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April 4, 1990

Via Telecopy

Mr. Hamilton S. Oven, Jr., P.E.
Administrator, Power Plant Siting
Florida Department of
Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2449

Re: Technical Comments to the Draft BACT Determination
Prepared by FDER on the Hardee Power Station

Dear Mr. Oven:

Attached please find a copy of our technical comments to the Draft BACT Determination on the Hardee Power Station prepared by the Florida Department of Environmental Regulation. We look forward to discussing these comments with you, Steve Smallwood, Claire Fancy, and Barry Andrews on Thursday, April 5, 1990, at 1:30 p.m.

Should you have any questions or comments, please call.

Sincerely,

Jerry L. Williams

Jerry L. Williams
Director
Environmental

JLW/ams/LL346.BCC

Attachment

cc: S. Smallwood, FDER-Tallahassee (w/attach.)
C. Fancy, FDER-Tallahassee (w/attach.)
B. Andrews, FDER-Tallahassee (w/attach.)
TECO Power Services Corp.
Seminole Electric Cooperative, Inc.

VB 4/4/90

**TECHNICAL COMMENTS TO THE DRAFT BACT DETERMINATION
PREPARED BY FDER ON THE
HARDEE POWER STATION**

The Florida Department of Environmental Regulation (FDER) has prepared a draft Best Available Control Technology (BACT) Determination for the proposed Hardee Power Station. This paper presents comments and additional information on the draft BACT analysis, as was requested by FDER at the meeting held in Tallahassee on March 26, 1990. The comments and additional information are organized according to the draft BACT Determination.

GENERAL

The draft BACT Determination briefly summarizes the proposed BACT emission limitations for the Hardee Power Station and provides a listing of the BACT requirements contained in Rule 17-2, Florida Administrative Code (F.A.C.). The BACT Determination Procedure also cites the use of the "top-down" approach, which is currently recommended by the U.S. Environmental Protection Agency (EPA), as the appropriate procedure for determination of BACT. Notwithstanding the appropriateness of the top-down approach, there are numerous areas in FDER's BACT Determination that are not consistent with its own regulations and EPA policy.

EPA guidance is clear concerning the top-down BACT approach. Specifically, EPA states in its June 13, 1989, Background Statement on the Top-Down Policy, regarding the factors of technical feasibility, and economic, environmental, and energy impacts:

> ... the final weighing of those factors and the final BACT decision, are made by the permitting authority. Rejection of a control technology by a reviewing agency must have a rationale arrived at after full consideration of data determined in a consistent and sound manner. Such decisions may not be arbitrary, capricious, or contrary to law.

Further, in EPA's draft document entitled Top-Down Best Available Control Technology: A Summary (May 25, 1989), it is stated:

However, when supported by a complete and objective review, technologies that can be demonstrated to be infeasible, unreasonable, or otherwise not achievable considering source-specific energy, economic, environmental, or technological reasons can be set aside.

In the BACT Determination for the Hardee Power Station, FDER has ignored this guidance by:

1. Not providing consistent and sound rationale for the BACT determination for several of the pollutants;
2. Arbitrarily rejecting the applicants' source-specific technical and economic data and using data from completely different projects; and
3. Making capricious and arbitrary use of data provided in the application and, thereby, resulting in a flawed BACT Determination.

Specific technical comments to support these conclusions are provided in the following paragraphs.

COMBUSTION PRODUCTS

FDER proposes that the BACT emission limit for PM and PM10 for the Hardee Power Station be 0.0025 and 0.006 pounds per million British thermal units (lb/MM Btu) heat input for natural gas and No. 2 fuel oil, respectively. The emission limits proposed for the Hardee Power Station, which were not referenced by FDER in the determination, were 0.005 and 0.05 lb/MM Btu heat input for natural gas and No. 2 fuel oil, respectively. No technical rationale is provided by FDER for rejecting the proposed emission limit. The specific turbine manufacturer is not identified. Rather, the only justification given is that "discussions with permitting authorities have indicated that stack testing shows these limitations are being met." The stack test data are not provided or evaluated, and there is no discussion of operating conditions, ambient conditions, or fuels burned during the stack tests.

The BACT limits proposed by FDER are not supported on several counts. First, the Hardee Power Station project potentially involves the selection of several combustion turbines which have different designs and operating conditions. The emission limits proposed for the Hardee Power Station reflect this design "envelope." FDER apparently rejects this project-specific requirement arbitrarily, as well as rejecting the requirement to evaluate the project on a case-by-case basis. FDER does not consider that different turbine manufacturers and combustion designs may emit slightly different levels of PM. Indeed, the emission limits proposed for the Hardee Power Station clearly fall within the particulate matter (PM/PM10) emission limits being established as BACT for the range of available combustion turbines. For example, the permitted PM/PM10 emission limits for the Pawtucket Power project located in Rhode Island were 0.007 and 0.045 lb/MM Btu heat input for natural gas and No. 2 fuel oil, respectively.

Second, conditions included in the last two combustion projects permitted by FDER have not even required PM testing when firing natural gas (see AC 05-144482, AC 05-146749, AC 05-146750, AC 05-146751, and AC 41-157745). Clearly, FDER recognizes that PM/PM10 emissions on natural gas are extremely low and that the primary purpose in the prevention of significant deterioration (PSD) evaluation is for completeness rather that setting a specific emission limit. Similarly, the emission limits proposed for the Hardee Power Station when firing No. 2 fuel are extremely low. As noted in the PSD application (see Page 4-26), the emissions will be less than that coming out of a typical baghouse, i.e., 0.01 grains/standard cubic feet of stack gas.

PRODUCTS OF INCOMPLETE COMBUSTION

Similar to the PM/PM10 decision, FDER does not provide a supportable technical rationale for the BACT determination for carbon monoxide (CO) and volatile organic compounds (VOC) emissions. As with PM/PM10 emissions, the Hardee Power Station project is designed to accomodate several different combustion turbines produced by different manufacturers. As a result, the proposed emission limits reflect a design envelope that is specific to the Hardee Power Station project. The CO and VOC emissions will be machine specific and highly dependent on the combustor design and the requirements for water injection to control nitrogen oxide (NO_x). Rejecting the proposed emission limits arbitrarily is contrary to EPA guidance and FDER rules; specifically, the determination of BACT on a case-by-case basis.

The economic and environmental impacts for both pollutants do not warrant lower emission limits than proposed. As discussed in the application, the economic impacts of further CO control will range from $2,663 to more than $5,000 per ton of CO removed. In addition, the CO impacts are well below the significant impact levels and further reductions from that proposed is not justified. The location of the Hardee Power Station is clearly not in a nonattainment area for ozone and, for an NO_x-dominated source, further control is not warranted (see EPRI, 1987; Altshuler, 1989; and EPA, 1988--refer to Attachment A).

ACID GASES

Sulfur Dioxide (SO_2)

FDER's proposed BACT for SO_2 is the use of No. 2 fuel oil with a sulfur content of 0.2 percent. The FDER analysis incorrectly evaluates the economics of lower sulfur fuel in making the BACT determination by assuming that 0.5 percent fuel oil will be actually burned. This is factually incorrect based on the fuel specifications for Hardee Power Station and the actual sulfur content in such fuels, i.e., very low sulfur oil.

The fuel specification for the Hardee Power Station project will be for a No. 2-GT grade as defined in the Standard Specification for Gas Turbine Fuel Oils ASTM designation 2880-78. This distillate fuel oil, which contains low ash and other potential contaminants, is suitable for combustion turbines and is inherently low in sulfur. Through the refining process, this fuel can have a maximum sulfur content of up to 0.5 percent. In order to assure that the Hardee Power Station meets this specification, the maximum assumed sulfur limit of 0.5 percent was used in all analyses, including the calculation of maximum emissions and in the impact analyses.

As discussed in the PSD application, the typical sulfur content of this fuel is around 0.3 percent. Data to support this statement were developed from a 5-year database of fuel samples taken from gas turbine fuel delivered to Tampa Electric Company during 1985 through 1989. From a database of 130 samples taken over this period, the average sulfur content was 0.31 percent. While the average sulfur content was 0.31 percent, some shipments had a sulfur content of more than 0.4 percent. EPA recognized the fluctuations in sulfur content by increasing the maximum sulfur for very low sulfur oils in its Subpart Db regulations from 0.3 percent to 0.5 percent (see 54 Federal Register 28447-28448 for rationale).

Assuming that the cost differential between the standard No. 2 GT fuel oil and a No.2 GT fuel with a specification of 0.2 percent is $0.03/gallon as stated by FDER, the actual cost effectiveness is calculated to be $3,788/ton of SO_2 removed ($0.03/gallon x gallon/7.2 lb fuel x lb fuel/0.0011 lb S x lb S/2 lb SO_2 x 2,000 lb/ton). However, the differential fuel cost stated in the FDER determination of $0.03/gallon is believed to be low, since no fuel suppliers currently provide this type of fuel in Florida, and would require suppliers to construct additional fuel handling and blending facilities. At a more appropriate fuel differential of about $0.05/gallon as provided in the PSD application, the cost effectiveness is calculated to be $6,313/ton of SO_2 removed. With either calculation, the cost effectiveness is substantially greater than the $2,000/ton of SO_2 stated by FDER as appropriate in determining BACT.

Moreover, the predicted air quality impacts in the application are conservative by assuming that the sulfur content will be 0.5 percent on a continuous basis, which is clearly not the case. The maximum PSD increment consumption will be less than 50 percent of the Class II allowable increment at a more nominal sulfur content of 0.3 percent. In addition, the maximum expected annual capacity factor for the facility on oil is only

15 percent. In order to maintain operating flexibility, the Hardee Power Station cannot accept a permit condition that limits the amount of fuel oil used, even though the annual maximum fuel oil usage will be low.

Nitrogen Oxides

FDER's evaluation of BACT for NO_x is particularly troublesome since source-specific project costs are rejected and new ones developed from totally different projects. This is contrary to the stated EPA BACT policy. Specifically, FDER rejects the capital and operating costs for the Hardee Power Station and develops "new" costs from the Lauderdale Repowering Project and the Martin Coal Gasification Combined Cycle Project. These latter two project are inappropriate comparisons to the Hardee Power Station for several reasons.

The Lauderdale Repowering Project and the Martin Coal Gasification Combined Cycle Project utilize "advanced" combustion turbines for base load generation. The Lauderdale project, which is closer in size and fuel types (i.e., natural gas and No. 2 fuel oil) to the Hardee Power Station, consists of four combustion turbines and is designed for base load operation. The Martin project also uses coal gas and any comparison with Hardee Power Station is technically inappropriate. In contrast, the Hardee Power Station project will have five or six combustion turbines and is designed for providing backup and peaking power for Seminole Electric Cooperative Incorporated and Tampa Electric Company, respectively. Because of these differences, as well as different bases for project-specific economics, direct comparison cannot be made. To appropriately compare these different projects, these differences must be accounted for.

FDER bases its "new" economics on a comparison of combustion turbine flow rates without taking into account the basis of the original costs. To appropriately compare flow rates, FDER should have compared the flow rate seen by the selective catalytic reduction (SCR) catalyst and the number of machines on which the cost analysis was based in order to evaluate the differences among projects. For the Hardee Power Station project, the costs were developed for installing SCR on six combustion turbine/heat recovery steam generator (HRSG) combinations. At the SCR temperature of 600°F, the total flow rate for six machines is 6,868,000 actual cubic feet per minute (acfm). For the Lauderdale project, which uses four machines, the total flow rate at 600°F is 6,763,000 acfm. While these flow rates are nearly identical, the number of machines for each project is substantially different (i.e., the Hardee Power Station has 50 percent more machines than the Lauderdale project) and would logically account for differences in the economics.

Furthermore, the economic factors used by each applicant are based on project-specific economics; rejecting such factors arbitrarily is inappropriate and contrary to the BACT guidelines. Nonetheless, when the annualized costs are compared, the Hardee Power Station project is only about 16 percent higher than the Lauderdale project, which is reasonable, given the fact that the costs developed for Hardee Power Station project involve six machines rather than the four machines proposed for the Lauderdale project. As stated in the PSD application, the annualized cost for SCR on the Hardee Power Station project is $19,524,500 (see Table 4-5 in the Hardee Power Station PSD application). It should be noted that FDER, when making the comparison of capital costs, did not subtract the costs for the standard combustor. The annualized cost for the Lauderdale project is $16,805,851 (see Table 4-4 in the Lauderdale Air Permit Application). While the economic factors used in each project are different, which would be expected given the purposes and makeup of each project, the annualized costs are reasonably similar.

Initial capacity factors for Hardee Power Station in the first 5 years are not expected to exceed 25 percent; the maximum capacity factor is expected to be about 55 percent. In addition, the expected fuel usage for the project is 80 percent natural gas and 20 percent No. 2 fuel oil. The cost effectiveness of SCR presented in the Hardee Power Station application was conservatively based on using No. 2 fuel oil 100 percent of the time. In fact, when the actual expected fuel use mix and maximum capacity factor are considered, the actual cost effectiveness is substantially greater than that presented in the application. The cost effectiveness for SCR based on the proposed BACT is $5,692/ton of NO_x removed at 80 percent natural gas and 20 percent oil operation, and with a capacity factor of 100 percent. At a capacity factor of 55 percent and with the same fuel mix, the cost effectiveness of SCR is $7,351/ton of NO_x removed. These costs are clearly above the $3,146 stated by FDER to be reasonable for SCR (calculations are provided in Attachment B).

It should be noted that FDER arbitrarily uses a cost effectiveness figure of $3,146 without justifying its basis (i.e., FDER policy or other basis). FDER apparently rejects the case-by-case basis for BACT determinations by using cost effectiveness figures from other projects without clearly justifying the similarity of the projects. In fact, there is no description of these other projects concerning combustion turbine size and operating conditions, fuel mix, air quality and energy impacts, etc., that may make those projects equivalent to the Hardee Power Station project. This is contrary to FDER's rules and EPA's top-down approach policy.

FDER rejects the Applicants' concern over the problems of using SCR with sulfur-containing fuels. For the Hardee Power Station project, this is a major concern because the facility must have the capability to fire No. 2 fuel oil. Unlike cogeneration projects which have accepted SCR in permit conditions, the Hardee Power Station must supply peak power regardless of the availability of natural gas. In contrast, cogenerators (i.e., qualifying facilities) can simply stop power production. Additional information on the difficulty of using SCR on fuel-oil-fired facilities is contained in Attachment C.

Finally, it must be recognized in the BACT determination that the environmental impacts for NO_2 will be less than 5 percent of the applicable ambient air quality standard (AAQS) and less than 25 percent of the applicable PSD increment. These impacts are based on 100 percent oil firing. The impacts for the actual expected fuel mix will be even less when compared to the standards. FDER's environmental impact analysis uses rationale that is very confusing. By its own admission, the background concentration of NO_x in Tampa (which is more than 20 miles away from the Hardee Power Station site) is less than 50 percent of the AAQS. At this distance, the impact of the Hardee Power Station will be less than the significant impact level and will not be measurable.

The only environmental argument for SCR presented by FDER is the suggestion that NO_x impacts to AAQS are moderate, i.e., FDER states that the Hardee Power Station project will contribute "moderately" to the NO_x concentrations in the area. The term "moderately" is not defined in the BACT Determination, nor is it contained in any FDER rule or policy. It is hard to see that less than 5 percent of the AAQS and less than 25 percent of the PSD increment is a "moderate" impact.

SUMMARY

The information contained in the PSD application for the Hardee Power Station supports the proposed emission limits by rejecting additional control technology based on project-specific technical feasibility, and economic, environmental, and energy impacts. The FDER BACT Determination does not invalidate the technical data presented nor does it substantiate the need for the additional controls specified in the draft determination. When the project-specific factors are taken into account, it must be concluded that the BACT proposed for the project by the applicants is reasonable.

ATTACHMENT A

Altshuler, A.P. 1989. Nonmethane Organic Compound to Nitrogen Oxide Ratios and Organic Composition in Cities and Rural Areas. The Journal of the Air & Waste Management Association. Vol. 39 No. 7.

EPA. 1988. VOC/NO_x Point Source Screening Tables (Draft). Office of Air Quality Planning and Standards. Source Receptor Analysis Branch.

EPRI. 1987. Effect of Power Plant NO_x Emissions on Ozone Levels. Prepared by Systems Applications Incorporated. EPRI EA-5333.

ATTACHMENT B

COST EFFECTIVENESS CALCULATION FOR NO_x

100-PERCENT CAPACITY FACTOR

NO_x emissions at 42 ppm natural gas =	4,729	TPY
NO_x emissions at 9 ppm natural gas =	1,018	TPY
Difference =	3,711	TPY removed
	x 0.80	natural gas usage
	2,969	TPY removed

NO_x emissions at 65 ppm No. 2 Fuel Oil =	8,405	TPY
NO_x emissions at 14 ppm No. 2 Fuel Oil =	1,810	TPY
Difference =	6,595	TPY removed
	x 0.20	No. 2 Fuel oil usage
	1,319	TPY removed

Total tons NO_x removed = 2,969 + 1,319 = 4,288 TPY

Cost effectiveness = $19,524,425/4,288 tons removed = $5,692/ton

55-PERCENT CAPACITY FACTOR

At 55 percent capacity factor, tons NO_x = 0.55 x 4,288 = 1,887 TPY

Annual Operating Cost =	$6,913,500	(55 percent of annual operating cost)
Annual Capital Cost =	6,955,012	
Total Annual Cost =	$13,868,512	

Cost effectiveness = $13,868,512/1,887 = $7,351/ton

ATTACHMENT C

SUPPLEMENT INFORMATION ON SCR OPERATION

EFFECTS OF SULFUR-BEARING FUELS ON SCR SYSTEM OPERATION

Sulfur contained in fuel will oxidize during combustion to form SO_2 and SO_3. In the SCR reactor, SO_3 will react with water and ammonia to form ammonium bisulfate, NH_4HSO_4, and ammonium sulfate, $(NH_4)_2SO_4$. The formation of ammonium bisulfate will lead to the rapid fouling and corrosion of the HRSG. Both compounds will result in high levels of PM10 emissions.

Ammonium bisulfate is an extremely corrosive and sticky substance that forms in the low temperature portion of the heat recovery steam generator (HRSG) where it deposits on the walls and heat transfer surfaces downstream. The deposits on the tube surfaces cause increased pressure drop with reduced power output and lower cycle efficiency. More importantly, the unit must be shut down and water-washed (to prevent corrosion damage) resulting in lower availability. Ammonium sulfate is not corrosive, but its formation will also contribute to plugging of the heat transfer system, leading to reduced efficiency and also contributing to higher particulate emissions.

The formation of ammonium bisulfate and sulfate downstream of the SCR reactor is a complex function of gas composition and temperature. This problem was evaluated in a study recently conducted by Exxon for General Electric Company. The results of Exxon's calculations are shown in Figures 1 and 2. Both calculations used an exhaust gas composition based on firing 0.2 percent sulfur distillate oil. In Figure 1, the unreacted ammonia leaving the SCR was assumed to be 6.5 ppm, and in Figure 2 it was 13 ppm. In Figure 1, ammonium bisulfate begins to form at temperatures below 380°, and below 360°, ammonium sulfate forms as well. By the time the gas reaches 260°, all of the sulfur present as either SO_3 or as H_2SO_4 has reacted, consuming all of the excess ammonia as well. Figure 2 shows

2

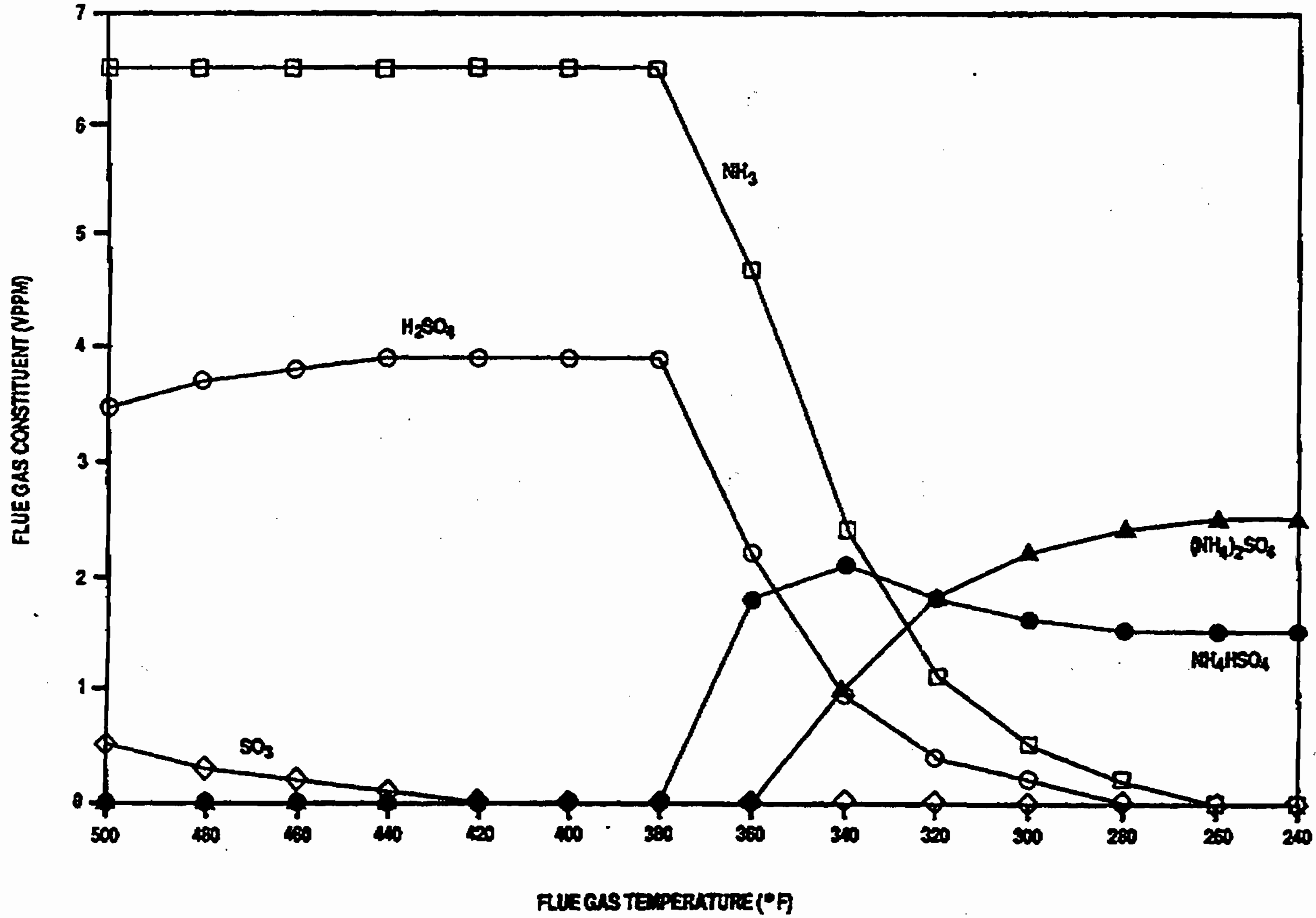

Figure 1 FLUE GAS EQUILIBRIUM COMPOSITIONS -- GAS NO. 2

Hardee Power Station

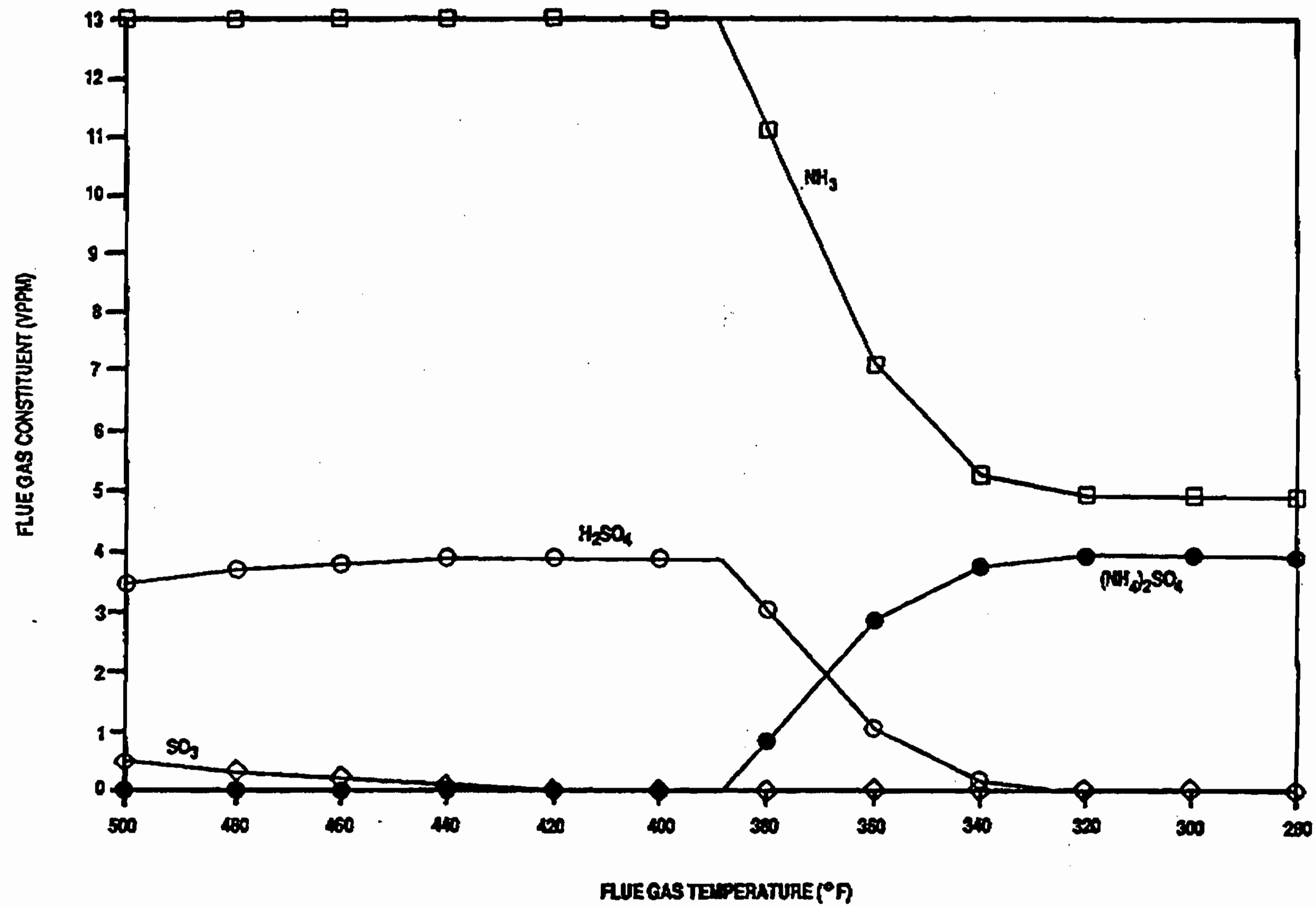

Figure 2 FLUE GAS EQUILIBRIUM COMPOSITIONS – GAS NO. 1

Hardee Power Station

that at the higher level of unreacted ammonia, only ammonium sulfate forms but excess ammonia in the stack gases would be 5 ppm.

The Exxon study was intended to illustrate that the formation of ammonium bisulfate is a complex function of the gas chemistry and temperature. These types of calculations are necessary but impractical on a real-time basis, and thus control of ammonium bisulfate over the full range of Hardee Power Station operating conditions is not practical.

The only effective means for limiting the formation of ammonium bisulfate is to limit the sulfur content of fuel. Pipeline quality natural gas has negligible sulfur content. However, the lowest sulfur content of the distillate oil available to Hardee Power Station is not low enough to prevent formation of ammonium bisulfate.

A further problem for SCR operation associated with firing sulfur-bearing fuels is the formation of particulate matter in the SCR. For the example shown in Figures 1 and 2, the sulfate particulates would increase the PM10 emissions by 49 and 55 lb/hr for each gas turbine, respectively.

In summary, there are two severe problems associated with the firing of fuels containing sulfur in a combustion turbine system with an SCR. First, a highly corrosive substance tends to form which rapidly deteriorates the system leading to reduced power generation efficiency and high maintenance costs. Second, measures taken to prevent formation of corrosives will lead to higher emissions of either NO_x or NH_3 and the PM10 emissions will be higher by a factor of five or six.

<u>OPERATING EXPERIENCE</u>

Combustion turbine operating experience with SCR in the U.S. has been limited to natural gas firing, except in one case, the United Airlines unit, which is discussed below. There are several facilities which have been licensed to operate using liquid fuel as a backup fuel; in all but the one case, however, those facilities have been permitted to shut down the

SCR system during the periods that oil firing takes place, or they have simply never fired oil at all. As an example, in California, out of 41 permitted SCRs only 11 have been licensed to fire oil as a backup fuel. Of those 11, only 3 are now in operation, and only one (United Airlines) has ever fired oil.

The only SCR-controlled combustion turbine system to have fired oil is the United Airlines cogeneration plant at the San Francisco, California, airport. This plant, which is required to meet a NO_2 limit of 16 ppmvd using SCR, is fired on natural gas with Jet-A fuel as a backup. Jet-A fuel has a much lower sulfur content (i.e., 0.05 percent) and ash content, and is much more expensive and less available that distillate oil. The plant experienced a number of problems in its operations. During the first year of operation, the catalyst failed and was replaced three times. The cause of the catalyst failure was attributed both to poisoning of the catalyst by ammonium bisulfate and to gas pressure surges caused by automatic switching to jet fuel. The operators of the facility have stated that they will no longer operate the system on liquid fuel.

The only other combustion turbine facility with SCR known to have fired liquid fuel is the Japanese National Railways (JNR) Kawasaki Power Station Unit No. 1 in Tokyo, Japan. This unit, a GE Frame 9B system, has operated successfully on liquid fuel for over 40,000 hours. The NO_x emission limit for this unit, however, is 25 ppmvd, which is higher than the 9/13 ppmvd limit FDER is considering for Hardee Power Station when operating on combined cycle. In addition, it should be noted that the JNR system differs from the proposed Hardee Power Station system in the following important ways.

The JNR system is fired with kerosene. Kerosene is lighter, costlier, and contains a lower level of sulfur that the lowest-sulfur distillate oil available to Hardee Power Station. In the U.S., sulfur levels in kerosene are on the order of 0.04 percent, compared to 0.3 percent for distillate oil. Sulfur levels in Japanese kerosene are unknown.

As an overseas facility, the JNR system is subject to an entirely different set of regulatory and economic conditions from the Hardee Power Station facility. For example, in terms of regulatory restrictions, the JNR facility is required to limit NO_x with its SCR to 25 ppmvd, whereas Hardee Power Station potentially would be required to meet 9/13 ppmvd with an SCR when operating on combined cycle mode.

In addition, JNR is not required to limit ammonia slip as Hardee Power Station would, and it is unknown whether JNR is required to limit CO or particulate emissions, as Hardee Power Station would. In terms of economic restrictions, it should be noted that JNR is a quasi government-owned firm and is therefore likely to be subject to much lower economic constraints than is the Hardee Power Station facility. (Note: at the time the facility was built, JNR was a government-run firm; more recently, some "privatization" of the firm has occurred).

Finally, the JNR system is operated much differently than the proposed Hardee Power Station system. The JNR system operates 14 to 16 hours per day, six days per week to supply electric power for railway operation in a metropolitan area. The unit is shut down at night and restarted in the morning. When in operation, the system is fired at one level continuously (i.e., it is not operated at varying load levels). In contrast, Hardee Power Station will be operated at varying load levels. Varying load levels result in changing temperatures at the SCR and the back end of the HRSG, which could cause formation of ammonium bisulfate, even at constant levels of ammonia and SO_2.

SCR manufacturers have stated that their systems have operated controlling oil and even coal-fired sources. SCR experience with oil and coal fuels has, however, only been demonstrated in conventional boiler plants where the SCR is not followed by heat transfer tubes which can be corroded by ammonium bisulfate. Conventional boilers also have much less exhaust gas temperature variation than an HRSG, facilitating a design which will avoid formation of ammonium bisulfate. Nevertheless, regenerative air heaters in some of these plants have experienced severe deposition/plugging and corrosion problems.

In summary, therefore, there is no clear example of technically demonstrated SCR performance for control of an oil-fired combustion turbine system, such as Hardee Power Station proposes.

RISKS ASSOCIATED WITH CATALYST HANDLING, DISPOSAL

Employment of an SCR would require the handling and disposal of spent catalyst materials. Spent catalyst materials typically contain a heavy metal oxide such as titanium or vanadium that can leach into groundwater. Recently, California agency officials declared that such materials should be considered hazardous. As such, the handling and disposal of spent catalyst would pose a certain level of risk to human health and the environment.

Many catalyst suppliers will agree to provide material removal and disposal services as part of their overall service contract. While this may remove an environmental problem for Hardee Power Station, it does not eliminate the problem because hazardous materials will be handled at and transported to and from the site. Further, it should be noted that such contracts do not guarantee that such services can be provided for the lifespan of the facility. Either a change in the status of the catalyst supplier or a change in the regulations affecting such an activity could result in the burden of catalyst removal and disposal being placed upon Hardee Power Station. For example, regulations are being developed in several states prohibiting or greatly restricting the importation or transportation of hazardous materials. Since Florida does not have a facility where spent SCR catalyst material may be disposed, Hardee Power Station would have no place in the state to send its spent catalyst.

Zeolite-coated ceramic catalysts (nonhazardous) have only been installed and operated on a limited basis to small gas turbines (i.e., less than about 5 MW; 3 in the U.S.) and internal combustion engines (1 in the U.S.).

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The applications in the U.S. are primarily on gas-fired facilities. This technology has not been demonstrated on large combustion turbines.
It is concluded, therefore, that handling and disposing of spent catalyst material constitutes an additional environmental impact that should be considered in the BACT decision.