UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IV
345 COURTLAND STREET, N.E.
ATLANTA, GEORGIA 30365

SEP 20 1991

Mr. J.S. Crall, Director
Environmental Division
Orlando Utilities Commission
500 South Orange Avenue
P.O. Box 3193
Orlando, Florida 32803

RE: Orlando Utilities Commission, Stanton Energy Center Unit 2
PSD-FL-084

Dear Mr. Crall:

The review of your application to modify the commence construction date for Stanton Unit 2 along with a determination of best available control technology (BACT) for this unit has been completed pursuant to federal Prevention of Significant Deterioration (PSD) regulations found at 40 CFR §52.21.

Attached is one copy of the Agency's Preliminary Determination and draft permit modifications for PSD-FL-084. This action addresses a modification to the commence construction date for Unit 2, a modification to the heat input rate for Unit 2, and a reevaluation of BACT for Unit 2.

A public notice soliciting comments and offering the availability of a public hearing on this determination will be published in the near future.

Sincerely yours,

Winston A. Smith, Director
Air, Pesticides and Toxics
Management Division

cc: Mr. C.H. Fancy, FDER

PRELIMINARY DETERMINATION
AND
TECHNICAL EVALUATION

PERFORMED FOR ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER UNIT 2
ORANGE COUNTY, FLORIDA
PSD-FL-084

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IV
AIR, PESTICIDES AND TOXICS MANAGEMENT DIVISION

SEPTEMBER 1991

BACKGROUND

On June 10, 1982, the Orlando Utilities Commission (OUC) received a federal Prevention of Significant Deterioration (PSD) permit for their Curtis H. Stanton Energy Center Units 1 and 2. The permit was a "phased" construction permit issued by EPA Region IV pursuant to federal PSD regulations (40 CFR §52.21) which required that construction on Unit 1 begin no later than 18 months after the issuance of the permit (PSD-FL-084) and that construction of Unit 2 commence no later than 18 months after July 1, 1990. In addition, pursuant to 40 CFR §52.21(j)(4), the "determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of a multi-phased project." Should these commence construction deadlines not be met, the PSD permit would expire pursuant to the provisions of 40 CFR §52.21(r).

Construction commenced on Unit 1 on or about November 29, 1983, with operation commencing on or about May 12, 1987. After further assessment of power needs, however, OUC determined that the most advantageous time for Unit 2 to come on line would be 1997. Based on this revised estimate, OUC requested a meeting with EPA to discuss available options for the construction of Unit 2. In the meeting of February 23, 1989, EPA explained OUC's options for delaying the construction of Unit 2, based on 40 CFR §52.21(r)(2) and EPA's "Revised Draft Policy on Permit Modifications and Extensions" which was issued on July 5, 1985. These options were as follows:

1. Commence construction of Unit 2 prior to the January 1, 1992 deadline.

2. Complete and submit a new, separate permit application for the construction of Unit 2, letting the original construction authority for Unit 2 expire.

3. Request a permit modification in order to change the commence construction dates for Unit 2. Such a request must be made no later than six months prior to the expiration of the original permit.

OUC chose option number 3 - to request a permit modification for the commence construction dates. Since EPA had issued the original permit and since the State of Florida does not have the authority to modify EPA issued permits, the permit modification request has been processed by EPA. OUC submitted the modification request to EPA on March 18, 1991, thus meeting the requirement that such application be submitted to the reviewing agency no later than six months prior to the expiration of the permit.

The proposed modification consists of three parts:

1. The insertion of a commence construction date for Unit 2 of January 1, 1992. This would allow OUC until June 1, 1993, to commence construction on Unit 2 before the permit would expire.

2. A change to Specific Condition #1 of PSD-FL-084 to specify a heat input rate of 4,286 MMBTU/hr for Unit 2. The current condition specifies a heat input rate of 4,136 MMBTU/hr for each unit. This change will not affect the power generation of Unit 2 which will remain rated at 460 MW (gross) and 440 MW (net) as originally permitted.

3. A revised BACT determination for Unit 2 in fulfillment of Specific Condition #2 of PSD-FL-084 and federal PSD regulations. This determination will be completed for the pollutants PM, SO_2, NO_x, VOC, CO, and visible emissions.

I. Commence Construction Date

As discussed previously, later phase commence construction dates in a PSD permit cannot be automatically extended utilizing the provisions of 40 CFR §52.21(r). This section allows the Administrator to extend the initial 18-month commence construction period where such extension is determined to be justified. It does not, however, allow for automatic extensions for time periods between construction of approved phases of multi-phased projects.

While later phase commence construction dates cannot be changed by the granting of extensions, they can be changed through a permit modification, since the dates are part of the permit itself. The permit modification policy addresses this fact as follows:

> [t]he intent of 40 CFR §52.21(r)(2) is to establish an automatic 18-month expiration date for permits, with provisions for extending the expiration on a case-by-case basis. For phased projects with a single comprehensive permit, EPA presumed that commencement dates for each phase of the project, except the initial phase commencement date, would be incorporated into the permit. Therefore, initial phase commencement date changes would be handled with a 40 CFR §52.21(r)(2) extension, and subsequent phase commencement dates would be handled through permit changes. This acknowledges and preserves the validity and legality of the conditions specified in a permit.

Thus the appropriate mechanism for changing the commence construction date for Stanton Unit 2 would be permit modification. Such a modification is considered to be an Administrative change requiring public notice and comment.

In the specific case of OUC Stanton Unit 2, the Agency finds that the applicant's request for a change in the commence construction date is justified based upon a reevaluated schedule of need for power. In keeping with EPA's past policy of generally only allowing an 18-month extension of commence construction dates, it is appropriate to set the commence construction date for Unit 2 as January 1, 1992. Under PSD regulations, a continuous program of construction of Unit 2 must begin no later than 18 months after the commence construction date or the permit will automatically expire.

II. Modification to Heat Input Rate

The original PSD permit for Stanton Energy Center specified a heat input rate for each of the identical coal-fired boilers, Units 1 and 2, of 4,136 MMBTU/hr each. The resulting power generation from each boiler was calculated to be 460 MW (gross) and 440 MW (net). Through experience with Unit 1 and with boiler design improvements, the applicant has requested that the heat input rate to be specified for Unit 2 be changed to 4,286 MMBTU/hr. Since the BACT for Unit 2 is being reevaluated and will result in much lower emissions than originally projected for Unit 2, this change is not considered significant.

III. BEST AVAILABLE CONTROL TECHNOLOGY

On June 10, 1982, OUC was issued a federal PSD permit (PSD-FL-084) for Units 1 and 2 of the Curtis H. Stanton Energy Center. Best available control technology (BACT) was established for each of the 460 MW (gross) coal-fired units in PSD-FL-084 as follows:

POLLUTANT	CONTROL	ALLOWABLE LIMIT
PM	electrostatic precipitator	0.03 lb/MMBTU
SO_2	flue gas desulfurization	1.14 lb/MMBTU(3-hr avg.) and 90% reduction (30-day rolling average)
NO_x	combustion controls	0.60 lb/MMBTU (30-day rolling average)
Visible Emissions		20% (6-min. avg), except for one 6-minute period per hour of not more than 27% opacity

In addition, since the PSD permit is a phased construction permit, Specific condition #2 contained a requirement that the adequacy of the BACT determination for Unit 2 be re-evaluated no later than 18 months prior to the commencement of construction of the unit.

The associated potential emissions for the two units combined was as follows in tons per year:

POLLUTANT	POTENTIAL EMISSIONS
PM	1,042
SO_2	39,606
NO_x	20,845
CO	1,737
VOC	17

a. Based on 4,136 X 10^6 BTU/hr heat input rate for each unit and 50 weeks per year operation.

b. Estimated 0.0005 lb VOC/MMBTU average emission rate.

These emissions were used in determining PSD applicability for the original permit and in the air quality analysis which demonstrated that the National Ambient Air Quality Standards would be protected while the PSD increments would not be exceeded.

BACT Determination Requested by the Applicant

OUC proposed a BACT determination consisting of an ESP to control particulates, flue-gas desulfurization (FGD) to control SO_2, and combustion controls for NO_x and CO.

The FGD system proposed by the applicant is a wet limestone scrubber designed to meet an emissions limit of 0.32 lb/MMBTU based upon a design coal sulfur content of 2.5%. The combustion control proposed by the applicant includes the use of "low-NO_x" burners to achieve a NO_x emission rate of 0.32 lb/MMBTU.

The applicant has requested BACT emissions rates on a pollutant-by-pollutant basis as shown below.

a. PM - (Total Suspended Particulate)

0.020 lb/MMBTU

b. PM_{10}

0.020 lb/MMBTU

c. SO_2

0.32 lb/MMBTU (30-day rolling average)
0.67 lb/MMBTU (24-hour average)
0.85 lb/MMBTU (3-hour average)

d. NO_x

0.32 lb/MMBTU (30-day rolling average)

e. CO

0.15 lb/MMBTU

Trace constituents of the coal will be controlled through the combination of wet scrubbing (acid gases) and the ESP (particulates and heavy metals).

BACT DETERMINATION PROCEDURE:

Pursuant to federal regulations for Prevention of Significant Deterioration (PSD), 40 CFR §52.21, a new major stationary source "must apply best available control technology for each pollutant subject to regulation under the Act that it would have the potential to emit in significant amounts." Additionally, in relation to phased construction projects, paragraph (j)(4) states:

> "For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable Stationary Source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source."

"Best available control technology" is defined in 40 CFR §52.21(b)(12) as:

> "an emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through the application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques of control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of a work standard infeasible, a design, equipment, work practice, operational standard, or a combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results."

In addition to the pollutants specifically subject to PSD review for a particular source, credence must be given to the control of any "unregulated" pollutants when determining best available control technology for an emissions unit. This policy, a result of the 1986 remand of a PSD permit for the North County Resource Recovery Facility by the Administrator of EPA, generally specifies that a more stringent emission limit for a "regulated" pollutant may be imposed if a reduction in "nonregulated" pollutants can be directly attributed to the control device selected as BACT for the "regulated" pollutants.

Emissions from fossil fuel-fired electric utility boilers can be grouped into categories based upon what control equipment and techniques are available to control emissions from these facilities. Using this approach, the air emissions can be classified as follows:

- Combustion Products (Particulates and Heavy Metals) controlled generally by particulate control devices.
- By-products of incomplete combustion (CO, VOC, toxic organic compounds). Control is largely achieved by proper combustion techniques.
- Acid gases (SO_2, NO_x, HCl, F, H_2SO_4) Controlled generally by gaseous control devices.

BACT ANALYSIS

Combustion Products:

Under the review completed for PSD-FL-084, the combustion product for which a BACT analysis is required is particulate matter. Based on information now available, vendors can use either an electrostatic precipitator or fabric filter technology to achieve a level of 0.02 lb/MMBTU.

The "Standards of Performance for New Sources" (NSPS) which apply to Stanton Unit 2 are found in 40 CFR Part 60 Subpart Da. These standards establish a particulate emissions limit of 0.03 lb/MMBTU. Under Clean Air Act requirements, an applicable NSPS or NESHAP limit is the minimally acceptable level which can be selected as BACT. In addition, Subpart Da limits opacity to a maximum of 20%.

A review of the BACT/LAER Clearinghouse indicates that recent emissions limits on PM from pulverized coal (PC) boilers have been as follows:

SOURCE	LIMIT
Mecklenburg Cogeneration, VA	PM - 0.020 lb/MMBTU PM_{10} - 0.018 lb/MMBTU
Chambers Cogeneration, NJ (fabric filtration)	PM - 0.018 lb/MMBTU PM_{10} - 0.018 lb/MMBTU
Roanoke Valley Project, NC	PM - 0.020 lb/MMBTU PM_{10} - 0.018 lb/MMBTU

The applicant evaluated the use of fabric filtration as well as an ESP. In this evaluation, the feasibility of reaching an emission level of 0.012 lb/MMBTU on a continuous basis was assessed in relation to energy, economic, and environmental impacts. The base case selected by the applicant was the emissions level of 0.020 lb/MMBTU.

ESPs are historically the most widely used particulate control equipment for coal-fired power plants. The devices remove particulate from the flue gas stream by charging fly ash particles with very high dc voltage and then attracting these particles to oppositely charged collection plates. The collected particulate is then removed from the plates by periodic "rapping" which causes the particulate to drop into collection hoppers below the ESP.

Fabric Filtration, as the name implies, utilizes filter bags to "trap" particulate from the flue gas stream. As the flue gas passes through the filter bags, a "cake" of collected particulate builds up. This cake is necessary to increase the collection efficiency of the bags. The collected particulate can be removed in a variety of methods: reverse gas, shake-deflate, or pulse jet. The applicant, based on the size of the gas stream along with relative economics, chose the reverse gas method to be used in the BACT analysis.

Energy Impacts

According to the applicant, the use of an ESP would consume 85% more energy than a fabric filter designed to meet the same emission level. The applicant points out, however, that this energy consumption is equivalent to only 0.2 percent of the plant power output.

Economic Impacts

The applicant evaluated three scenarios:

1. The use of fabric filtration to meet an emissions level of 0.012 lb/MMBTU;
2. The use of an ESP to meet an emissions level of 0.020 lb/MMBTU; and,
3. The use of fabric filtration to meet an emissions level of 0.02 lb/MMBTU.

The factors which influence the cost of fabric filtration to meet the lowest limit include increased frequency of bag change-out and construction material of the bags. In addition, due to the nature of the device, baghouses are more susceptible to flue gas slip. Increased inspection and maintenance would be needed to ensure compliance with the low limit.

Factors influencing the cost of an ESP designed to meet a level of 0.020 lb/MMBTU include increased collection area, increased power usage, and increased inspection and maintenance over that required to achieve a level of 0.030 lb/MMBTU.

The applicant compared annualized costs for each of these control devices (Table 3.4-5 of Attachment 1) with the following results:

	1997 Total Levelized Annual Cost
FF - 0.012	$11.5 million
ESP - 0.020	$8.65 million
FF - 0.020	$8.77 million

The incremental cost in achieving the lowest limit was calculated to be $19,180 per additional ton of particulate removed.

Environmental Impacts

According to the applicant, ESPs are more effective than fabric filters at limiting the emissions of particulate sized less than 10 microns (PM_{10}). The National Ambient Air Quality Standard (NAAQS) for particulate matter is based on PM_{10}. Other environmental impacts include the fact that ESPs do not need to be "conditioned" over time to achieve the established removal efficiency. It is not necessary to allow time for a filter cake to build up in order to achieve the required removal efficiency.

Products of Incomplete Combustion

The products of incomplete combustion which are subject to a revised BACT analysis are carbon monoxide and VOCs. These pollutants are a direct relation to combustion conditions in the boiler.

Recent determinations for PC boilers include the following:

Mecklenburg Cogeneration, VA	CO - 0.020 lb/MMBTU VOC - 0.003 lb/MMBTU
Chambers Cogeneration, NJ	CO - 0.11 lb/MMBTU VOC - 0.0036 lb/MMBTU
Roanoke Valley Project, NC	CO - 0.20 lb/MMBTU VOC - 0.03 lb/MMBTU

There are no emissions standards in Subpart Da for either CO or VOC. The possible alternatives for reducing the pollutants are to change the boiler operating conditions or to install a catalytic conversion device to complete the oxidation of these pollutants. At this time, however, catalytic conversion of CO and VOC is not technically feasible for pulverized coal-fired boilers.

In regards to changing boiler operating conditions, the major impact would be environmental, i.e., decreasing CO and VOC could cause a resultant increase in NO_x emissions. The emissions levels proposed by the applicant, 0.15 lb/MMBTU for CO and 0.015 lb/MMBTU for VOCs is based upon the utilization of "low-NO_x" burners.

ACID GASES

Emissions of sulfur dioxide and oxides of nitrogen are known precursors to "acid rain," a major emphasis of the Clean Air Act Amendments of 1990. In addition, NO_x is a known precursor of ground level ozone, another major concern of the CAAA of 1990. These amendments have mandated reductions of 10 million tons per year of SO_2 and 2 million tons per year of NO_x from existing coal-fired facilities. Although both pollutants are "acid gases," their formation and control are fundamentally different, thus, they will be addressed separately.

SO_2

The formation of sulfur dioxide and its subsequent emissions are a direct result of the sulfur content of the fuel to be used. For Stanton Unit 2, the applicant has proposed a maximum sulfur content of 2.5% in the coal. This corresponds to an uncontrolled SO_2 emissions rate of 4.0 lb/MMBTU. Current practice for new coal-fired units is to add a flue-gas desulfurization (FGD) unit to lower SO_2 emissions.

40 CFR Part 60, Subpart Da sets an emissions standard of 1.2 lb/MMBTU and 90% removal; or 0.6 lb/MMBTU and 70% removal.

The current permit for Unit 1 contains a limit of 1.14 lb/MMBTU; however, due to the usage of low sulfur coal, Unit 1 has historically been able to achieve a level of 0.20 to 0.27 lb/MMBTU.

Recent determinations for PC boilers have been as follows:

Mecklenburg Cogeneration, VA	SO_2 - 0.17 lb/MMBTU (30-day average)
Chambers Cogeneration, NJ	SO_2 - 0.22 lb/MMBTU (60-min. average)
Roanoke Valley Project	SO_2 - 0.213 lb/MMBTU (30-day average)

The applicant has proposed the following emission levels for Unit 2 based on the use of 2.5% S coal and 92% removal of SO_2 on a continuous basis:

0.32 lb/MMBTU - 30 day rolling average

0.67 lb/MMBTU - 24 hr. average

0.85 lb/MMBTU - 3 hr. average

The control scenarios evaluated by the applicant include the use of a wet lime scrubber to meet a level of 0.24 lb/MMBTU; a wet limestone scrubber designed to meet a level of 0.32 lb/MMBTU; and, a lime spray dryer system designed to meet a level of 0.32 lb/MMBTU. The corresponding emissions of SO_2 with these scenarios was provided by the applicant as follows:

	Uncontrolled Emission (lb/MMBTU)	Controlled Emission Rate (lb/MMBTU)	Annual Emission (tons/year)
Wet lime	4.03	0.24	4,506
Wet limestone	4.03	0.32	6,008
Lime spray dryer	4.03	0.32	6,008

The air quality control systems evaluated by the applicant for SO_2 removal included particulate removal equipment since ESP's can be used with the first two options but a fabric filter must be used in conjunction with the lime spray dryer.

Energy Impacts

The energy impacts provided by the applicant for the different control systems included the energy requirements of the particulate control devices. As discussed in the analysis of the energy impacts for combustion products, the energy requirement for the ESP is 85% greater than for the fabric filter. As a result, the lime spray dryer system shows the lowest energy impacts - roughly half of the energy requirements for the wet limestone system. The energy requirements for the wet lime scrubber system is roughly 4/5 of the requirements for the wet limestone system. The use of a lower sulfur coal does not result in any significant energy impacts.

Economic Impacts

The economics related to establishing a BACT level for SO_2 are two-fold. First, there are the economics related to the capital and operating costs of specific control equipment. Secondly, there are the much more speculative economics related to the availability and projected future costs of low sulfur coal.

In the first case, comparative costs of the selected air quality control systems were provided by the applicant (Table 3.4-11 of Attachment 1). The results from this analysis were as follows:

Control Devices	1997 Total Levelized Annual Cost
Wet Lime AQCS	$46,550,000
Wet Limestone AQCS	$36,270,000
Wet Spray Dryer AQCS	$52,440,000

The applicant calculated an incremental removal cost from 0.32 lb/MMBTU to 0.24 lb/MMBTU of $6,780 per additional ton removed. The main differential between the control devices lies in the cost of the additives, where the cost of pebble lime ($80/ton) is reported to be 10 times more expensive than the limestone ($8/ton).

The economics of future coal supplies are much more difficult to ascertain. The applicant provided an analysis (Attachment 2) of projected future low sulfur coal supplies as well as speculation on how costs and supplies of Eastern U.S. low sulfur coal could be affected by future "fuel-switchers." Fuel-switchers refers to existing coal-fired facilities which will switch to lower sulfur content coals in order to meet requirements of Title IV (Acid Rain) of the CAAA of 1990.

It is impossible for EPA to be a prognosticator of future coal market conditions and how changes of such conditions on a macro-economic scale would affect the ability of OUC to obtain low sulfur coal for Stanton Unit 2 at a reasonable cost. OUC is currently able to obtain 1% Sulfur coal for Unit 1. Recent BACT determinations have included the use of coal with sulfur content less than 2%. Considering BACT is determined on a case-by-case basis, that Stanton Unit 2 will not start-up until 1997, and that projections on future costs and supplies of low sulfur coals contain many factors that may or may not be altered during the life of the plant, it must be concluded that the use of lower sulfur content coal is currently a viable alternative.

Environmental Impacts

The original PSD permit for Stanton Unit 2, allowed SO_2 emissions of 1.14 lb/MMBTU which equates to 4,715 lb/hr. or 19,803 TPY (based on 50 week per year operation). The SO_2 emission level proposed by the applicant, 0.32 lb/MMBTU, equates to 6008 TPY. An emission limit comparable to recent BACT determinations (0.21 lb/MMBTU) would equate to 3,942 TPY SO_2 emissions.

As discussed previously, SO_2 is a precursor to acid rain. In keeping with the congressional mandate for reductions in acid rain - causing pollutants, SO_2 emissions from new sources need to be minimized.

Also of considerable importance is the fact that the air quality modelling for Unit 2 indicated that 99% of the PSD Class II 24-hr. increment will be consumed.

Other Considerations

According to the applicant, FGD systems can only be expected to achieve a removal efficiency of roughly 3% less than the target rate on a continuous basis. This assertion is based on a statistical analysis of the operation of FGD systems (Attachment 2) and carries the premise that a target removal rate guaranteed by a vendor (i.e., 95%) can be met only under ideal conditions, not on a continuous basis. Using this assumption, the highest practical removal rate for a target rate of 95% would be 92%.

If this assumption is accepted, the maximum continuous removal rate for the control systems evaluated would be:

Wet lime AQCS	94%
Wet limestone AQCS	92%
Lime spray dryer	92%

Unit 2, like Unit 1, will be a "zero (water) discharge" unit. This means that the scrubber effluent will be recycled numerous times. While environmentally beneficial from a water standpoint, this recycling causes a buildup in the concentrations of trace constituents such as chlorides in the scrubber system. The applicant has presented data to demonstrate that this chloride buildup has slightly degraded the removal efficiency of Unit 1's scrubber over time.

Nitrogen Oxides

As discussed previously, NO_x is a precursor to acid rain as well as to ground level ozone. Subpart Da of the NSPS establishes a NO_x limit for utility boilers burning bituminous coal of 0.60 lb/MMBTU of heat input. This NSPS limit was established as BACT in PSD-FL-084; however, Stanton Unit 1 has historically been able to achieve a NO_x emission level of 0.4 to 0.5 lb/MMBTU.

The current status of control techniques for NO_x includes the use of combustion controls to limit the formation of NO_x as well as add-on controls to reduce NO_x emissions. These add-on controls include selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR).

Recently permitted PC boilers have NO_x limits as follow:

Mecklenburg Cogeneration, VA low-NO_x	NO_x - 0.33 lb/MMBTU (30-day average)
Chambers Cogeneration, NJ SCR	NO_x - 0.17 lb/MMBTU (180 -min. average)
Roanoke Valley Project, NC low-NO_x burners	NO_x - 0.33 lb/MMBTU (30-day average)

Low NO_x Burners

The NO_x control system proposed by the applicant, the use of "low-NO_x" burners, is the result of efforts made by burner manufacturers to reduce the formation of fuel NO_x (the oxidation of fuel bound nitrogen). Over the last several years, burner manufacturers have been guaranteeing NO_x emissions levels of between 0.30 and 0.40 lb/MMBTU utilizing a "staged" combustion process for coal fired units.

While several recent permits have been issued for low-NO_x burners on coal-fired boilers, there has been some concern expressed as to whether these burners can meet manufacturers' claims on a continuous basis. In addition, test results have shown that the use of "staged" combustion will increase the fixed carbon content in the fly ash. This could present a problem to a source such as OUC which utilizes fly ash as a salable product. However, according to the applicant, estimates of carbon content in the fly ash for Stanton Unit 2 will not be high enough to cause the ash to fail to meet ASTM standards for mineral admixtures to concrete (C618-89a, Attachment 3).

Selective Catalytic Reduction

Selective catalytic reduction (SCR) is a flue gas cleaning method which utilizes the injection of ammonia into the flue gas in the presence of a catalyst to dissociate NO_x into N_2 and water. SCR was first developed in the U.S. in the late 1950's but received its first widespread use in power generation service in Japan in the 1970's. SCR has been utilized on gas, oil and coal-fired units. Likewise many West German coal-fired units (129 to date) have been retrofitted with SCR systems to minimize NO_x emissions. In the United States, one recent PSD permit was issued requiring SCR on a PC boiler (Chambers Cogeneration in New Jersey).

The major technical concerns in the past for the application of SCR to coal-fired service have revolved around potential ammonia slip; conversion of SO_2 to SO_3 by the catalysts and the resultant formation of ammonia salts; and poisoning of the catalyst by trace constituents of the coal.

Based upon operating experiences in Japan and Europe, catalysts manufacturers have developed "new generation" catalysts in an attempt to alleviate the problems mentioned above. The current status of the "sulfur resistant" catalysts on the market is such that manufacturers will guarantee that SO_2 to SO_3 conversion will be limited to less than 1%. By limiting this conversion, the amount of SO_3 available to react with ammonia is minimized. The new catalysts are typically of the extruded "honeycomb" type which offer better reaction surface area than the older plate-type catalysts.

The limiting of ammonia slip is also important for several reasons. First, in conjunction with the sulfur resistant catalysts, low ammonia slip minimizes formation of ammonia salts. Secondly, limiting ammonia slip reduces their potential for reaction with any trace quantities of chloride from the coal which may result in an ammonium chloride plume. At ammonia slip levels typically found with SCR systems (i.e., around 5 ppm), this potential is virtually eliminated. The third major reason for limiting ammonia slip is to prevent contamination of the fly ash such that the fly ash remains a salable product. According to the applicant, ammonia slip must be limited to below 5 ppm for coal with seven percent ash. The design coal, however, has an ash content of 12%, thus assuring that the fly ash ammonia concentrations will be even less. In any event, if the ash will be used in clinker production by the cement industry, the ammonia will be driven off in the clinker kiln.

In regards to catalyst poisoning by trace constituents in U.S. coals, the applicant has not provided any evidence that the projected constituents of the design coal are such that the projected catalyst life would be severely altered. Over normal operation of the SCR system, catalyst will degrade or deactivate and require change-out. There is no indication that the design coal constituents would cause more frequent change-out of catalyst than would normally be guaranteed.

Based on operating experiences with various coals, the availability of sulfur resistant catalysts and the ability to minimize ammonia slip, it must be concluded that the use of SCR is technically feasible for Stanton Unit 2.

Selective non-catalytic reduction

Selective non-catalytic reduction (SNCR) systems utilize either ammonia or urea as reagent to inject in the flue gas. There is a very precise temperature window in which the reagent must be injected. Additionally, since the reaction is not in the presence of a catalyst, a greater than stoichiometric amount of reagent is necessary to achieve desired NO_x removal efficiencies. This in turn can lead to ammonia slip much greater than from an SCR system. As discussed previously, elevated ammonia slip could result in excessive formation of ammonia salts, the formation of an ammonia chloride plume, or contamination of fly ash. To minimize ammonia slip it would be necessary to carefully limit the reagent/gas ratio which would probably result in an effective control efficiency of 30 to 40%.

Current installations of SNCR include municipal waste incinerators and circulating fluidized bed (CFB) coal-fired boilers. The temperature profile of a CFB is much more stable than in a PC boiler and thus is conducive to establishing the proper temperature window to effectively operate SNCR. An additional concern is the possibility that an SNCR system may convert some of the NO_x emissions into N_2O.

ENERGY IMPACTS

The energy impacts of an SNCR system include the need for both steam and electrical energy. The applicant has estimated this need to be roughly 0.5 percent of the total plant power output.

The power needs for the SCR system was also estimated at 0.5 percent of the total plant power output. Also an energy consideration is the possible loss of boiler efficiency due to higher air heater exit temperatures related to the presence of SO_3 in the flue gas.

ENVIRONMENTAL IMPACTS

The area in which Stanton Energy Center is located is currently designated attainment for NO_2. As stated previously, NO_x is a known precursor to both acid rain and ground level ozone.

The NO_x emissions of Unit 1 as compared to the evaluated alternatives is given below:

	EMISSIONS NO_x		EMISSIONS NH_3	
	lb/MMBTU	TPY	PPM	TPY
Conventional Burner	0.60	10,869	N/A	N/A
Low-NOx Burner	0.32	5,934	N/A	N/A
LNB + SNCR (40% removal)	0.19	3,604	20	240
LNB + SNCR (30% removal)	0.22	4,205	10	120
LNB + SCR (70% removal)	0.10	1,280	5	60

As discussed previously, ammonia slip from the SNCR system could result in the formation of ammonium chloride (visible plume) as well as increase the particulate loading due to formation of ammonia salts.

With the SCR system, ammonia slip related issues can be minimized. Systems manufacturers typically recommend special air heater designs which along with the sulfur resistant catalyst and minimum ammonia slip, serve to increase the reliability of the system. Japanese and

German experience has shown that cleaning ammonia salts from downstream components can be achieved with water washing and is usually limited to routine plant down-times, thus creating no impact on overall plant reliability.

The last environmental consideration is the storage of ammonia, a hazardous material. In order to alleviate safety concerns, many manufacturers recommend that aqueous ammonia be used rather than the much more volatile anhydrous ammonia. The PSD permit for Chambers Cogeneration requires the use of aqueous ammonia (less than 28% solution in water).

Economic Impacts

The economic analyses provided by the applicant (attachments 1 and 4) were incremental costs analyses for SNCR and SCR as compared to their base case of low-NO_x burners. In addition, cost analyses for low-NO_x burners and SCR were obtained from EPA's Air and Energy Environmental Research Laboratory, based on cost models established by the Electric Power Research Institute (EPRI).

The analysis for SNCR provided by the applicant estimated an increase in capital costs of $14 million and $11 million for systems designed to meet 40% and 30% removal respectively. These costs result in estimated incremental cost effectiveness numbers of $2,700 per ton of NO_x removed (40%) and $3,100 per ton of NO_x removed (30%).

The cost estimation provided by the AEERL for the low-NO_x burner estimated capital costs to be increased by about $3.6 million over the cost of a conventional burner. The model assumed a NO_x reduction of 62%, resulting in a cost effectiveness number of $41.86 per ton of NO_x removed. The model also estimated a first year busbar cost of power at 0.009 mills/KWH and a levelized annual busbar cost of 0.11 mills/KWH.

The long-term NO_x emission limit established for Chambers Cogeneration is 0.17 lb/MMBTU; however, the system must be designed for 70% removal with 5 ppm ammonia slip - equivalent to 0.10 lb/MMBTU.

The cost estimate provided by AEERL considered two different scenarios:

1) 100% capacity and reduction to 0.17 lb/MMBTU;
2) 100% capacity and reduction to 0.10 lb/MMBTU;

This model made estimates of total costs of the SCR plus the low NO_x burners. The results are as follows:

CASE	LEVELIZED ANNUAL REQUIREMENTS $	SYSTEM COST $/KW	FIRST YEAR BUSBAR MILLS/KWH	LEVELIZED ANNUAL BUSBAR MILLS/KWH	COST PER TON NO_x REMOVED $/TON
1	12,654,900	114.93	2.37	3.28	982.71
2	12,934,200	115.89	2.41	3.36	905.32

The cost analysis provided the applicant was an incremental analysis and evaluated two scenarios: 1) a two year catalyst life; and 2) a two to four year catalyst life: In each case, the amount of NO_x removed only considered reaching the level of 0.17 lb /MMBTU (i.e., a reduction of 47% of the NO_x available after application of low-NO_x burners). The analysis also included the cost of lost fly ash sales as well as the cost of landfilling the fly ash. As discussed earlier, it is not readily apparent that fly ash sales will be affected; thus, the $1.4 million in levelized annual costs attributed to these activities should not be included in the analysis.

The resulting incremental cost effectiveness numbers for each scenario, considering removals of 47% and 70%, are as follows:

	Total Annual Cost($)	NO_x Emissions Reduced (TPY)	Incremental Cost ($/Ton)
2 yr Catalyst	17,730,000	(47%) 2810 (70%) 4160	$6,309 $4,262
2/4 yr Catalyst	13,710,000	(47%) 2810 (70%) 4160	$4,879 $3,295

In a paper presented at the 1991 Joint Symposium on stationary combustion NO_x Control by C.P. Robie, et. al., entitled "Technical Feasibility and Cost of SCR for U.S. Utility Application" (Attachment 5) , costs were estimated by EPRI for SCR being installed on new 500 MW coal-fired units. From this study, costs were expected to be in the range of $78 - 87/KW. The levelized cost was estimated to be in the range of 5.3 - 5.9 mills/KWH. The resulting cost efficiency was estimated to be $3,300 - $3,800/ton of NO_x removed. In addition, the report stated that the SCR capital cost in a new plant is substantially less than in a retrofit application.

The report also pointed out that reductions in catalyst unit costs have a large impact on the levelized costs. This mirrors a trend in the catalyst manufacturer industry in which catalyst costs have steadily decreased over time.

BACT Determination by EPA

Based on the preceding analyses, information provided by the applicant, information obtained form AEERL, review of the BACT/LAER Clearinghouse, review of papers presented at the 1991 Joint Symposium on Stationary Combustion NO_x Control, as well as review of permits for similar sources, the Agency has the following determination.

Particulate Matter

The use of an electrostatic precipitator (ESP) for the control of particulates is acceptable as BACT for Stanton Unit 2. The emission limit proposed by the applicant, 0.020 lb/MMBTU, is consistent with recent BACT determinations. Emission limits for Unit 2 are being established as follows:

PM (Particulate Matter):

0.020 lb/MMBTU

PM_{10}

0.020 lb/MMBTU

VE (Visible Emission)

Visible emissions from the stack shall not exceed 20% (6 minute average) except for one 6 minute period for hour of not more than 27% opacity.

Sulfur Dioxide

The two major factors in SO_2 emissions are sulfur content of the coal and scrubber removal efficiency. The removal efficiency proposed by the applicant is 92% on a continuous basis utilizing a wet limestone scrubber. The vendor guarantee for this system is 95% removal; however, due to the fact that Stanton Unit 2 will be a "zero-discharge" unit, some degradation of the scrubber removal efficiency is expected. The applicant has stated that the maximum expected removal rate will be 93.7%

The second factor in the BACT determination for SO_2, sulfur content of the coal, must be evaluated based upon what is available today rather than on what may or may not be available in the future. OUC is currently able to obtain low sulfur coal (< 2% S) for Stanton Unit 1. Recent permits have been issued in Region IV on the basis of low sulfur coal. FDER is currently processing several permits in which coal-fired units will utilize low sulfur coal. In the current market, low sulfur coal is cheaper than high sulfur coal. It must be concluded that coal with a sulfur content less than that proposed by the applicant is readily available as of today.

The basis of the Agency's determination is the use of 2.0% sulfur coal along with a wet limestone scrubber with a continuous removal efficiency of 92%. Calculations of various removal efficiencies for different sulfur content coals (Attachment 7) yield an emission rate of 0.25 lb/MMBTU for 2.0% coal with 92% removal. An emission limit of 0.25 lb/MMBTU allows Stanton Unit 2 to utilize 2.5% sulfur coal when their scrubber removal efficiency approaches the expected maximum of 93.7%.

The SO_2 emission limits are being set for Stanton Unit 2 as follows:

0.25 lb/MMBTU (30-day rolling average)
0.67 lb/MMBTU (24 hour average)
0.85 lb/MMBTU (3 hour average)

Carbon Monoxide and Volatile Organic Compounds

The determination of BACT for the control of CO and VOCs is the use of combustion controls to minimize incomplete combustion. The resulting emissions rates for these pollutants are:

CO

0.15 lb/MMBTU

VOC

0.015 lb/MMBTU

Nitrogen Oxides

Selective catalytic reduction (SCR) is an available technology which has been utilized on combustion turbines, gas/oil-fired boilers, and coal-fired boilers world-wide. Through several decades of operating experience, SCR systems have been developed which, when properly designed and operated, can achieve high levels of NO_x reductions while minimizing ammonia slip and its associated problems. As discussed in the analysis, catalysts are readily available which are sulfur resistant.

The basis for the BACT determination for NO_x emissions is the use of a SCR system designed to achieve a NO_x emission limit of 0.1 lb/MMBTU with ammonia slip limited to a maximum of 5 ppm before catalyst changeout. Recognizing the importance of maintaining unit reliability, the emission limit being established contains flexibility for the source in order to ensure that ammonia slip is minimized. To that end, the NO_x emission limit for Unit 2 is being set as follows:

NO_x

0.17 lb/MMBTU (30-day rolling average)

OUC Stanton Unit 2 is not scheduled to begin operation until 1997. In deference to the constant improvement in burner technologies and the development of other NO_x control technologies such as SNCR, the permit is being conditioned such that should OUC be able to demonstrate the capability of a technology other than SCR to be able to meet the established limit, the permit may be revised to incorporate the alternative technology.

PROPOSED PERMIT MODIFICATIONS TO PSD-FL-084

The Specific Conditions of federal permit PSD-FL-084 shall be modified as follows:

1. The proposed steam generating station shall be constructed and operated in accordance with the capabilities and specifications of the application including the 4,136 MMBTU/hr heat input rate for Unit 1 and the 4,286 MMBTU/hr heat input rate for Unit 2.

2. The emissions for Unit 1 shall not exceed the allowable emission limits listed in the following Table for SO_2, PM, NO_x and visible emissions:

Allowable Emissions

Pollutant	lb/MMBTU
PM	0.03
SO_2	1.14 (3-hr average) and 90 percent reduction (30-day rolling average)
NO_x	0.60 (30-day rolling average)
Visible Emissions	20% (6-minute average), except for one 6-minute period per hour of not more than 27% opacity

The emissions for Unit 2 shall not exceed the allowable emission limits listed in the following Table for SO_2, PM, NO_x, CO, VOC, and visible emissions:

Allowable Emissions

Pollutant	lb/MMBTU
PM	0.02
PM_{10}	0.02
SO_2	0.25 (30-day rolling average) 0.67 (24-hour average) 0.85 (3-hour average)

Pollutant	lb/MMBTU
NO_x	0.17 (30-day rolling average)
CO	0.15
VOC	0.015
Visible Emissions	20% (6-minute average), except for one 6-minute period per hour of not more than 27% opacity.

Additional conditions are added to PSD-FL-084 as follows:

14. Compliance with the emission limits contained in Specific Condition #2 for Unit 2 shall be determined as follows:

PM Compliance with the particulate limits in this permit shall be demonstrated by emission tests conducted in accordance with the provisions of 40 CFR §60.48a(b).

SO_2 Compliance with the SO_2 emission limits and emission reduction requirements in this permit shall be demonstrated in accordance with the provisions of 40 CFR §60.48a(c).

NO_x Compliance with the NO_x emission limits in this permit shall be demonstrated in accordance with the provisions of 40 CFR §60.48a(d).

VOC Compliance with the volatile organic compound limit shall be determined in accordance with Reference Method 25 or 25A of 40 CFR Part 60, Appendix A.

CO Compliance with the carbon monoxide limit shall be determined in accordance with Reference Method 10A or 10B of 40 CFR Part 60, Appendix A.

VE Compliance with the opacity limit in this permit shall be demonstrated using EPA Reference Method 9 in accordance with the provisions of 40 CFR §60.11.