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

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 assummed 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: $63 \div 1.25 = 50.4$) 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 $726^{o} - 800^{o}$ 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.

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^{o} 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, $59^{o}F$ 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^{o}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^{o}F. It was not specified whether this was wet or dry volume. This would be a standard volume (at 60^{o}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

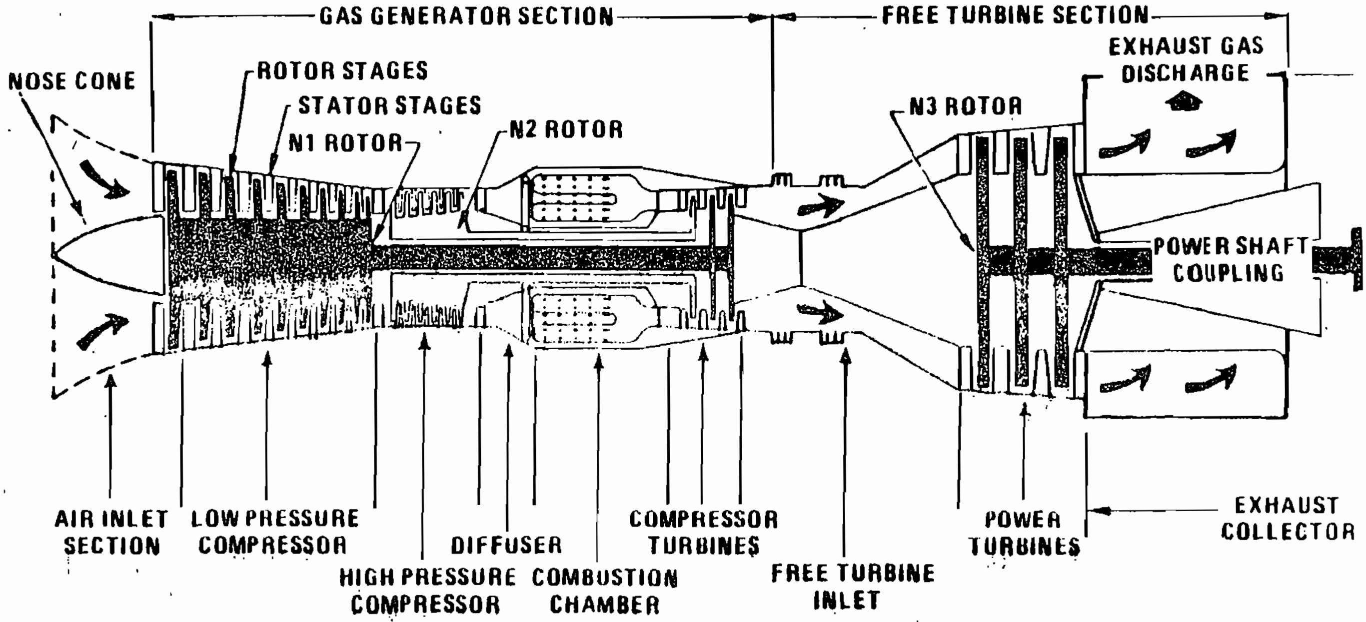

Figure 3-6. Cut-away view of a typical simple cycle gas turbine.

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.

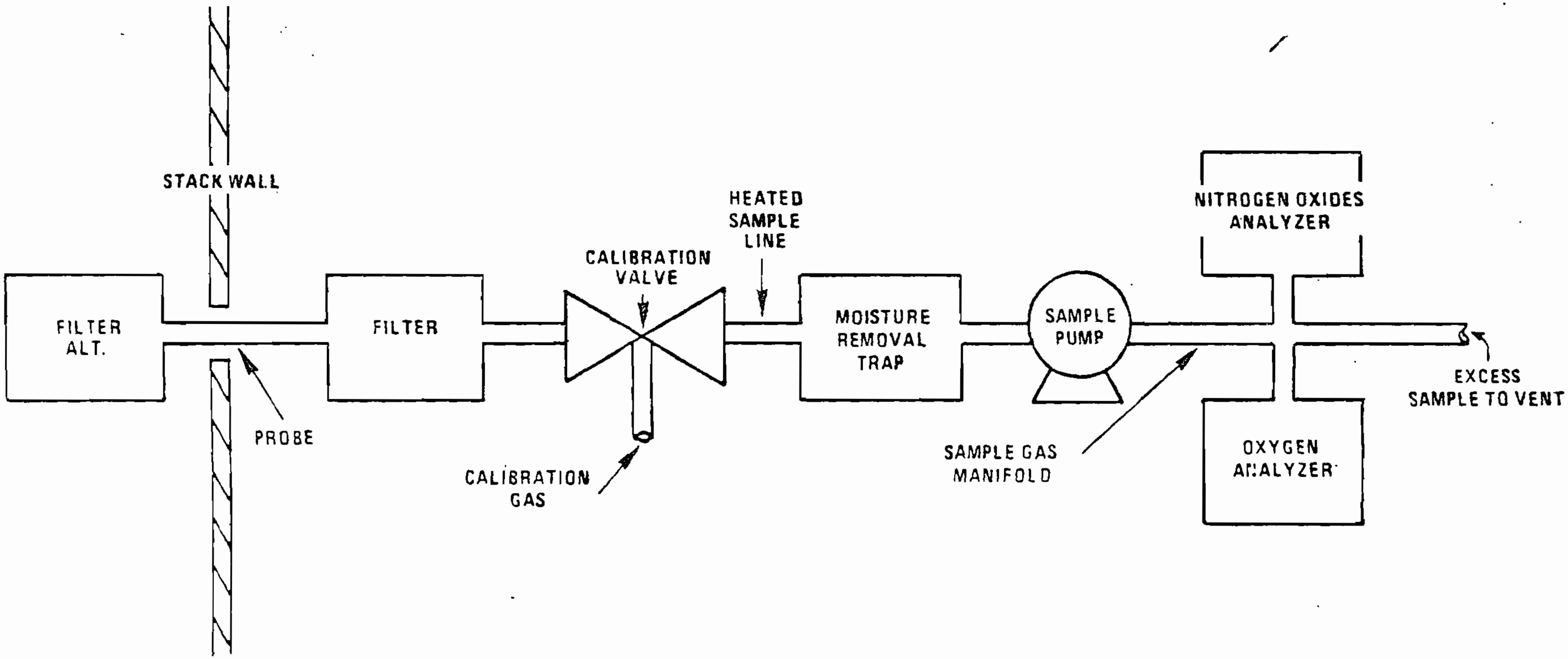

Figure 20.1 Measurement system design for stationary gas turbine tests.

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. <u>Measurement System Performance Specifications and Performance Test Procedures</u>

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	______	Date	______
Turbine ID	Type ______	Ultimate Fuel Analysis	C ______
	S/N ______		H ______
Location	Plant ______		O ______
	City ______		N ______
			S ______
Ambient Temperature	______		Ash ______
			H_2O ______
Ambient Humidity	______	Trace Metals	
Test Time Start	______		______
			Na ______
Test Time Finish	______		Va ______
			K ______
Fuel Flow Rate	______ *		etc.** ______
Water or Steam Flow Rate	______ *	Operating Load	______
Ambient Pressure	______		

*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 (±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.

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

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. ______________________________

<u>Low Range Calibration Gas Mixture</u>

Sample 1____________ppm

Sample 2____________ppm

Sample 3____________ppm

Average____________ppm

<u>Mid Range Calibration Gas Mixture</u>

Sample 1____________ppm

Sample 2____________ppm

Sample 3____________ppm

Average____________ppm

<u>High Range (span) Calibration Gas Mixture</u>

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 Region No. 4

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

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 assummed 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:

$$\text{Fuel (\#/hr)} \times \text{\% S}/100 \times 2(SO_2/S) \times \text{hr/yr} \div 2000 = \text{Tons/yr}$$
$$37{,}910 \times 0.005 \times 2 \times 1500/2000 = 284$$

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: gm/sec		GLC: ug/m^3 for each turbine 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.

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.

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

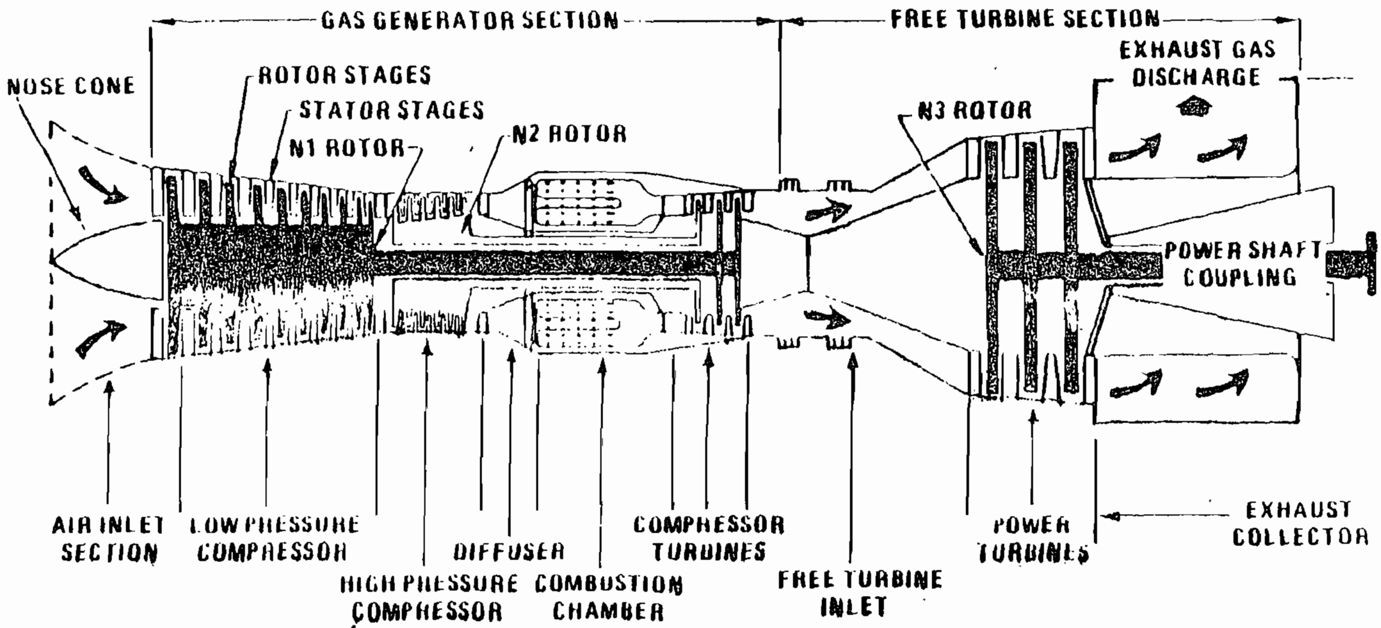

Figure 3-6. Cut away view of a typical simple cycle gas turbine.

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.

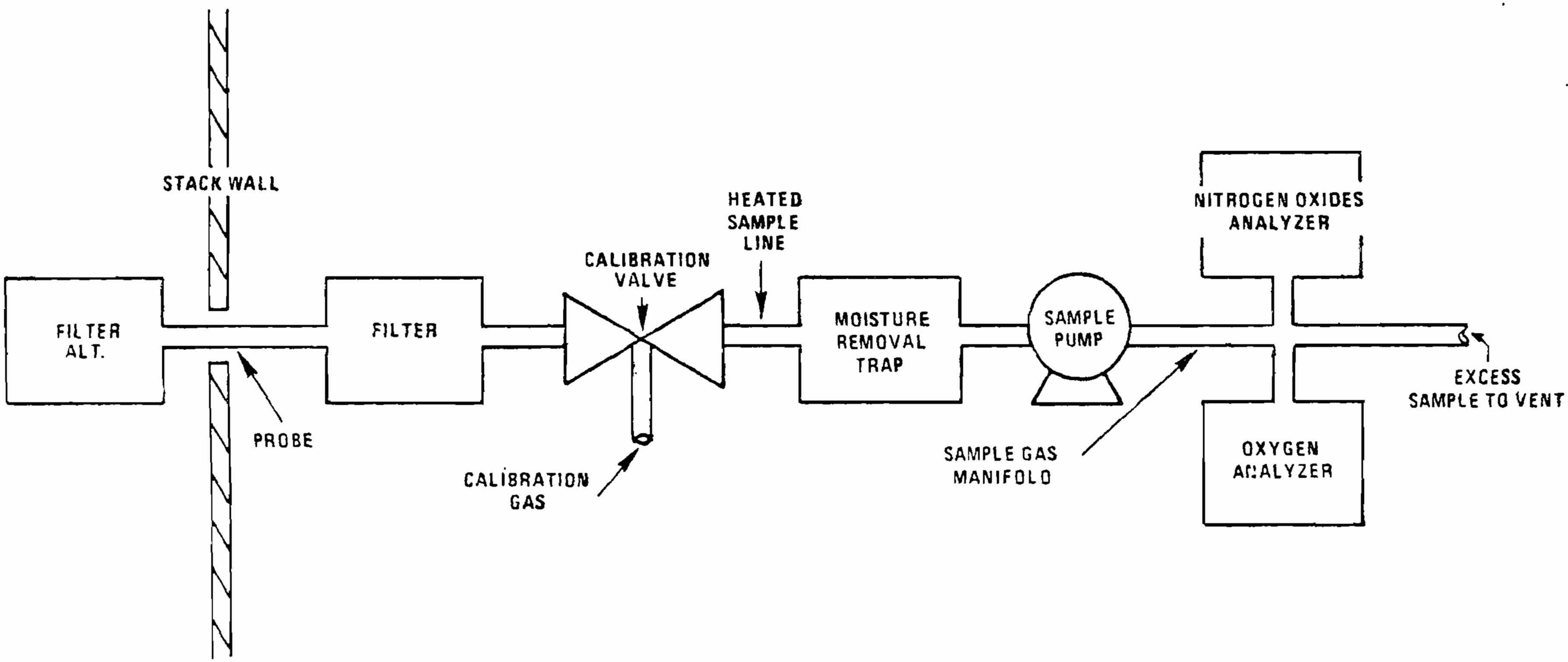

Figure 20.1 Measurement system design for stationary gas turbine tests.

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. <u>Procedure for Field Sampling</u>

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________________ 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 ____________________
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 (± 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 EPA Region No. 4

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

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 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: $63 \div 1.25 = 50.4$) 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: gm/sec		GLC: ug/m^3 for each turbine 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.

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^{o} 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 $80^{o}F$ 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 @ $726^{o}F$. It was not specified whether this was wet or dry volume. This would be a standard volume (at $60^{o}F$, 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