, tail end clean-up such as lime or soda scrubbing for SO_2 removal or ammonia scrubbing for NO_2 removal are prohibitively expensive: two to three times the cost of the gas turbine.

There is a group of turbine combustion design changes, usually called 'dry controls' which on prototype gas turbines have resulted in NO_2 reduction as great as that achieved with water injection. But these techniques have not been fully demonstrated in commercial operation. Such techniques include catalytic combustion, pre-mixing and vaporizing air and fuel, improved fuel injection (atomization), variable combustion chamber geometry to improve turbulence, smooth out combustion chamber temperature profiles, and reduce residence time in the primary combustion zone (50% of the NO_x is formed within the first 0.5 milliseconds of combustion time; 100% within 3 milliseconds), exhaust gas recirculation (however the exhaust must be cooled to prevent engine malfunction), and off-stoichiometric combustion. Many of these techniques look promising and some combination of them will probably become the best technology, at least for smaller gas turbines, within the next 3-5 year.

mixing

RECOMMENDED EMISSION STANDARDS

In applying this technology the degree of emission reduction recommended is not as much a matter of what what is technically feasible as it is a matter of what is economically reasonable within the constraint of what is needed to meet the applicable ambient air quality standards.

By using more water, NO_2 emissions can be reduced to very low levels, but at water to fuel ratios above about 1.4 the water injection begins to significantly interfere with efficient turbine operation. Cleaner fuels than #2 distillate fuel oil can be used but they are more costly and generally less available than #2 oil. # 2 distillate oil has an upper sulfur content limit of 0.7% however 0.3 - 0.5% s oil is generally available, and 0.1% sulfur distillate oil can be purchased, but at a higher cost.

Considering these factors, EPA has proposed the following as NSPS for stationary gas turbines:

> The numerical emission limit for NO_x is to be 75 ppm by volume corrected to 15 percent oxygen and ISO ambient atmosphere conditions. The proposed standard would also include an adjustment factor for gas turbine efficiency and a fuel-bound nitrogen allowance. NO_x emissions from gas turbines, therefore, would be limited according to the following equation:
>
> $$STD = (0.0075\ E) + F$$
>
> where:
>
> STD = allowable NO_x emissions (percent by volume at 15 percent oxygen)
>
> E = efficiency adjustment factor:
>
> $$\frac{14.4 \text{ kilojoules/watt} \cdot \text{hr}}{\text{Actual ISO heat rate}}$$
>
> F = fuel-bound nitrogen allowance:

Fuel-Bound Nitrogen (percent by weight)	F (NO_x - percent by volume)
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	0.04(N)
$0.1 < N \leq 0.25$	0.004 + 0.0067 (N-0.1)
$N > 0.25$	0.005

> During performance tests to determine compliance with the proposed standard, measured NO_x emissions at 15 percent oxygen would be adjusted to ISO ambient atmospheric conditions by the following correction factor:
>
> $$NO_x = (NO_{x_{obs}}) \left(\frac{P_{ref}}{P_{obs}}\right)^{0.5} e^{19(H_{obs}-0.00633)}$$
>
> Where:
>
> NO_x = emissions of NO_x at 15 percent oxygen and ISO standard ambient conditions.
>
> $NO_{x_{obs}}$ = Measured NO_x emissions at 15 percent oxygen, ppmv.
>
> P_{ref} = Reference combustor inlet absolute pressure at

101.3 kilopascals (1 atmosphere) ambient pressure.

P_{obs} = Measured combustor inlet absolute pressure.

H_{obs} = Specific humidity of ambient air.

e = Transcendental constant (2.718)

The numerical emission limit for SO_2 would be 150 ppm by volume corrected to 15 percent oxygen or a fuel sulfur content limit of 0.8 percent by weight. There would be no efficiency adjustment factor or ambient condition correction factor for SO_2 emissions, since SO_2 emissions are not affected by gas turbine efficiency or ambient atmospheric conditions.

Higher efficiencies are normally achieved by increasing combustor operating pressures and temperatures and NO_x formation generally increases exponentially with increased pressure and temperature. High efficiency turbines, therefore, generally discharge gases with higher NO_x concentrations than low efficiency turbines. A concentration standard based on low efficiency turbines could restrict the use of some high efficiency turbines. Conversely, a concentration standard based on high efficiency turbines could allow such high NO_x concentrations that low efficiency turbines would require no controls. Consequently, having selected a concentration format for standards of performance, an efficiency adjustment factor needs to be selected to permit higher NO_x emissions from high efficiency gas turbines.

As mentioned above, NO_x emissions tend to increase exponentially with increased efficiency. It is not reasonable from an emission control viewpoint, however, to select an exponential efficiency adjustment factor. Such an adjustment would at some point allow very large increases in emissions for very small increases in efficiency. The objective of an efficiency adjustment factor should be to give an emissions credit for the lower fuel consumption of high efficiency gas turbines. Since the relative fuel consumption of gas turbines varies linearly with efficiency, a linear efficiency adjustment factor is selected to permit increased NO_x emissions from high efficiency gas turbines. A linear efficiency adjustment factor also effectively limits NO_x emissions to a constant mass emission rate per unit of power output.

The efficiency adjustment factor needs to be referenced to a baseline efficiency. Since most existing simple cycle gas turbines fall in the range of 20 to 30 percent efficiency, 25 percent is selected as the baseline efficiency. The efficiency of stationary gas turbines is usually expressed in terms of heat rate which is the ratio of heat input, based on lower heating value (LHV) of the fuel, to the mechanical power output. The heat rate of a gas turbine operating at 25 percent efficiency is 14.4 kilojoules per watt-hr (10,180 Btu per hp·hr). Thus, the following linear adjustment factor is selected to permit increased NO_x emissions from high efficiency stationary gas turbines:

$$x_a = x \cdot \frac{14.4}{Y}$$

$x \cdot \frac{14.4}{Y}$

where:

x_a = adjusted NO_x emissions permitted at 15 percent oxygen and ISO conditions, ppmv.

x = NO_x emission limit specified in the standards at 15 percent oxygen and ISO conditions, (i.e. 75 ppmv).

Y = LHV heat input per unit of power output (kilojoules/watt·hr).

NOTE: ISO conditions refers to standard atmospheric conditions of 760 mm mercury, 288° Kelvin and 60 percent relative humidity.

The only intent of this efficiency adjustment factor is to permit a linear increase in NO_x emissions with increased efficiencies above 25 percent. Consequently, the adjustment factor would not be used to adjust the emission limit downward for gas turbines with efficiencies of less than 25 percent.

In the event of future limited distillate oil supplies, many new gas turbines would probably be designed to fire residual or heavy fuel oils. Consequently, in order to provide gas turbine owners and operators the flexibility to fire either premium or heavy and residual fuel oils, but to ensure that standards of performance add no impetus toward the firing of heavy fuel oils as a means of evading standards, a fuel bound nitrogen allowance is proposed for the standard of performance limiting NO_x emissions from stationary gas turbines.

An allowance in the NO_x emission limit dependent on fuel-bound nitrogen level with no upper limit on emissions, however, could permit extremely high NO_x emissions when firing some very high nitrogen-containing fuels. Thus, it is essential that restraints be placed on such an emission allowance. A fuel-bound nitrogen allowance has been developed that allows approximately 50 percent use of the heavy fuel oils such as #6 fuel oil (desulfurized). This corresponds to a fuel-bound nitrogen content of about 0.25 weight percent. Firing a fuel with 0.25 weight percent fuel-bound nitrogen increases controlled NO_x emissions by about 50 ppm. Consequently, a fuel-bound nitrogen NO_x emission allowance based on a straight line approximation of the relationship between total NO_x emissions and fuel-bound nitrogen content with a maximum allowance of 50 ppm, due to fuel bound nitrogen is selected for the standard of performance.

The effect of ambient atmospheric conditions on NO_x emissions from stationary gas turbines is substantial. Large changes in relative humidity, for example, can cause NO_x emissions to vary by a factor of 2 or more. In order to insure that standards of performance are enforced uniformly, therefore, the effect of ambient atmospheric conditions on NO_x emission levels needs to be taken into account. The equation presented above to correct measured NO_x emissions to ISO ambient atmospheric conditions was derived by extracting the common elements from several ambient correction factors proposed by gas turbine manufacturers. This correction factor, therefore, represents the general effect of ambient atmospheric conditions on NO_x emissions. Consequently, the correction factor listed above, or an alternative factor as discussed below, is to be used to adjust measured NO_x emissions during any performance test to determine compliance with the numerical emission limit.

As an alternative, gas turbine manufacturers may elect to develop custom correction factors for adjusting measured NO_x emissions from particular gas turbine models. Some gas turbine manufacturers have proposed ambient correction factors which include variables such as fuel-to-air ratios and combustor temperatures. These variables are difficult to measure and are operating parameters which may vary widely due to factors other than atmospheric conditions.

Correction factors to adjust NO_x emissions to a reference humidity and pressure are recommended. If a manufacturer develops a correction factor for humidity and pressure specifically for his model of turbine, he may use those correction factors after submittal of substantiating data to EPA and approval by EPA. Correction factors for temperature are optional and, if used, must be developed by the manufacturer for the specific model. The International Standards Organization (ISO) standard day conditions of one atmosphere, 59°F and 60 percent relative humidity are chosen as the reference conditions. Since the existing correction factors were developed by manufacturers for turbines which use conventional combustors operating at, or near, stoichiometric conditions, they cannot be applied to turbines which use emerging technology combustors such as the low emission lean-burn types which operate at off-stoichiometric conditions. Correction factors for turbines which use non-conventional combustors must be developed by the manufacturer and approved by EPA for each specific turbine model.

For large gas turbines used to generate peaking power and burning distillate fuel oil, such as the FPC proposed turbines, the rate of efficiency decrease can be expected to be about 1 percent per year, due to degradation of the combustors, and errosion and/or deposits on the compressor or turbine blades. Deposits are usually removed by steam cleaning or by introducing crushed walnut shells or rice hulls into the air intake. Combustor life can be estimated so that maintenance activities and compliance tests can be scheduled accordingly. Decrease in efficiency can be monitored by standard process instrumentation, by measuring such things as pressure ratios, exhaust temperatures, and fuel flow. Turbines equipped with water injection should have equipment to continuously measure the water/fuel ratio. Compliance test should be conducted after each major turbine repair and when combustor sections are modified or replaced using EPA Test Method 20-Determination of NO_x, SO_2, and O_2 emissions from Stationary Gas Turbines, a copy of which is attached. Tests should be conducted at full load conditions, using the highest sulfur content fuel normally used, with the turbine operated at the A/F ratio normally used, with the water injection/fuel ratio typically used.

The reason for selecting a concentration standard is the fact that the high turbulence of turbine exhaust gas makes the determination of exhaust flow rates subject to considerable error. Concentration measurements will generally be more accurate and less expensive. To prevent circumvention of the standard by adding dilution air the concentration standard is tied to a specified oxygen content in the exhaust gas: 15% by volume which approximately corresponds to the normal amount of excess air used to properly operate such turbines.

Since SO_2 emissions are directly related to the amount of sulfur in the fuel, SO_2 emissions can be determined from a fuel quality analysis and measurements of fuel use.

Opacity can be determined by a trained observer using standard observation procedures based on a six minute average opacity - one observation each 15 seconds.

If we were to consider large stationary gas turbines as a class, I would recommend the adoption of the US EPA proposed NSPS with the addition of an opacity standard and a tighter SO_2 standard, in the range of 100-125 ppmv.

Considering the four (4) large turbines proposed by FPC as individual units, I recommend that NO_2 emission be limited to no more than 75 ppmv adjusted and corrected as in the EPA proposal; SO_2 be limited to no more than 100 ppmv; with an opacity standard of no more than 20%. I think that in this particular case it might be reasonable to require a tighter set of standards such as 60 ppmv NO_2, 80 ppmv SO_2, and 10% opacity. Such a set of standards are achievable, particularly if FPC intends to use and has a long term supply of high quality distillate oil (#1 oil), but their BACT application does not provide information on which to base an economic analysis of this alternative vs. their proposal of 75 ppmv NO_2, 95 ppmv SO_2, and 20% opacity.

Before making a final determination on BACT for these specific turbines, you may wish to consider some of the points raised in the next section.

COMMENTS

1. On the BACT application forms, FPC listed each turbine as generating 63,000 MW at peak load. This is a typographical error. They apparently meant 63 MW. In an attachment to the application, each unit was listed as 63,000 KW peak load, with the whole installation rated at 200 MW base load. This agrees with the AP-42 assumption of peak load being 1.25 times base load. One of the largest coal-fired steam-electric units in the country generates only 1300 MW. (the whole plant, which consists of three units, generates 2900 MW.)

2. FPC lists the specification for the distillate oil they plan to burn as 6.8 #/gal, 19,494 BTU/lb, with a maximum sulfur content of 0.5%. These are approximately the specifications for #1 distillate oil. #2 oil specifications are: 7.3 #/gal, 19,420 BTU/lb, with a maximum sulfur content of 0.7%. Both #1 and #2 oil are to have a water and sediment content of less than 0.1%. These standard specifications are based on the National Oil Fuel Institute's publication No. 68-101 "Fuel Oil Specifications".

3. In some cases steam injection appears to be more effective in reducing NO_x. In other cases water injection seems to work best. The difference appears to be related to specific design of the various machines tested and the way in which the injection is accomplished. Either steam or water injection are acceptable control techniques for NO_x.

4. Gas turbines are less fuel efficient than reciprocating engines, but they generally release lesser amounts of air pollutants. Diesel engines of comparable size to the turbines proposed by FPC, to my knowledge, do not exist.

5. Per pound of gas or oil burned, gas turbines, generally emit more HC, CO, and NO_x than external combustion boilers.

6. Feed water for the water injection system should be filtered and demineralized (less than 1% sodium) but it does not need to be of boiler feedwater purity.

7. In an attachment to their application (Exhibit B) FPC indicated that at a 1 to 1 water to fuel ratio turbine efficiency would be reduced by 6.95%. This was based on assuming that all of the heat used to vaporize the water and raise this vapor to 726°F (the stack gas exit temperature) was lost. Therefore, the 700 BTU's per lb for vaporation plus the 656 BTU/lb to raise the vapor temperature to 726°F was lost. Hence (1356/19,500) 6.95% of the heat input value of the fuel would be unavailable for producing work output.

   The overall efficiency of a heat engine is a function of the total heat input and the usable heat or work output. The heat rejected to the stack is lost whether it is transported by dry stack gas or by water vapor. In the engine, the water vapor absorbs and transfers usable energy. The real loss due to water injection is the unrecoverable heat used to convert liquid water to vapor, approximately 700 BTU/lb, about a 3.6% decrease in available heat input energy. If the turbine was 30% efficient without water injection, each BTU heat input would produce 0.30 BTU of work or electric energy output. A 3.6 decrease in available input energy would decrease output energy by the same amount. ✓ Thus the output would drop to 0.289 BTU's output, or an overall 1 percent decrease in thermal efficiency. The primary reason for low efficiency for gas turbines is the large amount of heat rejected to the stack. However, even if the turbine was a perfect thermal machine operating at a temperature of 3000°F (3460°R), with an ambient air temperature of 70°F (530°R) the highest thermal efficiency possible, due to thermodynamic considerations, would be 85% (3460-530)/3460. If such a machine rejected heat at 726°F (1186°R) its maximum possible efficiency would be 65%.

8. Table 4.2 on page 4-28 of EPA's SSEIS document for stationary gas turbines list 58 turbine installations which are currently on order or in operation with either water or steam injection. Seven installations were listed for Florida: One GE unit on order for the City of Jacksonville. One Westinghouse unit with 857 hours of operation owned by Jacksonville Electric; Four Westinghouse units owned by Florida Power and Light with water injection systems available, but not being used; one Westinghouse unit owned by Florida Power Company, located at Enterprise, Florida, with 718 hours of operation. Enterprise is in Volusia County, near Sanford.

9. The following is an analysis of the relationships among the data provided by FPC for each gas turbine.

Each turbine is to burn a maximum of 37,910 #/hr of light distillate fuel oil. Theoretical Air calculations indicate that about 14.5 lbs of air per lb of fuel is required for stoichiometric combustion. This results in 589,121 lbs/hr of exhaust or approximately 133,406 scfm of exhaust. Atmospheric moisture at 80°F would add about 2600 scfm. If a 1:1 water-fuel ratio is used for water injection the water would add about 14,000 scfm. At 15% oxygen there would be approximately 270% excess air, for a total dry volume of 470,420 scfm. FPC lists the exit gas volume for each turbine as 1,255,500 ACFM @ 726°F. It was not specified whether this was wet or dry volume. This would be a standard volume (at 60°F, 1atm) of 550,472 scfm. Assuming that this is meant to be wet or total volume including moisture , the turbine would be operated at 320% excess air which would correspond to 15.75% oxygen in the exit gas. Neither excess air or percent oxygen was specified in the application. Note the considerable change in indicated excess air for a small change in percent oxygen. This underscores the need for accurate O_2 measurements when conducting compliance tests.

Basing the 75 ppmv NO_2 standard on dry gas volume (Test Method 20 attached), and using the previously calculated dry volume of 470,420 scfm, the standard for these turbines is equivalent to 248 lb/hr emission, which agrees with FPC's estimate of 250 #/hr.

Using the same volume estimates, and FPC's recommended standard of 95 ppmv SO_2, I estimate an emission rate of 437 lb/hr, which corresponds to 0.575% S Fuel oil. FPC listed their maximum sulfur content at 0.5% S which is approximately equivalent to 80 ppmv. However, note that a small change in either exit volume due to a small change in theoretical air required, or sulfur content, or fuel heating value could result in 0.5 sulfur fuel being equivalent to 90-100 ppmv. Burning 0.5% sulfur light fuel oil results in SO_2 emissions of approximately 0.51 lbs/MMBTU. EPA's SSEIS document on gas turbines says that 150 ppmv is approximately equivalent to 0.8% S in fuel oil, which would imply that 95 ppmv is roughly equivalent to 0.5% sulfur.

10. There are several questions which I have noted in this report which you may wish to obtain more information on, before declaring BACT for these turbines, or before a Construction Permit is issued, whichever is appropriate.

Is an economic analysis of an alternate set of standards, such as 60 ppmv NO_2, 80 ppmv SO_2 and 10% opacity appropriate or necessary? If so additional information is needed.

What amount of "spinning reserve" is planned for these turbines?

What is the possibility of all four turbines operating at full load at the same time? It might affect the PSD review.

What other SO_2 sources are located near this site? An attachment to the BACT application indicated that there are existing fossil-fuel fired units at this site.

What bearing does EPA's development of a short term NO_2 standard have on the permit review for this facility?

What is the Air/fuel ratio for maximum load operation? What is the excess air? Is the exit volume listed on a total or dry basis? What is the planned water to fuel ratio? What has been FPC's experience with water injection at their Enterprise plant? What is the possibility of increasing the stack height to, say, 45 feet? What is the source of their fuel oil supply, and how certain is FPC that they can continue to obtain high grade light fuel oil for gas turbine fuel?

Many of these questions do not necessarily need to be answered prior to making the BACT determination, but they probably should be answered before a construction permit is issued.

11. If the nominal 75 ppmv NO_x emission standard is applied, the FPC turbines would actually be allowed an emission rate of 87 ppmv due to the efficiency adjustment factor, which would increase all of the NO_2 emission estimates included in FPC BACT application and this report by 16.4% (29.1/25.0). 25% is the base efficiency for the adjustment factor. Typical gas turbine thermal efficiencies range from 20-30%.

SS/ca

Attachments
Turbine pictorial
EPA Test Method 20

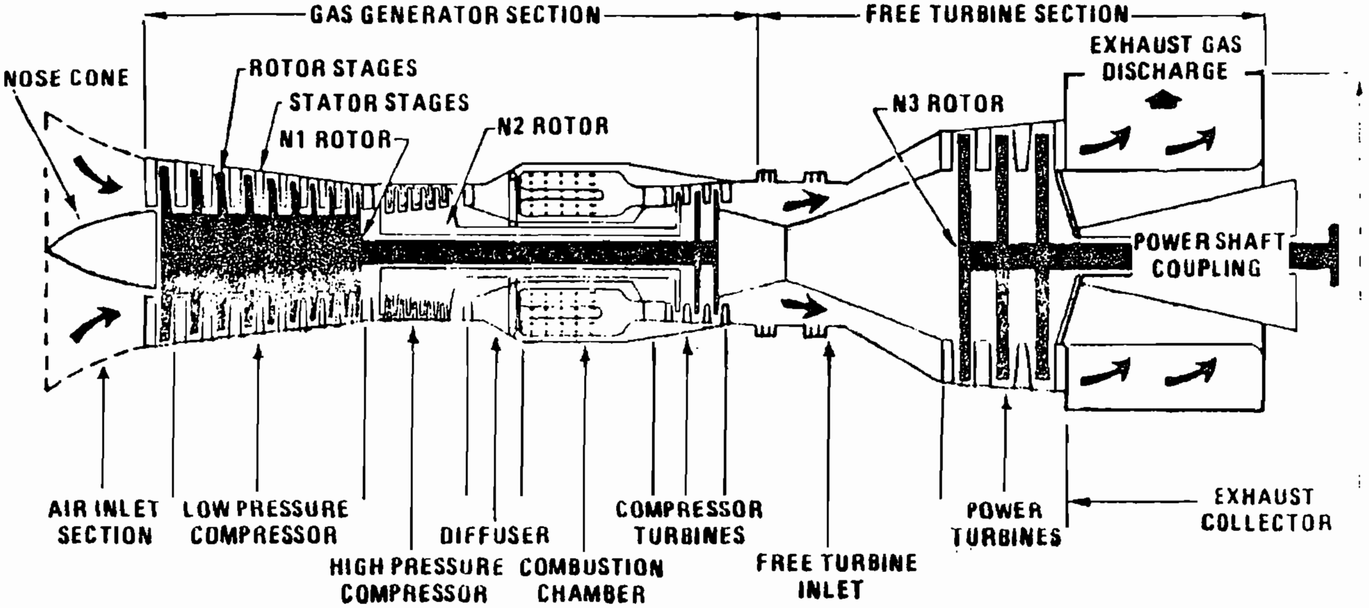

Figure 3-6. Cut away view of a typical simple cycle gas turbine.

APPENDIX - G

METHOD 20--DETERMINATION OF NITROGEN OXIDES, SULFUR DIOXIDE, AND OXYGEN EMISSIONS FROM STATIONARY GAS TURBINES

1. Principle and Applicability

1.1 Principle. A gas sample is continuously extracted from the exhaust stream of a stationary gas turbine; a portion of the sample stream is conveyed to instrumental analyzers for determination of nitrogen oxides (NO_x) and oxygen (O_2) content. During each NO_x and O_2 determination, a separate measurement of sulfur dioxide (SO_2) emissions is made, using Method 6, or its equivalent. The O_2 determination is used to adjust the NO_x and SO_2 to a reference condition.

1.2 Applicability. This method is applicable for the determination of nitrogen oxide, sulfur dioxide, and oxygen emissions from stationary gas turbines. For the NO_x and O_2 determinations, this method includes: (1) measurement system design criteria, (2) analyzer performance specifications and performance test procedures; and (3) procedures for emission testing.

2. Apparatus and Reagents

2.1 Measurement System. The equipment required to extract, transport, and analyze the gas sample constitutes the "measurement system." A schematic of the measurement system is shown in Figure 20-1. (Measurement system performance specifications are described in detail in Section 3.) The essential components of the measurement system are described below.

2.1.1 Probe. Stainless steel type 316 or equivalent, to transport gas from stack.

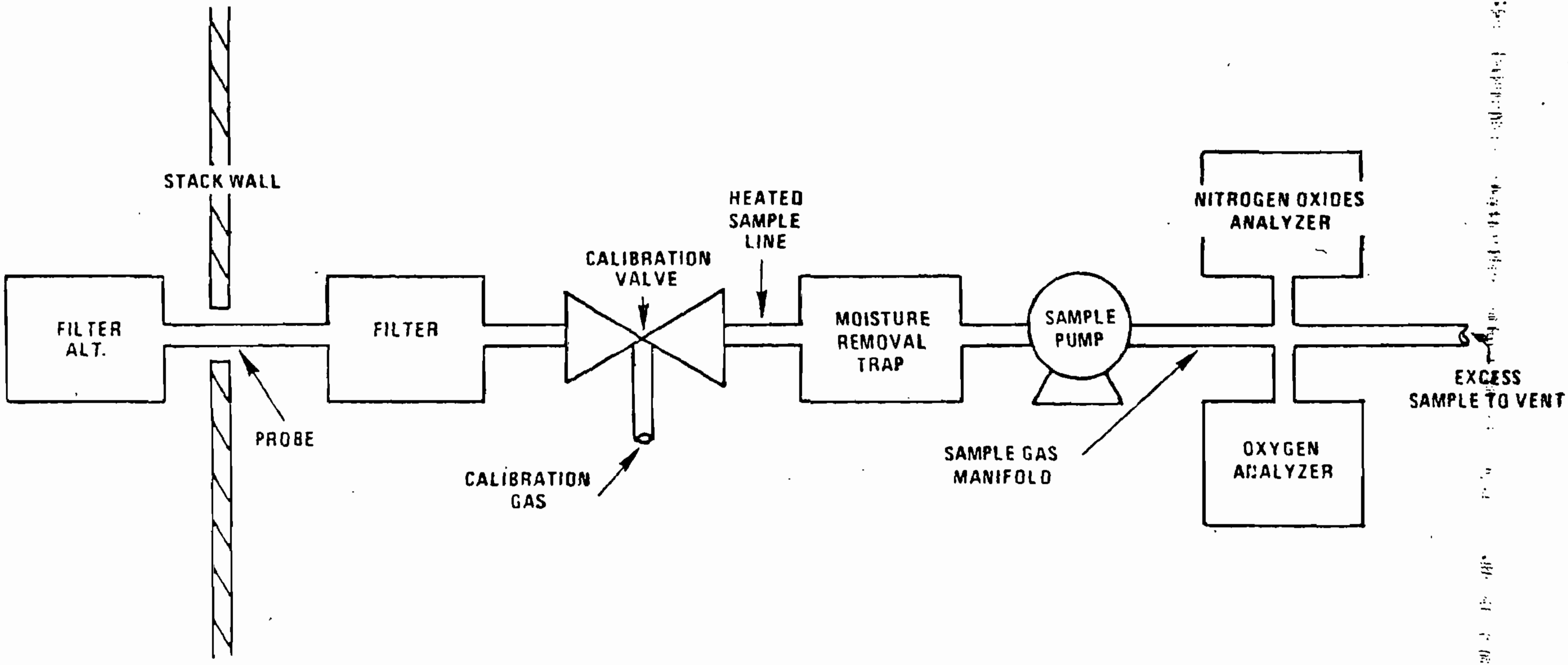

Figure 20.1 Measurement system design for stationary gas turbine tests.

2.1.2 Particulate Filter. A filter is used to remove particulates ahead of the calibration valve assembly. In most cases, either in-stack or out-stack filter location is acceptable; however, out-stack filtration is required when the sample gas temperature is above 500°C (930°F). The filtration temperature shall be at least 120°C (250°F) to prevent moisture condensation. Glass fiber filters, of the type specified in EPA Method 5, or equivalent, are recommended.

2.1.3 Calibration Valve Assembly. A three-way valve assembly is used to direct the zero and span calibration gases to the analyzers. This assembly shall be located directly behind the probe and filter and shall be capable of blocking the sample gas flow and introducing the span and zero gases when the system is in the calibration mode.

2.1.4 Calibration Gases. Calibration gases are used to perform zero, span and calibration checks of the analyzers during each test run. The concentrations and specifications of these gases are described in detail in Sections 2.2 and 6.2.

2.1.5 Heated Sample Line. A FEP fluorocarbon or stainless steel (type 316 or equivalent) sample line is used to transport the gases to the sample conditioner and analyzers. The sample gas shall be maintained at least 5°C (10°F) above the stack gas dew point to prevent moisture condensation.

2.1.6 Moisture Trap. A moisture trap, designed to reduce the dew point of the sample gas to 3°C (37°F) or less, is used. For instruments not affected by water vapor, this device is not required; however, the moisture content shall be determined using methods subject to the approval of the Administrator and the NO_x and O_2 concentrations shall be corrected to a dry gas basis.

2.1.7 Pump. A nonreactive leak-free sample pump is used to pull the sample gas through the system at a flow rate sufficient to minimize transport delay. The pump shall be made from or coated with nonreactive material (FEP fluorocarbon or type 316 stainless steel).

2.1.8 Sample Gas Manifold. A sample gas manifold is recommended for diverting portions of the sample gas stream to the analyzers. The manifold may be constructed of glass, FEP fluorocarbon, or stainless steel (type 316 or equivalent). Instead of using the manifold, separate sample lines may be connected to each analyzer.

2.1.9 Oxygen Analyzer. An oxygen analyzer is used to determine the oxygen concentration (percent O_2) of the sample gas stream.

2.1.10 Nitrogen Oxides Analyzer. A NO_x analyzer is used to determine the ppm concentration of nitrogen oxides in the sample gas stream.

2.1.11 Sulfur Dioxide Analysis. Method 6 apparatus, or equivalent, is required for sulfur dioxide determination.

2.2 Calibration Gas Specifications.

2.2.1 Zero Gas. Prepurified nitrogen is used.

2.2.2 Nitrogen Oxide Calibration Gases. Mixtures of known concentrations of NO in nitrogen are required. Nominal NO concentrations of 25, 50, and 90 percent of the instrument full scale range are needed. The 90 percent gas mixture is used to set and check the instrument span and is referred to as span gas. The 25 and 50 percent gas mixtures shall be used to validate the analyzer calibration, prior to each test.

2.2.3 Oxygen Calibration Gases. Ambient air at 20.9 percent oxygen shall be used as the span gas (high range concentration gas). A midscale calibration gas (approximately 13 percent O_2 in nitrogen) shall be used to validate the analyzer calibration prior to each test.

2.2.4 Concentration Validation. Within one month prior to test use, calibration gases shall be analyzed, by the appropriate test method specified in Section 6.2, to determine their true concentration levels. Gas concentrations that are traceable to the National Bureau of Standards and which can be demonstrated to be stable are exempted from the analysis requirements.

3. Measurement System Performance Specifications and Performance Test Procedures

3.1 Analyzer. "Span" is defined as the concentration range (specified by manufacturer) over which an analyzer will give valid readings. The spans for the analyzers used in this method shall be as follows:

3.1.1 Oxygen Analyzer: 0 to 25% O_2

3.1.2 NO_x Analyzer: 0 to 120 ppm

3.2 Analyzer Interferences and Interference Response. The "interference response" of an analyzer is defined as the output response to a component in the sample gas stream, other than the gas component being analyzed; the analyzers used in this method shall not have a total interference response of more than ± 2 percent of span.

Particulate matter and water vapor are the primary interfering species for most instrumental analyzers, but these may be removed physically by using filters and condensers. Other possible specific interferents found in turbine exhaust streams include carbon monoxide, carbon dioxide, nitrogen oxides, sulfur dioxide and hydrocarbons. Each analyzing instrument may respond to one or more of these interferents in ways that alter the desired measurement.

The interference response of an analyzer is determined by measuring the total analyzer response to the gaseous components (or mixtures) listed in Table 20.1; these gases may either be introduced into the analyzer separately, or as a single gas mixture. The total interference output response of the analyzer to these components, if any, shall be determined (in concentration units). The values obtained in an interference response test shall be recorded on a form similar to Figure 20.2. If the sum of the interference responses of the test gases is greater than 2 percent of the instrument span, the analyzer shall not be used in the measurement system of this method.

An interference response test of each analyzer shall be conducted prior to its initial use in the field. Thereafter, if changes are made in the instrumentation which could alter the interference response, e.g., changes in the type of gas detector, the instruments shall be retested.

In lieu of conducting the interference response test, instrument vendor data, which demonstrate that for the test gases of Table 20.1 the interference performance specification is not exceeded, are acceptable. If these data are not available, the tests shall be made.

TABLE 20.1 INTERFERENCE TEST GAS CONCENTRATIONS

CO	500 ppm
SO_2	200 ppm
NO/NO_2	200 ppm
CO_2	10%
O_2	20.9% (Air)

FIGURE 20.2 INTERFERENCE RESPONSE

Date of Test:____________________

Analyzer Type:____________________ S/N_______________

Test Gas Type	Conc.	Analyzer Output Response	% of Span

$$\% \text{ of Span} = \frac{\text{Analyzer Output Response}}{\text{Instrument Span}} \times 100$$

3.3 Analyzer Response Time. When a change in pollutant concentration occurs at the inlet of the measurement system (i.e., at probe), the change is not immediately registered by the analyzer; "response time" is defined as the amount of time that it takes for the analyzer to register a concentration value within 5 percent of the new inlet concentration. The maximum response time for the analyzers used in this method is three minutes.

To determine response time, first introduce zero gas into the system until all readings are stable; then, introduce span gas into the system. The amount of time that it takes for the analyzer to register 95 percent of the final span gas concentration is the upscale response time. Next, reintroduce zero gas into the system; the length of time that it takes for the analyzer output to come within 5 percent of the final reading is the downscale response time. The upscale and downscale response times shall each be measured three times. The readings shall be averaged, and the average upscale or downscale response time, whichever is greater, shall be reported as the "response time" for the analyzer. Response time data are recorded on a form similar to Figure 20.3. A response time test shall be conducted prior to the initial field use of the measurement system, and shall be repeated if changes are made in the measurement system.

3.4 Zero Drift. "Zero drift" is the change in analyzer output during a turbine performance test, when the input to the measurement system is a pure grade of nitrogen (zero gas). The maximum allowable

RESPONSE TIME

Date of Test ______________________

Analyzer Type ______________________ S/N ______________________

Span Gas Concentration ____________ ppm

Analyzer Span Setting _____________ ppm

	1 ____________	seconds
Upscale	2 ____________	seconds
	3 ____________	seconds

Average upscale response __________ seconds

	1 ____________	seconds
Downscale	2 ____________	seconds
	3 ____________	seconds

Average downscale response __________ seconds

System response time = slower average time = __________ seconds.

Figure 20.3

zero drift for the analyzers used in this method is ± 2 percent of the specified instrument span. The zero drift calculation is made for each gas for each turbine test run; this is done by taking the difference of the zero gas concentration values measured at the start and finish of the test (see Section 6.1). The zero drift is recorded (as a percentage of the instrument span) on a form similar to Figure 20.4.

3.5 Span Drift. "Span drift" is the change in the analyzer output during a turbine performance test, when the input to the measurement system is span gas. The maximum allowable span drift for the analyzers used in this method is ± 2 percent of the specified instrument span. The span drift calculation is to be made for each gas for each turbine test run; this is done by taking the difference between the span gas concentration values measured at the beginning and end of the test. Span drift is recorded (as a percentage of instrument span) on a form similar to Figure 20.4. Span drift must be corrected for any zero drift that occurred during the test period (see Figure 20.4).

4. Procedure for Field Sampling

4.1 Selection of a Sampling Site and the Minimum Number of Traverse Points.

4.1.1 Select a sampling site as close as practical to the exhaust of the turbine. Turbine geometry, stack configuration, internal baffling, and point of introduction of dilution air will vary for different turbine designs. Thus, each of these factors must be given special consideration in order to obtain a representative sample. Whenever possible, the sampling site shall be located upstream of the

TURBINE SAMPLING SYSTEM

Zero and Span Drift Data

Turbine Type ____________________ S/N ____________________

Date: ____________________

Test No.: ____________________

Analyzer: Type ____________________ S/N ____________________

	Initial Calibration ppm or %	Final Calibration ppm or %	Difference Initial-Final ppm or %	% of Span
Zero Gas				
High Calibration Gas (Span Gas)			*	

$$\% \text{ of Span} = \frac{\text{Absolute Value of Difference}}{\text{Instrument Span}} \times 100$$

*Corrected for zero drift, i.e., if zero drift over test period is +2 ppm then 2 ppm shall be subtracted from the difference between the initial and final readings.

Figure 20.4

point of introduction of dilution air into the duct. Sample ports may be located before or after the upturn elbow, in order to accommodate the configuration of the turning vanes and baffles and to permit a complete, unobstructed traverse of the stack. The sample ports shall not be located within 5 feet or 2 diameters (whichever is less) of the gas discharge to atmosphere. For supplementary-fired, combined-cycle plants, the sampling site shall be located between the gas turbine and the boiler.

4.1.2 The minimum diameter of the sample ports shall be 3-inch nominal pipe size (NPS).

4.1.3 The minimum number of points for the preliminary O_2 sampling (Section 8.3.2) shall be as follows: (1) eight, for stacks having cross-sectional areas less than 1.5 m^2 (16.1 ft^2); (2) one sample point for each 0.2 m^2 (2.2 ft^2) of area, for stacks of 1.5 m^2 to 10.0 m^2 (16.1 - 107.6 ft^2) in cross-sectional area; and (3) one sample point for each 0.4 m^2 (4.4 ft^2) of area, for stacks greater than 10.0 m^2 (107.6 ft^2) in cross-sectional area. Note that for circular ducts, the number of sample points must be a multiple of 4, and for rectangular ducts, the number of points must be one of those listed in Table 20.2; therefore, round off the number of points (upward), when appropriate.

4.2 Cross-sectional Layout and Location of Traverse Points. After the number of traverse points for the preliminary O_2 sampling has been determined, use Method 1 to locate the traverse points.

TABLE 20.2 CROSS-SECTIONAL LAYOUT FOR RECTANGULAR STACKS

No. of traverse points	Matrix layout
9	3 x 3
12	4 x 3
16	4 x 4
20	5 x 4
25	5 x 5
30	6 x 5
36	6 x 6
42	7 x 6
49	7 x 7

4.3 Measurement System Operation.

4.3.1 Preliminaries.

4.3.1.1 Prior to the turbine test, the measurement system shall have been demonstrated to have met the performance specifications for interference response and response time described in Sections 3.2 and 3.3.

4.3.1.2 Turn on the sample pump and instruments; allow the normal warmup time required for stable instrument operation.

4.3.1.3 After the instruments have stabilized, the measurement system shall be calibrated using the procedures detailed in Section 6.1. Transfer the zero and span gas calibration data from Figure 20.5 to a form similar to Figure 20.4.

4.3.1.4 At the beginning of each NO_x test run and, as applicable, during the run, record turbine data as indicated in Figure 20.6 Also, record the location and number of the traverse points on a diagram.

4.3.2 Preliminary Oxygen Sampling.

4.3.2.1 At the start of a 3-run sample sequence, position the probe at the first traverse point and begin sampling. The minimum sampling time at each point shall be 1 minute plus the average system response time. Determine the average steady-state concentration of O_2 at each point and record the data on Figure 20.7.

4.3.2.2 Select the eight sample points at which the lowest oxygen concentrations were obtained. These same points shall be used for all three runs which comprise the emission test. More points may be used, if desired.

Figure 20.5

CALIBRATION DATA

Date________________________

Analyzer Type__________________ S/N__________________________

High Range Gas Conc.____________ % Full Scale__________________

Mid Range Gas Conc.____________ % Full Scale__________________

Low Range Gas Conc.____________ % Full Scale__________________

Zero Gas______________________ % Full Scale__________________

Figure 20.6

STATIONARY GAS TURBINE

TURBINE OPERATION RECORD

Test Operator____________________ Date____________________

Turbine ID
Type________________
S/N________________

Location
Plant________________
City________________

Ambient Temperature________________

Ambient Humidity________________

Test Time Start________________

Test Time Finish________________

Fuel Flow Rate________________*

Water or Steam Flow Rate________________*

Ambient Pressure ________________

Ultimate Fuel Analysis
C________________
H________________
O________________
N________________
S________________
Ash________________
H_2O________________

Trace Metals
____
Na________________
Va________________
K________________
etc.**________________

Operating Load________________

---

*Describe measurement method, i.e., continuous flow meter, start finish volumes, etc.

**i.e., Additional elements added for smoke suppression.

FIGURE 20.7

Preliminary Oxygen Traverse

Location ________________ Date ____________

Plant ________________________

City, State ________________________

Turbine ID

Mfg. ________________________

Model, serial number ________________________

Sample Point	Oxygen Concentration

4.3.3 Emission Sampling.

4.3.3.1 Position the probe at the first point determined in the preceding section and begin sampling. The minimum sampling time at each point shall be 3 minutes plus the average system response time. Determine the average steady-state concentration of O_2 and NO_x at each point and record the data on Figure 20.8.

4.3.2.2 After sampling the last point, conclude the test run by recording the final turbine operating parameters and by determining the zero and span drift, as described in Sections 3.4 and 3.5. If the zero and/or span drift exceed ±2.0 percent the run may be considered invalid, or may be accepted provided the calibration data which results in the highest corrected emission concentration is used.

4.3.2.3 If additional turbine runs are conducted within 4 hours of the previous run, an initial calibration of the measurement system is not required. If more than 4 hours have elapsed between runs, the pretest calibration shall be done.

4.4 An SO_2 determination shall be made (using Method 6, or equivalent) during the test. A minimum of six total points, selected from those required for the NO_x measurement, shall be sampled; two points shall be used for each sample run. The sample time at each point shall be at least 10 minutes. The oxygen readings taken during the NO_x test runs corresponding to the SO_2 traverse points (see Section 4.3.3.1) shall be averaged, and this average oxygen concentration shall be used to correct the integrated SO_2 concentration obtained by Method 6 to 15 percent O_2 (see Equation 20-1).

Figure 20.8

STATIONARY GAS TURBINE
GAS SAMPLE POINT RECORD

Turbine ID
Mfg. ____________________
Model & S/N ________________

Location
Plant ____________________
City ____________________
State ____________________

Ambient Temp. ____________________
Ambient Press ____________________
Ambient Humidity ____________________
Date ____________________
Test Time Start ____________________
Test Time Finish ____________________

Test Operator Name ____________________
O_2 Instrument Type ____________ S/N ____________
NO_x Instrument Type ____________ S/N ____________

Sample Point	Time (Min)	O_2* (%)	NO_x* (ppm)
1	0		

*Average steady state value from recorder or instrument readout.

5. Emission Calculations

5.1 Correction to 15 Percent Oxygen. Using Equation 20-1, calculate the NO_x and SO_2 concentrations (adjusted to 15 percent O_2). The correction to 15 percent oxygen is sensitive to the accuracy of the oxygen measurement. At the level of analyzer drift specified in the method (±2 percent of full scale), the change in the oxygen concentration correction can exceed 10 percent when the oxygen content of the exhaust is above 16 percent O_2. Therefore O_2 analyzer stability and careful calibration are necessary.

$$\begin{array}{c}\text{Actual Pollutant}\\ \text{Concentration}\\ (NO_x \text{ or } SO_2)\end{array} \times \frac{5.9\%}{20.9\% - O_2\% \text{ actual}} = \begin{array}{c}\text{Pollutant concentration}\\ \text{adjusted to } 15\%\ O_2\end{array}$$

Equation 20-1

where:

5.9% is 20.9% - 15% (the defined concentration basis)

O_2 actual is the sample point oxygen concentration for NO_x calculation, and the average O_2 concentration for SO_2 calculation.

5.2 Calculate the average adjusted NO_x concentration by summing the point values and dividing by the number of sample points.

6. Calibration

6.1 Measurement System. Prior to each turbine test, the measurement system shall be calibrated according to the procedures described below. The manufacturer's operation and calibration instructions are also to be followed as required for each specific analyzer.

6.1.1 Turn on all measurement system components and allow them to warm up until stable conditions are achieved. Next, introduce zero gas and each of the calibration gases described in Section 6.2, one at a time, into the inlet of the probe. The responses of the analyzer to these gases shall be used to establish a calibration curve or to verify the manufacturers calibration curve. The data obtained in these procedures shall be recorded on a form similar to Figure 20.4. If, for the mid-scale gases, the accuracy of the manufacturer's calibration curve or the expected response curve cannot be shown to be ±2 percent of full scale (or better), the calibration shall be considered invalid and corrective measures on the instrument shall be taken. The calibration procedure shall be repeated, using only zero gas and span gas, at the conclusion of test; this allows calculation of zero and span drift (Sections 3.2 and 3.3).

6.2 Calibration Gas Mixtures.

6.2.1 Within one month prior to the turbine test, the NO_x calibration gas mixtures shall be analyzed, using the phenoldisulfonic acid procedure (Method 7) for nitrogen oxides. A minimum of three analyses shall be done, and the average concentration of each gas shall be reported as the true calibration gas value (see Figure 20.9). Alternate procedures may be employed, subject to the approval of the Administrator, to determine the calibration gas concentration.

Note: The NO_x calibration gas mixtures shall contain nitric oxide (NO) in nitrogen. Instruments which require conversion of one nitrogen

Figure 20.9

ANALYSIS OF CALIBRATION GAS MIXTURES

CYLINDER GAS COMPOSITION   Reference Method Used________

ID. ______________________________

Low Range Calibration Gas Mixture

Sample 1____________ppm

Sample 2____________ppm

Sample 3____________ppm

Average_____________ppm

Mid Range Calibration Gas Mixture

Sample 1____________ppm

Sample 2____________ppm

Sample 3____________ppm

Average_____________ppm

High Range (Span) Calibration Gas Mixture

Sample 1____________ppm

Sample 2____________ppm

Sample 3____________ppm

Average_____________ppm

oxide component to another for total NO_x measurement shall be checked to ensure that this conversion is complete and reproducible, as specified by the manufacturer.

6.2.2 Ambient air may be used as the oxygen span gas. The mid-scale calibration gas concentration shall be certified (by vendor) as being within ±2 percent of the indicated concentration.

• U.S. GOVERNMENT PRINTING OFFICE: 1977--740-261 [illegible] Region No. 4

Walt Starnes

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

INTEROFFICE MEMORANDUM

For Routing To District Offices And/Or To Other Than The Addressee

To: ______________ Loctn.: ______________
To: ______________ Loctn.: ______________
To: ______________ Loctn.: ______________
From: ______________ Date: ______________

TO: J. P. Subramani

THROUGH: Frank Darabi FD

FROM: Ray DiNardo RD

DATE: June 13, 1978

SUBJECT: BACT Deterinimation for 4 stationary gas turbines to be constructed at the Suwannee River Power Plant site, Suwannee County Florida.

Florida Power Corporation proposes control strategy on each of 4 63 kw distillate oil fired gas turbines as follows:

> Particulate - Design. SO_x - Limit % sulfur to .5% by wieght; concentrations not to exceed 95 ppm by volume. The EPA proposed SO_x turbine standard is 150 ppm by volume. No_x - H_2O/Steam injection or combustion design not to exceed 75 ppmv. Opacity - $<$ 20% by design.

DER Gainesville proposed standards: Particulate - Emissions are not to exceed .08 #/mm BTU. FPC is allowed 59.12 #/hr @ 739 X 10^6 BTU/hr heat in. The proposed standard is a reduction of 20% from the EPA steam performance reg. It is expected that FPC will be able to comply utilizing low ash content fuel and advanced combustor design. SO_x - limit fuel oil to .3% by weight. FPC is allowed only 114 #/hr per turbine (assuming 37910 # of distillate in.) and would emit 85 tons per year. FPC esitmates SO_x emissions at 379 #/hr and 284 tons/yr. The proposed fuel sulfur limitation would provide for a substantial reduction in SO_x emissions at a location with a potential for high SO_2 concentrations. Fuel containing .3% S is currently available in Suwannee County. NO_x - A concentration of 75 ppmv is proposed. The standard is equivalent to the EPA proposed turbine standard and is achievable through H_2O, steam injection or an alternate technology with a removable efficiency in excess of 65%. Increased construction, maintenance, and operational costs in conjunction with overall efficiency loss discourages more stringent standards. OPACITY - a 20% standard is proposed. HC, CO - no standards proposed. NOISE should be minimized so as not to constitute annoyance at property lines. DISCUSSION: Emission control for gas turbines is currently achieved through low sulfur fuels, fuel additives, combustion modification,

continued....

and water or steam injection. Advanced NO_x control technology provides for staged fuel injection and combustion at various axial positions to maintain desired temperatures and or fuel/air ratio throughout the combustor. This method is preferable assuming adequate efficiency when consideration is given to economics, fuel consumption and maintenance costs. FPC declares dry NO_x control commercially unavailable at present; Mr. Donald Goodling, Westinghouse Gas Turbine Division, is in agreement. Teller Environmental Systems, Worcester Mass., markets innovative turbine control technology for particulates, NO_x, opacity, and noise. Control strategy incorporates flow augmentation, quenching, and a "nucleator" collector for low energy submicron particle collection. (APCA Journal February 1977 Vol. 27.2) test data; however, is not available to certify lower emissions for a 35 mw turbine unit.

There are fundemental design conflicts between CO and HC control on one hand and NO_x control on the other, especially when fuel economy, energy, and opacity are considered. Lowering the average temperature in the primary zone will greatly reduce NO_x, but will increase CO and HC. A cooling of the combustion process will result in nonoxidation of CO to CO_2. CO and HC are complex functions of air fuel ratio, degree of mixing and velocity. Smoke typically increases with combustor total inlet pressure and decreases with total temperature. Fuel additives can be effective in reducing opacity improving combustion; however, additives could have an adverse impact on engine life and may be a potential health hazard. There is a narrow band of temperatures and design specification within which it is possible to maintain acceptable emission levels. It is expected that suitable design and equipment standards in conjunction with wet NO_x control can be considered state of the art technology.

Although standards proposed by this office are reasonable, total hourly emissions would be in vilation of SDAPCD and LACAPCD regulations. Compliance with California standards could be achieved by decreasing the design output and increasing the number of peaking units with an overall reduction in total efficiency. An alternative would require expanded capacity of the primary generating facility.

Should you have any questions, please call.

RD/FD/bs

ATTACHMENT C

DER's PROPOSED BACT

Walt Starnes

State of Florida

DEPARTMENT OF ENVIRONMENTAL REGULATION

INTEROFFICE MEMORANDUM

For Routing To District Offices And/Or To Other Than The Addressee

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