ATTACHMENT 13

AUGUST 16, 1991 LETTER
FROM EPA TO OUC

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

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

4APT-AEB

AUG 16 1991

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

RE: Orlando Utilities Commission, Stanton Energy Center (PSD-FL-084)

Dear Mr. Fancy:

As you know, EPA is in the process of preparing a preliminary determination and draft permit modification for the previously issued Prevention of Significant Deterioration (PSD) permit for the Stanton Energy Center of the Orlando Utilities Commission. The purpose of the modification is to extend the commence construction date for Unit #2, which was previously permitted as part of a phased construction permit (PSD-FL-084). The original permit was issued by EPA on June 10, 1982. At the request of OUC, the federally issued permit is being modified rather than allowing the permit to expire and permitting Unit #2 under the Florida PSD regulations. It is therefore necessary for EPA to process the modification under federal regulations.

We are aware that Florida is reviewing the modification under the Florida Site Certification Act as a separate action. As stated in our letter to Jim Crall of OUC on January 28, 1991, we view the federal PSD process to be separate from the Site Certification process. It is our understanding, however, that FDER wishes to include EPA's preliminary determination as part of the Site Certification Hearing Report. To that end we are presenting you with a tentative schedule for issuing a prelimary determination.

August 23, 1991 - Internal Draft of Preliminary Determination

August 26, 1991 - Briefing of EPA senior management

September 15, 1991 - Publishing of Public Notice

October 29-30, 1991 - Public Hearing, if requested

As discussed between you and Mr. Brian Beals of my staff on August 16, 1991, we will provide a copy of our preliminary determination for internal review only by FDER prior to the public notice date. If you have any further questions or suggestions on this issue, please do not hesitate to contact Mr. Brian Beals of my staff at (404) 347-5014.

Sincerely yours,

Jewell Harper

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

ATTACHMENT 12

JULY 2, 1991 LETTER
FROM EPA TO OUC

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

JUL 02 1991

4APT-AEB

Mr. James P. Crall, Director
Environmental Division
Orlando Utilities Commission
500 South Orange Avenue
P.O. Box 3193
Orlando, Florida 32802

RE: Orlando Utilities Commission SEC Unit No. 2 (PSD-FL-084)

Dear Mr. Crall:

This is to acknowledge receipt of your request for a modification to your previously issued Prevention of Significant Deterioration (PSD) permit transmitted by letter dated March 18, 1991, as well as the additional information submitted with your letter dated June 20, 1991. I want to take this opportunity to thank you for the effort you and your staff have gone to in order to facilitate the review process for this project. The information presented by your consultants in our meeting of June 7 was quite helpful. After reviewing the information you have submitted along with the application, our staff has raised the following questions and concerns.

Sulfur Dioxide BACT

The SO_2 emission limit which you have proposed is 0.32 lb/MMBTU on a thirty-day rolling average, based on a design coal with a maximum sulfur content of 2.5% and a control system removal efficiency of 92%. The presentation made by your consultant gave the basis of this estimate as a statistical analysis utilizing a computer model which estimated that the reduction level that could be achieved with a 99% confidence limit over a thirty-day rolling average would be 92%. The assumptions made for this model include the use of 95% as the "target" removal efficiency since this level is "the highest guaranteed by any vendor. What is the basis for the vendor guarantee of 95%? What is the confidence limit for this guarantee? Over what averaging time has the vendor guaranteed 95% removal? It would seem that the 95% removal number, if it was guaranteed by the vendor, is the result of experience and analysis rather than a "target" number which is the starting point of the analysis.

Nitrogen Oxides BACT Analysis

The control technology which OUC has proposed as BACT for the PC boiler is the use of in-furnace combustion control (low NO_x burners) to achieve a NO_x emission level of 0.32 lb/MMBTU. The application stated that OUC intends to sell the fly ash resulting from the combustion of coal to the concrete industry.

> What is the resulting carbon loss from the utilization of low NO_x burners?
>
> To what extent does the carbon content of the fly ash increase as a result of the utilization of low NO_x burners to achieve a level of 0.32 lb/MMBTU?
>
> How does the increased carbon content of the fly ash affect the salability of the fly ash?

The use of selective catalytic reduction (SCR) on Stanton Unit No. 2 was dismissed in the application based on "the complete lack of SCR experience with these [Eastern United States] coals." Stated concerns include the sulfur content of the design coal and ammonia slip. As you may know, the new generation of SCR catalysts are generally sulfur resistant. For example, the Takehara Power Station has been operating with SCR while firing 2.5% sulfur coal since 1981. The NO_x removal rate is 80% and ammonia slip is minimized, thus there has been no evidence of ammonia salts fouling equipment downstream. (E.S. Brehens, et. al., SCR Operating Experience on Coal-Fired Boilers and Recent Progress, 1991 Joint Symposium on Stationary Combustion NO_x Control - EPA/EPRI, March 25-28, 1991)

There are numerous pilot studies being conducted to study the utilization of SCR on eastern U.S. coals. These include the study at TVA Shawnee, the study by the Southern Company in conjunction with Georgia Power, and the planned study at TVA Kingston Unit No. 9. In addition, the Chambers Cogeneration facility, located in New Jersey, was permitted in December of 1990 and required SCR on each of two PC boilers. Many facilities in both Japan and Germany will have nearly 20 years of operating experience with SCR by the time Stanton Unit No. 2 starts up in 1997.

The literature suggests that an ammonia slip level of 1 ppm is achievable through proper design and in fact is the target rate of many of the German applications. With the low ammonia slip, the concerns relating to the formation of an ammonia chloride plume and the formation of ammonium salts are alleviated. In addition, with low ammonia slip, the fly ash is not contaminated and remains a high quality salable product. (H. Maier, et. al., Operating Experience With Tail-End and High-Dust $DeNO_x$ Techniques at the Power Plant of Heilbronn, 1991 Joint Symposium on Stationary Combustion NO_x Control-EPA/EPRI, March 25-28, 1991)

As far as the reliability of a SCR system in coal-fired service, the German and Japanese units have been able to limit maintenance on the SCR system to scheduled shutdowns of the unit. In other words, the SCR systems have roughly the same reliability as the FGD systems. The keys to a successful system appear to be the utilization of second generation catalysts which minimize the conversion of SO_2 to SO_3; the use of steam assisted soot blowers in the air heater; and, the use of reliable ammonia monitors to minimize ammonia slip.

Based on the available literature and the fact that SCR has already been permitted in the U.S. for a PC boiler as the result of a BACT analysis, it would appear that SCR is indeed technically feasible. In addition, due to the development of second generation catalysts, the capital costs for installing SCR continue to decrease. In order to make an educated judgement as to whether SCR is applicable to Stanton Unit No. 2, it is necessary to obtain vendor quotes with guarantees on NO_x reduction, ammonia slip, and SO_2 to SO_3 conversion. To that end we are requesting that you obtain vendor quotes for an SCR system based on the following parameters.

> Conventional Boiler with uncontrolled NO_x emissions of 0.45 lb/MMBTU in order to minimize the carbon content in the fly ash such that the ash remains a salable product;
>
> NO_x reductions of 80%;
>
> Ammonia slip initially limited to 1 ppm with a maximum degradation to 5 ppm before changeout of the catalyst modules begins;
>
> The design coal presented in your application;

Evaluate both the high dust and tail-end configurations. Although the use of a tail-end system substantially extends the catalyst life, there is a heat rate penalty associated with reheating the flue gas. An assessment should be made of the heat rate penalty vs. the extended catalyst life.

In summary, we feel that these issues need to be addressed before a preliminary determination can be made. If you have any questions on these comments, please contact Mr. Gregg Worley of my staff at (404) 347-5014.

Sincerely yours,

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

cc: B. Andrews, FDER
S. Day, Black & Veatch
T. Tart, Esq., OUC.

ATTACHMENT 9

PSD PERMIT FOR CHAMBERS COGENERATION

BEST AVAILABLE COPY

State of New Jersey
DEPARTMENT OF ENVIRONMENTAL PROTECTION
DIVISION OF ENVIRONMENTAL QUALITY
CN 027 TRENTON, N.J. 08625-0027

PERMIT TO CONSTRUCT, INSTALL, OR ALTER CONTROL APPARATUS OR EQUIPMENT AND TEMPORARY CERTIFICATE TO OPERATE CONTROL APPARATUS OR EQUIPMENT AND PREVENTION OF SIGNIFICANT DETERIORATION PERMIT

NAME: Chambers Cogeneration Limited Partnership (CCLP)

ID NUMBER: To be assigned.

PLANT LOCATION: Route 130, Shell Road,
Carneys Point, NJ-08069, Salem County

STACK DESIGNATIONS: 001

SOURCE DESCRIPTION: Two pulverized coal fired boilers each 1309 MMBTU/hr heat input, auxiliary boiler, lime silo, lime slurry preparation system, ash storage silo, coal unloading area, stack out and coal reclaim conveyor, crusher feeder, coal transfer conveyor, coal silo bay, active coal pile, and coal yard storage.

DATE OF PERMIT:

EXPIRATION DATE: 90 calendar days after startup.

TRACKING [redacted]RS: 01-89-3086, 01-90-1903, 01-90-1904, 01-90-1905, 01-90-1906, 01-90-1907, 01-90-1908, 01-90-1909, 01-90-1910, 01-90-1911, 01-90-1912, 01-90-1913

On the basis of all the information available to the Department regarding the proposed Chambers Cogeneration Limited Partnership (CCLP) facility, the New Jersey Department of Environmental Protection (the Department) concludes that this project will meet all applicable requirements of the Prevention of Significant Deterioration (PSD) regulations codified at 40 CFR 52.21, New Source Performance Standards (NSPS) codified at 40 CFR 60, Subparts A, Da, Db, and Dc and of the New Jersey Air Pollution Control Regulations codified at

N.J.A.C. 7:27-1 et. seq. Accordingly, the Department issues this determination of approval to CCLP for the proposed cogeneration facility.

You are authorized to commence construction on this project on the effective date of this permit provided all preconstruction permit conditions have been met. The effective date of this permit is 30 calendar days after the Department gives notice of permit issuance, except when there is a request for administrative review pursuant to 40 CFR 124.19, in which case the effective date is the date administrative review is denied, or the administrative review is completed and the permit is approved. Those who commented during the public comment period may file an appeal up to [illegible] calendar days after the notice of issuance of the permit. If construction is not commenced within 18 months of this approval, this permit shall become invalid upon cancellation by the Department. Commence, as applied to construction of this source, is defined in the Code of Federal Regulations, [illegible] CFR. 52.21(b) (9).

This permit incorporates by reference all conditions in the PSD application submitted in October 1989, and all other submittals, and the conditions of approval listed in Attachment I. The conditions of approval take precedence over conditions described in the application and subsequent submittals if there is any inconsistency.

The opportunity for administrative review of the final PSD permit decision will commence with notice of its issuance to the public. The procedural requirements for administrative review are defined in the Consolidated Permits Regulations codified at 40 CFR Part 124 (45 FR 33405). Requests for administrative review of a final PSD Permit decision should be made to the Administrator of the United States Environmental Protection Agency, 401 M Street S.W., Washington, DC 20460. Administrative review is available only to those persons who commented during the public comment period and is restricted to issues raised during the comment period with the exception that any person, including those who failed to file comments on the preliminary permit determination, may petition for administrative review of the changes from the draft PSD to the final PSD permit. Upon issuance by the Department of the final permit decisions, or in the case of an administrative review upon completion of the administrative review process, the PSD final permit decision will be a final U.S. Environmental Protection Agency (USEPA) action and will be published in the Federal Register. This final action may be challenged only by filing a petition for review in the United States Court of Appeals for the appropriate circuit within 60 calendar days of the date of the Federal Register notice. The final PSD permit shall not be subject to later judicial review in enforcement proceedings. Opportunity for judicial review is only provided at the completion of the administrative appeals process and is only provided to those persons who were parties in an administrative appeal.

You will be sent form VEM-017 at a later date. Form VEM-017 will include your New Jersey Plant ID Number, New Jersey Stack Number, and Permit/Certificate Number. The Temporary Operating Certificate may be extended for additional 90 calendar day periods to allow for testing and evaluation of the equipment. The Department will not issue a 5-year certificate to operate unless and until the applicant conducts the stack tests specified in Attachment I and demonstrates that the conditions of approval are met.

Sincerely,

Iclal Atay, Ph.D., Chief
Bureau of Engineering and
Regulatory Development

Date: 12/20/90

c: J. Keith, Assistant Commissioner
N. Wittenberg, Director, DEQ
A. McMahon, Deputy Director
J. Elston, Assistant Director
W. O'Sullivan, Assistant Director
C. Salmi, Acting Chief
H. Hornikel, Acting Regional Enforcement Officer (SRO)
S. Riva, Chief, USEPA Region II
J. Rees, Supervisor
Y. Doshi, Acting Supervisor

ATTACHMENT 1

CONDITIONS FOR AIR POLLUTION CONTROL
PERMIT TO CONSTRUCT, INSTALL OR ALTER
CONTROL APPARATUS OR EQUIPMENT AND
TEMPORARY CERTIFICATE TO OPERATE CONTROL APPARATUS OR EQUIPMENT
AND PREVENTION OF SIGNIFICANT DETERIORATION PERMIT
FOR THE
CHAMBERS COGENERATION LIMITED PARTNERSHIP (CCLP)

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I. EMISSION LIMITS

A. **Maximum** PC Boiler Emission Rates

During any of the specified compliance time periods (see Table 1), the maximum emissions from each pulverized coal (PC) boiler, except during start-up and shut-down periods, shall not exceed the limits in Table 1. Compliance shall be determined by the use of New Jersey Air Test Methods 1 and 3 (N.J.A.C. 7:27-B), USEPA reference methods (40 CFR 60, Appendix A), and by continuous emission monitors (CEM) specified in permit condition V.

B. Maximum Auxiliary Boiler Emission Rates

During any one hour period, the maximum emissions from the auxiliary boiler, except during start-up and shut-down periods, shall not exceed the limits in Table 2. Compliance shall be determined by the use of New Jersey Air Test Methods 1 and 3 (N.J.A.C. 7:27-B) and USEPA reference methods (40 CFR 60, Appendix A).

C. Specific Organic Substances

Emissions of 2,3,7,8-tetrachloro dibenzo-p-dioxin (2,3,7,8 TCDD) and benzo(a) pyrene must be measured during the stack emission tests using methods approved by the Department. The emission rates from 3 successive stack emission tests conducted on one unit shall be determined.

D. PC Boiler Start-up and Shut-down

1. PC boiler start-up is defined as the period beginning with initial firing with No. 2 Fuel oil and ending at the time the boiler is being fired only with coal and/or No. 6 oil. No coal or No. 6 oil may be fired until all air pollution control equipment is in operation. The duration of the start up period, during which exemption from emission limits specified in permit condition I.A. applies, shall not exceed five hours.

2. **PC boiler shut-down is defined as the period of time beginning with the interruption of coal feed and ending when fuel is no longer being introduced into the combustion chamber of the boiler. All air pollution control equipment must be operating when coal or No. 6 oil is burning. This duration will not exceed 30 minutes.**

E. **Auxiliary Boiler Start-up and Shut-down**

1. **Auxiliary boiler start-up is defined as the period of time from boiler ignition until steam is available for customer use. This period shall not exceed 60 minutes.**

2. **Auxiliary** boiler shut-down is defined as the period of time after which steam is no longer available for customer use until cessation of fuel flow to the auxiliary boiler. This period shall not exceed 15 minutes.

F. Visible Emissions

1. The opacity of the emissions from each PC boiler shall not exceed 10% except for a period not longer than 3 minutes in any consecutive 30 minutes period, as determined by continuous opacity monitors and continuous recorders or by New Jersey Air Test Method 2. An exception to this requirement is that the opacity may not exceed 20% except for 3 minutes during a period of PC boiler start-up and shut-down. The Department may set lower opacity limits after the results from initial compliance testing are reviewed.

2. The auxiliary boiler shall not be operated in a manner which will cause visible emissions for more than 3 minutes in any consecutive 30 minute period. Compliance with this provision shall be determined by the use of New Jersey Air Test Method 2 (N.J.A.C. 7:27B.2) or approved equivalent.

G. General Prohibition of Air Pollution

The equipment in this permit shall not cause any air contaminant, including an air contaminant detectable by the sense of smell, to be present in the outdoor atmosphere in such quantity and duration which is, or tends to be, injurious to human health or welfare, animal or plant life or property, or would unreasonably interfere with the enjoyment of life or property, except in areas over which the owner or operator has exclusive use or occupancy.

II. OPERATING REQUIREMENTS

A. Limits on Operation

The auxiliary boiler shall not be operated at the same time as either PC boiler, except when auxiliary steam is required during PC boiler start-up or shut-down.

B. Limits on Fuel Firing

1. **Total coal, No. 2 oil, and No. 6 oil fired in the two PC boilers is limited to 2.44×10^{13} BTU, (HHV) per calendar year.**

2. **Total No. 2 oil fired in the auxiliary boiler is limited to 7.7×10^{10} BTU, (HHV) per calendar year.**

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C. **Limits** on Substance Content

1. The sulfur content of the bituminous coal to be burned in the two PC boilers shall not exceed 2% by weight.

2. The sulfur content of the No. 2 fuel oil to be burned in the facility shall not exceed 0.2 percent by weight.

3. The sulfur content of the No. 6 fuel oil to be burned in the facility shall not exceed 0.3 percent by weight.

4. Water treatment chemicals containing hexavalent chromium shall not be added to the cooling tower circulating water.

III. EMISSIONS CONTROL

A. Particulate Matter

1. Particulate emissions from the PC boilers shall be controlled by fabric filters. The fabric filters shall be provided with adequate access for inspection. The fabric filters may only be bypassed when using No. 2 fuel oil.

2. Particulate emissions from the coal storage silos, lime storage silo, recycle silo, and ash storage silo shall be controlled by fabric filters. The fabric filters shall be provided with adequate access for inspection.

3. The design parameters for the baghouses (for all above listed sources) must be submitted to the Department for approval within two months of the date of approval of this permit.

B. Sulfur Dioxide (SO_2)

1. Sulfur dioxide emissions from the PC boilers shall be controlled by lime spray dryer absorber scrubbers, except when burning No. 2 fuel oil. The average one-hour concentration and emission rate of SO_2 in the stack gas from each unit must comply with Table 1 as determined by the continuous emission monitoring and continuous recording and testing.

2. The design parameters for scrubbers must be submitted to the Department for approval within two months of the date of approval of this permit. The submittal shall contain details including, but not limited to: the redundancy of the reagent feed system, the spare parts inventory for the reagent injection devices, the time required to remedy typical equipment malfunctions, and the minimum ratio of actual lime to stoichiometric lime.

C. Nitrogen Dioxide (NO_2)

1. Nitrogen oxide emissions from the PC boilers shall be controlled with low NO_x burners, advanced combustion controls, and Selective Catalytic Reduction (SCR) technology.

2. Design

   a. The system will be designed to achieve a NO_x emission rate of less than 0.10 lbs/MMBTU (HHV).

   b. The design specification of the proposed SCR system will be submitted to the Department for review and approval within two months of the date of approval of this permit. Such information will include, but not be limited to, the capacity of the ammonia feed system, catalyst replacement schedule to achieve maximum control of nitrogen oxides, and the operating range for nitrogen oxide to ammonia mole ratio.

3. Operation

   a. The catalyst bed shall be replaced as necessary so that the maximum allowable emission rate of NO_x does not exceed 0.17 pounds per million BTU (lbs/MMBTU, HHV) averaged over any consecutive 180 minutes.

   b. The SCR system shall be optimized to achieve a NO_x emission rate of less than 0.10 lbs/MMBTU, (HHV) averaged over any consecutive 180 minutes by catalyst addition and/or replacement as necessary, but no more than 50% of the initial catalyst bed within each 5-year operating period for this facility.

   c. At the end of the first 5-year operating period, permit condition III.C.1 for the maximum NO_x emission limit shall be modified by multiplying the optimized NO_x emission rate by 1.2. The new maximum allowable NO_x emission rate shall be the rate that is demonstrated to be consistently achievable (not including malfunctions) and shall not be less than 0.10 lbs/MMBTU (HHV) nor more than 0.17 lbs/mmBTU, (HHV).

D. Other Sources of Emissions

1. The maximum emissions from all other sources listed in Table 3 shall not exceed the limits specified in that table. Each source shall be equipped with control measures and/or control devices listed in Table 3.

2. Fugitive dust emissions from coal unloading and stack out shall be controlled by wet suppression and/or surfactant as necessary. Dust emissions at other coal conveyor transfer points shall be controlled by dust collectors.

3. There shall be no visible fugitive emissions to the outdoor air from the coal unloading, stack out, coal storage and other coal handling operations.

4. The pulverizers shall be located indoors. The coal crusher will be enclosed and provided with a dust collector to prevent fugitive dust emissions.

5. All conveyor belts shall be covered.

6. Inactive coal stockpiles shall be moistened or treated (wet suppression and/or surfactant) and the inactive stockpile surfaces shall be kept moist or otherwise treated at all times to minimize emissions during storage.

7. Fugitive emissions from all permanent facility access roads on facility property shall be controlled by paving and road cleaning.

IV. TESTING

A. Before a 5-year certificate to operate is issued, the applicant must:

1. Conduct stack emission tests in accordance with N.J.A.C. 7:27-8.4(c) for all the pollutants that are listed in Table 1 and Table 2. All tests, on a given unit must be conducted within 60 calendar days after achieving the coal combustion rate at which the facility will be normally operated, but not later than 180 calendar days after initial start-up.

2. A detailed description of the sampling point locations, sampling equipment, sampling and analytical procedures, data reporting forms, quality assurance procedures and operating conditions for such tests must be submitted to the Chief, Bureau of Technical Services, at least 180 calendar days prior to start-up of the facility to obtain approval of a stack emission test protocol.

3. Contact the Bureau of Technical Services, at (609) 530-4041, within 14 calendar days of approval of the stack test protocol to establish a mutually acceptable stack test date in order that representatives of this office may be scheduled to observe the conduct of the tests.

B. Three stack emission tests shall be conducted on each PC boiler and auxiliary boiler for the pollutants listed in Table 1 and 2. Such tests shall be conducted at 100% load.

C. **Heat input** (MMBTU/hr, HHV) shall be determined for each stack test. **Emission** levels of nitrogen oxides, carbon monoxide, sulfur oxides, **ammonia**, particulate matter and volatile organic compounds shall be reported in pounds per hour, parts per million on dry volume basis (ppmdv) corrected to 7% oxygen (except particulate matter) and pounds per million BTU (HHV) heat input.

D. The permittee must conduct comprehensive stack emission test and submit the test results at least 180 calendar days prior to expiration of each 5-year certificate to operate in order to renew a certificate to operate. A test protocol for such testing shall be submitted to the Department for approval one year prior to expiration of the certificate to operate.

E. Permanent sampling and testing facilities must be provided as required by the Department to determine the nature and quantity of emissions from the boiler. Such facilities shall conform to all applicable laws and regulations concerning safe construction and safe practices.

F. The Department may require at any time additional stack emission testing of the pollutants for which an emission limit has been set in permit condition I.A. of this permit or any other air pollutants potentially emitted by the facility.

V. MONITORING, RECORDING AND RECORDKEEPING

A. Continuous Emission Monitors and Recorders

1. For each PC unit, continuous monitors and continuous recorders shall be installed and operated to continuously measure and continuously record the opacity of the stack gas and emission concentrations of carbon monoxide, oxygen, nitrogen oxides, **ammonia, and sulfur dioxide. Monitors must comply with EPA performance and siting specification pursuant to 40 CFR Part 60, Appendix B as applicable. Equipment specifications, calibration and operating procedures, and data evaluation and reporting procedures must be submitted for approval to the Chief, Bureau of Technical Services, CN-411, Trenton, New Jersey 08625. The Department may require a continuous emission monitor and continuous emission recorder for non-methane hydrocarbons in each boiler stack.**

2. **All continuous emission monitors and recorders required pursuant to permit condition V.A.1. shall be operational prior to the initial burning of coal in the furnace.**

3. **All continuous emission monitors and continuous emission recorders required by permit condition V.A.1. shall undergo the appropriate Performance Specification Test (PST) and the report**

must be submitted to the Chief, Bureau of Technical Services. These performance tests must be conducted prior to conducting the compliance stack emission tests.

4. All continuous emission monitors required by permit condition V.A.1. must comply with the quality assurance requirements outlined in 40 CFR Part 60, Appendix F as applicable.

B. Operating Log

Operating logs shall be kept for each unit to maintain the following records accurately. Logs shall be maintained in a manner approved by the Regional Enforcement Officer.

1. The specific times of operation of each boiler.
2. The specific times of operation of the auxiliary boiler.
3. Exceedances of emission standards determined by continuous monitoring and recording.
4. Recording of pressure drop across entire fabric filters for the PC boilers.

C. Recordkeeping

1. CCLP shall maintain records of all shipping receipts from the fuel suppliers for each shipment of coal, No. 6 fuel oil and No. 2 fuel oil delivered certifying that the shipment contains maximum 2% sulfur by weight in coal, a maximum of 0.3% sulfur by weight in No. 6 fuel oil, and a maximum of 0.2% sulfur by weight in No. 2 fuel oil.

2. All continuous emission monitoring records and log books specified in permit conditions V.A. and V.B. must be maintained in a manner approved by the Regional Enforcement Officer and made available for inspection by the Department for a period of three years after the date of each record. The format of these reports shall be submitted to Regional Enforcement Officer, Southern Regional Office, 20 E. Clementon Road, 3rd Floor, Gibbsboro, New Jersey 08026, for approval 180 calendar days prior to initial start-up of the facility

D. Telemetry of Continuous Monitoring Data

The continuous emission monitoring data collected pursuant to permit condition V.A. shall be transmitted to the Department via a remote telemetry system. A plan identifying the specific details of the telemetry system and the reporting format must be submitted to the Chief, Bureau of Air Monitoring, Division of Environmental Quality,

CN 027, Trenton, NJ 08625, for approval six months prior to purchase of the equipment. The Department reserves the right to suspend the requirement of remote telemetry system.

VI. REPORTING REQUIREMENTS

A. Three copies of the report of the results of each stack emission tests must be submitted within 60 calendar days after completion of the stack emission tests to:

Assistant Director, Enforcement Element
Division of Environmental Quality
CN 027
Trenton, New Jersey 08625

B. Occurrences of excess emissions and actions taken must be reported in writing within 3 calendar days to the Assistant Director, Enforcement, Division of Environmental Quality, CN 027, Trenton, New Jersey 08625.

C. Quarterly Excess Emission Reports (EER) required by 40 CFR 60.3(c) for all continuous emission monitors must be submitted to the Regional Enforcement Officer, Southern Regional Office, within 30 calendar days after each calendar quarter. The EER format must be approved by the Chief, Bureau of Technical Services, prior to the start-up of the facility. The quarterly EER must include a summary of any exceedances and the corrective action taken.

The quarterly EER must also be submitted to:

Chief, Air Monitoring Section
USEPA, Region II
Woodbridge Avenue
Edison, New Jersey 08839

VII. FEDERAL NSPS REQUIREMENTS:

The facility is subject to the federal New Source Performance Standards (NSPS) codified at 40 CFR Part 60 Subparts A (General provisions), Da (Electric steam generating units), Db (Industrial-Commercial-Institutional steam generating units), and Dc (Small Industrial-Commercial-Institutional steam generating units). Compliance with all applicable provisions of these regulations is required.

VIII. BIOLOGICAL MONITORING

The Chambers Cogeneration Limited Partnership shall provide a total $40,000 in funding support to the National Park Service, Air Quality Division, to help establish a biological monitoring program at the Brigantine Wildlife Refuge to determine the effects of air contaminants on plants and wildlife at the refuge. Funding shall be submitted to the National Park Service within 30 calendar days of the start of construction.

IX. AMBIENT AIR QUALITY MONITORING

1. The Chambers Cogeneration Limited Partnership (CCLP) shall install and operate ambient air monitoring samplers for sulfur dioxide, PM-10, and nitrogen oxides in order to determine ambient concentrations for comparison with National and New Jersey Ambient Air Quality Standards. Within 6 months of the effective date of this permit, the operator shall submit for approval of the Department, a detailed protocol for ambient air sampling and analysis, including proposed site locations and the rationale for site selection. This protocol shall be prepared in accordance with the Department's "Overall Strategy for Point Source Oriented Ambient Air Monitoring of Specific Criteria Pollutants and Air Toxics".

2. The Department shall oversee and audit the monitoring and shall be provided access to the monitoring sites upon request. Data shall be submitted at least once per calendar quarter.

3. The monitoring program shall be in operation for a minimum of six months before combustion of coal commences at the CCLP and shall continue in operation for a minimum of two years after the CCLP receives a five year certificate to operate, or longer if the Department determines that the contaminant levels detected, warrant additional sampling.

4. All contacts regarding the monitoring, location approval, methods of measurement, and data submittal, shall be made to the Chief, Bureau of Air Monitoring, Division of Environmental Quality, CN-027, Trenton, NJ-08625.

X. AMMONIA STORAGE

If the facility is subject to the New Jersey Toxic Catastrophe Prevention Act, N.J.A.C. 7:31-1 to 6, compliance with the applicable provisions of this regulation is required. Compliance shall be demonstrated by submitting all the design documents for ammonia storage and handling, six months prior to ordering the equipment, for review and approval to the Chief, Bureau of Release Prevention, CN-027, Trenton, NJ-08625.

TABLE 1

MAXIMUM EMISSIONS RATES FOR EACH PULVERIZED COAL PC BOILER

CONTAMINANT	MAXIMUM EMISSIONS	COMPLIANCE BASIS
Total Suspended Particulates		
- lbs/hr	25.0	
- lbs/MM BTU	0.018	60 minutes
PM-10		
- lbs/hr	25.0	
- lbs/MM BTU	0.018	60 minutes
Sulfur Oxides (as SO_2)		
- lbs/hr	305.6	
- lbs/MM BTU	0.22	60 minutes
- ppm dry vol. at 7% O_2	100.0	
Nitrogen Oxides (as NO_2)*		
- lbs/hr	236.3	
- lbs/MM BTU	0.17	180 minutes
- ppm dry vol. at 7% O_2	100	
Carbon Monoxide		
- lbs/hr	152.8	
- lbs/MM BTU	0.11	180 minutes
- ppm dry vol. at 7% O_2	100.0	
Total Non-Methane Hydrocarbons (as CH_4)		
- lbs/hr	5.0	
- lbs/MM BTU	0.0036	60 minutes
Ammonia		
- lbs/hr	10	180 minutes
- ppm dry vol. at 7% O_2	10	180 minutes
- ppm dry vol. at 7% O_2	5	30 day
Fluorides (as HF)		
-lbs/hr	**2.78**	**EPA Method 13B**
Heavy Metals		
Arsenic		
- lbs/hr	**0.117**	**EPA Multimetal test method**
Beryllium		
- lbs/hr	**0.0058**	**EPA Multimetal test method**

CONTAMINANT	MAXIMUM EMISSIONS	COMPLIANCE BASIS
Cadmium - lbs/hr	0.003	EPA Multimetal test method
Chromium (Total) - lbs/hr	0.051	EPA Multimetal test method
Lead - lbs/hr	0.040	EPA Reference method 12
Mercury - lbs/hr	0.026	EPA Reference method 101A

*See permit Condition III.C.3. for additional provisions on NO_x emission limits.

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TABLE 2

MAXIMUM HOURLY EMISSION RATES FROM AUXILIARY BOILER

CONTAMINANT	(77 MM BTU/HR) NO. 2 FUEL OIL
Total Particulate Matter	
- lbs/hr	1.5
- lbs/MM BTU	0.02
PM-10	
- lbs/hr	1.54
- lbs/MM BTU	0.02
Sulfur Oxides (as SO_2)	
- lbs/hr	24.3
- lbs/MM BTU	0.315
Nitrogen Oxides (as NO_2)	
- lbs/hr	13.0
- lbs/MM BTU	0.17
Carbon Monoxide	
- lbs/hr	13.2
- lbs/MM BTU	0.172
- ppm dry vol. at 7% O_2	100
Total Non-Methane Hydrocarbons	
- lbs/hr	0.6
- lbs/MM BTU	0.008

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TABLE 3

OTHER SOURCES IN THE FACILITY

	Source	Control	Maximum Particulate Emission (lbs/hr)
1.	Lime Silo	Baghouse	0.01
2.	Lime Slurry Tank	Baghouse	0.001
3.	Ash Storage Pile	Baghouse	0.6
4.	Coal Unloader	Water Spray	0.34
5.	Hopper Pit Unloader	Baghouse	0.001
6.	Stack out conveyor	Water Spray	0.03
7.	Crusher feeder	Baghouse	0.18
8.	Two silo feed conveyors	Baghouse	0.001
9.	Coal Pile	Spray	0.00003
10.	Inactive coal storage	Water Spray	0.00001
11.	Reclaim Conveyor	Baghouse	0.0001
12.	Coal Transfer Conveyor	Baghouse	0.001

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[illegible]. CHANGES TO THE PSD PERMIT

The following changes were made in response to the public comments. Changes are marked by underlines:

I. Permit Condition II. B.2

B. Limits on Fuel Firing

1. Total No. 2 oil fired in the auxiliary boiler is limited to [illegible] x 10^{10} BTU (HHV) per calendar year.

II. Permit Condition III. C.3.b & III. C.3.c.

C. Nitrogen Oxides (NO_2)

3. Operation

b. The SCR system shall be optimized to achieve a NO_x emission rate of less than 0.10 lbs/MMBTU (HHV) averaged over a consecutive 180 minutes by catalyst addition and/or replacement as necessary, but no more than 50% of the initial catalyst bed within each 5-year operating period for this facility.

c. At the end of the first 5-year operating period, permit condition III. C.1 for the maximum NO_x emission limit shall be modified by multiplying the optimized NO_x emission rate by 1.2. The new maximum allowable NO_x emission rate shall be the rate that is demonstrated to be consistently achievable (not including malfunctions) and shall not be less than 0.10 lbs/MMBTU (HHV) nor more than 0.17 lbs/MMBTU (HHV).

III. Permit Condition V.B.4.

B. Operating Log

4. Recording of pressure drop across entire fabric filters for the PC boilers.

IV. Permit Condition V.D.

D. Telemetry of Continuous Monitoring Data

The continuous emission monitoring data collected as per [illegible] condition [illegible], shall be transmitted to the Department via a [illegible] telemetry system. A plan identifying the specific details of the telemetry system and the reporting format must be submitted to the Chief, Bureau of Air Monitoring, Division of Environmental Quality, CN 027, Trenton, NJ 08625, for approval six months prior to purchase of the equipment.

V. Permit Condition IX. 1.

IX. AMBIENT AIR QUALITY MONITORING

1. The Chambers Cogeneration Limited Partnership (CCLP) shall install and operate ambient air monitoring samplers for sulfur dioxide, PM-10, and nitrogen oxides in order to determine ambient concentrations for comparison with National and New Jersey Ambient Air Quality Standards. Within 6 months of the effective date of this permit, the operator shall submit for approval of the Department, a detailed protocol for ambient air sampling and analysis, including proposed site locations and the rationale for site selection. This protocol shall be prepared in accordance with the Department's "Overall Strategy for Point Source Oriented Ambient Air Monitoring of Specific Criteria Pollutants and Air Toxics".

VI.

TABLE 1

MAXIMUM EMISSIONS RATES FOR EACH PULVERIZED COAL PC BOILER

CONTAMINANT	MAXIMUM EMISSIONS	COMPLIANCE BASIS
Total Suspended Particulates		
- lbs/hr	25.0	
- lbs/MM BTU	0.018	60 minutes
PM-10		
- lbs/hr	25.0	
- lbs/MM BTU	0.018	60 minutes
Sulfur Oxides (as SO_2)		
- lbs/hr	305.6	
- lbs/MM BTU	0.22	60 minutes
- ppm dry vol. at 7% O_2	100.0	
Nitrogen Oxides (as NO_2)*		
- lbs/hr	236.3	
- lbs/MM BTU	0.17	180 minutes
- ppm dry vol. at 7% O_2	100	
Carbon Monoxide		
- lbs/hr	152.8	
- lbs/MM BTU	0.11	180 minutes
- ppm dry vol. at 7% O_2	100.0	
Total Non-Methane Hydrocarbons (as CH_4)		
- lbs/hr	5.0	
- lbs/MM BTU	0.0036	60 minutes
Ammonia		
- lbs/hr	**10**	**180 minutes**
- ppm dry vol. at 7% O_2	**10**	**180 minutes**
- ppm dry vol. at 7% O_2	**5**	**30 day**
Fluorides (as HF)		
-lbs/hr	**2.78**	**EPA Method 13B**
Heavy Metals		
Arsenic		
- lbs/hr	**0.117**	**EPA Multimetal test method**
Beryllium		
- lbs/hr	**0.0058**	**EPA Multimetal test method**

CONTAMINANT	MAXIMUM EMISSIONS	COMPLIANCE BASIS
Cadmium - lbs/hr	0.003	EPA Multimetal test method
Chromium (Total) - lbs/hr	0.051	EPA Multimetal test method
Lead - lbs/hr	0.040	EPA Reference method 12
Mercury - lbs/hr	0.026	EPA Reference method 101A

*See permit Condition III.C.3. for additional provisions on NO_x emission limits.

APPENDIX A

Following people commented during the public hearing. The names appear in order of appearance.

1. Mr. Dennis Dubberley, NUS Corporation
2. Mr. Carl Graskill, Carneys Point Township Planning Board
3. Mr. Frank Santucci, Community Advisory Coalition
4. Chief Ed Spinelli, Pennsgrove Police Department

APPENDIX B

Following parties have provided written comments:

1. United States Department of the Interior, Fish and Wildlife Service

2. Chambers Cogeneration Limited Partnership

APPENDIX C

Following people represented the Department during the public hearing:

1. Anthony McMahon, Deputy Director, Division of Environmental Quality
2. Iclal Atay, Ph.D., Chief, Bureau of Engineering and Regulatory Development, Division of Environmental Quality
3. Yogesh Doshi, Principal Environmental Engineer, Bureau of Engineering and Regulatory Development, Division of Environmental Quality
4. Gay Pearson, Senior Environmental Specialist, Bureau of Air Quality Planning and Evaluation, Division of Environmental Quality
5. Rajesh Patel, Assistant Environmental Engineer, Bureau of Engineering and Regulatory Development, Division of Environmental Quality.

Let's protect our earth

State of New Jersey
DEPARTMENT OF ENVIRONMENTAL PROTECTION
DIVISION OF ENVIRONMENTAL QUALITY
CN 027, TRENTON, N.J. 08625-0027
Fax # (609) 292-1074

RECEIVED
JAN 06 1991
NEW SOURCE REVIEW SECTION
EPA Region III

December 26, 1990

Mr. William Brown
Chief, Air Permits Section
USEPA Region 3
841 Chestnut St.
Philadelphia, PA 19107

REFERENCE: Chambers Cogeneration Limited Partnership
Proposed Coal-Fired Cogeneration Facility

Dear Sir/Madam:

Enclosed please find the hearing officer's report on the referenced facility.

After considering all the comments received, the Department approved the proposed air pollution control permit for the Chambers Cogeneration Limited Partnership (CCLP), with minor modification of the permit conditions in response to public comments. The hearing officer's report contains final permit, final permit conditions and the Department's responses to the relevant comments raised during the public comment period.

In response to comments received, the Department added ambient air monitoring for PM-10 and nitrogen oxides. The Department has also required telemetry of continuous emission monitoring data.

Thank you for your concern for the environment.

Sincerely,

Iclal Atay, Ph.D.
Chief
Bureau of Engineering & Regulatory
Development

c: Anthony McMahon, Deputy Director
William O'Sullivan, Assistant Director
Yogesh Doshi, Principal Environmental Engineer

DEPARTMENT OF ENVIRONMENTAL PROTECTION

DIVISION OF ENVIRONMENTAL QUALITY

HEARING OFFICER'S REPORT FOR THE APPLICATION BY CHAMBERS COGENERATION LIMITED PARTNERSHIP TO CONSTRUCT AND OPERATE A COGENERATION FACILITY

Anthony J. McMahon
Deputy Director
Hearing Officer

December 26, 1990

TABLE OF CONTENTS

1. Introduction
    - A. Facility Application
    - B. Public Comment Period
    - C. Public Hearing
2. Response to Comments
3. Prevention of Significant Deterioration (PSD) Permit
4. Changes to the PSD Permit

APPENDIX A: List of Participants Providing Verbal Testimony at the Public Hearing

APPENDIX B: List of Participants Providing Written Testimony

APPENDIX C: List of Department Representatives Available at the Public Hearing

1. INTRODUCTION

A. Facility Application

On July 5, 1989, a pulverized coal fired cogeneration facility permit application package, including Best Available Control Technology Analysis (BACT) and air quality modelling studies, were submitted by the Chambers Cogeneration Limited Partnership (CCLP). The permit application package was reviewed by the Division and following additional submissions at the request of the Department, the application was found administratively complete on November 1, 1990. Copies of the air pollution control permit conditions and project summary document were subsequently distributed to various agencies and United States Environmental Protection Agency for their review and comments.

During the period from July 1989 to October 1990, the Bureau of Engineering and Regulatory Development requested additional information, clarifications and modifications from the applicant. The applicant forwarded submittals and addendums responding to the comments and issues raised during this review period.

On November 5, 1990, in conformance with New Jersey Air Pollution Control Laws and the Federal Prevention of Significant Deterioration (PSD) regulations codified at 40 CFR 52.21, the Division of Environmental Quality issued a draft permit (tentative approval subject to public comments) for the construction and operation of the proposed cogeneration facility and scheduled a public hearing to solicit testimony concerning this decision.

B. Public Comment Period

The public comment period for the draft air pollution control permit began on November 5, 1990, and ended on December 10, 1990. Copies of the draft permit, the project summary document and supporting permit application were made available for public review at the following locations: Office of the Mayor of Carneys Point Township, Southern Regional Office, Gibbsboro, and the Department of Environmental Protection, Trenton.

During this public comment period, written and verbal comments were received. The list of those who provided testimony and written comments are identified in Appendix A and B respectively. The concerns reflected in the verbal and written commentary are addressed in this response to comment document.

C. Public Hearing

The public hearing was held at Pennsgrove High School, Carneys Point, New Jersey on December 5, 1990. The Department's hearing panel consisted of:

Anthony J. McMahon (Hearing Officer)
Deputy Director
Air Programs
Division of Environmental Quality

And

Iclal Atay, Ph.D.
Chief, Bureau of Engineering and Regulatory Development
Division of Environmental Quality.

Other Departmental staff who were present during the public hearing are listed in Appendix C.

Prior to opening the hearing to public comment at 5:00 P.M., Mr. Anthony McMahon, Deputy Director, read statements into the record, which described the project, outlined the Department's review process relative to the application, briefly discussed the project and outlined the procedures which would be followed during the hearing. The hearing was then opened for the receipt of public comment. Approximately 15 individuals were present during the session and 4 of these individuals offered verbal testimony. The hearing was adjourned at 9:00 P.M. that evening, with no one present offering additional verbal testimony.

2. RESPONSE TO COMMENTS

Comment 1: How did the Department model for ammonia slip and what considerations were given in determining the concentrations of ammonia at the plant boundary and in the surrounding area?

Response: The amnmonia emissions were modeled using the same modeling procedures applied to other pollutants. The impacts (shown below) are well below the threshold levels for odor and health effects.

Ammonia Emissions

1.	Chronic Health Effect Criteria (24 hour average) 34 ug/m^3	CCLP Contribution (24 hour average) 0.16 ug/m^3
2.	Odor Threshold (1 hour average) 3600 ug/m^3	Predicted Concentration from CCLP (1 hour average) 1.74 ug/m^3

Comment 2: The applicant must be required to install, operate and maintain three ambient air quality monitoring stations at various locations within Carneys Point Township. These monitoring stations will record ambient air quality for PM-10 (particulate matter having aerodynamic diameter less than 10 microns), sulfur oxides and nitrogen oxides.

Response: Draft Permit Condition IX required the CCLP to install and operate ambient air monitoring samplers for sulfur dioxide.

Permit Condition IX.1 has been revised to require ambient air monitoring for PM-10 and nitrogen oxides.

Regarding the number of ambient air quality monitoring stations, Permit Condition IX.1 requires the permittee to submit for Departmental approval a detailed protocol, including proposed site locations and the rational for site selection. The number and location of monitoring stations shall be determined at the completion of the review of these documents.

Comment 3: The Department must receive all continuous emission monitoring data via remote telemetry and review this data for compliance with permit requirements.

Response: Permit Condition V.D. is revised to require telemetry of the continuous emission monitoring data to the offices of the Department.

Comment 4: Will this facility be a danger to the community? What corrective steps will be taken to ensure the public safety and well-being of the people?

Department's Response: The CCLP has been permitted under federal PSD regulations codified at 40 CFR 52.21, which requires the applicant to employ Best Available Control Technology (BACT) to reduce the emissions of each PSD applicable pollutant. The CCLP has demonstrated to the satisfaction of the Department that the technology used is BACT. Also, the long term effects of criteria pollutants emitted from the proposed facility are accounted for in the demonstration of compliance with the state and federal ambient air quality standards. The health risk assessment of non-criteria pollutants (heavy metals) has predicted maximum increased cancer risk at the point of maximum impact for 70 years of constant exposure in the range of 0.01 to 0.5 in a million, which is considered negligible by the Department.

Applicant's Response: The plant will not handle, store, or use materials more hazardous than No. 2 fuel oil, which is contemplated as the back-up fuel for the boilers, or the catalyst, which is essential for the required stringent NO_x control. The fuel oil will be stored in a tank which will be properly surrounded by a dike to retain any potential spill. The catalyst will be delivered and removed by the manufacturer under controlled conditions and is not subject to spill.

The facility will use aqueous ammonia (less than 28% solution in water), rather than anhydrous ammonia, in the Selective Catalytic Reduction (SCR) system.

With respect to the emergencies with CCLP's plant, such as fires or employee safety, CCLP has coordinated with the Carney's Point Fire Department regarding its emergency planning, in-plant training and the design of emergency equipment (see attached letter). Additionally, there will be coordination with the Salem County Emergency Fire and Disaster Control Center to improve response times, particularly with respect to train traffic.

Comment 5: The following comment was made by the US Department of the Interior, Fish and Wildlife Services.

CCLP has made an investment in SYCOM, an energy conservation company. SYCOM presently has 15 MW under contract in New Jersey, and CCLP anticipates that within ten years they will have enough energy conservation investments to offset all of the emissions from the proposed facility. However, we are concerned that the energy conservation program proposed by Chambers may not fullfill their expectations, and may not result in a total offset of emissions.

Department's Response: Emission offsets are not required pursuant to present state and federal air pollution control rules.

Applicant's Response: SYCOM Partners Inc., is a demand-side (or energy conservation) company. Principal to Chambers's agreement with SYCOM are the rights to air offsets, which result from the partnerships investments in energy conservation projects. SYCOM has 15 MW of conservation contracts with New Jersey Utilities. Those "megawatts" convert into roughly 59,130 MW hours (1 MW of conservation yields about 45% in reduced energy demand on an annual basis). The average NO_x emission rate for utility boilers in the state of New Jersey for 1985-1987 was 9.09 lbs/MW hr. Thus, 59,130 MW hrs equals about 270 tons/year of NO_x reduction. The corresponding reductions for SO_2 and particulates are 289 tons and 3.5 tons respectively.

And as utilities in New Jersey hold new energy conservation bid programs, it is possible that Chambers can make enough energy conservation investments over the next ten years to offset nearly all of the emissions from the Chambers facility.

Comment 6: Air Quality staff of the US Fish and Wildlife Service has performed visibility screening analysis. The results indicate that the proposed facility passes the Level 1 screening test for the Brigantine Wilderness Area, but fails both Level 1 and Level 2 tests for the Killcohook National Wildlife Refuse (NWR). The results predict that a plume will be visible in the refuge even when using favorable dispersion conditions (D stability, 2 m/s wind speed).

Response: The Air Quality staff of the U.S. Fish & Wildlife indicated that there may be visibility impairment at the Killcohook National Wildlife Refuge (NWR). They also recommend that VISCREEN model be used to determine visibility impairment. The applicant is not required to address these issues for the following reasons:

1. The Killcohook NWR is in a Class II area, therefore not subject to Class I requirements.

2. The VISCREEN model, although more realistic and sophisticated than the EPA approved PLUVUE model, has not been officially adopted for regulatory use.

The following comments were submitted to the Department by the Applicant, Chambers Cogeneration Limited Partnership:

Comment 1: All reference to 2.0% coal should be followed by "(based on 12,500 BTU heat value coal)".

Response: The Department does not agree with this comment. The permittee is only allowed to burn up to 2% sulfur coal, regardless of the other physical or chemical properties of the coal.

Comment 2: The Chambers Works fabric filter will be the reverse air, rather than pulse jet, type (summary document).

Response: A reverse air baghouse is acceptable.

Comment 3: The source listed as "lime slurry preparation tank" should be "lime slurry preparation system.". There are several tanks and all are indoors. (Draft permit condition, Page 1, Source Description).

Response: The correction has been incorporated into the permit condition document. The source description now reads as "lime slurry preparation system".

Comment 4: The PSD submittals were based on 1000 hours per year of auxiliary boiler operation at a full load of 77 MMBTU/hour. Thus, the limit should be 7.7×10^{10} BTU rather than 2.3×10^{10} BTU, (HHV) per calendar year. (Permit Condition II.B.2 Operating Requirement).

Response: The comment is correct. Permit Condition II.B.2 is now corrected to read as "Total No. 2 oil fired in the auxiliary boiler is limited to $7.7\text{x}10^{10}$ BTU, (HHV) per calendar year."

Comment 5: Catalyst "replacement" should be "catalyst addition and/or replacement, but no more than 50% of the <u>initial</u> catalyst bed. (Draft Permit Condition III.C.3.b.)

Response: Permit Condition III.C.3.b., now incorporates the suggested change in language. It now reads as follows: "The SCR system shall be optimized to achieve a NO_x emissions rate of less than 0.10 lbs/MMBTU, (HHV) averaged over any consecutive 180 minutes, by catalyst addition and/or replacement as necessary, but no more than 50% of the initial catalyst bed within each 5-year operating period for this facility."

Comment 6: The pressure drop across each fabric filter compartment is not monitored and reported separately. The pressure drop across the entire filter is monitored. (Draft Permit Condition V.B.4)

Response: Permit Condition V.B.4 is now changed as follows:

"Recording of pressure drop across entire fabric filters for the PC boilers."

Comment 7: Particulate and PM-10 compliance will be determined by New Jersey Test Method 1. Averaging time is not applicable (Reference Table 1).

Response: Averaging times for certain air contaminants are specified in Table 1 of the conditions of approval. Where such averaging times are specified, each of the three required test runs shall be for the duration specified, and compliance shall be required for each test run. These averaging times are also relevant for determining if the continuous emission monitoring data complies with the concentration limits.

For trace pollutants, averaging time have not been specified because the need to obtain a quantifiable sample may require longer sampling times than the 1 or 3 hour times typically specified by the Department for compliance demonstration purposes. For these air contaminants, the duration of each test run shall be approved by the Department after review of the test protocol submitted by the applicant. Here also, compliance with the specified maximum emission rate shall be demonstrated by each test run.

The above response also applies to comments 8 and 9.

Comment 8: VOC compliance will be determined by New Jersey Method 3. Averaging time is not applicable. (Ref. Table-1)

Response: New Jersey rules for VOC require 1-hour or batch average, whichever is greater to determine compliance. In this particulate case, the batch average is not applicable. Hence, the compliance basis of 60 minutes averaging is correct.

Comment 9: Trace element compliance will be determined by sampling tests. Averaging time is not applicable.

Response: The compliance basis for heavy metals is changed as follows:

1. Arsenic, Beryllium, Cadmium and Chromium-EPA multimetal test method.

2. Lead: EPA Reference Method 12.

3. Mercury: EPA Reference Method 101A.

Comment 10: Ammonia should be measured at 7% O_2, the same O_2 level as the other emissions. Nowhere is O_2 expected to be 15%.

Response: Table 1 of the permit conditions requires concentration of ammonia in terms of parts per million by dry volume corrected to 15% Oxygen. This oxygen correction is now changed to 7% O_2, which is consistent with oxygen correction applied to other pollutants. The emission limit becomes more stringent based on 7% oxygen than based on 15% oxygen, because 10 ppm of ammonia corrected to 15% oxygen is roughly equivalent to 24 ppm corrected to 7% oxygen. The permit emission limit will be 10 ppm corrected to 7% oxygen.

3. PREVENTION OF SIGNIFICANT DETERIORATION PERMIT

ATTACHMENT 10

AUGUST 15, 1991 LETTER
FROM OUC TO EPA

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ORLANDO UTILITIES COMMISSION
500 SOUTH ORANGE AVENUE • P. O. BOX 3193 • ORLANDO, FLORIDA 32802 • 407/423-9100

August 15, 1991

Mr. Gregg M. Worley
Air, Pesticides and Toxics
Management Division
U. S. Environmental Protection
Agency, Region IV
345 Courtland Street, N. E.
Atlanta, GA 30365

Re: Orlando Utilities Commission SEC Unit 2
BACT (PSD-FL-084)

Dear Mr. Worley:

Per our conversation of August 14, 1991, I am submitting the additional information you advised would be helpful in your analysis.

Your comments and OUC's responses include:

1. Telephone Comment:

Page 3, paragraph 3 of OUC's response of August 2, 1991 did not contain all the details of vendor quotes as previously requested.

Response:

Unit No.2 is a duplication of Unit No.1 and, therefore, B&W was contacted for the quote. The quote is attached (Attachment I) along with a more recent telephone memorandum (Attachment II) discussing the SO_2 to SO_3 conversion rate and catalyst type. It is my understanding that the 5 ppm ammonia slip is a guarantee and represents the maximum degradation before changeout of the catalyst begins.

Administration Fax: (407) 236-9616 ● Purchasing Fax: (407) 423-9199

2. Telephone Comment:

The Takehara Power Station has been operating with SCR while firing 2.5% sulfur coal since 1981.

Response

According to Joy Technologies (Attachment III), Takehara was specified with 15 different fuels of which all were low sulfur except for one which was 2.5 percent sulfur. This 2.5 percent sulfur coal was fired for a several month trial burn and has not been fuel of choice for a ten year period.

It is my further understanding that by 1985 Takehara's old generation catalyst was replaced with the high reactivity type which is similar to B&W's (Attachment I).

3. Telephone Comment:

You requested additional details regarding fly ash sold at Stanton Unit No.1.

Response:

In 1991 (through July), we sold 62.87 percent of the fly ash generated and used 37.13 percent in fixation of the scrubber sludge. Conversion Systems, Inc., who operates this process, also manages our ash sales.

As we discussed, if you can expedite the preliminary determination and draft permit so that DER has it available on or before August 23, both OUC and DER will appreciate your efforts.

Thank you.

Very truly yours,

J. S. Crall, Director
Environmental Division

JSC:rc
Attachment

cc: W. H. Herrington
T. B. Tart
S. M. Day (B&V)
C. M. Fancy (FDER)

RECEIVED
JUL 29 1991
BLACK & VEATCH

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Babcock & Wilcox

a McDermott company

13000 Wyandotte Street
Kansas City, MO 64145
(818) 941-2073

ATTACHMENT I

Project 16805	
Files 62.340101	
Date 7-29-91	
DISTRIBUTION	
	[illegible]
LTS	X
DOS	X
E&E	

July 26, 1991

Black & Veatch
P O Box 8405
Kansas City, MO 64114

Attention: Mr. Morgan Fagan

RE: Orlando Utilities
Commission
Stanton Energy Center
B&V Ref: 16805
B&W Ref: RB-621
SCR Budget Price

Gentlemen:

In confirmation of our telephone conversation this morning, we are pleased to reiterate that for an approximate price for a SCR to install behind this referenced unit, guaranteeing five PPM ammonium slip would be:

Fifteen Million Nine Hundred Thousand
Dollars........................$15,900,000

The erection price to go with that material price is $2,000,000.

As we discussed, this is based upon the boiler modifications included to install this SCR between the economizer outlet and the air heater inlet. This would put it in a high dust application. For your information and use, approximately $2,000,000 of the material price and $300,000 of the erection price is to make modifications to the boiler to handle this installation, such as the ductwork to and from the SCR as well as a larger airheater to protect from ammonia sulfate.

In order to guarantee an ammonia slip to two PPM, the material price would increase to approximately:

Two Million Three Hundred Thousand
Dollars.......................$ 2,300,000

and the erection price by roughly $300,000.

The scope of supply that we have used for these figures are shown on Attachment 1. We have also enclosed a sketch showing the sizing of this SCR. Once we receive a quality sketch, we will submit it to you. The dimensions are not easy to read since this was sent to us by thermofax.

This SCR design is based on the following conditions:

Flue Gas Flow (Econ Outlet) - 4,465,600 lb/hr
Gas Temperature - 700° F
SCR inlet NOx - 0.32 lb/mmbtu
SCR efficiency - 80%
Ammonia slip - 5 ppm

For the 5ppm slip on the base unit at the end of a two year guarantee period, the SCR system was sized as follows:

Catalyst volume - $488 m^3$
Catalyst pressure drop - 2.5 in H^2O
Anhydrous Ammonia consumption - 425 lb/hr

As we discussed, we recommend the high dust application over the low dust application due to the additional capital and operating expenses associated with the low dust application such as:

1. Gas-gas heat exchanger required
2. Duct burner to reheat flue gas
3. Difficult component configuration
4. Additional flue and ducts
5. Fuel requirements for duct burner
6. Added system pressure drop
7. Increased system complexity

If you have any additional questions or comments, we will be happy to discuss them with you at your convenience.

Very truly yours,

BABCOCK & WILCOX
a McDermott company

J. A. Shildmyer
District Manager

JAS:jf

SELECTIVE CATALYTIC REDUCTION SYSTEM DESCRIPTION

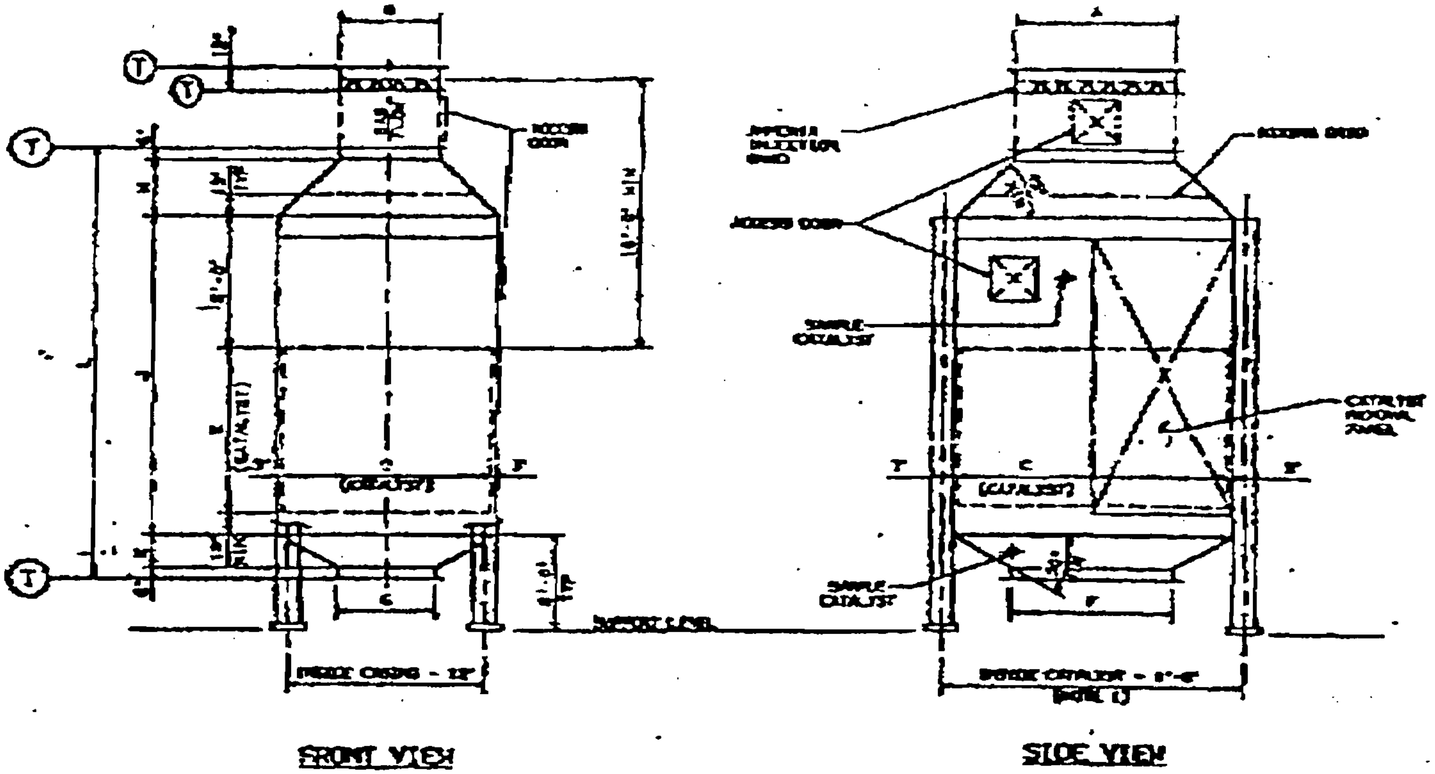
SCOPE OF SUPPLY

One (1) SCR system including the following:

- One (1) vertical SCR reactor chamber including transitions, integral support steel and test connections.
- Plate-type catalyst with sample catalyst.
- Reactor access panel for catalyst installation and removal.
- Ammonia injection grid.
- Ammonia dilution and mixing system, including piping, valves, and instruments.
- Engineering.
- Ammonia storage and vaporization.
- Flue modifications.
- Air heater modifications.
- Erection.

ITEMS TO BE SUPPLIED BY OTHERS

- Instrument air.
- Gaseous ammonia.
- Steam.
- Foundations, anchor bolts, concrete work and grouting.
- Hookup of air, steam and electric power.
- Interconnecting piping from ammonia storage to the ammonia dilution and mixing skid.
- Structural steel, platforms, stairs.
- Continuous emissions monitoring system.



One of Two Reactors

2e

A	B	C	D	E	F	G	H	J	K	L
5'-0"	11'-0"	11'-2"	[illegible]	5'-6"	11'-0"	11'-0"	[illegible]	[illegible]	[illegible]	[illegible]

BABCOCK & WILCOX

ORLANDO UTILITIES - STANTON #2

BABCOCK & WILCO

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ATTACHMENT II

BLACK & VEATCH

TELEPHONE MEMORANDUM

Orlando Utilities Commission
Stanton Energy Center, Unit 2
Steam Generator - SCR

B&V Project 16805
B&V File 62.3401.01
August 14, 1991
2:30 p.m.

To: John Clifton
Company: Babcock & Wilcox
Phone No.: 216-860-1989

Recorded by: D. D. Schultz

Babcock & Wilcox (B&W) reported that the conversion of SO_2 to SO_3 in the SCR ranged from .5 percent to .6 percent.

B&W was not sure what a "New" vs "Old" catalyst referred to. The catalyst included in B&W's quote is a type X. This catalyst is not new for this type of application.

lts

cc: J. Crall (OUC)
S. M. Day
J. R. Cochran
H. E. Smith
E. C. Windisch
A. W. Ferguson
Project File

ATTACHMENT III

BLACK & VEATCH

TELEPHONE MEMORANDUM

OUC
SEC 2
NO_x Catalyst
Takehara (Japan)

B&V Project 16805.030

August 14, 1991
4:30 p.m.

FACSIMILE TRANSMISSION

To:	Sharon Kilborn - Marketing
Company:	Joy Technologies
Phone No.:	818-301-1171
Recorded by:	A. W. Ferguson

Odette Zourhalsen - FGD 818-301-1125
Alan Kissam - NO_x 818-301-1166
Ted Barrons - NO_x expert (out of office)

Takehara was specified with 15 different fuels, all but the 2.5% S were low sulfur. They burned 2.5% sulfur coal as a trial burn (a few months) but not necessarily all the time. Rest of the time have been using low S coal. (Confidential information provided to B&V shows historical fuel is about 1.5% S or less.) The paper by E. S. Behrens shows inlet SO_2 levels of 1100 ppm SO_2 which is appropriate for 1.0% to 1.5% sulfur coal despite that Takehara Unit 1 was designed for 2.5% S coal.

High reactivity catalyst was installed in 1983 - 1985 time period. Prior to installing this catalyst, the original was tubular catalyst. Joy's contract replaced the tabular catalyst and installed high reactivity bed which is still operating. This new catalyst was installed prior to the test burn on the 2.5% sulfur coal. This is a second generation of catalyst, similar to new offering for SCR applied to new units.

dm

cc: Don Schultz

ATTACHMENT 4

AUGUST 2, 1991 LETTER
FROM OUC TO EPA

Beals

ORLANDO UTILITIES COMMISSION
500 SOUTH ORANGE AVENUE • P. O. BOX 3193 • ORLANDO, FLORIDA 32802 • 407/423-9100

August 2, 1991

Ms. Jewell A. Harper
Chief, Air Enforcement Branch
U. S. Environmental Protection Agency
Region IV
345 Courtland Street, N.E.
Atlanta, GA 30365

Dear Ms. Harper:

RE: Orlando Utilities Commission
SEC Unit 2
Permit Modification (PSD-FL-084)

Enclosed are OUC's responses to the questions your staff raised regarding our submittal, as transmitted in your letter of July 2, 1991.

The staff and management of OUC appreciate the frank and efficient working relationship that our staffs have developed during this project.

Please have Gregg Worley give Jim Crall a call at (407) 423-9141 if it would be helpful to have an additional meeting prior to your preparation of the preliminary determination and draft permit.

Very truly yours,

Thomas Tart

Thomas Brogden Tart
General Counsel

cc: Gregg Worley, EPA
Nancy Pommelleo, Esq., EPA
Hamilton S. Oven, FDER
Clair M. Fancy, FDER

AUG 2 91

COMMENT:

(Reference EPA Region IV staff July 2, 1991 letter to Mr. James P. Crall of the Orlando Utilities Commission.)

"The SO2 emission limit which you have proposed is 0.32 lb/MMBTU on a thirty-day rolling average, based on a design coal with a maximum sulfur content of 2.5% and a control system removal efficiency of 92%. The presentation made by your consultant gave the basis of this estimate as a statistical analysis utilizing a computer model which estimated that the reduction level that could be achieved with 99% confidence limit over a thirty-day rolling average would be 92%. The assumptions made for this model include the use of 95% as the "target" removal efficency since this is the highest guaranteed by any vendor. What is the basis for the vendor guarantee of 95%? It would seem that the 95% removal number, if it was guaranteed by the vendor, is the result of experience and analysis rather than a "target" number which is the starting point of the analysis."

RESPONSE:

(Reference July 12, 1991 memorandum from M. F. McClernon to E. C. Windisch, B&V File 16805.32.0402.)

The information concerning performance tests and guarantees included here is based on the "offer to ABB" and is not finalized in a conformed document at this time. It does, however, represent the current state of negotiated agreement.

"Target", as referred to in the BACT analysis, implies conditions achieved when parameters that might be responsible for variation in SO2 removal rate are held in strict design tolerance levels, i.e "on target." These parameters include slurry pH, L/G ratio, limestone grind and quality, coal quality, gas flow magnitude and distribution, scrubber slurry liquid phase alkalinity, spray distribution, module pressure drop, mist eliminator cleanliness, and makeup water quality. When these conditions meet target, "target removal efficiency" results.

EPA has requested information on how "target removal", as described above and used in the computer simulation model, relates to the "manufacturer's guarantee." (The manufacturer's guarantee of 95 per cent removal efficiency has been used as target removal in the computer modeling.) EPA has also raised questions of whether a 95 per cent removal efficiency "guarantee" might not actually represent a "confidence limit", based on manufacturer experience and analysis, that assures consistent success in achieving 95 per cent removal, and indicates a target substantially higher than 95 per cent.

To answer these questions, it is informative to examine conditions that constitute "meeting guarantee."

The guarantee test times are basically at the discretion of the manufacturer. He is allowed to pre-test, inspect, and adjust the system until he is satisfied with it's performance. This ensures that all performance parameters are "on target" before the test begins. Limestone grind is tested for fineness; limestone is quality tested for minimum 90 per cent calcium carbonate content and available alkalinity of 1.0; "design" coal, blended to specified quality levels, is brought in specifically for the test; scrubber slurry pH is carefully controlled to a specified level optimum for the design coal(s); load (and consequently gas flow, temperature, and SO2 content) is held constant for the duration of the test; gas flow is checked both by experimental measurement and stoichometric flow calculation, and averaged for accuracy; the number of spray pumps operating is held constant; spray nozzles are clean and in unworn condition for uniform spray distribution; mist eliminator blades are in clean condition; ductwork and damper settings are clean and tuned for uniform gas flow distribution; makeup water is monitored for quality; and buffering of scrubber liquor is allowed (and monitored) through addition of adipic acid at maximum additive rate.

Under these controlled conditions, SO2 removal rate is monitored for a period of four (4) hours. Three such tests are performed and averaged at each load condition. Since the three tests are not necessarily consecutive, the manufacturer can adjust the system for each sample to assure "target" conditions. If an average removal efficiency of 95 per cent is achieved, the performance guarantee is met.

The test, as described above, basically is one that "guarantees" a "target" removal efficiency of 95 per cent. That is, when chemistry and process condition "targets" are achieved, 95 per cent average removal efficiency is "guaranteed" to result. This is the exact form of the simulation model, and the correct format for representation of the guarantee.

Several questions may be raised concerning the form of guarantee as described above. First, is a four-hour test a fair test of the system's performance? Deviation away from 95 per cent can only be caused by deviation away from "target" conditions. Although it is acknowledged that this variation is a "normal" part of day-to-day operation, the magnitude and rate of these variations are not completely within the control of the manufacturer. For his own protection, the manufacturer will only guarantee performance under controlled conditions. Test result variation is therefore only a function of measurement error propagation and minor fluctuations in "target" conditions, and is relatively small. The system either meets, or does not meet guarantee, and four hour tests are a sufficient and appropriate time frame to establish this condition.

Second, what level of expected performance is necessary for a manufacturer to prudently (or "confidently") guarantee 95 per cent removal efficiency? (This question is actually irrelevant to the engineer or owner at time of design, since the answer not guaranteed. It is interesting, however, to analyze the situation.)

From the manufacturer's point of view, a guarantee is not an absolute assurance that promised performance will be met. It is a single component of an overall risk evaluation. He must evaluate the benefits of success (his profit) against the consequences of failure (liquidated damages.) No real project presents a zero probability of either of these states. The most instructive example of this may be that the OUC Stanton Unit 1 scrubber, using similar (two hour) tests in a similar environment, did not meet guarantee requirement of 90 per cent removal at high sulfur design coal conditions.

At 95 per cent removal efficiency, the chemistry of the system has essentially been pushed to the limit, and remaining gains in efficiency are basically a fairly unpredictable function of uniformity in spray, inter-module and intra-module flow distribution, and fortuitous combinations of off-design conditions. A manufacturer with a true 95 per cent expected removal efficiency (50 per cent confidence) can expect a statistical distribution of random four-hour removal efficiencies characterized as follows for normal, non-outage hours:

4-Hour Removal Efficiency	Per Cent of Time	Cumulative % of Time
88	0.0000	0.0000
89	0.0002	0.0002
90	0.0006	0.0007
91	0.0039	0.0046
92	0.0376	0.0422
93	0.2127	0.2549
94	0.4164	0.6713
95	0.2700	0.9412
96	0.0552	0.9964
97	0.0035	0.9999
98	0.0001	1.0000

(These figures are based on OUC Stanton Unit 2 scrubber model predictions using 100 per cent availability and a target/guarantee removal efficiency performance level of 95 per cent.)

During normal, non-outage hours of operation, the scrubber is removing 95 per cent or more of the SO2 about 33 per cent of the time. Because of the high levels of autocorrelation in 4-hour performance levels, prediction of near term operation levels can be made with high levels of confidence. That is, if it observed that the scrubber is operating at 95 per cent on a given day (indicating target conditions), it is probable that those levels will be sustained for several days. The probability of a scrubber with 95 per cent target removal (zero design margin) passing the 95 per cent guarantee performance test is very high. Further, if the manufacturer should not pass the test, he simply "adjusts" the system, and calls for a new test.

The following summary points may be made. The scrubber performance test is a series of three short-term (4 hour) tests. This test is appropriate and sufficient to assure that under controlled (target) conditions, a guaranteed (target) removal efficiency will be achieved. No design margin is guaranteed, and no design margin (or confidence limit) is required to assure high likelihood of passing the guarantee test. Accordingly, the use of guarantee level as "target" in the computer simulation model is the most appropriate value available.

Supplemental NO_x BACT Analysis

The original Best Available Control Technology (BACT) analysis for the Orlando Utilities Commission C. H. Stanton Unit 2 was submitted on March 15, 1991 as part of the Supplemental Site Certification Application. This supplemental NO_x BACT analysis addresses specific issues identified by the Environmental Protection Agency in letter dated July 2, 1991. Assumptions regarding plant, fuels and evaluation criteria remain the same as presented in that document. The substantive issues identified for further information submittal included the effects of low NO_x burners on carbon losses, and a detailed technical and economic evaluation for installation of a selective catalytic NO_x emission reduction (SCR) system on Stanton 2. The following discussion addresses these specific issues identified.

1.0 Boiler Carbon Losses

Low NO_x burners reduce NO_x emissions by effectively staging combustion. Unfortunately, this results in less efficient combustion, increasing levels of unburned combustibles. This will be exhibited by higher fly ash carbon contents. It is estimated by the boiler manufacturer that unburned carbon levels will increase from 0.3 percent for burners designed to meet a New Source Performance Standard NO_x emission of 0.60 lb/MBtu to 0.4 percent for low NO_x burners designed to meet a NO_x emission of 0.32 lb/MBtu. This corresponds to a coincidental increase in fly ash carbon contents from 2.9 percent to 3.8 percent for low NO_x burners.

ASTM has established standard specifications for the use of fly ash as a mineral admixture in concrete (designation C618-91). These specifications indicate that fly ash with carbon contents up to 6 percent are allowed to be used as concrete admixture. Accordingly, fly ash carbon losses from the use of low NO_x burners will not prohibit the sale of fly ash from Stanton 2.

2.0 Selective Catalytic Reduction

Selective catalytic reduction systems limit NO_x emissions by injecting ammonia upstream of a catalytic reactor. The ammonia molecules in the presence of the catalyst dissociate reducing a significant portion of the NO_x into nitrogen and water. SCR systems may potentially reduce NO_x emissions by as much as 70 to 90 percent.

The ammonia is received and stored as a liquid. The ammonia is vaporized and subsequently injected into the flue gas by either compressed air or steam carrier. The optimum ammonia injection temperature occurs between 650 and 750 F. Therefore, the system is logically located between the economizer outlet and the air heater inlet. An economizer bypass may be required to maintain the reactor temperature during low load operation. This will reduce boiler efficiency at lower loads.

2.1 Coal Fired SCR Experience

Selective catalytic reduction (SCR) systems were first used in Japan during the 1970's. Through 1990, 40 SCR systems were operating on 10,852 MW of coal fired utility service. Japanese SCR systems were operated to achieve between 70 and 80 percent NO_x reduction with ammonia slip less than 10 ppm. Coals burned in the Japanese boilers have low sulfur (less than one percent) and low ash (less than 10 percent) contents.[1]

In response to acid rain legislation, SCR was retrofitted to 129 German coal fired boilers totalling 30,625 MW. Most of the Japanese and German SCR systems are generally operated to achieve 80 percent NO_x reduction to meet a NO_x emission limit of approximately 100 ppm while maintaining ammonia (NH_3) slip emissions to below 5 ppm. Similar to Japanese SCR experience, coals burned at these facilities have relatively low sulfur (0.7 to 1.2 percent) and low ash contents.[2]

To date, there are no coal fired boilers using SCR systems in the United States. However, a 140 MW coal fired pulverized coal boiler with SCR was recently permitted in New Jersey. For that facility NO_x emissions were limited to a maximum of 0.17 lb/MBtu based on the use of low NO_x burners and SCR. The facility will not operate for two to three years. Therefore, it is not possible to presently evaluate the effectiveness of SCR at facilities burning U.S. coals.

It is OUC's belief that the SCR technology is insufficiently developed for use on Stanton 2 based on inexperience with U.S. coals (detailed in subsequent sections). However, since the precedent has been established for use of SCR on a pulverized coal fired plant, this BACT analysis will evaluate SCR on a technical, economic, environmental, and energy basis. Based on the New Jersey facility, the analysis will be based on the use of low NO_x burners followed by an SCR system designed to limit NO_x emissions to 0.17 lb/MBtu.

There are two SCR system configurations that can be considered for application on pulverized coal boilers. A high dust application locates the SCR before the particulate collection equipment, typically between the economizer outlet and the air heater inlet. A low dust or cool side application is located downstream of the particulate and flue gas desulfurization control equipment.

The high dust application requires the SCR to be located between the economizer outlet and the air heater inlet in order the required SCR operating temperature of approximately 650 F to 750 F. The low dust application of SCR would locate the catalyst downstream of the particulate control and flue gas desulfurization equipment. Less catalyst volume is needed for the low dust application since the majority of the particulate and SO_2 has been removed. However, a major disadvantage of this alternative is a requirement for supplemental fuel firing to achieve sufficient flue gas operating temperatures. There is only a limited amount of low dust SCR experience worldwide. Considering the developmental nature of this alternative, this analysis will only consider the use of high dust SCR systems.

2.2 SCR Technology Status

The Japanese and European experience with SCR cannot be blindly applied to U.S. facilities. There remain two significant uncertainties about design, performance, operating parameters, and cost of SCR systems. First, U.S. utility power plants operate under more variable loads. Second the amounts and types of sulfur, ash, and trace elements in U.S. coals are different from those in coals consumed in Japan and Europe.[3] [4]

Variable load conditions results in variable temperatures in the SCR reactor. At lower temperatures SCR reaction efficiencies drop off markedly resulting in either lower NO_x reduction or additional ammonia slip emissions.

Japanese and German SCR experience has been with coals with relatively low sulfur and ash contents. Combustion of higher sulfur coals will result in the emission of larger quantities of sulfur trioxide (SO_3). In addition, SCR catalysts oxidize SO_2 resulting in an increase in SO_3 emissions of between 50 and 100 percent.[5] [6]

Sulfur trioxide in the presence of ammonia will form ammonia sulfate and ammonia bisulfate salts. Resultant particle diameters are on the order of 1 to 3 microns (potentially increasing plant PM10 emissions).[7] Ammonia bisulfate can foul the catalyst's micropore structure limiting reactivity.[8] In addition, ammonia bisulfate is a sticky substance which can deposit on downstream equipment. Ammonia bisulfate will tend to liquefy at a temperature of about 410 F in the intermediate baskets of the air heater. Once liquefied it solidifies in nodules in the space between the intermediate and cold end baskets. The result can be increased pressure drop, and eventual plugging (resulting in decreased unit reliability). Off-line water washings are necessary to remove the soluble deposits. Cold-end sootblowers are not generally effective in reaching and removing these deposits on-line. To alleviate this problem in Japan and Germany, recent SCR designs have limited ammonia slip emissions to between 3 and 5 ppm.[9] Based on the relatively high sulfur concentrations of coals under consideration for C. H. Stanton Unit 2 it may be necessary to limit ammonia slip to 2 ppm, further limiting maximum SCR effectiveness to somewhere between 60 and 70 percent NO_x reduction.

Increased SO_3 concentrations lead to an increase in the acid dew point. Hence higher air heater exit temperatures and decreased boiler efficiency will result from the use of SCR.[10]

A number of alkali metals and trace elements (especially arsenic) poison the catalyst significantly affecting reactivity and life.[11] Average arsenic concentrations for U.S. coals are three times the worldwide average.[12] Other elements such as sodium and potassium can also poison the catalyst by neutralizing the active acid sites. Poisoning of the catalyst does not occur immediately but is a continual process over the life of the catalyst. As the catalyst becomes deactivated more NH_3 must be injected to compensate and meet NO_x emission limits. This will result in an increased amount of NH_3 slip. Increased NH_3 slip will in turn result in additional ammonia salt formation and fouling of downstream equipment.

A significant quantity of ammonia slip from SCR system will condense onto fly ash. The ammonia content of the fly ash can have an impact on waste disposal or marketing practices. At elevated pH, ammonia in the fly ash will be released possibly leading to odorous emissions. While eastern U.S. coals are not inherently alkaline, fixation with alkaline species from the wet limestone scrubber or when used as admixture for cement manufacturing will result in ammonia releases.[13]

Fly ash NH_3 concentrations greater than 100 mg/kg fly ash results in noticeable odor and resultant rejection by the cement industry. Testing has indicated that for a coal with seven percent ash ammonia slip must be limited to below 2 ppm to avoid any potential problem.[14] [15] [16] Currently, SCR system suppliers will only guarantee ammonia slip levels of 5 ppm for a period of two years. It is likely that initial ammonia slip emissions will be below the 2 ppm criteria. However, as the catalyst ages ammonia slips will approach the guaranteed 5 ppm value. Accordingly, it is a possibility that Stanton 2 will lose fly ash sales should SCR be required.

2.3 SCR Economic Evaluation

Table 2.3-1 lists the estimated total capital and annual cost for installation of a SCR NO_x emission reduction system on C. H. Stanton Unit 2. The table lists all costs for a complete SCR system designed to meet a NO_x emission limit of 0.17 lb/MBtu. Costs presented in the table are based on manufacturers estimates for Stanton 2. The economic criteria used are identical to those used in the original BACT analysis.

The total capital cost for installation of a SCR system on Stanton 2 is estimated to be $31.2 million. The capital costs include ammonia receiving, storage, and injection equipment, catalyst, and balance of plant equipment. Ammonia receiving and storage equipment will primarily consist of ammonia truck receipt equipment, onsite ammonia storage tanks, piping and pumps to transport ammonia to the storage tanks, and foundations (including spill containment dikes). Ammonia injection equipment include ammonia vaporizers, air compressors or dilution air fans to provide a carrier medium, injections nozzles or headers, and associated piping and controls. Catalyst costs include four layers of catalyst, housing, maintenance access provisions, and associated transition ductwork. Balance-of-plant costs include air heater modifications to accommodate operational problems associated with unreacted ammonia and SO_3 in the flue gas stream, personnel safety equipment, boiler modification costs to accomodate the SCR catalyst reactor, and incremental ID fan capacity to overcome draft losses.

Table 2.3-1. SCR Capital and Annual Costs

	2-Year Catalyst Life	2/4-Year Catalyst Life
	($1,000)	($1,000)
Capital Costs:		
Equipment	13,900	13,900
Field Labor	1,700	1,700
Balance of Plant	2,680	2,680
Total	18,280	18,280
Contingency	1,830	1,830
Escalation	3,340	3,340
Direct Capital Cost	23,450	23,450
Indirects	3,750	3,750
Interest During Construction	4,000	4,000
Total Capital Cost	31,200	31,200
Levelized Annual Costs:		
Operating Personnel	190	190
Maintenance	12,670	8,650
Additive	600	600
Energy	800	800
Demand	100	100
Loss in Fly Ash Sales	1,080	1,080
Fly Ash Landfill Costs	320	320
Boiler Efficiency Impact	910	910
Annual Operating Cost	16,670	12,650
Fixed Charges	2,460	2,460
Total Annual Cost	19,130	15,110
NO_x Emissions Reduced, tpy	2,810	2,810
Incremental Reduction Cost, $/ton	$6,810	$5,380

Levelized annual operating costs listed in Table 2.3-1 include operating personnel, maintenance, ammonia additive, electric energy and demand costs, and lost fly ash sales as well as the resulting fly ash disposal costs. The total levelized annual operating cost for installation of a SCR system on Stanton 2 is estimated to be $16.7 million assuming the maximum guaranteed catalyst life of 2 years. If a somewhat less conservative assumption is made that the first two layers of the catalyst have a life of two years and the last two layers have a life of four years the levelized annual operating cost decreases to $12.7 million.

Operating personnel costs include two full time equivalent personnel to operate the SCR system and associated auxiliaries. Maintenance costs are primarily related to the replacement of spent catalyst. Manufacturers typically provide a two year catalyst guarantee for coal fired applications. Ammonia costs are based on NO_x reduction requirements and the resulting molar ratios of ammonia to NO_x.

Energy costs reflect the energy required to operate air compressors and ammonia vaporizers. Energy costs also include the additional ID fan energy that would be necessary to overcome the added pressure drop from the catalyst. The demand cost is included to reflect the cost of building additional generating capacity into the unit to account for the capacity comsumed by the additional ID fan power requirements.

Stanton 1 has historically been capable of selling all ash production for use in the concrete industry. It was expected that Stanton 2 would be similarily capable. However should an SCR system be required, the potential for fly ash sales from Stanton 2 would greatly reduced due to ammonia contamination. As a result, this contaminated fly ash must be disposed of in an onsite landfill, incurring additional cost. For the purposes of costs presented in Table 2.3-1 it has been assumed that only 50 percent of these sales would be lost on the average (periodic catalyst replacements may result in cyclic possibilities for fly ash sales).

The total levelized annual cost for a SCR system on Stanton 2 would be $19.1 million based on a maximum guaranteed catlyst life of two years. These costs result in an incremental NO_x reduction cost of $6,810 per ton to achieve an outlet emission of 0.17 lb/MBtu as compared to a low NO_x burner NO_x emission of 0.32 lb/MBtu. If a less conservative assumption is made regarding catalyst life incremental NO_x reduction costs are lowered to $5,380 per ton.

2.4 SCR Environmental Evaluation

Areas surrounding Stanton 2 are classified as attainment areas for nitrogen oxide emissions. Modeling analyses based on a NO_x emission rate of 0.32 lb/MBtu indicate ambient impacts below impacts predicted in the original Stanton 1 Site Certification Application.

Operation of a SCR system to meet a NO_x emission limitation of 0.17 lb/MBtu will result in ammonia slip emissions of between 2 and 10 ppm. Catalyst manufacturers will guarantee ammonia slip emissions of 5 ppm or less during the first two years of operation. When catalyst surfaces are relatively new ammonia slips will be very low. However, as the catalyst ages and becomes either deactivated or blinded, ammonia slip emissions will increase. As mentioned previously, should ammonia slip emissions exceed 2 ppm it is likely that all fly ash sales would be lost.

Use of SCR results in a 50 to 100 percent increase in SO_3 emissions. Unreacted ammonia and sulfur trioxide can react to form ammonia bisulfate and ammonia sulfate salts. These particulates will generally be smaller than 10 microns, and thereby, potentially increase PM_{10} emissions. Sulfur trioxide emissions that do not react with ammonia will exit the unit as sulfuric acid mist emissions.

Ammonia is a hazardous material. Therefore, ammonia must be handled and stored with extreme care. Storage and use of ammonia on-site will increase the likelyhood of hazardous or fatal accidents. Recent projects in California required to use ammonia have had difficulty obtaining local permits allowing ammonia use.

2.5 SCR Energy Evaluation

A SCR system consumes electrical energy for SCR auxiliary system operation and for incremental ID fan demand to overcome SCR draft losses. This energy requirement is approximately 1,870 kW. This represents approximately 0.5 percent of total plant power output.

2.6 Conclusions

Advances in the control of NO_x from pulverized coal boilers enable the project to lower anticipated NO_x emissions from the Stanton 1 emission limit of 0.6 lb/MBtu to 0.32 lb/MBtu. Selective catalytic reduction systems are insufficiently developed for use on pulverized coal fired boilers buring U.S. coal.

However, a recently permitted pulverized coal fired facility incorporated the use of low NO_x burners followed by a SCR system. This facility is not in operation.

The total levelized annual cost for a SCR system on Stanton 2 would be $19.1 million based on a maximum guaranteed catalyst life of two years. These costs result in an incremental NO_x reduction cost of $6,810 per ton to achieve an outlet emission of 0.17 lb/MBtu as compared to a low NO_x burner NO_x emission of 0.32 lb/MBtu. If a less conservative assumption is made regarding catalyst life incremental NO_x reduction costs are lowered to $5,380 per ton.

Since SCR systems are not demonstrated on plants burning U.S. coals it is likely that plant reliability would be reduced if an SCR system were used. These reliability decreases are likely to result from secondary effects such as air heater fouling by ammonia sulfate deposits. Previous experience with initial transfer of flue gas desulfurization technology resulted in increased plant forced outage rates of between 5 and 15 percent. In addition use of a more speculative technology will likely result in a reduction of bond rating for OUC of between 15 and 30 points. Considering the range of these cost impacts incremental NO_x reduction would increase to between $9,200/ton and $13,700/ton assuming a two year catalyst life.

The preceding discussion strongly supports that on the basis of technical, economic, energy, and environmental considerations, combustion controls designed to meet a NO_x emission requirement of 0.32 lb/MBtu represents BACT for Stanton 2 and SCR should not be applied to this installation.

References

1. P. A. Lowe, "Understanding the German and Japanese Coal_Fired SCR Experience,", Intech Enc., presented at the EPA/EPRI 1991 Joint Symposium on Stationary Combustion NO_x Control, March 1991.

2. P. A. Lowe.

3. S. C. Tseng, et al, "Pilot Plant Investigation of the Technology of Selective Catalytic Reduction of Nitrogen Oxides,", Acurex, presented at the 1991 EPA/EPRI Joint Symposium on Stationary Combustion NO_x Control, March 1991.

4. J. E. Damon, "Updated Technical and Economic Review of Selective Catalytic NO_x Reduction Systems,", United Engineers & Constructors, 1988.

5. T. Mori, "Operating Experience of SCR Systems at EPDC's Coal Fired Power Stations,", Electric Power Development Co., presented at the 1989 EPA/EPRI Joint Symposium on Stationary Combustion NO_x Control, March 1989.

6. J. E. Damon.

7. B. E. Hurst, "Exxon Thermal DeNOx Process for Utility Boiler Applications," Exxon, 1981.

8. S. Matsuda, et al, "Deposition of Ammonia Bisulfate in the Selective Catalytic Reduction of Nitrogen Oxides with Ammonia," Hitachi, 1982.

9. J. E. Damon.

10. J. E. Damon.

11. P. Necker, "Experience Gained by Neckarwerke from Operation of SCR DeNOx Units," Esslingen, presented at the 1989 EPA/EPRI Joint Symposium on Stationary Combustion NO_x Control, March 1989.

12. V. Valcovic, "Trace Elements in Coal," CRC Press, Boca Raton, Florida, 1983.

13. C. P. Robie, et al, "Technical Feasibility and Cost of SCR for U.S. Utility Application," United Engineers & Constructors Inc., presented at the 1991 EPA/EPRI Joint Symposium on Stationary Combustion NO_x Control, March 1991.

14. P. Necker.

15. B. Schonbucher, "Reduction of Nitrogen Oxides from Coal-Fired Power Plants by Using the SCR Process," EVS Germany, presented at the 1989 EPA/EPRI Joint Symposium on Stationary Combustion NO_x Control, March 1989.

16. J. M. Koppius-Odink, et al, "The First DeNOx Installation in the Netherlands," presented at the 1989 EPA/EPRI Joint Symposium on Stationary Combustion NO_x Control, March 1989.

ATTACHMENT 11

JANUARY 28, 1991 LETTER
FROM EPA TO OUC

Worley

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

4APT-AEB

JAN 28 1991

Mr. James S. Crall, Director
Environmental Division
Orlando Utilities Commission
500 South Orange Avenue
P.O. Box 3193
Orlando, Florida 32802

RE: Orlando Utilities Commission, Stanton Energy Center (PSD-FL-084)

Dear Mr. Crall:

In a meeting on December 21, 1990, between you and your representatives, FDER, and representatives of EPA Region IV, you raised several questions concerning the procedures necessary to modify the existing Prevention of Significant Deterioration (PSD) permit for the Stanton Energy Center. The purpose of the modification will be to change the start construction dates for Unit 2 as part of a phased construction permit. As committed to you by my staff at the meeting, we are providing you with answers to your procedural questions as follows:

1. What level of air quality analysis will be required for the modification?

Based upon the air quality analysis previously completed for Unit 2 and discussions between Mr. Lew Nagler of EPA with Mr. Max Linn of FDER, it was agreed that there would not be a need to repeat the air quality analysis in full provided the stack parameters remain unchanged from the previous application. The modeling that needs to be done should be based on the new emission rate for Unit 2 using the critical meteorological periods identified from the earlier refined impact analysis.

2. What level of preconstruction monitoring will be required?

Our PSD monitoring rules allow for the use of monitoring data collected within the past three years. It is our feeling that the data for 1986-87 would satisfy this requirement. In addition, we believe that the regional ozone monitors would satisfy the preconstruction monitoring requirements for VOC emissions.

3. Are the EPA issued PSD permits processed separately from the Florida Site Certification Process? (i.e., can a PSD permit be issued by EPA independent of what stage the Florida Site Certification process is in?)

EPA views the PSD process to be totally separate from the State's Site Certification Process; therefore, after analysis and recommendation by FDER, EPA will issue a preliminary determination and give the opportunity for public comment. After such time, a final determination and PSD permit will be issued.

Mr. Crall, thank you for contacting EPA early in the process so that any outstanding issues may be resolved prior to any critical junctures. We look forward to your continued cooperation throughout the permitting process. Should you have any additional questions concerning the modelling or monitoring issues, please contact Mr. Lew Nagler of my staff at (404) 347-2904. Any other questions may be directed to Mr. Gregg Worley of my staff, also at (404) 347-2904.

Sincerely yours,

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

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

Mr. Steven M. Day
Black & Veatch
1500 Meadow Lake Parkway
Kansas City, Missouri 64114

ATTACHMENT 14

MAY 6, 1991 LETTER
FROM FDER TO OUC

Florida Department of Environmental Regulation

Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400

Lawton Chiles, Governor

Carol M. Browner, Secretary

May 6, 1991

Diane K. Kiesling
Division of Administrative Hearings
Desoto Building
1230 Apalachee Parkway
Tallahassee, FL 32399-1550

RE: Orlando Utilities Commission
Curtis H. Stanton Unit 2
PA 81-14B, DOAH Case No. 91-1813 EPP

Dear Ms. Kiesling:

Pursuant to Section 403.5067, F.S., The Department of Environmental Regulation finds the following insufficiencies in the Supplemental application for site certification:

1. Please revise Figures 6.1.2., 3 and 4 to show the boundaries of the previously certified corridor.

2. Please provide a map showing the previously certified corridor and delineating the aerial extent of the red cockaded woodpecker habitat mentioned in the application narrative.

3. Please review the proposed culvert crossings to determine whether some or all of the crossings could be constructed as swale crossings rather than culvert crossings.

4. Please clarify when the jurisdictional survey of the certified corridor was done and by whom.

5. Please describe how the stormwater run-off from the proposed alternate access road will be treated.

6. The narrative stated that additional bridges would be placed in the alternate access road for wildlife crossings, if required. Please clarify what will determine if wildlife crossings are required.

7. The Joint Application for Works in Waters of the State form has been revised. Please replace the obsolete form submitted in the application with a current form which is attached.

8. The applicant should be more specific in identifying which wetlands (waters of the state) are anticipated to be crossed with bridges versus culverted fill roads.

9. Information should be provided which reflects how the decision was reached for each type of crossing. This information should include, but not necessarily be limited to: flood state date, general hydrologic characteristics of each site, vegetative characteristics (herbaceous versus forested), etc. It is suggested that waters of the state containing well-defined water channels should be traversed with bridges while braided, less clear systems could be crossed using culverts. In all cases it is important to maintain natural flow patterns as much as possible.

10. On what basis are culvert sizes determined?

11. Waters of the state to be cleared and maintained in that condition should be identified. The acreage involved also should be identified. (This is an important point since the department previously has sought mitigation for the clearing of forested wetlands associated with power lines).

12. Will the cleared areas be maintained in essentially a mowed condition or will hardwoods be allowed to reach a height allowing them to function as trees?

13. What is the anticipated bottom width of the access roads through waters of the state?

14. What is the acreage of waters of the state anticipated to be filled for access road construction?

15. How will side slopes be stabilized?

16. Who will be responsible for installing and <u>maintaining</u> turbidity control devices while construction is under way?

17. How large an area will be cleared and/or filled for construction equipment in waters of the state?

18. Provide any available information regarding the current status and location of red cockaded woodpecker clans on the property. These areas should be identified in relationship to their distance from all construction proposed in the supplemental application.

19. The following statement is made on page 6.1-10 of the supplemental application: "No significant impacts on the woodpeckers are anticipated." What specific information provides the basis for this statement?

20. Reference Volume 1A.2.1.5 - Please provide a site plan showing location and details of existing and new coal handling and storage area. The detail must include type of liner, thickness, details for collecting, treating and disposing of rainfall run-off generated in coal pile area, to name a few.

Details for dust control methods are also required.

21. Reference 1A.2.1.6 - Electrical Distribution - Are the transformers oil cooled? Please provide details of the containment area as well as the treatment and disposal system for contaminated stormwater run-off. This concern shall also be addressed for other similar areas such as switchgear units, etc.

22. Reference Volume 1A.2.1.7 - Provide site plan and details of make-up water supply storage pond (MWSSP). Evaluate and submit calculations to support the holding capacity of this pond since the flow from Orange County Easterly Subregional Wastewater Treatment Plant will more than double (from 4.5 MGD to 10.0 MGD). Calculations must include rainfall on the catchment, ground water mounding and free board requirements and run-off from other areas such as plant roof drains, active combustion waste area run-off pond, coal storage run-off ponds and cooling tower blowdown.

23. Since existing MWSSP is not a lined pond, all other waste streams discharging into this pond shall be identified. Details pertaining to each waste stream shall include information such as, but not limited to, point of origination, quantity (flow), raw wastewater characteristic, treatment provided, treated effluent characterization, hydraulic profile and engineering site location details. This site plan shall include all new and existing waste streams.

24. How is reject water from brine concentrators reused? (Refer to Volume 2, Sketch 3.5-2).

25. Reference 1A 2.1.8 - Coal and Oil Supply

Provide details of treatment and disposal method for contaminated stormwater from fuel oil containment areas.

26. Reference 1A 2.1.10.2 and 1A 2.1.10.3

How are the air preheater, air heater, etc. maintained? Details of wastewater generated at these and all other auxiliary equipment shall be submitted for department review.

27. Reference 1A 2.1.13.2

Do the bulk entrainment separator and contacting sprayer generate wastewater that is discharged to waters of the state? Please provide details.

28. Reference 1A 2.1.15.1

Provide a list and chemical composition of all chemicals used, including details for storage and handling, spill containment and measures to prevent contact with stormwater run-off. Please include and identify separately chemicals that will be used for Unit #2 and chemicals that are currently being used for Unit #1.

29. Reference 1A 2.1.15.4

A detail of the conveyer and mixer subsystem is required. Is this system open or covered? If the conveyer system is open, how is the contaminated stormwater collected, treated and disposed of? Also, please submit details for the landfill area, as related to leachate collection, disposal and ground water monitoring.

30. Reference 1A 2.1.16.1

Are the railroad cars bringing coal at the facility covered or open? The open cars loaded with coal have a potential for contaminating rainfall run-off during a rainfall event. How is leachate from the cars collected and disposed of?

31. Radioactive materials are used for monitoring levels of bulk storage of materials, liquids and combustion wastes. Does any radioactive material have potential of direct accidental discharge into, or coming in contact with, any wastewater generated? Provide details of radioactive materials used and best management practices to prevent contamination.

32. Reference Volume 2, Page 3.6-1, Item 3.6

Please provide a flow diagram and wastewater characterization for cooling tower lowdown that uses polyacrylate. How is this wastestream disposed of? If hauled away from the site, provide the name of the hauler and the company that receives this wastewater. Please include the department permit number for the company that will receive the wastewater.

33. Is the recycle basin (#65 on Figure 3.2-1) lined or unlined? A detailed evaluation shall be submitted for the capacity and adequacy of proposed expansion (Reference Volume 2, Page 3.8-1, Item 3.8).

Potable Water Section Comments

34. A complete application including plans and specification for a permit to construct modification to the existing water treatment plant and distribution system associated with construction of Unit No. 2 is required.

35. The applicant should provide a comprehensive summary of the ground water monitoring data. The summary should include a site map with well locations and both tabular and graphical summaries of the ground water data.

36. Provide the names and emission rates of those commercial installations of low NOx burners over the last several years which represent an advance in the control of NOx emissions from pulverized coal boilers. (page 3.4-22)

37. Provide references and results on some of the SCR systems used on Japanese and West German gas, oil, and coal fired boilers. (page 3.4-23)

38. Provide an explanation of the requirement of low-sulfur coal in use with an ammonia SCR system. Is high sulfur coal the reason why no coal fired boilers are using SCR systems in the United States. (page 3.4-23)

39. Provide references of those SCR systems which have an ammonia slip of 5-10 ppm. (page 3.4-23)

40. provide references on some urea or ammonia injection NOx reduction systems which illustrate an efficiency decrease rapidly outside the temperature range of 1550-1900 F. (page 3.4-24)

41. How much will the temperature location change for SNCR reduction, since the plant is designed as a baseload unit. (page 3.4-24)

42. Provide references on some SNCR systems which show that pulverized coal boilers are capable of between 40-50 percent Nox reduction. Are these facilities operated like Curtis Stanton? (page 3.4-25)

43. Provide references which shown an ammonia slip of between 10 and 50 ppm on pulverized coal boilers operated like Curtis Stanton. (page 3.4-25)

44. Provide references which show an ammonia odor in flyash making its commercial sale impossible. (page 3.4-25)

45. Describe how the tube spacing, temperature profiles, and physical size of the designed pulverized boiler greatly complicate additive injection. (page 3.4-25)

46. List continuous ammonia monitors that have proven unreliable? Can a NOx monitor and fuel rates provide good reagent injection control? (page 3.4-25)

47. Provide documentation of the occurrence of a continuous ammonia chloride plume at a pulverized coal fired power plant operated like Curtis Stanton. (page 3.4-26)

48. Provide a reference that ammonia slips greater than 5 ppm will occur whenever NOx reduction is greater than 30 percent. (page 3.4-26)

49. Has the company investigated the use of phosphorus injection to reduce NOx emissions.

50. Does the CSXT Appalachian rail corridor to Orlando include coal train traffic through the city of Orlando.

51. Have paragraphs 17 and 18 of Consent Order OGC 90-0108 been completed?

52. Provide a copy of the SO_2 scrubber system trend data, as described in paragraph 17 of OGC 90-0108, for the period January through March 1991.

Atlanta 53. BACT analysis for Sulfur Dioxide should evaluate the use of lower sulfur content coals. Recent permitting evaluations have limited the sulfur content of coal to 1.7 percent for CFB boilers and to 2.0 percent for pulverized coal fired boilers.

Atlanta 54. BACT analysis for particulates/heavy metals should evaluate the use of higher efficiency electrostatic precipitators. Recent permitting evaluations have limited particulate emissions to 0.018 lb/MMBtu for pulverized coal fired boilers.

Atlanta 55. BACT analysis for nitrogen oxides should evaluate the use of boiler~~s~~ with inherently better control. Recent applications have ~~prepared~~ Proposed uncontrolled NOx levels, as low as 0.27 lb/MMBtu for pulverized coal fired boilers.

56. Your BACT for NOx selects improved combustion controls. Provide actual performance and outage incidents to support the negative attributes of SNCR. Provide test performance information on boilers equipped with combustion control. Also, include manufacturer's published papers and emission performance assumptions.

57. For particulate control provide actual data to demonstrate the superiority of ESP VS fabric filters in limiting PM10.

58. Provide data on the actual time to obtain the necessary dust cake for optimum filtering.

59. Provide supporting information of expecting an ammonia chloride plume use either manufacturer or user information.

60. Provide supporting information on expected problems and projected affect on reliability due to "Sticky" compounds down stream.

61. Provide documentation on problem of fly ash becoming odorous due to absorbing ammonia and the affect on markets for this material.

62. Discuss the reliability effect from the use of SNCR. Provide actual data on similar applications. Give source of information.

Also attached are requests for information from the St. Johns River Water Management District and South Florida Water Management District.

Sincerely,

Hamilton S. Oven

Hamilton S. Oven, Jr., P.E.
Administrator
Office of Siting Coordination
Division of Air Resources
Management

HSO/ah
Attachments
cc: All Parties

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing has been furnished to the parties listed below by U.S. Mail this 6th of May, 1991.

Hamilton S Oven Jr
Hamilton S. Oven, Jr.

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ATTACHMENT 2

JUNE 20, 1991, LETTER FROM OUC TO EPA WITH ENCLOSURES

ORLANDO UTILITIES COMMISSION
500 SOUTH ORANGE AVENUE • P. O. BOX 3193 • ORLANDO, FLORIDA 32802 • 407/423-9100

June 20, 1991

Mr. Gregg M. Worley
Air, Pesticides and Toxics
Management Division
U. S. Environmental
Protection Agency, Region IV
345 Courtland Street, N. E.
Atlanta, GA 30365

Re: Orlando Utilities Commission SEC Unit No. 2 BACT (PSD-FL-084)

Dear Mr. Worley:

We appreciate the opportunity you provided us to meet with EPA air management staff on Friday, June 7. At the conclusion of the meeting, you asked for copies of the slides used in the presentation and copies of our reply to FDER's sufficiency questions.

Enclosed are copies of the slides presented. One of the slides on Potential SO$_2$ Emissions presented by Mr. Ken Carlson was corrected to include a footnote. During Mr. John Cochran's presentation on SNCR, costs were presented in terms of dollars per ton of NO$_x$ removed. Additional costs reflecting reduced plant availability were not available at the time of presentation and have been included as an additional slide.

Also enclosed, are copies of OUC's responses to FDER's sufficiency questions pertinent to the BACT determination.

Please call me at 407/423-9141 if you have questions regarding this transmittal.

Very truly yours,

J. S. Crall
Director
Environmental Division

JSC:rc
Attachment

cc: Barry Andrews - FDER, w/enclosure
Nancy Tommelleo, Esq. - EPA Reg.IV
W. H. Herrington
T. B. Tart, Esq.
Ken van Assenderp, Esq., w/enclosure

Administration Fax: (407) 236-9616 ● Purchasing Fax: (407) 423-9199

FDER - Question 36

Question. Provide the names and emission rates of those commercial installations of low NO_x burners over the last several years which represent an advance in the control of NO_x emissions from pulverized coal boilers. (page 3.4-22)

Response. Experience lists for the three large U.S. manufacturers are attached. These lists indicate both new installation and retrofit low NO_x burner experience. The following are the principal low NO_x wall mounted burner types available.

- o Babcock & Wilcox XCL.
- o Foster Wheeler Internal Fuel Staged (IFS).
- o Foster Wheeler Controlled Flow/Split Flame (CF/SF).
- o Riley Stoker Controlled Combustion Venturi (CCV).

These installations represent state-of-the-art for commercial installation of low NO_x burners.[1] [2] [3] [4] [5] [51]

Cited references for this question and others related to air quality emissions are included with the response to this question.

Babcock & Wilcox
Low NO_x DRB-XCL Burner Contracts

	Customer	Fuels	No. of Burners	Design	Start-Up	Nox Guar.
	Ohio Edison	PC (1)	12	Single Wall, Impellers	1986	
	Cal. Inst. Tech.	Gas(2)/No. 2 Oil	1	FM - No GR (5)	1988	
	Black Hills Power & Light	PC	4	Single Wall, Impellers	1990	
NEW	Exxon	Gas/Wax Oil	1	FM - No GR	1990	
	ENEL	Oil(3)/Gas	18	Opposed, NO_x Ports, GR	1990	
	Nova Scotia	PC/Oil	16	Single Wall, Impellers	1990	
	Basin Elec. Pwr. Co-op.	PC/Lignite	4	Opposed, Partial Retrofit	1990	
NEW	Egyptian Elec. Auth.-Unit 1	Oil/Gas	9	Front Wall Fired, no NO_x Ports, No GR	1991	
	ENEL	PC/Oil/Gas	56	Opposed, NO_x Ports, GR	1991	
NEW	Stone Container	Gas/Fut(4) PC	6	CCZ - Rearwall Fired	1991	
NEW	Egyptian Elec. Auth.-Unit 2	Oil/Gas	9	Front Wall Fired, No NO_x Ports, No GR	1992	
NEW	Egyptian Elec. Auth.-Unit 3	Oil/Gas	9	Front Wall Fired, No NO_x Ports, No GR	1992	
NEW	Union Camp	Oil/Fut PC	6	CCZ - Sidewall Opposed	1991	
	ENEL	PC/Oil/Gas	56	Opposed, NO_x Ports, GR	1991	
	ENEL	PC/Oil/Gas	30	Opposed, NO_x Ports, GR	1992	
	ENEL	PC/Oil/Gas	30	Opposed, NO_x Ports, GR	1992	
	Ohio Edison - Sammis 6	PC	36	Opposed w/diff., 12 NO_x Ports, No GR	1992	
	Penntech/Willamette	PC/Oil	8	Single Wall, NO_x Ports	1992	
NEW	Egyptian Elec. Auth.-Unit 4	Oil/Gas	9	Front Wall Fired, No NO_x Ports, No GR	1993	
	ENEL	PC/Oil/Gas	56	Opposed, NO_x Ports, GR	1993	
		Total	376			

(1) PC = Pulverized Coal
(2) Gas = Natural Gas
(3) Oil = No. 6, Heavy Oil
(4) Fut = Future
(5) GR = Gas Recirculation
Diff. = Conical Diffuser

Issued: February 1991

TABLE 1

LIST OF UNITS EQUIPPED WITH FW'S CONTROLLED FLOW SPLIT-FLAME LOW NOx BURNERS

UTILITY	PLANT NAME	UNIT TYPE	NEW OR RETROFIT	BOILER OUTPUT MWG	YEAR ON LINE	COAL**	NO. BURNERS	NOx LEVEL	NOx GUARANTEE	UNCON-TROLLED NOx
PS New Mexico	San Juan #1	S	R	350	79	S	16	0.45	0.45	1.0
Dupont	Martinsville	S	R	*	84	B	4	0.45	B/E	0.85
Sierra Pacific Power Company	North Valmy #2	S	N	250	85	B	16	0.50	0.50	--
Nevada Power Co.	Reid Gardner #4	S	N+	275	84	B	16	0.45	0.60	--
Grand River Dam Authority	Unit #2	HO	N	490	86	S	28	0.45	0.50	--
Jacksonville Elec. Authority	Units 1 & 2	HO	N	600	86	B	28	0.60	0.60	--
Central & Southwest Services	Oklaunion #1	HO	N	720	86	S	30	0.50	0.50	--
Deseret Generation & Transmission Coop	Moon Lake #1	HO	N	440	86	B	20	0.50	0.50	--
Big Rivers Electric Corp.	Wilson #1	HO	N	440	85	B	25	0.60	0.60	--
Portland GE	Boardman #1	HO	N+	550	82	S	32	0.45	0.70	--
Allegheny Power	Pleasants #2	HO	R	660	86	B	24	0.45	0.60	1.0
CEGB	Eggborough	S	R	500	86	B	24	0.55	B/E	1.15

TABLE 1 (CONTINUED)

LIST OF UNITS EQUIPPED WITH FW'S CONTROLLED FLOW SPLIT-FLAME LOW NOx BURNERS

UTILITY	PLANT NAME	UNIT TYPE	NEW OR RETROFIT	BOILER OUTPUT MWG	YEAR ON LINE	COAL**	NO. BURNERS	NOx LEVEL	NOx GUARANTEE	UNCON-TROLLED NOx
Arizona PS	Four Corners #4	HO	R	800	89	S	48	0.55	0.65	1.3
Arizona PS	Four Corners #3	S	R	225	90	S	18		0.55	1.1
Consumers Power Co.	Campbell #3	HO	R	770	90	B	48		0.49	1.0
Taiwan PC	Hsin-Ta #1 & #2	HO	R	500	90	S	24		0.57	1.2

* Industrial unit, 110,000 lb/hr
** B=Bituminous; S=Sub-bituminous
\+ Retrofitted with Low NOx Burners during original construction.

S = Single Wall Fired
HO = Horizontal Opposed Fired

Notes:

- All NOx levels given in lbs. per MBtu of heat input.
- All NOx levels are independent of any overfire air system (if so equipped).
- There are additional units that are equipped with only Controlled Flow air register.

FDER - Question 37

Question. Provide references and results on some of the SCR systems used on Japanese and West German gas, oil, and coal fired boilers. (page 3.4-23)

Response. Selective catalytic reduction (SCR) systems were first used in Japan during the 1970's. Through 1990, 40 SCR systems were operating on 10,852 MW of coal fired utility service. Japanese SCR systems were operated to achieve between 70 and 80 percent NO_x reduction with ammonia slip less than 10 ppm. Coals burned in the Japanese boilers have low sulfur (less than one percent) and low ash (less than 10 percent) contents.[6]

In response to German acid rain legislation, SCR was retrofitted to 129 coal fired boilers totalling 30,625 MW. Most of the Japanese and German SCR systems are generally operated to achieve 80 percent NO_x reduction to meet a NO_x emission limit of approximately 100 ppm while maintaining ammonia (NH_3) slip emissions to below 5 ppm. Similar to Japanese SCR experience, coals burned at these facilities have relatively low sulfur (0.7 to 1.2 percent) and low ash contents.[7]

The Japanese and European experience with SCR cannot be blindly applied to U.S. facilities. There remain two significant uncertainties about design, performance, operating parameters, and cost of SCR systems. First, U.S. utility power plants operate under more variable loads. Second the amounts and types of trace elements in U.S. coals are different from those in the fuel consumed in Japan and Europe.[8] [9]

Variable load conditions result in variable temperatures in the SCR reactor. At lower temperatures SCR reaction efficiencies drop off markedly, resulting in either lower NO_x reduction or additional ammonia slip emissions.

A number of alkali metals and trace elements (especially arsenic) poison the catalyst, significantly affecting reactivity and life.[10] Average arsenic concentrations for U.S. coals are three times the worldwide average.[11]

NOx REMOVAL PLANT SUPPLY LIST (1/4)

(IN USA)

As of Jan., 1991

№	CUSTOMER	GAS TURBINE	GAS FLOWRATE Nm^3/H	FUEL	DeNOx EFF. (%)	COMMERCIAL OPERATION
1	B&W / WILLAMETTE / OXNARD (CA)	LM2500	195,000 (21MW)	NG	80	1986-3
2	VOGT / FLUOR / ARCO / WATSON (CA)	FRAME 7E	830,000 (80MW)	NG	90	1987-12
3	VOGT / FLUOR / ARCO / WATSON (CA)	FRAME 7E	830,000 (80MW)	NG	90	1988-2
4	VOGT / FLUOR / ARCO / WATSON (CA)	FRAME 7E	830,000 (80MW)	NG	90	1988-3
5	STFC / B&R / CHEVRON / EL SEGUNDO (CA)	FRAME 6	406,000 (37MW)	NG	90	1988-3
6	STFC / B&R / CHEVRON / EL SEGUNDO (CA)	FRAME 6	406,000 (37MW)	NG	90	1988-3
7	VOGT / FLUOR / ARCO / WATSON (CA)	FRAME 7E	830,000 (80MW)	NG	90	1988-5
8	NECS / R. M. PARSONS / LA COUNTY / PITCHESS (CA)	LM2500	194,000 (21MW)	NG	79	1988-8
9	NECS / R. M. PARSONS / LA COUNTY / CIVIC CENTER (CA)	LM2500	200,000 (21MW)	NG	79	1988-9
10	VOGT / GE / COGEN TECH. / BAYONNE (NJ)	FRAME 6	450,000 (37MW)	NG	80	1988-10

NOx REMOVAL PLANT SUPPLY LIST (2/4)

(IN USA)

As of Jan., 1991

No	CUSTOMER	GAS TURBINE	GAS FLOWRATE Nm^3/H	FUEL	DeNOx EFF. (%)	COMMERCIAL OPERATION
11	VOGT / GE / COGEN TECH. / BAYONNE (NJ)	FRAME 6	450,000 (37MW)	NG	80	1988-10
12	VOGT / GE / COGEN TECH. / BAYONNE (NJ)	FRAME 6	450,000 (37MW)	NG	80	1988-10
13	ZURN / NEPCO / BAKERSFIELD (CA)	LM2500	240,500 (21MW)	NG	80	1989-4
14	VOGT / EBASCO / EFI / NAVY (CA)	LM2500	240,000 (21MW)	NG	80	1989-6
15	VOGT / EBASCO / EFI / NAVY (CA)	LM5000	399,600 (33MW)	NG	80	1989-7
16	VOGT / EBASCO / EFI / NAVY (CA)	FRAME 6	419,000 (37MW)	NG	80	1989-7
17	VOGT / CHEVRON / RICHMOND (CA)	ABB#8	538,000 (49MW)	NG	90	?
18	VOGT / CHEVRON / RICHMOND (CA)	ABB#8	538,000 (49MW)	NG	90	?
19	VOGT / ESI / P&G / OXNARD (CA)	LM5000	452,000 (33MW)	NG	80	1989-12
20	VOGT / B&W / ICE HAUS II (CA)	LM5000	392,000 (33MW)	NG	80	1990-1

NOx REMOVAL PLANT SUPPLY LIST (3/4)

(IN USA)

As of Jan., 1991

No.	CUSTOMER	GAS TURBINE	GAS FLOWRATE Nm^3/H	FUEL	DeNOx EFF. (%)	COMMERCIAL OPERATION
21	STFC / YEI / TENNECO / PLACERITA CANYON (CA)	LM2500	189,000 (21MW)	NG	79	1990-3
22	STFC / YEI / TENNECO / PLACERITA CANYON (CA)	LM2500	189,000 (21MW)	NG	79	1990-5
23	ENTEC / B&R / EXXON / SANTA YNEZ (CA)	FRAME 6	421,000 (37MW)	NG	90	1990
24	DELTAK / CTM / DEXZEL (CA)	LM2500	200,000 (21MW)	NG	84	1990-1
25	ENTEC / HSPE / SALINAS (CA)	LM5000	482,000 (33MW)	NG	65	1990
26	ENTEC / HSPE / NEWARK (NJ)	FRAME 6	461,000 (37MW)	NG	53	1990-9
27	ENTEC / HSPE / PARLIN (NJ)	FRAME 6	461,000 (37MW)	NG	68	1990
28	ENTEC / HSPE / PARLIN (NJ)	FRAME 6	461,000 (37MW)	NG	68	1990
29	ENTEC / FLUOR / TEXACO / LOS ANGELS (CA)	PROCESS HEATER	20,000	NG	82	1990
30	B&W / KAL KAN FOODS (CA)	BOILER	26,000	NG	88	1990

NOx REMOVAL PLANT SUPPLY LIST (4/4)

(IN USA) As of Jan., 1991

№	CUSTOMER	GAS TURBINE	GAS FLOWRATE Nm^3/H	FUEL	DeNOx EFF. (%)	COMMERCIAL OPERATION
31	ENTEC / HSPE / RICHMOND / VIRGINIA (VA)	ABB#11N	1,053,000 (83MW)	NG/OIL	80	1990-11
32	ENTEC / HSPE / RICHMOND / VIRGINIA (VA)	ABB#11N	1,053,000 (83MW)	NG/OIL	80	1990-11
33	VOGT / GE / OCEAN STATE / BURRILLVILLE (RI)	FRAME 7E	944,000 (80MW)	NG/OIL	79	1990
34	VOGT / GE / OCEAN STATE / BURRILLVILLE (RI)	FRAME 7E	944,000 (80MW)	NG/OIL	79	1990
35	B&W / MOBIL / TORRANCE (CA) No.1	PROCESS HEATER	33,000	NG	90	1990
36	B&W / MOBIL / TORRANCE (CA) No.2	PROCESS HEATER	33,000	NG	90	1990
37	B&W / MOBIL / TORRANCE (CA) No.3	PROCESS HEATER	362,000	NG	87	1990
38	ENTEC / EBASCO / CITY OF ANAHEIM (CA)	LM5000	460,000 (33MW)	NG	76	1991
39	VOGT / GE / OCEAN STATE / BURRILLVILLE (RI)	FRAME 7E	944,000 (80MW)	NG/OIL	79	1992
40	VOGT / GE / OCEAN STATE / BURRILLVILLE (RI)	FRAME 7E	944,000 (80MW)	NG/OIL	79	1992

NOx REMOVAL PLANT SUPPLY LIST (1/2)
(IN EUROPE)

As of Jan., 1991

NO.	CUSTOMER		GAS FLOW RATE (Nm^3/H)	FUEL	DeNOx EFF. (%)	COMMERCIAL OPERATION
1	VKG / DURNROHR 1	(AUSTRIA)	1,235,000 (405 MW)	COAL	80	1986
2	EVN / DURNROHR 2	(AUSTRIA)	1,138,000 (320 MW)	COAL	80	1986
3	VKR / KNEPPER C	(FRG)	260,000 (370 MW x 1/4)	COAL	90	1986
4	IAW / LEININGERWERK 5	(FRG)	1,400,000 (450 MW)	COAL	70	1988
5	BAYERNWERK / SCHWANDORF-C	(FRG)	464,000 (100 MW)	COAL	80	1988
6	BAYERNWERK / SCHWANDORF-D	(FRG)	1,393,000 (300 MW)	COAL	80	1988
7	KW MEHRUM / MEHRUM 3	(FRG)	2,240,000 (700 MW)	COAL	75	1988
8	STEAG / WALSUM-7	(FRG)	547,000 (150 MW)	COAL	90	1988
9	STW FRANKFURT / WEST-2	(FRG)	287,500 (90 MW)	COAL	80	1989
10	STW FRANKFURT / WEST-3	(FRG)	287,500 (90 MW)	COAL	80	1989
11	BAYERNWERK / SCHWANDORF-B	(FRG)	464,400 (100 MW)	COAL	80	1989
12	PREUSSENELEKTRA / HEYDEN-4	(FRG)	2,470,000 (800 MW)	COAL	75	1989

NOx REMOVAL PLANT SUPPLY LIST (2/2)
(IN EUROPE)

As of Jan., 1991

NO.	CUSTOMER		GAS FLOW RATE (Nm^3/H)	FUEL	DeNOx EFF. (%)	COMMERCIAL OPERATION
13	VKR / KNEPPER C (ADDITION)	(FRG)	260,000	COAL	--	1988
14	VKR / KNEPPER C (EXTENTION)	(FRG)	510,000 (370 MW × 1/2)	COAL	90	1989
15	WESER / VELTHEIM 1	(FRG)	301,000 (100 MW)	COAL	82	1989
16	IAW / LEININGERWERK 5 (EXCHANGE)	(FRG)	1,370,000 (450 MW)	COAL	70	1990
17	CONFIDENTIAL	(SWEDEN)	255,000	COAL	33	1991
18	VÅSTERAS / VÅSTERAS 1 & 2	(SWEDEN)	190,000 × 2 --	COAL	84	1992
19	IVO / MERI PORI	(FINLAND)	1,558,000 (550 MW)	COAL	50	1993

NOx REMOVAL PLANT SUPPLY LIST (1/2)

(DOMESTIC UTILITY IN JAPAN)

As of Jan., 1991

NO.	CUSTOMER	PLANT	GAS FLOW RATE (Nm3/H)	FUEL	DeNOx EFF. (%)	COMMERCIAL OPERATION
1	KANSAI	·KAINAN 1	300,000	CRUDE OIL	75	1977
2	CHUBU	·CHITA 5	1,910,000	LNG	80	1978
3	CHUBU	·CHITA 6	1,910,000	LNG	80	1978
4	TOKYO	·YOKOHAMA 1	483,000	HEAVY OIL	50	1978
5	KANSAI	·AMAGASAKI HIGASHI 1	466,000	HEAVY OIL	30	1978
6	HOKKAIDO	·TOMATO ATSUMA 1	280,000	COAL	80	1980
7	KANSAI	·AMAGASAKI HIGASHI 2	466,000	HEAVY OIL	30	1980
8	KANSAI	·AMAGASAKI No. 3 3	450,000	HEAVY OIL	30	1980
9	KANSAI	·AMAGASAKI No. 3 2	470,000	HEAVY OIL	30	1980
10	KANSAI	·SAKAIKO 5	740,000	HEAVY OIL	75	1980
11	E.J.R.C.	·KAWASAKI 1	1,024,000	KEROSENE	80	1981
12	E.P.D.C.	·TAKEHARA 1	399,500	COAL	80	1981
13	CHUBU	·NISHINAGOYA 4	970,000	HEAVY OIL	80	1981
14	KANSAI	·TANAGAWA No. 2 2	1,565,000	HEAVY OIL	75	1981
15	KANSAI	·KAINAN 4	1,645,000	HEAVY OIL	75	1981
16	KANSAI	·AMAGASAKI No. 3 1	470,000	HEAVY OIL	30	1981
17	CHUBU	·NISHINAGOYA 3	970,000	HEAVY OIL	80	1981
18	E.P.D.C.	·TAKEHARA 3	2,320,000	COAL	80	1983
19	CHUGOKU	·TAMASHIMA 1	950,000	HEAVY OIL	80	1983
20	CHUBU	·CHITA No. 2 1	1,910,000	LNG	80	1983
21	TOHOKU	·SENDAI 3	599,000	COAL	60	1983
22	TOHOKU	·SENDAI 2	599,000	COAL	60	1983
23	CHUGOKU	·MIZUSHIMA 3	950,000	HEAVY OIL	80	1983
24	M.I.T.I.	·MOON LIGHT	603,100	LNG	84	1984
25	KANSAI	·GOBO 2	1,525,300	HEAVY OIL	75	1984

NOx REMOVAL PLANT SUPPLY LIST (2/2)

(DOMESTIC UTILITY IN JAPAN)

As of Jan., 1991

NO.	CUSTOMER	PLANT	GAS FLOW RATE (Nm^3/H)	FUEL	DeNOx EFF. (%)	COMMERCIAL OPERATION
26	CHUGOKU	·MIZUSHIMA 1	450,000	COAL	80	1984
27	CHUGOKU	·MIZUSHIMA 2	540,000	COAL	80	1984
28	TOYAMA JOINT	·TOYAMA SHINKO 1	629,000	COAL	53	1984
29	TOYAMA JOINT	·TOYAMA SHINKO 2	629,000	COAL	53	1984
30	TOKYO	·YOKOHAMA 3	512,300	LNG , OIL	33	1985
31	TOKYO	·YOKOHAMA 1	512,300	LNG , OIL	33	1985
32	CHUBU	·OWASE 3	1,370,000	HEAVY OIL	80	1987
33	E.P.D.C	·WAKAMATSU	188,700	COAL	60	1987
34	TOKYO	·HIGASHI OHGISHIMA 1	2,770,000	LNG	80	1987
35	KYUSHU	SHINOHITA 1	(690 MW)	LNG	80	1990
36	CHUGOKU	YANAI 1	(700 MW)	LNG	80	1990
37	E.P.D.C.	MATSUURA 1	3,100,000	COAL	80	1990
38	TOKYO	HIGASHI OHGISHIMA 2	2,770,000	LNG	80	1991
39	KANSAI	NANKO 2	(600 MW)	LNG	80	1991
40	CHUBU	HEKINAN 2	(700 MW)	COAL	80	1992
41	CHUGOKU	YANAI 2	(700 MW)	LNG	80	1993
42.	SOMA JOINT	SHINCHI 1	(1000 MW)	COAL	—	1994

NOTE 1. IN No. 4. 5. 7. 8. 9. 16. 30. AND 31 PLATE CATALYST ARE INSTALLED IN THE RESTRICTED SPACE OF THE FLUE GAS DUCT BETWEEN ECONOMIZER AND AIR PREHEATER.

NOTE 2. PLANTS MARKED WITH "·" ARE IN OPERATION.

NOTE 3. E.P.D.C. IS AN ABBREVIATION OF ELECTRIC POWER DEVELOPMENT CO.

NOTE 4. M.I.T.I. IS AN ABBREVIATION OF MINISTRY OF INTERNATIONAL TRADE & INDUSTRY.

NOTE 5. E.J.R.C. IS AN ABBREVIATION OF EAST JAPAN RAILWAY COMPANY.

NOx REMOVAL PLANT SUPPLY LIST

(DOMESTIC INDUSTRY IN JAPAN)

As of Jan., 1991

NO.	CUSTOMER	PLANT	GAS SOURCE	GAS FLOW RATE (Nm3/H)	FUEL	DeNOx EFF. (%)	COMMERCIAL OPERATION
1	CHIYODA KENZAI	KAIZUKA	BOILER	15,000	HEAVY OIL	70	1976
2	KAWASAKI STEEL	CHIBA	COKES OVEN	500,000	COG/BFG	95	1976
3	MATUO ELECTRIC	TOYONAKA	ELECTRIC FURNACE	3,600	-	84	1977
4	NISSHIN STEEL	AMAGASAKI	BOILER	20,000	HEAVY OIL	90	1977
5	KANSAI PAINT	AMAGASAKI	BOILER	16,000	KEROSENE	90	1978
6	NIPPON OIL & FATS	AMAGASAKI	BOILER	20,000	HEAVY OIL	90	1978
7	NISSHIN STEEL	SAKAI	BOILER	30,000	KEROSENE	90	1978
8	MITSUBISHI PETROCHEMICAL	KASHIMA	FURNACE	53,000	ASPHALT	80	1980
9	NIPPON YAKIN	KAWASAKI	ACID PICKLED	10,000	-	90	1980
10	NIPPON YAKIN	KAWASAKI	ACID PICKLED	10,000	-	90	1981
11	KAWASAKI STEEL	CHIBA	ACID PICKLED	9,000	-	95	1982
12	NIPPON YAKIN	KAWASAKI	ACID PICKLED	4,800	-	90	1984
13	SHOWA DENKO	KAWASAKI	BOILER	95,000	PETRO COKE	46	1986
14	IDEMITSU KOUSAN	HYOGO	BOILER	155,000	COAL	60	1986
15	YOSHINO SEKKO	CHIBA	FLUIDIZED BED BOILER	62,500	COAL	66	1987
16	CONFIDENTIAL	-	DIESEL	31,090	HEAVY OIL	86	1988
17	CONFIDENTIAL	-	DIESEL	6,600	HEAVY OIL	60	1988
18	CHUETSU PULP	FUTATSUKA	BOILER	91,200	PETRO COKE	69.4	1988
19	CONFIDENTIAL	-	DIESEL	47,600	HEAVY OIL	58	1989
20	GENERAL PETROLEUM	SAKAI	GAS TURBINE	261,200	OFF GAS	85.5	1989
21	NIHONKOGYO	CHITA	GAS TURBINE	115,600	OFF GAS	80	1989
22	CONFIDENTIAL	-	DIESEL	31,090	HEAVY OIL	86	1990

NOx REMOVAL PLANT SUPPLY LIST
(IN ASIA EXCEPT JAPAN)

As of Jan., 1991

NO.	CUSTOMER	GAS FLOW RATE (Nm^3/H)	FUEL	DeNOx EFF. (%)	COMMERCIAL OPERATION
1	CCMC / CHINESE PETOLEUM CORP. (FORMOSA)	126,300	OIL	83	1991
2	BEL / HONG-KONG & CHINA GAS(HONG-KONG)	(46,700 x 4)	Naphtha	90	1991
3	CCMC / CHINESE PETOLEUM CORP. (FORMOSA)	145,440	OIL	83	1992

TABLE 1 – COAL RESERVE BASE BY SULFUR CONTENT(1) (MILLION TONS)

State	< 1.0%		1.1 - 3.0%		>3.0%		Total(2)	
E. Kentucky	6,558	64%	3,322	33%	299	3%	10,179	100%
Virginia	2,088	64%	1,163	36%	14	<1%	3,265	100%
W. Kentucky	0	0%	564	6%	9,244	94%	9,808	100%
Illinois	1,095	2%	7,341	14%	42,969	84%	51,405	100%
Total	9,741	13%	12,390	17%	52,526	70%	74,657	100%

(1) For Coalbeds >28" to a Maximum Depth of 1,000 Feet

(2) Total is Less than that of Total Reserve Base Since There are Reserves with an Unknown Sulfur Content

Source: Adapted from the Reserve Base of U.S. Coals in Sulfur Content, Part I; The Eastern States

Figure 1 COAL SHIPMENTS

BY SULFUR CONTENT (LBS02/MMBTU)

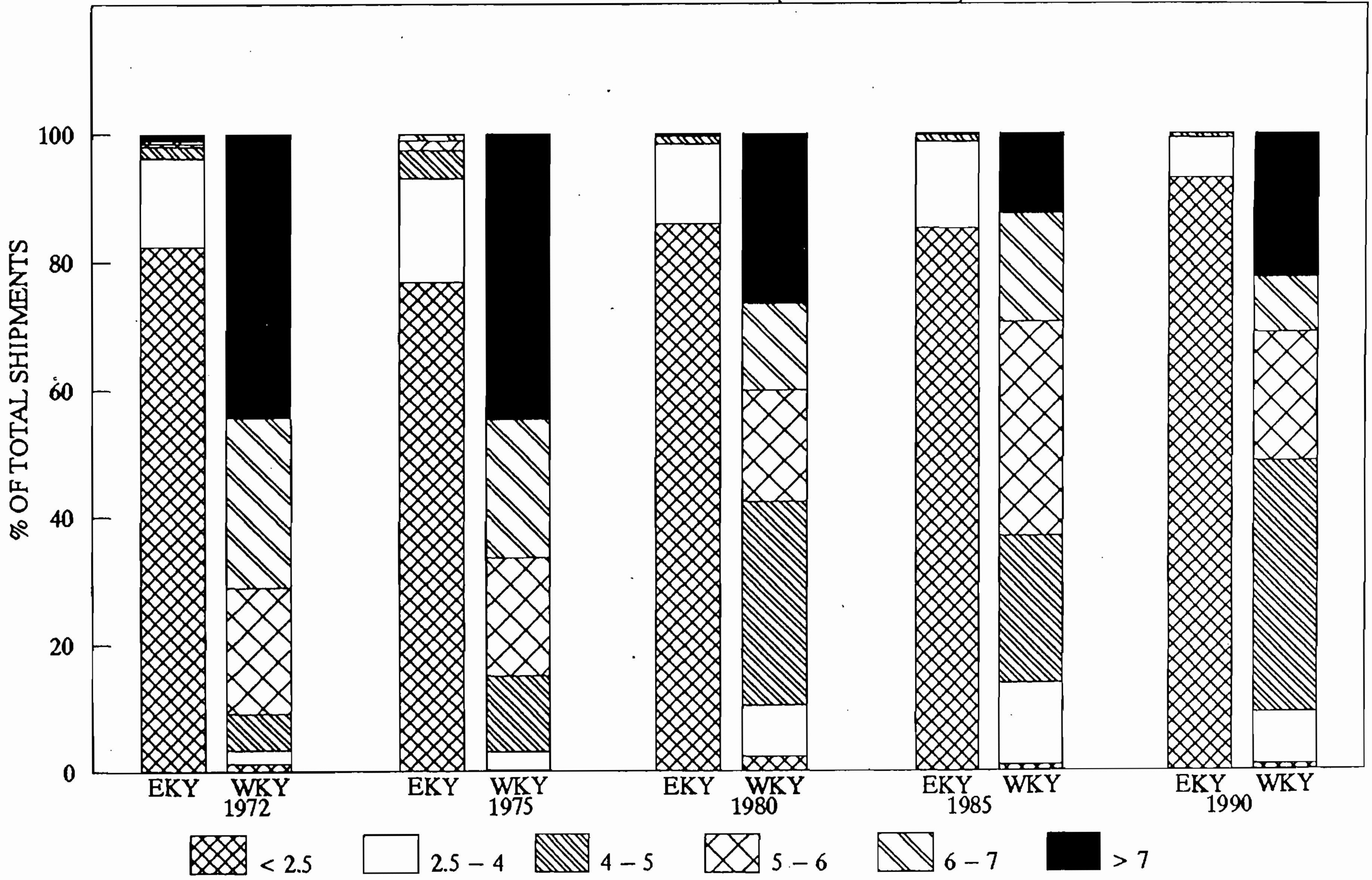
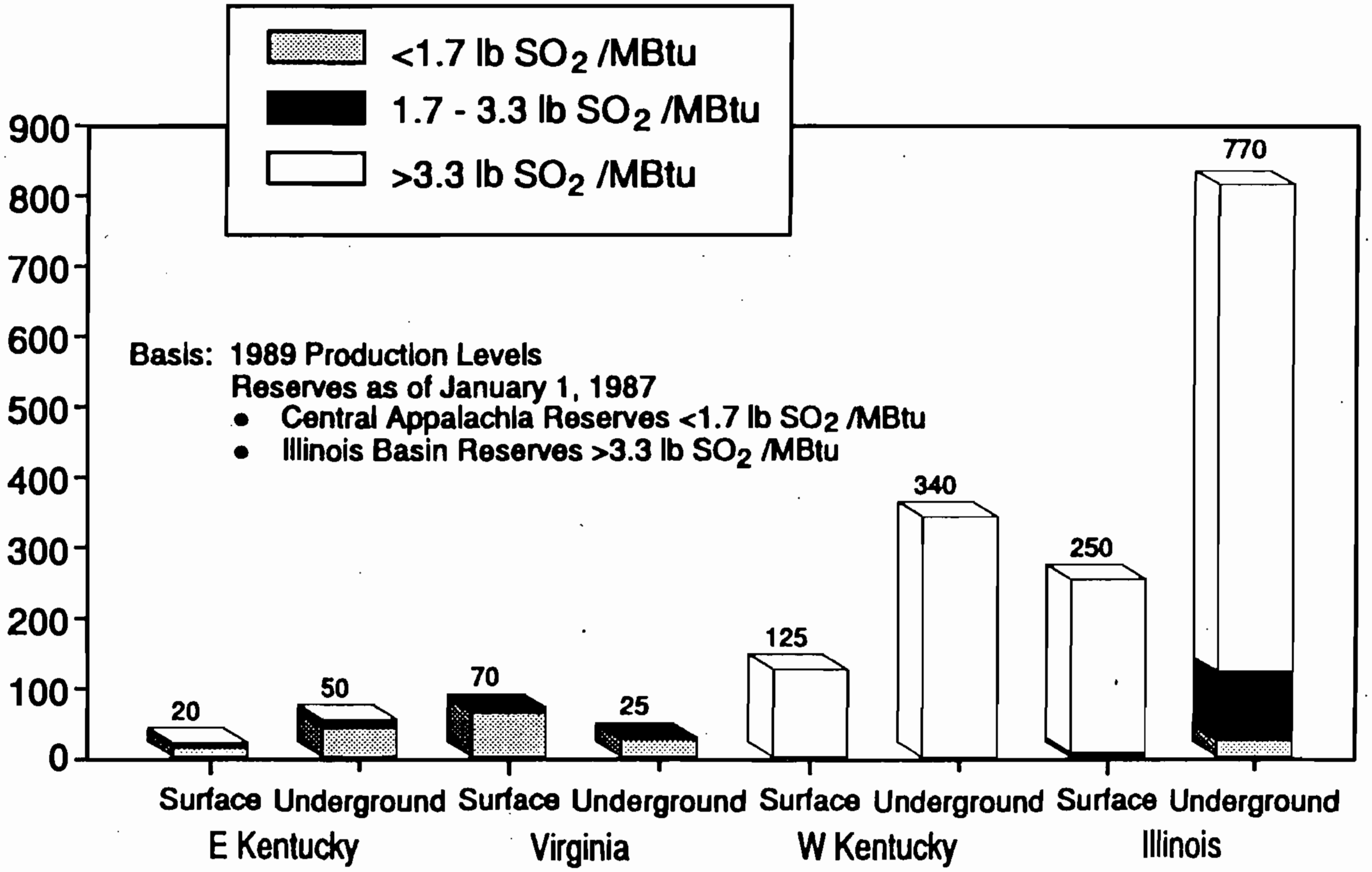
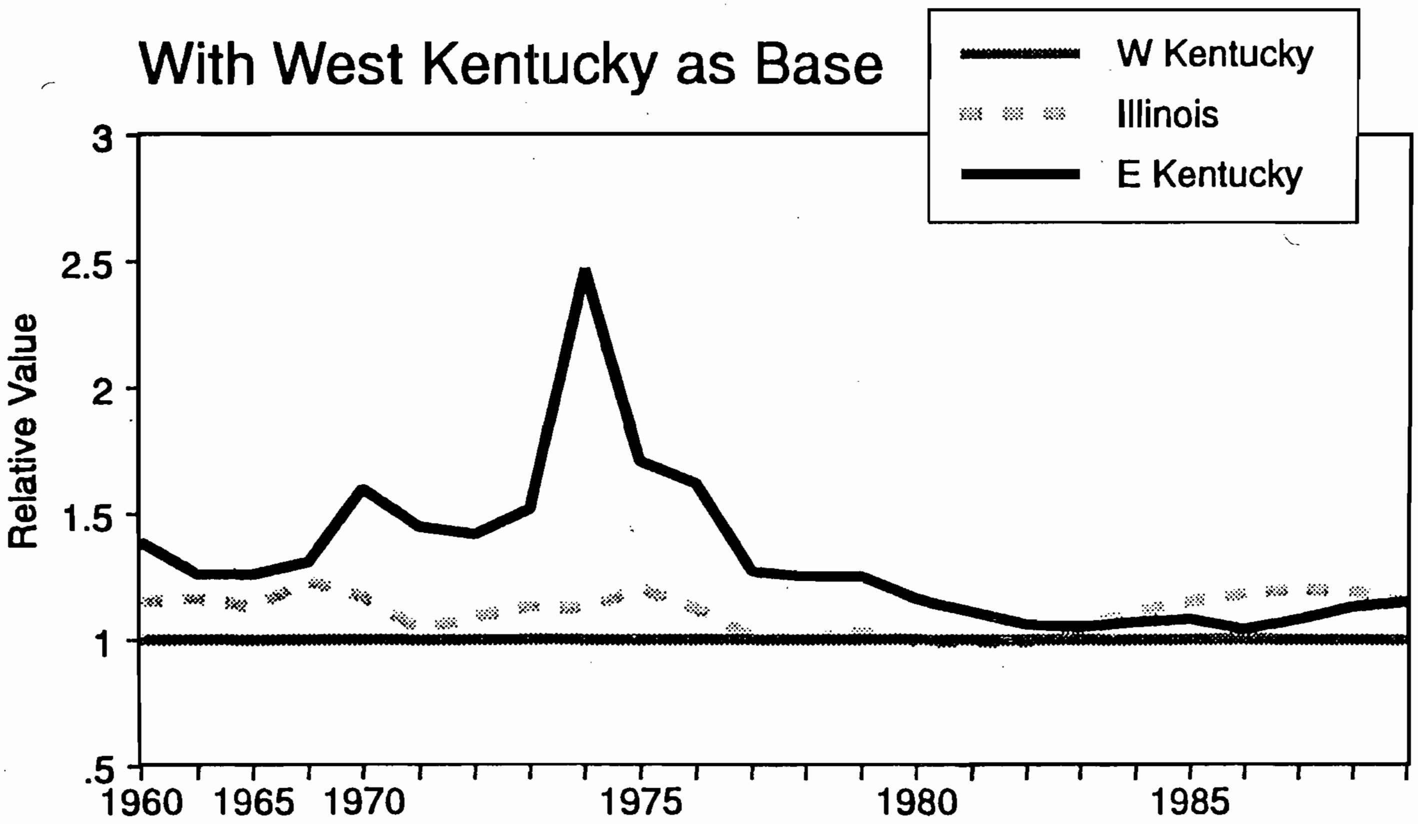


FIGURE 2 – YEARS OF REMAINING RESERVES



OUC277

FIGURE 3 – RELATIVE COST OF COAL



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FDER - Question 54

Question. BACT analysis for particulates/heavy metals should evaluate the use of higher efficiency electrostatic precipitators. Recent permitting evaluations have limited particulate emissions to 0.018 lb/MBtu for pulverized coal fired boilers.

Response. The BACT analysis evaluated the use of either fabric filters or electrostatic precipitators to meet an particulate emission limit of 0.02 lb/MBtu as compared to an optimized fabric filter designed to limit emissions to 0.012 lb/MBtu. The electrostatic precipitator manufacturer for C. H. Stanton Unit 2 will only guarantee the precipitator for an outlet emission of 0.02 lb/MBtu. However, fabric filters are capable of limiting particulate emissions to 0.018 lb/MBtu.

The fabric filter manufacturer will raise the price of equipment nominally to cover the risk of not achieving the specified emission limit. In addition, maintenance costs would increase slightly to reflect a nominally shortened bag life. Assuming a two percent increase in capital cost and a five percent increase in maintenance cost, the 1997 total levelized annual cost for a 0.018 lb/MBtu fabric filter is $8.9 million. This represents an incremental particulate removal cost of $6,700 per ton. This cost is excessive by BACT standards. In addition, this expense occurs without any significant improvement in the collection of heavy metals. Therefore, the BACT recommendation remains for an electrostatic precipitator at 0.02 lb/MBtu.

FDER - Question 55

Question. BACT analysis for nitrogen oxides should evaluate the use of boilers with inherently better control. Recent applications have proposed uncontrolled NO_x levels as low as 0.27 lb/MBtu for pulverized coal fired boilers.

Response. Non-pulverized coal boilers with inherently better NO_x control would include atmospheric circulating fluidized bed combustion (CFB) and pressurized fluidized bed combustion (PFB). However, both of these technologies are not well demonstrated in sizes above 1,000,000 lb/h steam flow, and would require the use of multiple boilers to achieve the required Unit 2 steam flow of approximately 3,400,000 lb/h. The use of multiple boilers would increase the cost of the project substantially. In addition, while CFB boilers are a maturing technology, PFB boiler technology (with only one operating unit in the U.S.) has not been demonstrated sufficiently to be considered for use on Unit 2.

Foster Wheeler, in particular, discusses pulverized coal fired boiler NO_x emission levels below 0.27 lb/MBtu when using the IFS burner design. However, a recent paper by Foster Wheeler indicates the following NO_x guarantees on new units.[42]

- 0.32 lb/MBtu for two 65 MW boilers.
- 0.27 lb/MBtu for two 150 MW boilers.
- 0.32 lb/MBtu for one 550 MW boiler.

This indicates that site or fuel specific conditions may affect the NO_x emission guarantee, and that 0.32 lb/MBtu is a reasonably current commercially available guaranteed emission value for a Unit 2 sized facility.

FDER - Question 56

Question. Your BACT for NO_x selects improved combustion controls. Provide actual performance and outage incidents to support the negative attributes of SNCR. Provide test performance information on boilers equipped with combustion control. Also, include manufacturer's published papers and emission performance assumptions.

Response. The response to Question 36 references a listing of relevant manufacturer's published papers for boiler combustion control of NO_x emissions.

Negative performance attributes of SNCR include ammonia slip emissions, difficulty of SNCR to work well as load varies, fly ash contamination, increased carbon monoxide emissions (urea based SNCR only), increased nitrous oxide emissions, potential for an ammonia chloride plume, and potential for equipment fouling by ammonia bicarbonate. Additional negative attributes of SNCR include safety consideration for ammonia handling and storage (ammonia based SNCR only) and scale up of the technology for use at a facility the size of Unit 2. Previous and subsequent responses have addressed ammonia slip emissions (Questions 43 and 48), load varying operation difficulty (Question 41), fly ash contamination (Question 44), ammonia chloride plume (Question 47), ammonia bicarbonate fouling (Questions 38 and 60), and scale up considerations (Question 45).

As discussed in the BACT analysis, use of a SNCR system will result in increased carbon monoxide emissions. Testing at the Argus plant in California indicates a 55 percent increase in CO emissions with the use of the SNCR system. However, baseline CO emissions from this plant were very low.[43] The SNCR system manufacturer has estimated that CO emissions from Unit 2 could increase by as much as 20 percent.

Ammonia is a hazardous material. Accordingly, this material for an ammonia based SNCR system must be handled and stored with extreme care. German and California regulators are increasingly worried about the safety implications of storage and use of anhydrous ammonia.[44] [45]

An additional concern has surfaced with respect to the use of SNCR systems. Testing indicates that the use of SNCR systems significantly increases the emission of nitrous oxide (N_2O). Increases of between 4 and 25 percent were observed using ammonia and urea based SNCR systems.[46] Nitrous oxide is a long-lived greenhouse gas with 250 times the warming potential of carbon dioxide molecules.[47]

FDER - Question 57

Question. For particulate control provide actual data to demonstrate the superiority of ESP versus fabric filters in limiting PM10.

Response. As discussed in the BACT analysis, approximately 92 percent of particulate emissions from a fabric filter will consist of PM10. Alternatively, only 67 percent of particulate emissions from a precipitator consist of PM10.[48] It is likely that the EPA based these factors from AP-42 on actual operating data.

Particulate emissions from properly maintained and operated fabric filters will be predominately of particles less than 10 microns due to the filtering mechanism. The primary filtering mechanism in a fabric filter is the steady state dust cake that forms on the bags. This dust cake consists of densely packed fly ash particles. As this dust cake forms, small fissures occur providing a gas path for particulate emissions. The size and torturous path of these fissures prevents all but the smallest particles (PM10) from passing through the filter cake. Larger particles cannot pass through these fissures.[49] Alternatively, precipitators will collect a fraction of all particle sizes. Although PM10 particles will be disproportionately represented due to easier reentrainment, the relative portion of larger particles results in lower PM10 emissions from an electrostatic precipitator.

FDER - Question 58

Question. Provide data on the actual time to obtain the necessary dust cake for optimum filtering.

Response. The heart of the fabric filter technology is the bag itself. The bag acts principally as a matrix on which the filter cake is formed, and as such, the bag itself does not act as the primary filtering medium. The initial efficiency of a new filter bag is relatively low--on the order of 75 to 90 percent. As particulate accumulates on a filter bag, the pressure drop increases across the bag. At a preset time or pressure drop, the bag is cleaned by reverse gas flow. For a new bag, a small amount of particulate remains on the bag after cleaning. During subsequent cleaning cycles this residual dust layer increases in thickness (increasing filtering efficiency to in excess of 99 percent) until a steady state condition occurs. Subsequent cleaning cycles do not remove a significant portion of this residual dust layer. It is this steady state dust cake that acts as the primary filtering medium, achieving maximum particulate removal efficiencies. Therefore, conditioning of the filter bags may be divided into three distinct time regimes: filtration by a clean fabric (least efficient particulate collection), establishment of a residual dust cake (as the filter goes through regular cleaning cycles), and filtration by a steady state dust cake. Establishment of this steady state dust cake generally takes between three and nine months.[50] Reestablishment of the dust cake will be necessary whenever bag replacements occur (approximately every three to four years).

FDER - Question 59

Question. Provide supporting information of expecting an ammonia chloride plume use either manufacturer or user information.

Response. See response to Question 47.

FDER - Question 60

Question. Provide supporting information on expected problems and projected affect on reliability due to "sticky" compounds downstream.

Response. As documented in the response to Question 38, ammonia slip can combine with sulfur trioxide in the flue gas to form ammonia bisulfate. Ammonia bisulfate is a sticky substance which will tend to liquefy and deposit at temperatures downstream of the intermediate baskets of the air heater. As documented previously, Japanese and German experience has been with coals with relatively low sulfur contents.

Fuel for Unit 2 will have a higher sulfur content than previous NO_x reduction experience. Accordingly, Unit 2 is likely to have higher baseline SO_3 emissions. In addition, a requirement for an SNCR system would represent a significant scale up of this technology, probably resulting in additional ammonia slip. Based on higher relative SO_3 and ammonia slip emissions, it is highly likely that ammonia bisulfate deposits will occur. Therefore, although no reliability problems have been reported due to ammonia bisulfate deposits at existing pulverized coal fired boiler SNCR installations, it is quite possible that Unit 2 reliability will be negatively affected by the use of an SNCR system.

FDER - Question 61

Question. Provide documentation on problem of fly ash becoming odorous due to absorbing ammonia and the affect on markets for this material.

Response. See response to Question 44.

FDER - Question 62

Question. Discuss the reliability effect from the use of SNCR. Provide actual data on similar applications. Give source of information.

Response. SNCR systems have only been permanently installed at two pulverized coal fired facilities similar to Unit 2 design (see response to Question 42). No data has been published regarding the reliability effects of SNCR operation at these installations.

A number of the responses to previous questions have detailed potential developmental and operational problems that may occur with use of an SNCR system on Unit 2. Most all of SNCR system's negative attributes could significantly affect unit reliability. Risk management of experimental or developmental techniques must be conservative when dealing with critical applications such as Unit 2. This is especially true when a high potential for indirect reliability impacts exists. Indirect reliability impacts include failure of components and systems outside the primary system due to operational impacts of the primary system. These may include corrosion, fouling, thermal stresses, or increased maintenance. Based on the limited experience record of SNCR systems on pulverized coal fired facilities, and the complete absence of experience in large, load varying pulverized coal facilities, SNCR is currently considered unacceptable for C. H. Stanton Unit 2 from a reliability standpoint.

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TABLE 1 – COAL RESERVE BASE BY SULFUR CONTENT(1) (MILLION TONS)

State	< 1.0%		1.1 - 3.0%		>3.0%		Total[2]	
E. Kentucky	6,558	64%	3,322	33%	299	3%	10,179	100%
Virginia	2,088	64%	1,163	36%	14	<1%	3,265	100%
W. Kentucky	0	0%	564	6%	9,244	94%	9,808	100%
Illinois	1,095	2%	7,341	14%	42,969	84%	51,405	100%
Total	9,741	13%	12,390	17%	52,526	70%	74,657	100%

(1) For Coalbeds >28" to a Maximum Depth of 1,000 Feet

(2) Total is Less than that of Total Reserve Base Since There are Reserves with an Unknown Sulfur Content

Source: Adapted from the Reserve Base of U.S. Coals in Sulfur Content, Part I; The Eastern States

Figure 1 COAL SHIPMENTS

BY SULFUR CONTENT (LBS02/MMBTU)

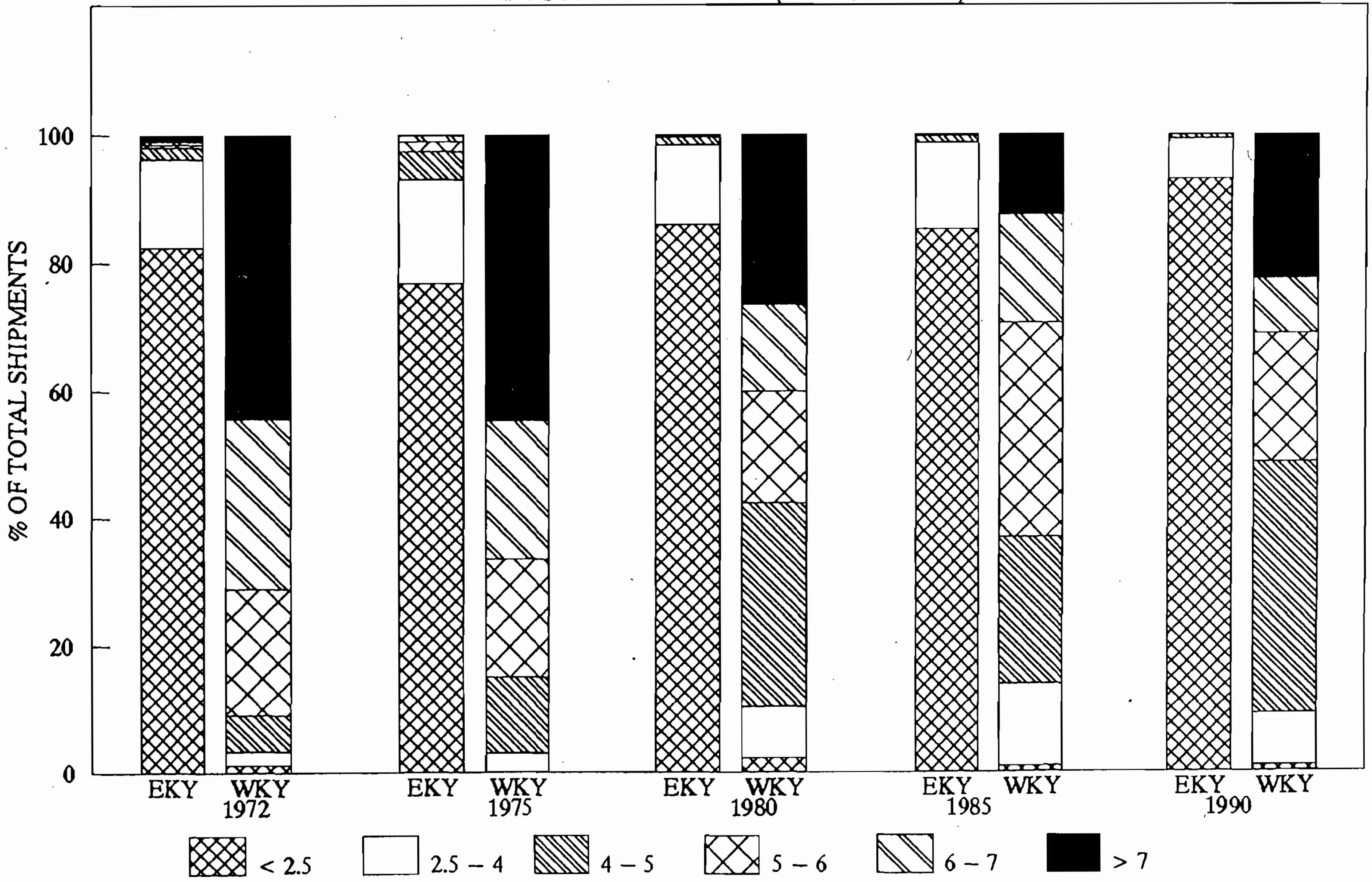

FIGURE 2 – YEARS OF REMAINING RESERVES

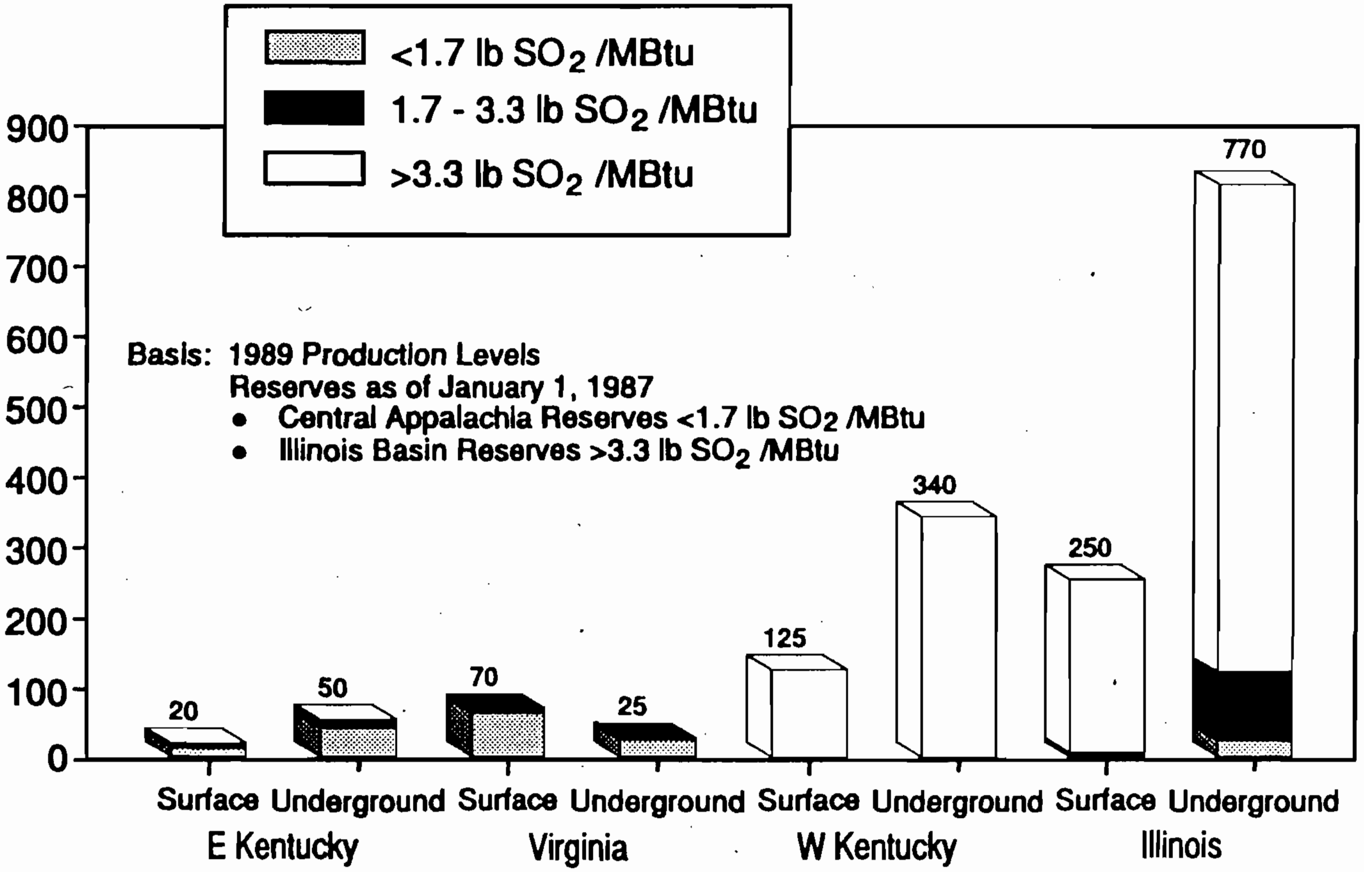

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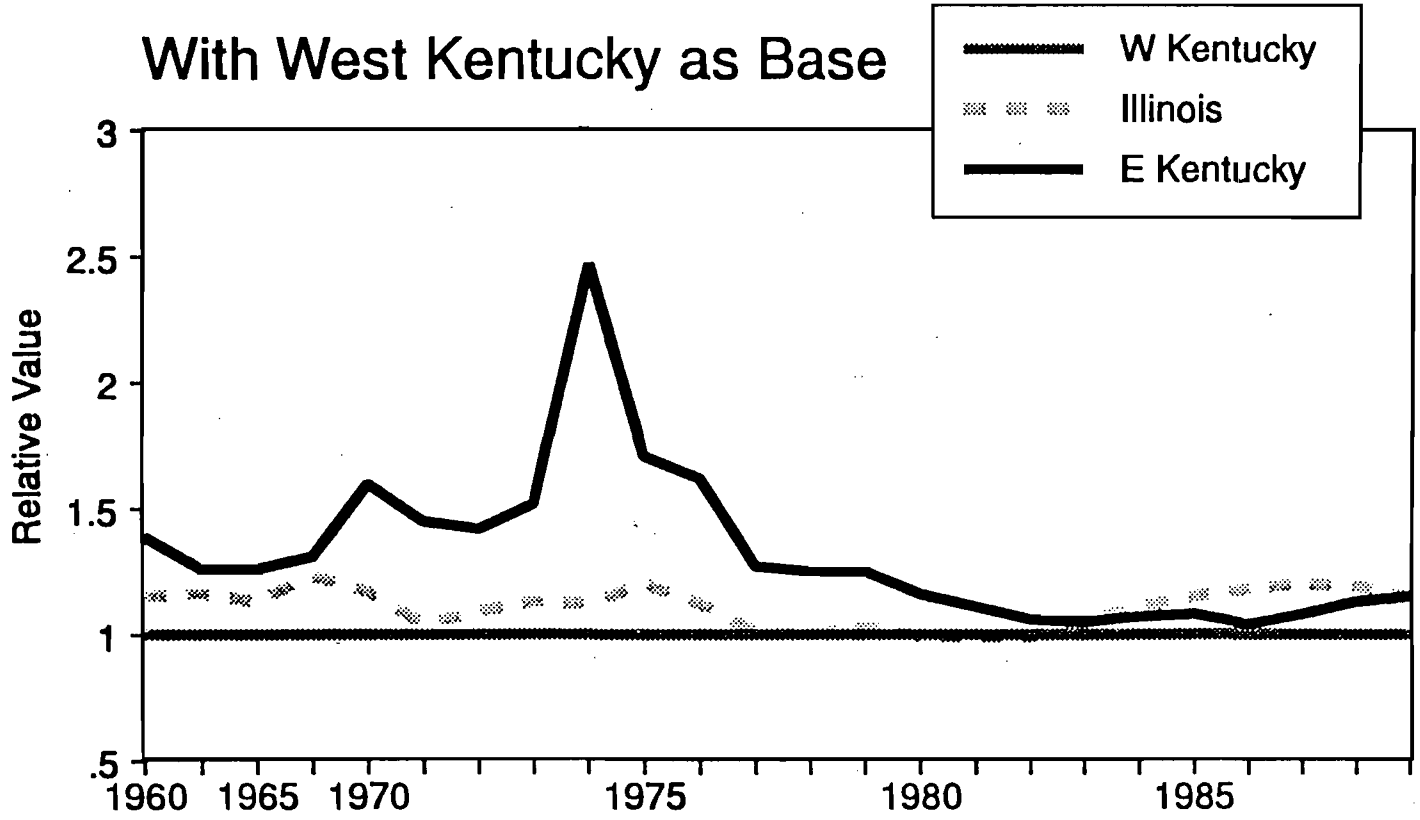
FIGURE 3 – RELATIVE COST OF COAL



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FDER - Question 54

<u>Question</u>. BACT analysis for particulates/heavy metals should evaluate the use of higher efficiency electrostatic precipitators. Recent permitting evaluations have limited particulate emissions to 0.018 lb/MBtu for pulverized coal fired boilers.

<u>Response</u>. The BACT analysis evaluated the use of either fabric filters or electrostatic precipitators to meet an particulate emission limit of 0.02 lb/MBtu as compared to an optimized fabric filter designed to limit emissions to 0.012 lb/MBtu. The electrostatic precipitator manufacturer for C. H. Stanton Unit 2 will only guarantee the precipitator for an outlet emission of 0.02 lb/MBtu. However, fabric filters are capable of limiting particulate emissions to 0.018 lb/MBtu.

The fabric filter manufacturer will raise the price of equipment nominally to cover the risk of not achieving the specified emission limit. In addition, maintenance costs would increase slightly to reflect a nominally shortened bag life. Assuming a two percent increase in capital cost and a five percent increase in maintenance cost, the 1997 total levelized annual cost for a 0.018 lb/MBtu fabric filter is $8.9 million. This represents an incremental particulate removal cost of $6,700 per ton. This cost is excessive by BACT standards. In addition, this expense occurs without any significant improvement in the collection of heavy metals. Therefore, the BACT recommendation remains for an electrostatic precipitator at 0.02 lb/MBtu.

FDER - Question 55

Question. BACT analysis for nitrogen oxides should evaluate the use of boilers with inherently better control. Recent applications have proposed uncontrolled NO_x levels as low as 0.27 lb/MBtu for pulverized coal fired boilers.

Response. Non-pulverized coal boilers with inherently better NO_x control would include atmospheric circulating fluidized bed combustion (CFB) and pressurized fluidized bed combustion (PFB). However, both of these technologies are not well demonstrated in sizes above 1,000,000 lb/h steam flow, and would require the use of multiple boilers to achieve the required Unit 2 steam flow of approximately 3,400,000 lb/h. The use of multiple boilers would increase the cost of the project substantially. In addition, while CFB boilers are a maturing technology, PFB boiler technology (with only one operating unit in the U.S.) has not been demonstrated sufficiently to be considered for use on Unit 2.

Foster Wheeler, in particular, discusses pulverized coal fired boiler NO_x emission levels below 0.27 lb/MBtu when using the IFS burner design. However, a recent paper by Foster Wheeler indicates the following NO_x guarantees on new units.[42]

- 0.32 lb/MBtu for two 65 MW boilers.
- 0.27 lb/MBtu for two 150 MW boilers.
- 0.32 lb/MBtu for one 550 MW boiler.

This indicates that site or fuel specific conditions may affect the NO_x emission guarantee, and that 0.32 lb/MBtu is a reasonably current commercially available guaranteed emission value for a Unit 2 sized facility.

FDER - Question 56

Question. Your BACT for NO_x selects improved combustion controls. Provide actual performance and outage incidents to support the negative attributes of SNCR. Provide test performance information on boilers equipped with combustion control. Also, include manufacturer's published papers and emission performance assumptions.

Response. The response to Question 36 references a listing of relevant manufacturer's published papers for boiler combustion control of NO_x emissions.

Negative performance attributes of SNCR include ammonia slip emissions, difficulty of SNCR to work well as load varies, fly ash contamination, increased carbon monoxide emissions (urea based SNCR only), increased nitrous oxide emissions, potential for an ammonia chloride plume, and potential for equipment fouling by ammonia bicarbonate. Additional negative attributes of SNCR include safety consideration for ammonia handling and storage (ammonia based SNCR only) and scale up of the technology for use at a facility the size of Unit 2. Previous and subsequent responses have addressed ammonia slip emissions (Questions 43 and 48), load varying operation difficulty (Question 41), fly ash contamination (Question 44), ammonia chloride plume (Question 47), ammonia bicarbonate fouling (Questions 38 and 60), and scale up considerations (Question 45).

As discussed in the BACT analysis, use of a SNCR system will result in increased carbon monoxide emissions. Testing at the Argus plant in California indicates a 55 percent increase in CO emissions with the use of the SNCR system. However, baseline CO emissions from this plant were very low.[43] The SNCR system manufacturer has estimated that CO emissions from Unit 2 could increase by as much as 20 percent.

Ammonia is a hazardous material. Accordingly, this material for an ammonia based SNCR system must be handled and stored with extreme care. German and California regulators are increasingly worried about the safety implications of storage and use of anhydrous ammonia.[44] [45]

An additional concern has surfaced with respect to the use of SNCR systems. Testing indicates that the use of SNCR systems significantly increases the emission of nitrous oxide (N_2O). Increases of between 4 and 25 percent were observed using ammonia and urea based SNCR systems.[46] Nitrous oxide is a long-lived greenhouse gas with 250 times the warming potential of carbon dioxide molecules.[47]

FDER - Question 57

Question. For particulate control provide actual data to demonstrate the superiority of ESP versus fabric filters in limiting PM10.

Response. As discussed in the BACT analysis, approximately 92 percent of particulate emissions from a fabric filter will consist of PM10. Alternatively, only 67 percent of particulate emissions from a precipitator consist of PM10.[48] It is likely that the EPA based these factors from AP-42 on actual operating data.

Particulate emissions from properly maintained and operated fabric filters will be predominately of particles less than 10 microns due to the filtering mechanism. The primary filtering mechanism in a fabric filter is the steady state dust cake that forms on the bags. This dust cake consists of densely packed fly ash particles. As this dust cake forms, small fissures occur providing a gas path for particulate emissions. The size and torturous path of these fissures prevents all but the smallest particles (PM10) from passing through the filter cake. Larger particles cannot pass through these fissures.[49] Alternatively, precipitators will collect a fraction of all particle sizes. Although PM10 particles will be disproportionately represented due to easier reentrainment, the relative portion of larger particles results in lower PM10 emissions from an electrostatic precipitator.

FDER - Question 58

Question. Provide data on the actual time to obtain the necessary dust cake for optimum filtering.

Response. The heart of the fabric filter technology is the bag itself. The bag acts principally as a matrix on which the filter cake is formed, and as such, the bag itself does not act as the primary filtering medium. The initial efficiency of a new filter bag is relatively low--on the order of 75 to 90 percent. As particulate accumulates on a filter bag, the pressure drop increases across the bag. At a preset time or pressure drop, the bag is cleaned by reverse gas flow. For a new bag, a small amount of particulate remains on the bag after cleaning. During subsequent cleaning cycles this residual dust layer increases in thickness (increasing filtering efficiency to in excess of 99 percent) until a steady state condition occurs. Subsequent cleaning cycles do not remove a significant portion of this residual dust layer. It is this steady state dust cake that acts as the primary filtering medium, achieving maximum particulate removal efficiencies. Therefore, conditioning of the filter bags may be divided into three distinct time regimes: filtration by a clean fabric (least efficient particulate collection), establishment of a residual dust cake (as the filter goes through regular cleaning cycles), and filtration by a steady state dust cake. Establishment of this steady state dust cake generally takes between three and nine months.[50] Reestablishment of the dust cake will be necessary whenever bag replacements occur (approximately every three to four years).

FDER - Question 59

Question. Provide supporting information of expecting an ammonia chloride plume use either manufacturer or user information.

Response. See response to Question 47.

FDER - Question 60

Question. Provide supporting information on expected problems and projected affect on reliability due to "sticky" compounds downstream.

Response. As documented in the response to Question 38, ammonia slip can combine with sulfur trioxide in the flue gas to form ammonia bisulfate. Ammonia bisulfate is a sticky substance which will tend to liquefy and deposit at temperatures downstream of the intermediate baskets of the air heater. As documented previously, Japanese and German experience has been with coals with relatively low sulfur contents.

Fuel for Unit 2 will have a higher sulfur content than previous NO_x reduction experience. Accordingly, Unit 2 is likely to have higher baseline SO_3 emissions. In addition, a requirement for an SNCR system would represent a significant scale up of this technology, probably resulting in additional ammonia slip. Based on higher relative SO_3 and ammonia slip emissions, it is highly likely that ammonia bisulfate deposits will occur. Therefore, although no reliability problems have been reported due to ammonia bisulfate deposits at existing pulverized coal fired boiler SNCR installations, it is quite possible that Unit 2 reliability will be negatively affected by the use of an SNCR system.

FDER - Question 61

Question. Provide documentation on problem of fly ash becoming odorous due to absorbing ammonia and the affect on markets for this material.

Response. See response to Question 44.

FDER - Question 62

Question. Discuss the reliability effect from the use of SNCR. Provide actual data on similar applications. Give source of information.

Response. SNCR systems have only been permanently installed at two pulverized coal fired facilities similar to Unit 2 design (see response to Question 42). No data has been published regarding the reliability effects of SNCR operation at these installations.

A number of the responses to previous questions have detailed potential developmental and operational problems that may occur with use of an SNCR system on Unit 2. Most all of SNCR system's negative attributes could significantly affect unit reliability. Risk management of experimental or developmental techniques must be conservative when dealing with critical applications such as Unit 2. This is especially true when a high potential for indirect reliability impacts exists. Indirect reliability impacts include failure of components and systems outside the primary system due to operational impacts of the primary system. These may include corrosion, fouling, thermal stresses, or increased maintenance. Based on the limited experience record of SNCR systems on pulverized coal fired facilities, and the complete absence of experience in large, load varying pulverized coal facilities, SNCR is currently considered unacceptable for C. H. Stanton Unit 2 from a reliability standpoint.

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STANTON ENERGY CENTER UNIT 2
ORLANDO UTILITIES COMMISSION

Presentation to

EPA AND FLORIDA DER

June 7, 1991

BLACK & VEATCH
PROGRESS BY DESIGN

OUC200A

Table 5.6-1
Steam Generator Emission Rates for Units 1 and 2

Pollutant	Unit 1	Unit 2
Sulfur Dioxide, lb/MBtu		
Long-Term Emission Rate	1.14	0.32
24-Hour Emission Rate	1.14	0.67
3-Hour Emission Rate	1.14	0.85
Nitrogen Oxides, lb/MBtu	0.60	0.32
Particulate Matter, lb/MBtu		
TSP	0.03	0.02
PM_{10}	–	0.02
Carbon Monoxide		
lb/MBtu	–	0.15
lb/Ton Coal[a]	1.00	–

[a] Emission Estimate was Based on Recommended Emission Factor from EPA's Document AP-42, Applicable at the Time of the Original SCA Submittal

OUC STANTON
UNIT 2

SCRUBBER PERFORMANCE

WET LIMESTONE SCRUBBER

- Additive System
- Scrubbing System
  - 2 Active Modules
  - 1 Spare Module
- Solids Disposal System

METHOD OF ANALYSIS

Monte Carlo Computer Simulation

- 166 Components
- 88 Logic Gates
- Process Chemistry Simulation
- Process Control Simulation

VERIFICATION OF METHOD

- Experience
- Site Calibration

VERIFICATION OF METHOD

Experience

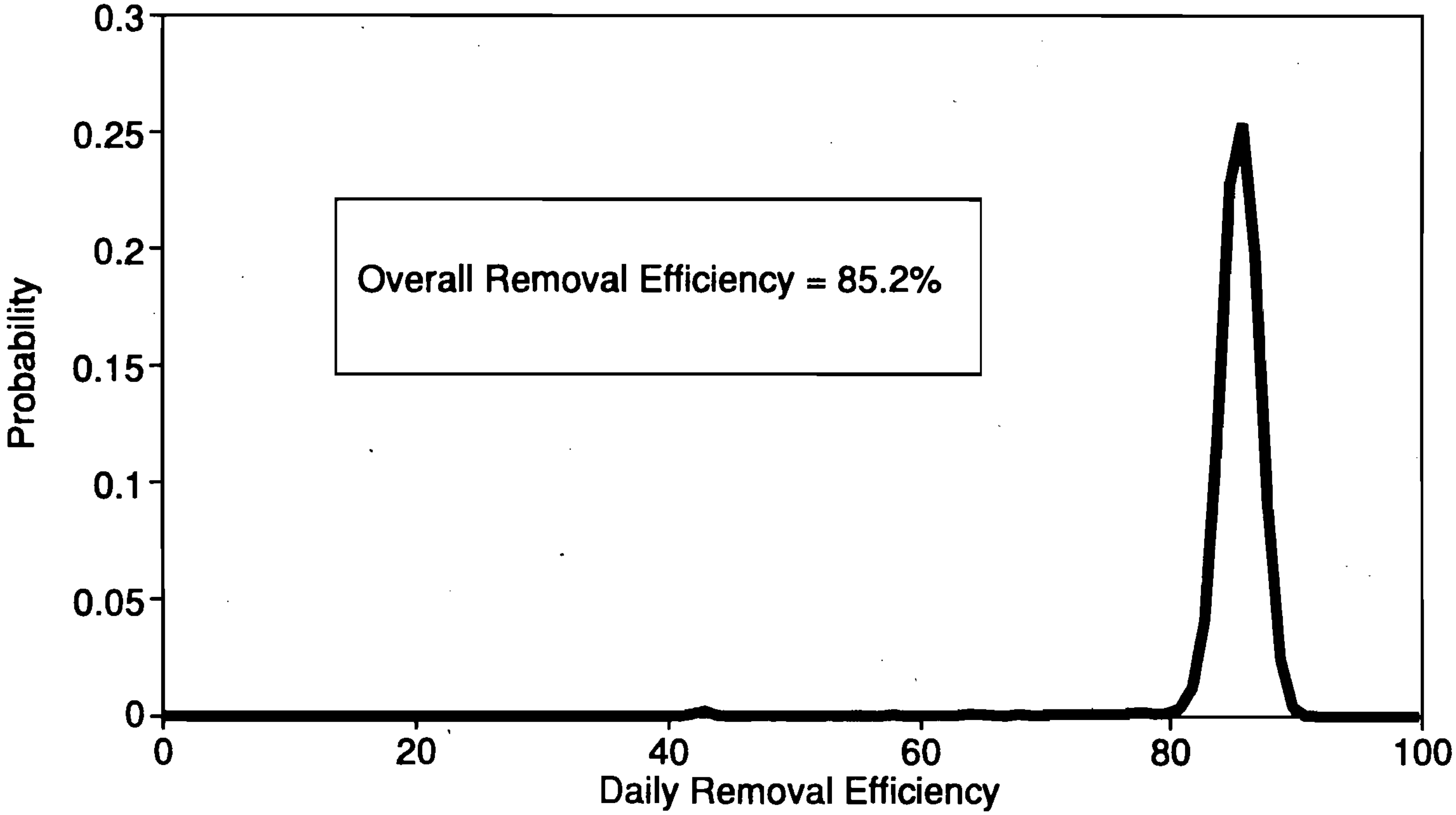
- APS Four Corners – 1979
- Seven Units – 1980-1991
- Success Rate: 100%

Site Calibration

- Stanton Unit 1 Performance
  - – Control
  - – Availability
- As Operating

SITE CALIBRATION

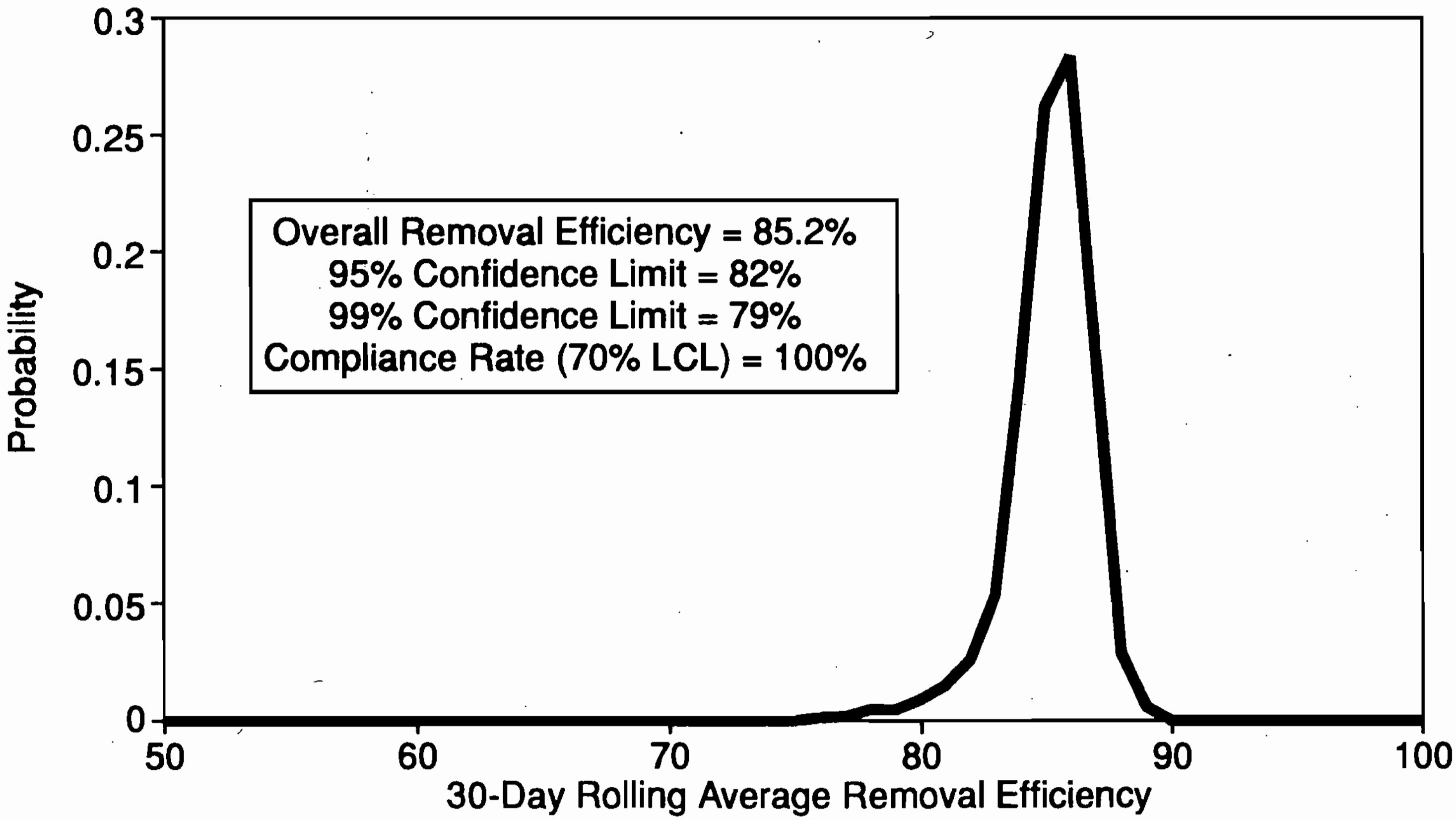
Stanton Unit 1 Scrubber Performance



Overall Removal Efficiency = 85.2%

SITE CALIBRATION

Stanton Unit 1 Scrubber Performance



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STANTON UNIT 1 SCRUBBER PERFORMANCE

Removal Efficiency
Variability Analysis

- Control
- Reliability

STANTON UNIT 1 SCRUBBER PERFORMANCE

Removal Efficiency Variability Analysis

Reliability Profile

- Average Equivalent Available ≃ 99.3%
  (Typical Design = 96 - 98%)
- No Derate Necessary (Margin Control)

STANTON UNIT 1 SCRUBBER PERFORMANCE

Removal Efficiency Variability Analysis

Control Profile

- System Jitter
  - Fuel Variability
  - Load Variability
  - Slurry Grind Variability

- Module Jitter
  - Additive Feed Control
  - M.E. Wash Cycles
  - Temperature Variation

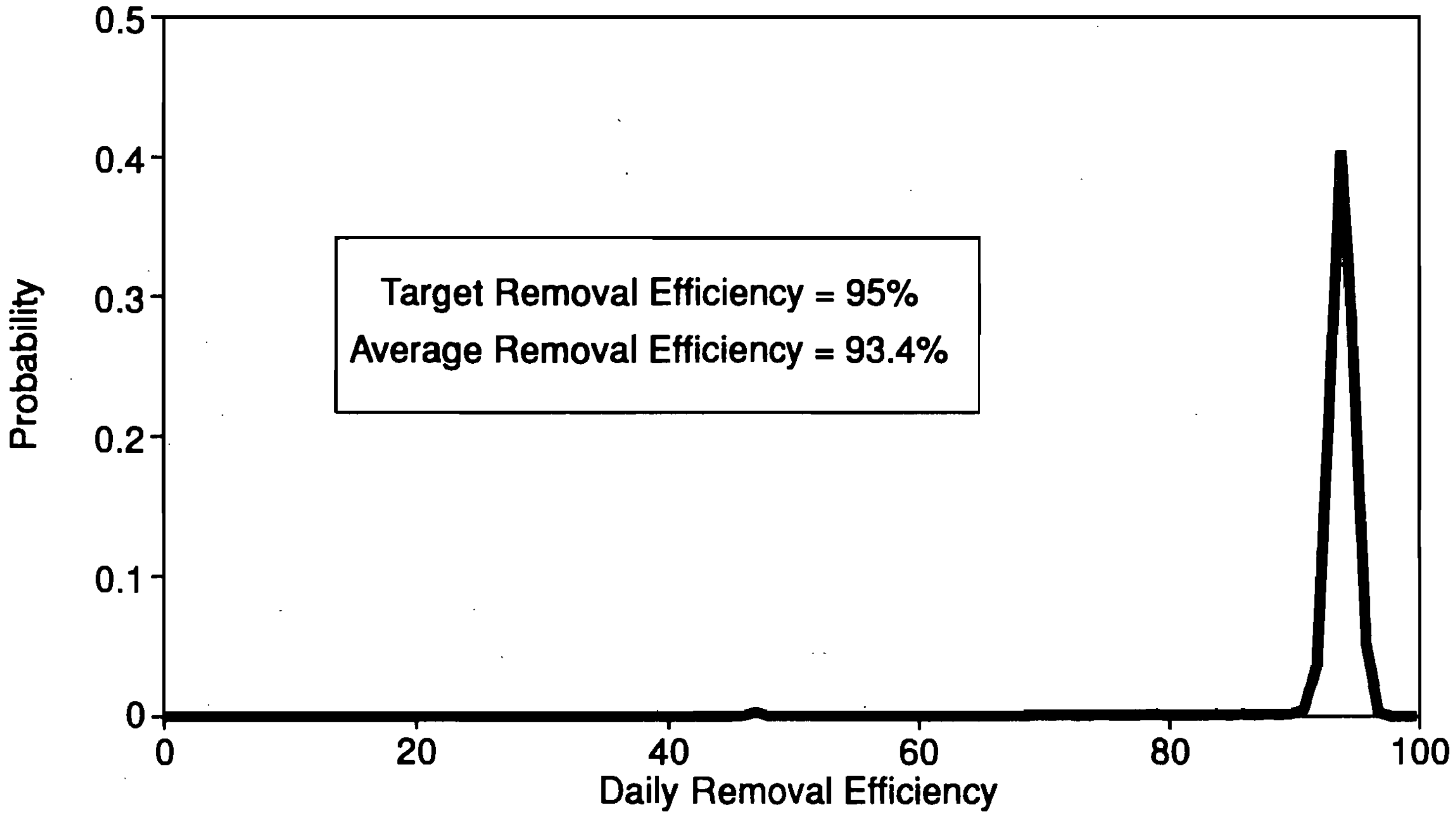
- Short Term Drift
  - pH Measurement
  - Density Control

- Long Cycle Drift
  - Flow Imbalance
  - Make-Up Water Chemistry (Zero Discharge)

STANTON UNIT 2 SCRUBBER MODEL

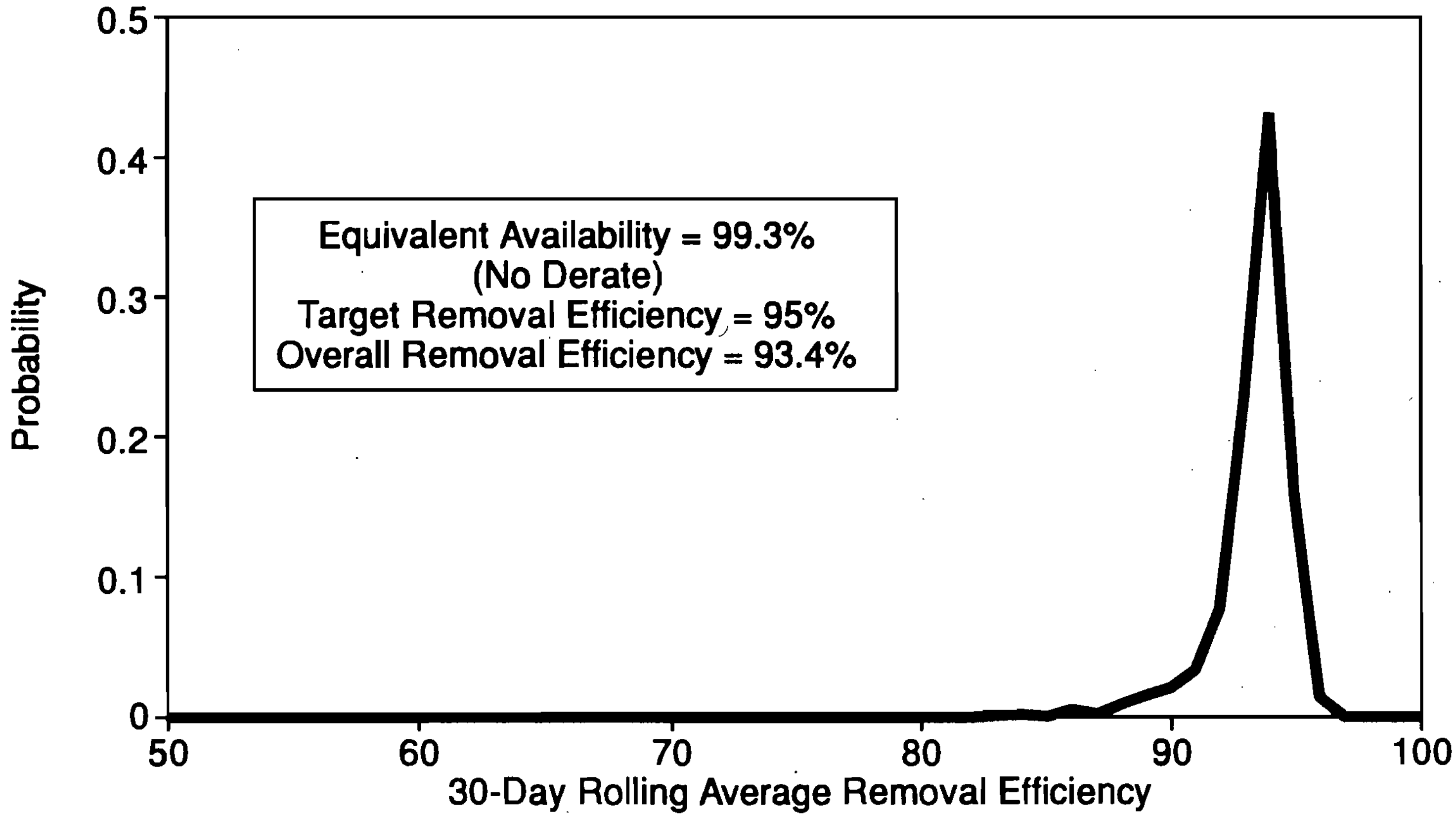
- Unit 1 Basis
- 95% Target Removal Efficiency
  (Highest Guaranteed Removal Rate)

STANTON UNIT 2 SCRUBBER MODEL



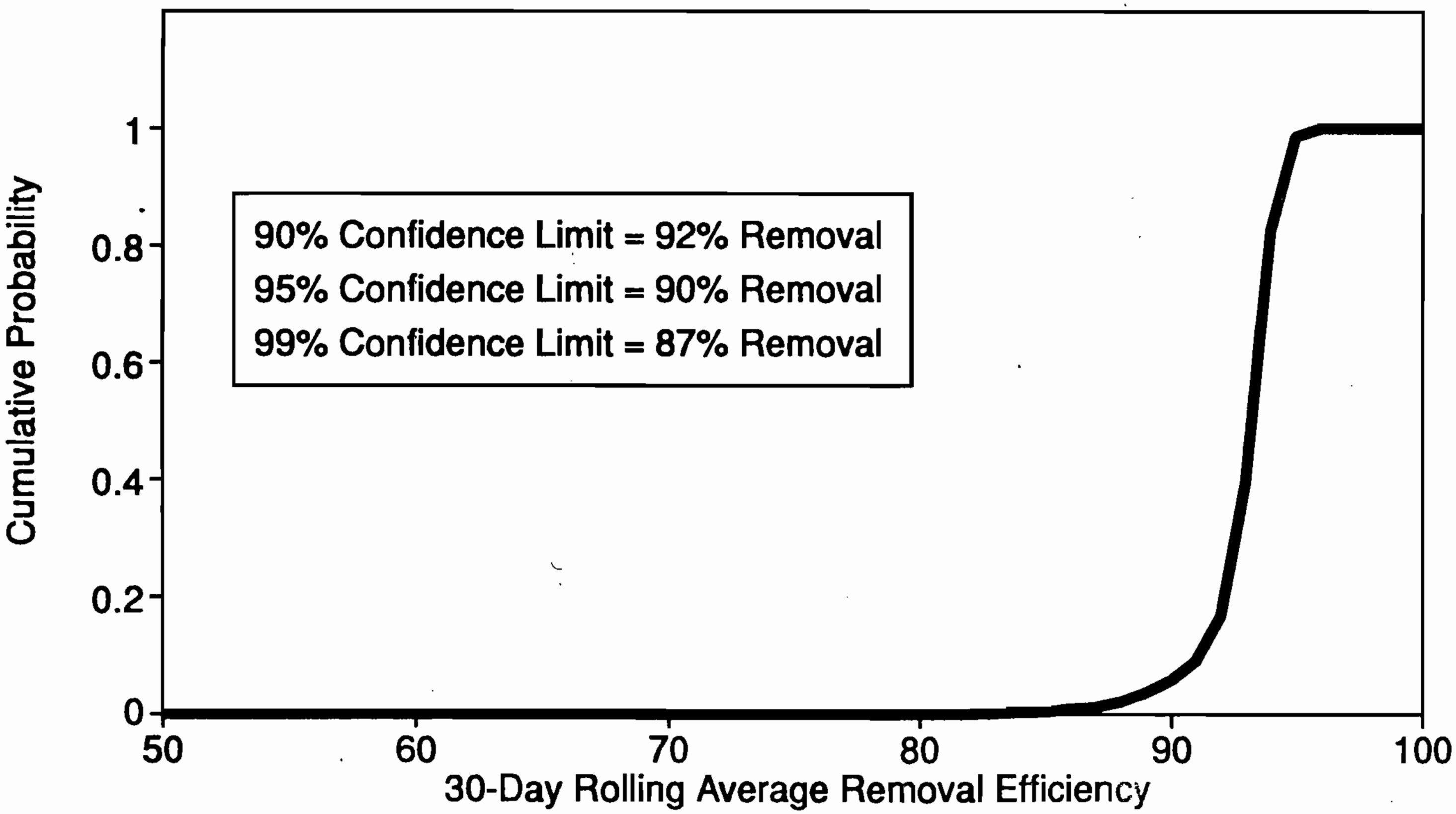
Target Removal Efficiency = 95%
Average Removal Efficiency = 93.4%

STANTON UNIT 2 SCRUBBER MODEL



Equivalent Availability = 99.3%
(No Derate)
Target Removal Efficiency = 95%
Overall Removal Efficiency = 93.4%

STANTON UNIT 2 SCRUBBER MODEL


90% Confidence Limit = 92% Removal
95% Confidence Limit = 90% Removal
99% Confidence Limit = 87% Removal

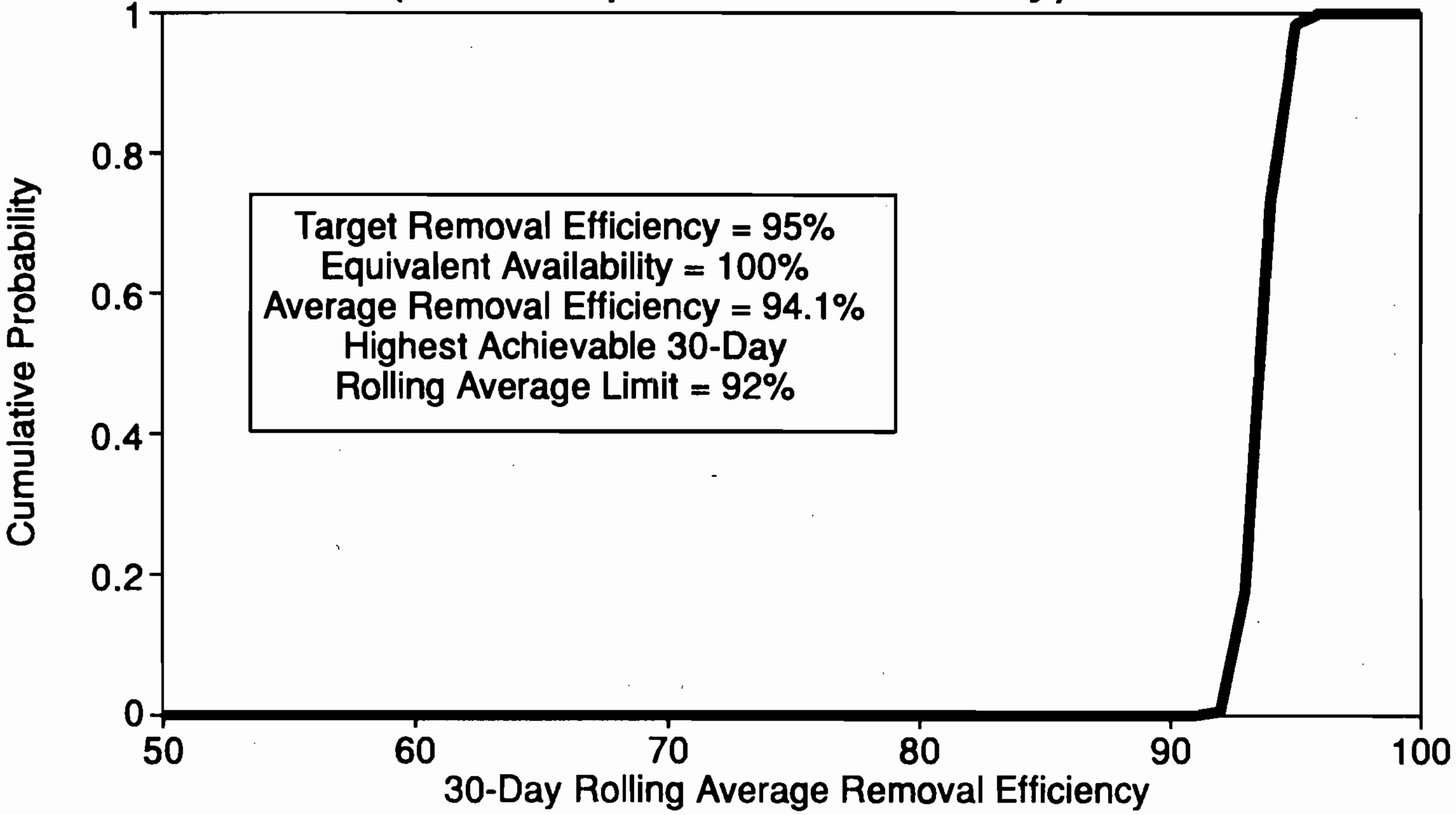
STANTON UNIT 2 SCRUBBER MODEL

30-Day Rolling Average Improvement Options:

- Raise Target Removal Efficiency
  - Already at Maximum Guarantee
- Improve Control
  - Already Best Available Control for Zero Discharge Environment
- Derate on Outage

STANTON UNIT 2 SCRUBBER MODEL

Derate on Outage Sensitivity Analysis: (100% Equivalent Availability)

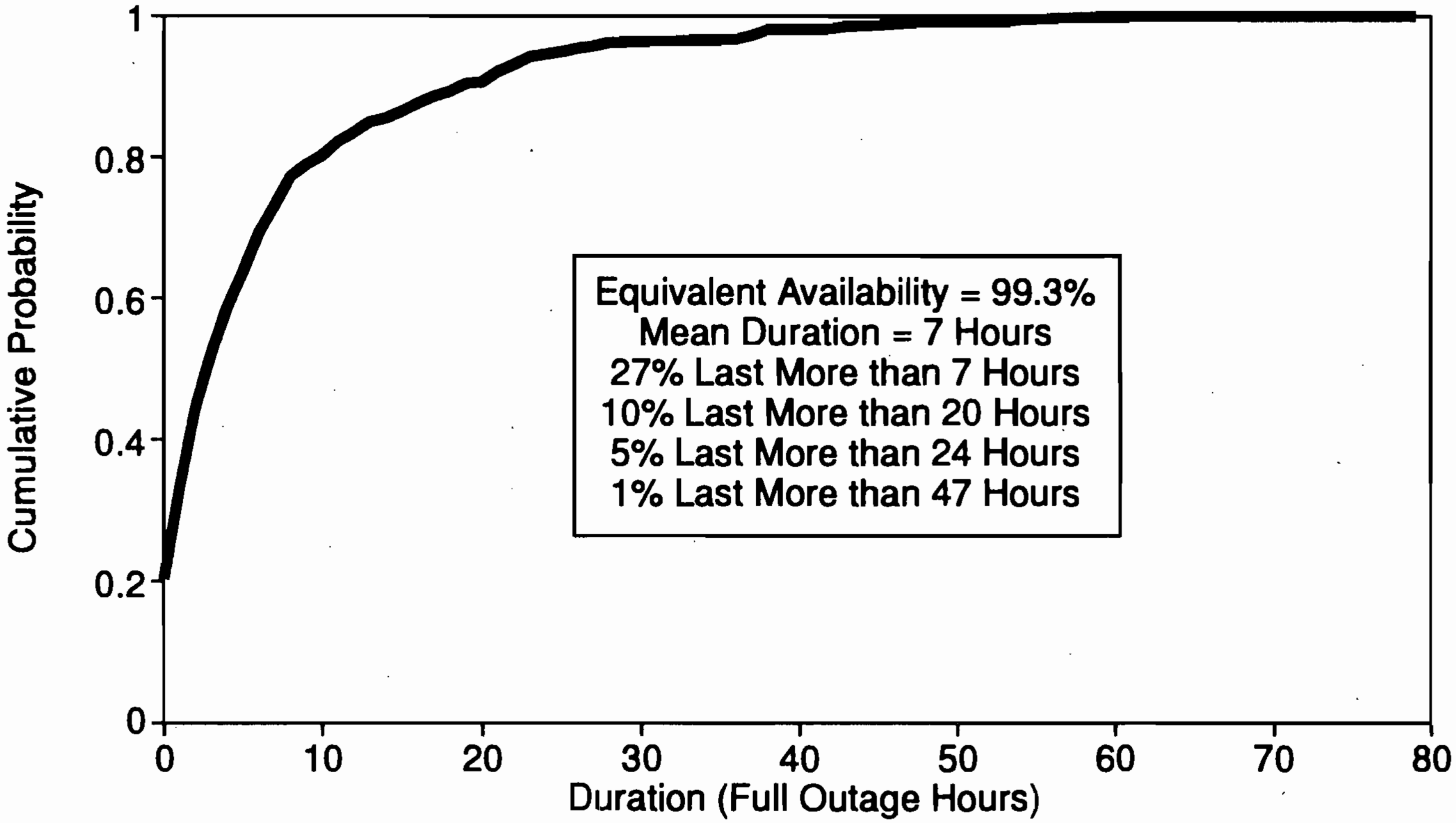


Target Removal Efficiency = 95%
Equivalent Availability = 100%
Average Removal Efficiency = 94.1%
Highest Achievable 30-Day
Rolling Average Limit = 92%

How Can a .007 Decrease in Scrubber Equivalent Availability Change 100% Compliance at 92% into 90% Compliance at 92%?

SCRUBBER RELIABILITY PROFILE

Stanton Unit 2 Scrubber Outage Profile

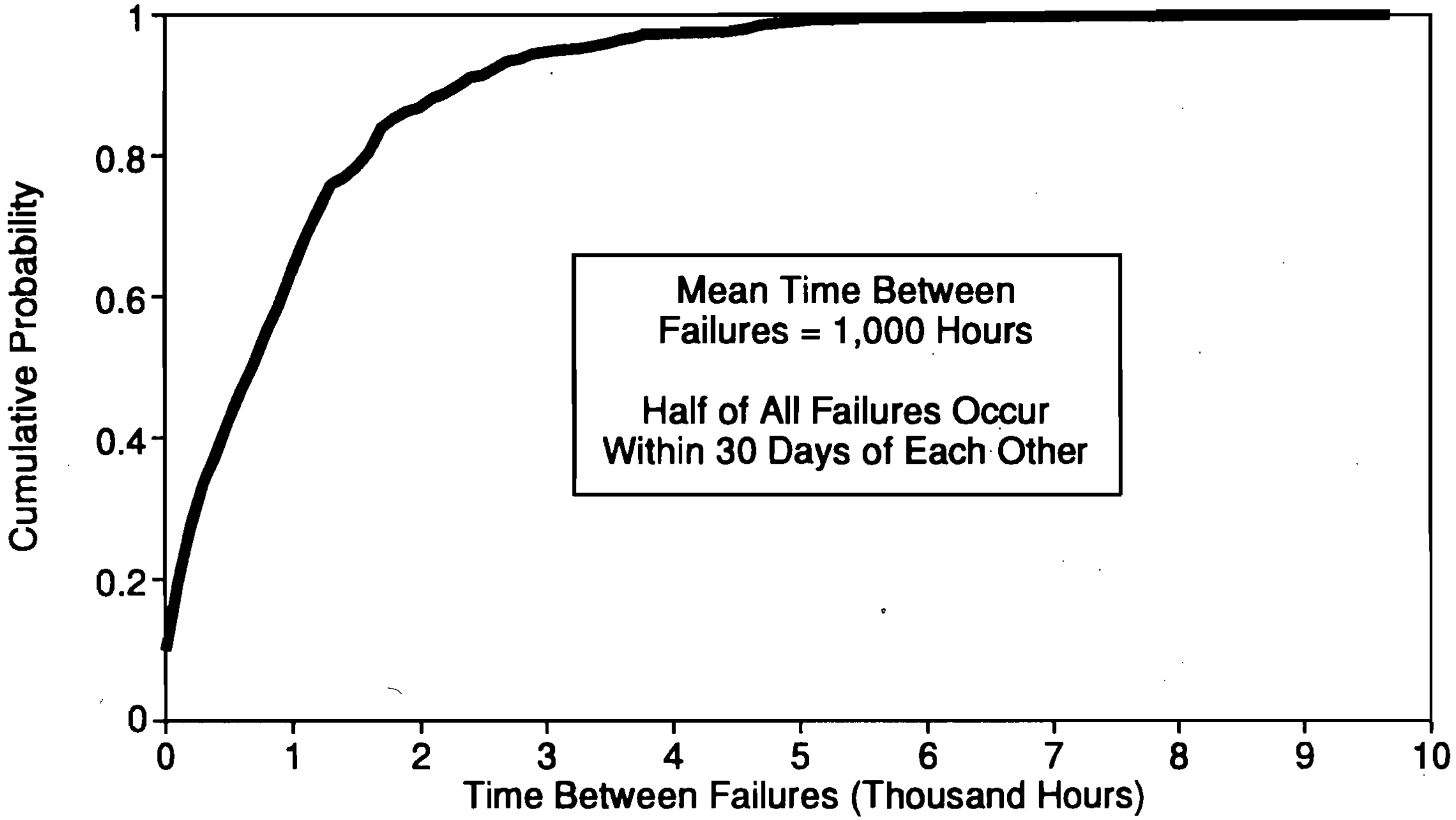


Equivalent Availability = 99.3%
Mean Duration = 7 Hours
27% Last More than 7 Hours
10% Last More than 20 Hours
5% Last More than 24 Hours
1% Last More than 47 Hours

OUC217

SCRUBBER RELIABILITY PROFILE

Stanton Unit 2 Scrubber Time to Failure



Mean Time Between Failures = 1,000 Hours

Half of All Failures Occur Within 30 Days of Each Other

30-DAY REMOVAL EFFICIENCY

Outage Impacts

92% 30-Day Rolling Average Limit

(Note: Each Outage Impacts 30 Averages,
About 9% of the Operating Year)

Outage Duration	30-Day Average Impact
7 Hours	- 0.9%
8 Hours	- 1.0%
20 Hours	- 2.5%
24 Hours	- 3.1%
47 Hours	- 6.0%

UNAVOIDABLE AVAILABILITY LOSSES

- Startup
  - 6 Hours
  - Avoid Mist Eliminator Pluggage
- Derate Delay
  - Recognition
  - Reaction
  - Ramp (2 MW/min)
- Unavoidable Reduction in 30-Day Rolling Average

STANTON UNIT 2 SCRUBBER
PROPOSED BACT OPERATION

Strategy

- 95% Target SO_2 Removal
- Derate When Possible to Control Outage Impacts

Expected Net Results

30-Day Rolling Average	Frequency	Cumulative Frequency
91%	.01	.01
92%	.07	.08
93%	.32	.40
94%	.43	.83
95%	.16	.99
96%	.01	1.00

- Average Removal Efficiency = 93.7%
- 99% Confidence Limit = 92%

SUMMARY

- Target Removal Efficiency = 95%
- Average Removal Efficiency = 93.7%
- Derate When Possible to Control Outage Impacts
- Best Achievable Limit (99% Confidence) on 30-Day Rolling Average = 92%

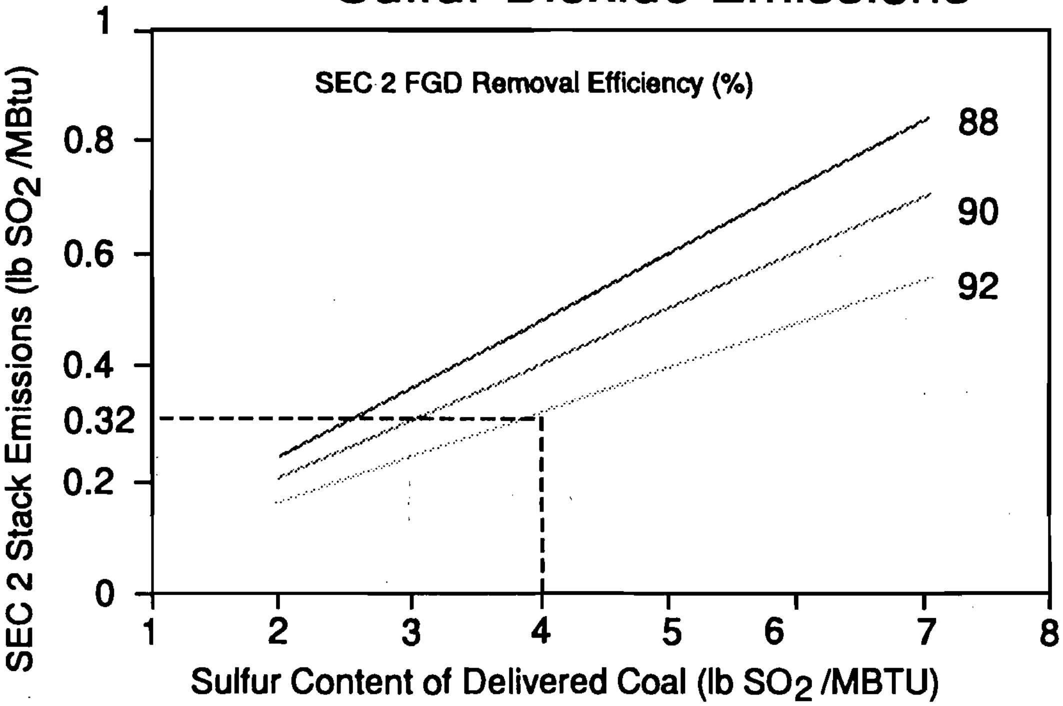
COST AND QUALITY
OF
COAL FOR SEC 2

TOPICS TO BE COVERED

- Coal Reserves and Quality
- Future Demand for Low Sulfur Coals
- Cost of Coal by Sulfur Content
- Future Cost of Coal
- Cost of Reducing SO_2 Emissions by Fuel Selection

STANTON ENERGY CENTER 2

Sulfur Dioxide Emissions



AVAILABILITY OF COAL

State	Energy Content of Coal Reserves as a Percentage of US Total (1)	SO_2 Emission Potential (2)
Montana	18	1.2
Illinois	17	4.7
West Virginia	12	2.6
Wyoming	12	0.9
Pennsylvania	9	2.8
W. Kentucky	4	5.7
E. Kentucky	3	1.7
Ohio	6	5.6
Colorado	4	0.8
Indiana	3	4.6
Alaska	3	0.8
North Dakota	2	2.3
Other States	7	
Total US	100	

(1) Adapted from Data in Coal and Water Resources for Coal Conversion in Illinois

(2) Based Upon 1989 Shipments to Electric Utilities

COAL RESERVE BASE OF THE U.S. BY SULFUR CONTENT(1) (MILLION TONS)

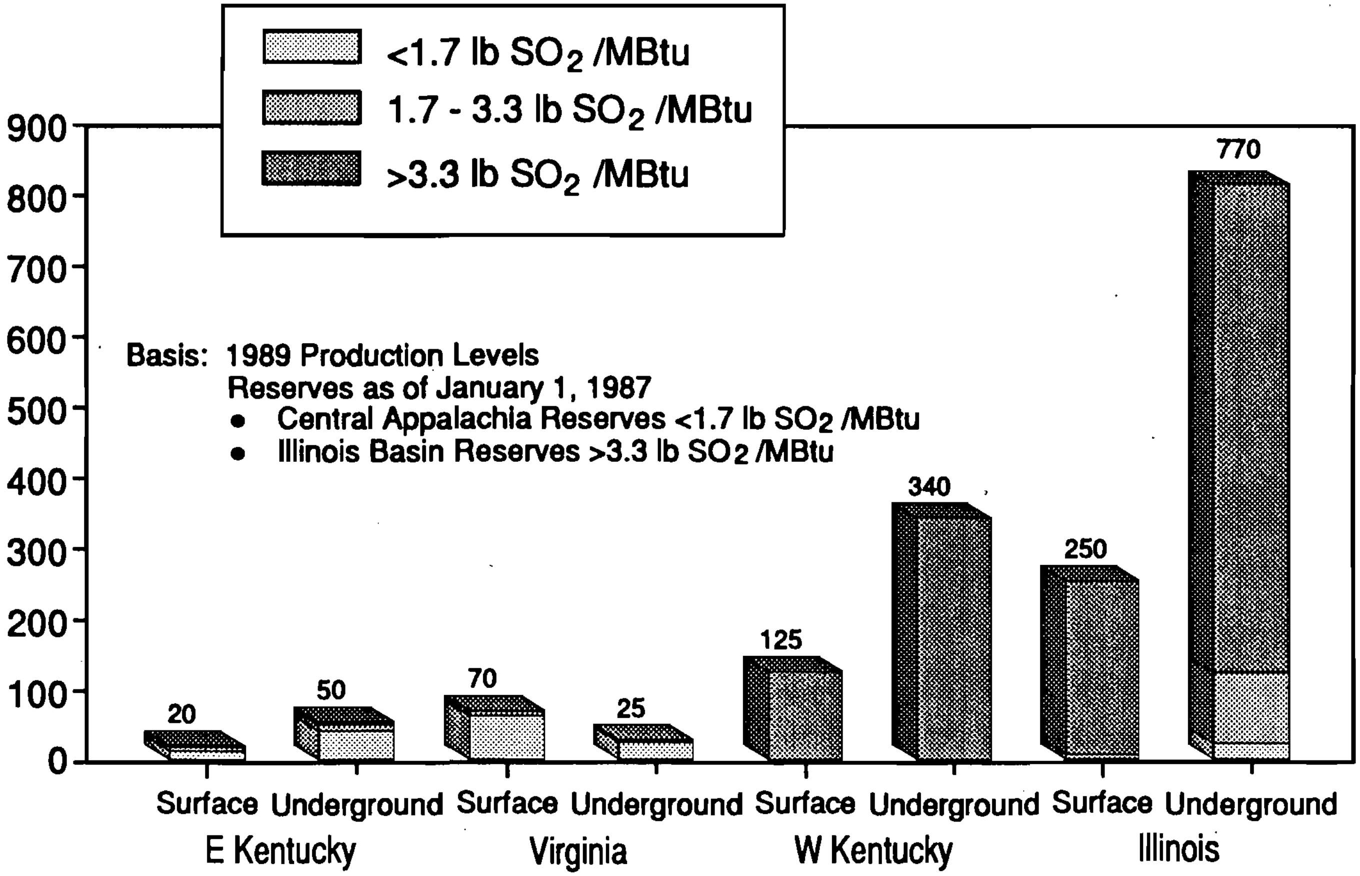
State	< 1.0%		1.1 - 3.0%		>3.0%		Total(2)	
E. Kentucky	6,558	64%	3,322	33%	299	3%	10,179	100%
Virginia	2,088	64%	1,163	36%	14	<1%	3,265	100%
W. Kentucky	0	0%	564	6%	9,244	94%	9,808	100%
Illinois	1,095	2%	7,341	14%	42,969	84%	51,405	100%
Total	9,741	13%	12,390	17%	52,526	70%	74,657	100%

(1) For Coalbeds >28" to a Maximum Depth of 1,000 Feet

(2) Total is Less than that of Total Reserve Base Since There are Reserves with an Unknown Sulfur Content

Source: Adapted from the Reserve Base of U.S. Coals in Sulfur Content, Part I; The Eastern States

YEARS OF REMAINING RESERVES

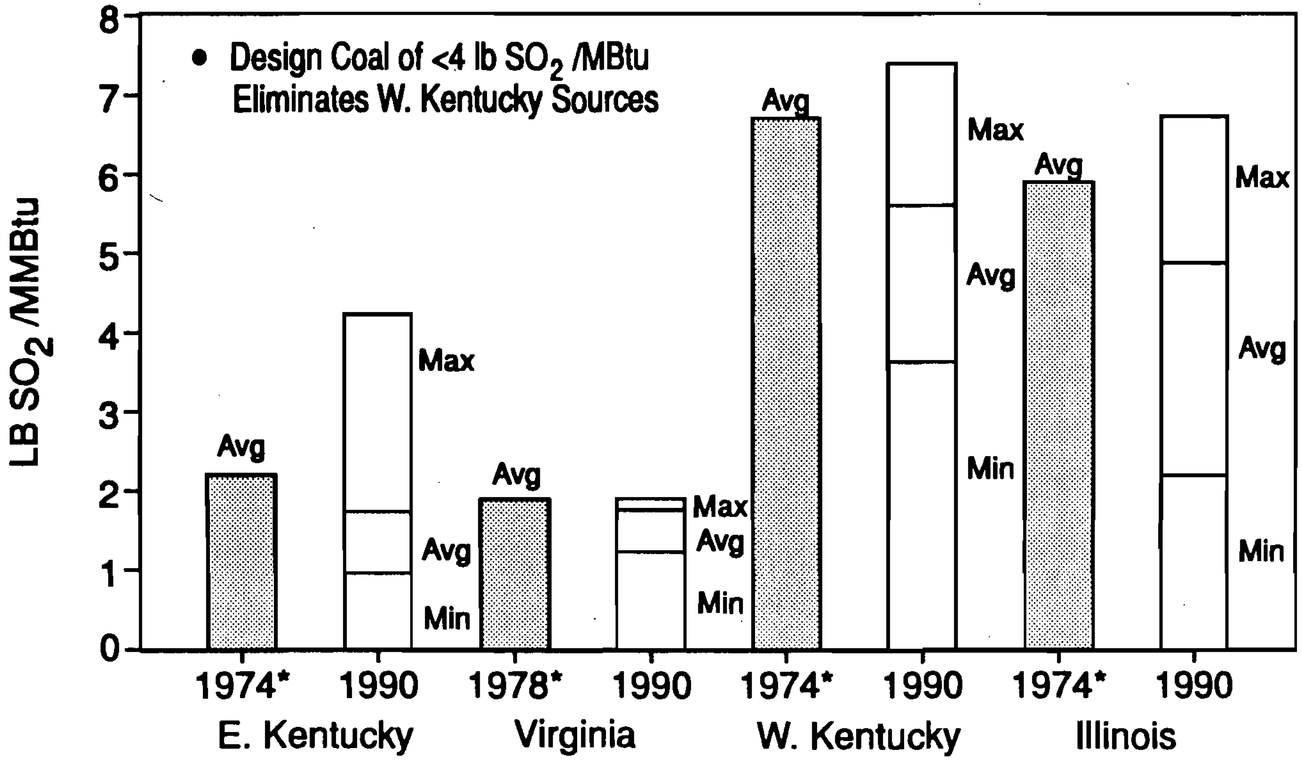


Basis: 1989 Production Levels
Reserves as of January 1, 1987

- Central Appalachia Reserves <1.7 lb SO_2 /MBtu
- Illinois Basin Reserves >3.3 lb SO_2 /MBtu

(SLIDE AS PRESENTED)

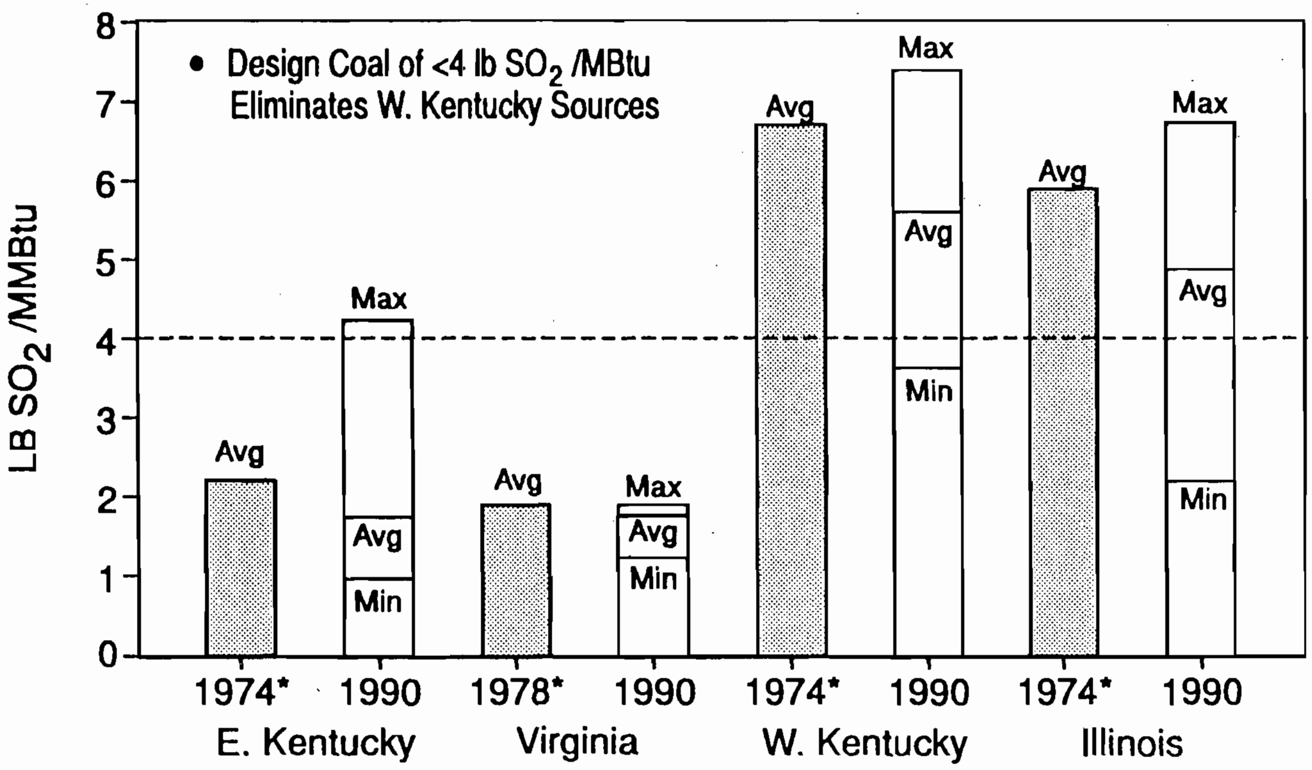
SULFUR DIOXIDE EMISSION POTENTIAL OF COAL SHIPMENTS



OUC243

(CORRECTED SLIDE)

SULFUR DIOXIDE EMISSION POTENTIAL OF COAL SHIPMENTS



Note: Maximum and Minimum Values are Based Upon County Averages
* Year When Average Emission Potential was the Highest for the Period (1972-1990)

OUC243

FUTURE DEMAND FOR CENTRAL APPALACHIAN COAL

- Significant Fuel Switching Resulting from New Clean Air Act
- Need for Super Compliance coal
- European Requirements Will Increase
  - Removal of Domestic Coal Subsidies
  - Lower SO_2 Emissions Requirements

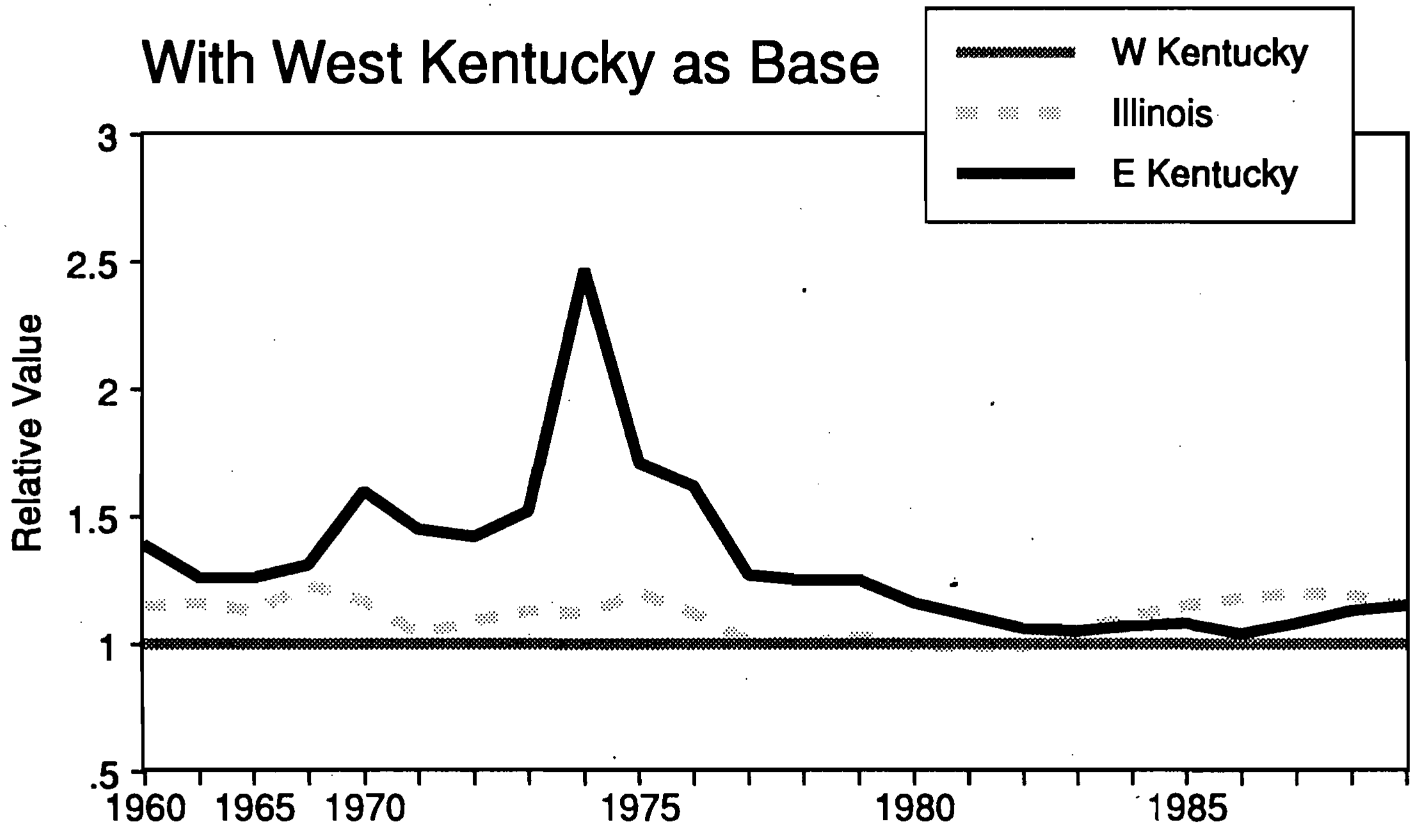
USE OF MIDDLINGS PRODUCT

Selling Rather than Disposing of Middlings

- Allows Coal Supplier to
  - Significantly Reduce Capital and Operating Costs
  - Reduce the Sulfur Content of Clean Coal (<1.2 lb SO_2 /MBtu)
  - Allows Fuel Switching to Take Place at Lower Cost to Ratepayer
  - Decreases the Amount of Refuse and Its Cost of Disposal
  - Reduces Environmental Impact at the Mine Site
  - Decreases Waste of a Valuable Resource
- Price of Middlings/Raw Coal Blend
  - Significantly Less than Clean Coal

RELATIVE COST OF COAL

With West Kentucky as Base



CURRENT MARKET CONDITIONS

- High Productivity of Capital and Labor
- Excess Production Capacity
- Spot Prices Near Cash Cost of Production
- High-Grading Reserves
- Only the Best Quality Coals Get the Business
- Idled Mines (Particularly in the Illinois Basin)
- About 50% of Coal Production is Rebid Each Year

FORECAST FOR LOW SULFUR COAL

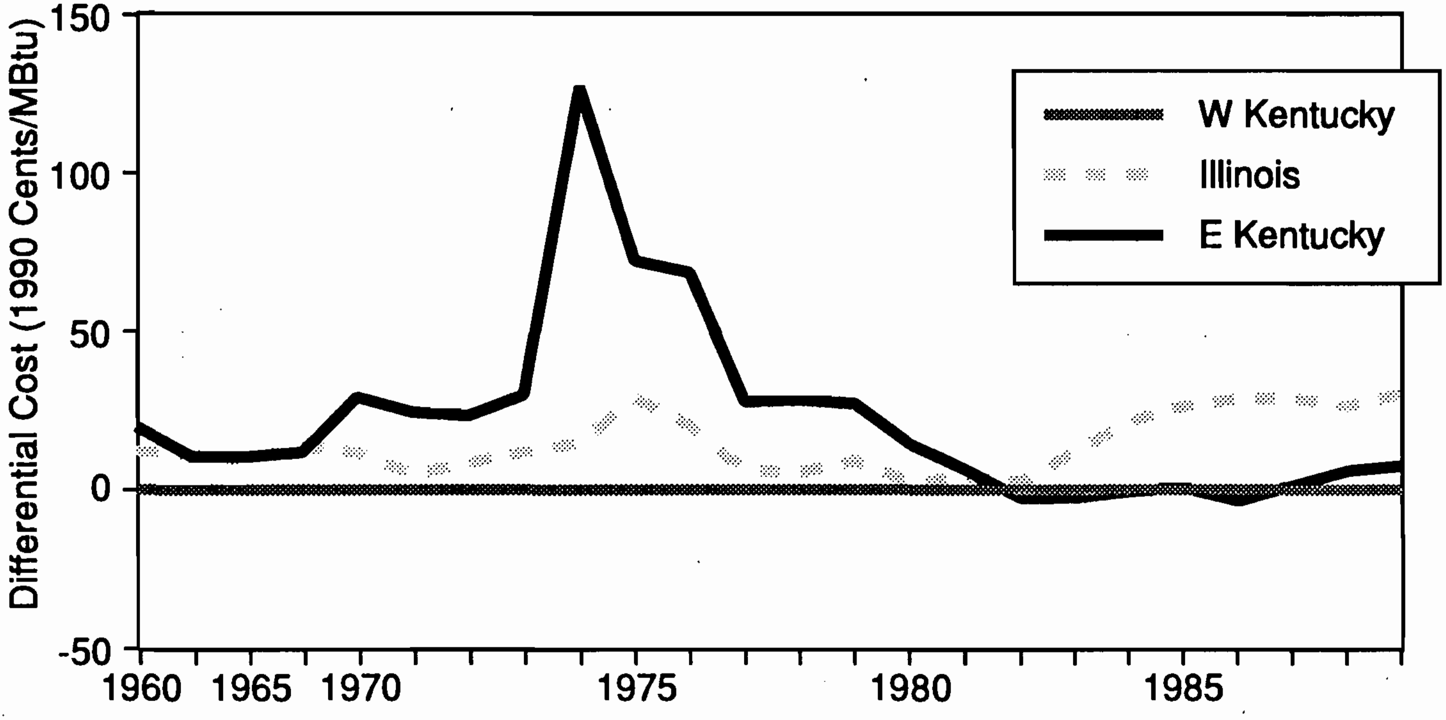
- Many Low Sulfur E. Kentucky Mines Developed in the 1970's Were Predicated on a 20 Year Reserve Block
- Capacity Factors of Coal Fired Units in 2000 is Significantly Greater than During '85-'87 Base Years
- New Clean Air Act Enhances Demand for Low Sulfur Coal
- Cost of New mines and Preparation Plants Requires a Significant Increase in market Price
- Cost of New Mines and Preparation Plants Will Add $10-20 (High Demand Scenario) to Cash Costs
- Labor Costs Will Increase as Productivity Declines and Real Wages Increase

FORECAST FOR MID-SULFUR COAL

- Moderate Price Increases
- Can Reactivate Idled Mines in W. Kentucky and Illinois with a Minimal Increase in Market Price
- Less Market Price Volatility
- Significantly Longer Reserve Life for Mid-Sulfur Coals
- Availability of Mid-Sulfur Middlings Product from Central Appalachia to Increase

DIFFERENTIAL COST OF COAL

With West Kentucky as Base



Based on 1972 - 1982 Average Heating Value

OUC262

SUMMARY

Use of Design Coal at SEC 2 Allows...

- Use of Coal Preparation Plant Middlings
- Use of Significantly Lower Cost Coals
- Coal and Transportation Sourcing Flexibility
- Fuel and Transportation Contracting Flexibility
- Lower Cost Generation for OUC Customers
- Provides Access to Significantly Greater and Lower Cost Reserve Base
- Removes the Need to Compete with CAAA Fuel Switchers in East Kentucky

NO_x BACT DETERMINATION

NO_X EMISSION REDUCTION SYSTEMS

- Selective Catalytic Reduction
- Selective Non-Catalytic Reduction

SELECTIVE CATALYTIC REDUCTION

- Widely Used in Japan and Germany
- Limited U.S. Fuel Experience
  - – Catalyst Poisioning
  - – Sulfur/Ash
- Increased SO_3 Emissions
- Increased PM_{10} Emissions
- Lost Fly Ash Sales
- Ammonia Storage Considerations
- High Capital and Operating Cost
- EPA/EPRI Developing Technology Transfer

SELECTIVE NON-CATALYTIC REDUCTION (SNCR) SYSTEMS

- Thermal DeNO$_x$
  - Exxon Patent
  - Ammonia Based System
- NO$_x$ OUT
  - EPRI Patent
  - Marketed by Nalco/Fuel Tech
  - Urea Based System

SNCR SYSTEM CAPABILITIES

- Optimum Injection Temperature 1,600 to 1,900 F
- 70 to 80% NO_X Reduction with Adequate Reaction Time
- Ammonia Slip of Between 10 and 50 ppm
- Injection Below 1,600 F Results in Excessive Ammonia Slip
- Injection Above 1,900 F Results in Higher NO_X Emissions

SNCR SYSTEM PULVERIZED COAL EXPERIENCE

- German 75 MW Boiler
  - Urea Based System
  - Low Sulfur Lignite
  - Baseloaded Utility Unit
  - 30% NO_X Reduction

- California 75 MW Boiler
  - Urea Based System
  - Low Sulfur Bituminous Coal
  - Baseloaded Industrial Boiler
  - 30% NO_X Reduction

SNCR SYSTEM COMPLICATIONS ON PULVERIZED COAL BOILERS

- Fuel Quality
  - Sulfur - Ammonia Bisulfate Fouling
  - Chlorine - Ammonia Chloride Plume
- Large Size Complicates Additive Injection
- Boiler Heat Transfer Reduces Effectiveness
- Poor Load Following Capabilities

SNCR SYSTEMS

Environmental Considerations

- Ammonia Slip Emissions
- Carbon Monoxide Emissions
- Nitrous Oxide Emissions
- PM_{10} Emissions
- Lost Fly Ash Sales
- Ammonia Chloride Plume
- Ammonia Storage

SNCR SYSTEMS

Economic Considerations

- Base Incremental Reduction Cost
  - 40% NO_X Reduction = $2,700/Ton
  - 30% NO_X Reduction = $3,100/Ton
- Equivalent Pollutant Value
  - Ammonia Slip = 20 ppm/10 ppm
  - Carbon Monoxide Emission Increase = 10 Percent
  - 40% NO_X Reduction = $3,500/Ton
  - 30% NO_X Reduction = $4,000/Ton
- Costs Do Not Reflect Reliability Impacts

(additional slide)

SNCR SYSTEM ADDITIONAL ECONOMIC IMPACTS

Use of a SNCR System Will Possibly...

- Increase Unit Forced Outage Rate by 5 to 15%
- Decrease OUC Bond Rating 15 to 30 Basis Points

Consideration of These Potential Impacts Will Increase Incremental NO_x Reduction Costs to...

- \$6,300/Ton to \$11,600/Ton for 40% NO_x Reduction
- \$7,700/Ton to \$14,800/Ton for 30% NO_x Reduction

C. H. STANTON UNIT 2

BACT Recommendation

- SNCR Systems Inadequately Demonstrated on Large Pulverized Coal Installations
- SNCR System Use Will Limit Unit Reliability
- SNCR System Environmental Considerations
- SNCR System Economic Considerations
- Combustion Controls Can Meet 0.32 lb/MBtu Limit
- 0.32 lb/MBtu Limit is 47% Lower than Unit 1 Limit of 0.60 lb/MBtu (NSPS)

ATTACHMENT 3

ASTM STANDARD C618-89a

Designation: C 618 – 89a

AMERICAN SOCIETY FOR TESTING AND MATERIALS
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Standard Specification for Fly Ash and Raw or Calcined Natural Pozzolan for use as a Mineral Admixture in Portland Cement Concrete[1]

This standard is issued under the fixed designation C 618; the number immediately following the designation indicates the year of original adoption or, in the case of revision, the year of last revision. A number in parentheses indicates the year of last reapproval. A superscript epsilon (ε) indicates an editorial change since the last revision or reapproval.

This specification has been approved for use by agencies of the Department of Defense. Consult the DoD Index of Specifications and Standards for the specific year of issue which has been adopted by the Department of Defense.

1. Scope

1.1 This specification covers fly ash and raw or calcined natural pozzolan for use as a mineral admixture in concrete where cementitious or pozzolanic action, or both, is desired, or where other properties normally attributed to finely divided mineral admixtures may be desired or where both objectives are to be achieved.

NOTE—Finely divided materials may tend to reduce the entrained air content of concrete. Hence, if a mineral admixture is added to any concrete for which entrainment of air is specified, provision should be made to assure that the specified air content is maintained by air content tests and by use of additional air-entraining admixture or use of an air-entraining admixture in combination with air-entraining hydraulic cement.

1.2 The values stated in inch-pound units are to be regarded as the standard.

2. Referenced Documents

2.1 *ASTM Standards:*
C 260 Specification for Air-Entraining Admixtures for Concrete[2]
C 311 Methods of Sampling and Testing Fly Ash or Natural Pozzolans for Use as a Mineral Admixture in Portland Cement Concrete[2]

3. Terminology

3.1 *Definitions:*

3.1.1 *fly ash*—finely divided residue that results from the combustion of ground or powdered coal.

NOTE—This definition of fly ash does not include, among other things, the residue resulting from: (1) the burning of municipal garbage or any other refuse with coal; or (2) the injection of lime directly into the boiler for sulfur removal; or (3) the burning of industrial or municipal garbage in incinerators commonly known as "incinerator ash."

3.1.2 *pozzolans*—siliceous or siliceous and aluminous materials which in themselves possess little or no cementitious value but will, in finely divided form and in the presence of moisture, chemically react with calcium hydroxide at ordinary temperatures to form compounds possessing cementitious properties.

4. Classification

4.1 *Class N*—Raw or calcined natural pozzolans that comply with the applicable requirements for the class as given herein, such as some diatomaceous earths; opaline cherts and shales; tuffs and volcanic ashes or pumicites, any of which may or may not be processed by calcination; and various materials requiring calcination to induce satisfactory properties, such as some clays and shales.

4.2 *Class F*—Fly ash normally produced from burning anthracite or bituminous coal that meets the applicable requirements for this class as given herein. This class fly ash has pozzolanic properties.

4.3 *Class C*—Fly ash normally produced from lignite or subbituminous coal that meets the applicable requirements for this class as given herein. This class of fly ash, in addition to having pozzolanic properties, also has some cementitious properties. Some Class C fly ashes may contain lime contents higher than 10 %.

5. Chemical Composition

5.1 Fly ash and natural pozzolans shall conform to the requirements as to chemical composition prescribed in Table 1. Supplementary optional chemical requirements are shown in Table 2.

6. Physical Properties

6.1 Fly ash and natural pozzolans shall conform to the physical requirements prescribed in Table 3. Supplementary optional physical requirements are shown in Table 4.

7. Methods of Sampling and Testing

7.1 Sample and test the mineral admixture in accordance with the requirements of Methods C 311.

7.2 Use cement of the type proposed for use in the work and, if available, from the mill proposed as the source of the cement, in all tests requiring the use of hydraulic cement.

8. Storage and Inspection

8.1 The mineral admixture shall be stored in such a manner as to permit easy access for proper inspection and identification of each shipment. Every facility shall be provided the purchaser for careful sampling and inspection, either at the source or at the site of the work as may be specified by the purchaser.

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[1] This specification is under the jurisdiction of ASTM Committee C-9 on Concrete and Concrete Aggregates, and is the direct responsibility of Subcommittee C09.03.10 on Fly Ash, Slag, Mineral Admixtures, and Supplementary Cementitious Materials.

Current edition approved Oct. 27, 1989. Published December 1989. Originally published as C 618 – 68 T to replace C 350 and C 402. Last previous edition C 618 – 87.

[2] *Annual Book of ASTM Standards*, Vol 04.02.

TABLE 1 Chemical Requirements

	Mineral Admixture Class		
	N	F	C
Silicon dioxide (SiO_2) plus aluminum oxide (Al_2O_3) plus iron oxide (Fe_2O_3), min, %	70.0	70.0	50.0
Sulfur trioxide (SO_3), max, %	4.0	5.0	5.0
Moisture content, max, %	3.0	3.0	3.0
Loss on ignition, max, %	10.0	6.0[A]	6.0

[A] The use of Class F pozzolan containing up to 12.0 % loss on ignition may be approved by the user if either acceptable performance records or laboratory test results are made available.

TABLE 1A Supplementary Optional Chemical Requirement

NOTE—This optional requirement applies only when specifically requested.

	Mineral Admixture Class		
	N	F	C
Available alkalies, as Na_2O, max, %[A]	1.5	1.5	1.5

[A] Applicable only when specifically required by the purchaser for mineral admixture to be used in concrete containing reactive aggregate and cement to meet a limitation on content of alkalies.

TABLE 2 Physical Requirements

	Mineral Admixture Class		
	N	F	C
Fineness:			
Amount retained when wet-sieved on 45 μm (No. 325) sieve, max, %[A]	34	34	34
Strength activity index:[B]			
With portland cement, at 7 days, min, percent of control	75[D]	75[D]	75[D]
With portland cement, at 28 days, min, percent of control	75[D]	75[D]	75[D]
With lime, at 7 days min, psi (kPa)	800 (5500)	800 (5500)	. . .
Water requirement, max, percent of control	115	105	105
Soundness:[C]			
Autoclave expansion or contraction, max, %	0.8	0.8	0.8
Uniformity requirements:			
The specific gravity and fineness of individual samples shall not vary from the average established by the ten preceding tests, or by all preceding tests if the number is less than ten, by more than:			
Specific gravity, max variation from average, %	5	5	5
Percent retained on 45-μm (No. 325), max variation, percentage points from average	5	5	5

[A] Care should be taken to avoid the retaining of agglomerations of extremely fine material.

[B] Neither the *strength* activity index with portland cement nor the pozzolanic activity index with lime is to be considered a measure of the compressive strength of concrete containing the mineral admixture. The *strength* activity index with portland cement is determined by an accelerated test, and is intended to evaluate the contribution to be expected from the mineral admixture to the longer strength development of concrete. The weight of mineral admixture specified for the test to determine the *strength* activity index with portland cement is not considered to be the proportion recommended for the concrete to be used in the work. The optimum amount of mineral admixture for any specific project is determined by the required properties of the concrete and other constituents of the concrete and should be established by testing. *Strength* activity index with portland cement is a measure of reactivity with a given cement and may vary as to the source of both the fly ash and the cement.

[C] If the mineral admixture will constitute more than 20 % by weight of the cementitious material in the project mix design, the test specimens for autoclave expansion shall contain that anticipated percentage. Excessive autoclave expansion is highly significant in cases where water to mineral admixture and cement ratios are low, for example, in block or shotcrete mixes.

[D] Meeting the 7 day or 28 day *strength* activity index will indicate specification compliance.

9. Rejection

9.1 The mineral admixture may be rejected if it fails to meet any of the requirements of this specification.

9.2 Packages varying more than 5 % from the stated weight may be rejected. If the average weight of the packages in any shipment, as shown by weighing 50 packages taken at random, is less than that specified, the entire shipment may be rejected.

9.3 Mineral admixture in storage prior to shipment for a period longer than 6 months after testing may be retested and may be rejected if it fails to meet the fineness requirements.

TABLE 2A Supplementary Optional Physical Requirements

NOTE—These optional requirements apply only when specifically requested.

	Mineral Admixture Class		
	N	F	C
Multiple factor, calculated as the product of loss on ignition and fineness, amount retained when wet-sieved on No. 325 (45-μm) sieve, max, % [A]	....	255	....
Increase of drying shrinkage of mortar bars at 28 days, max, % [B]	0.03	0.03	0.03
Uniformity Requirements:			
In addition, when air-entraining concrete is specified, the quantity of air-entraining agent required to produce an air content of 18.0 vol % of mortar shall not vary from the average established by the ten preceding tests or by all preceding tests if less than ten, by more than, %	20	20	20
Reactivity with Cement Alkalies: [C]			
Reduction of mortar expansion at 14 days, min, %	75	....	....
Mortar expansion at 14 days, max, %	0.020	0.020	0.020

[A] Applicable only for Class F mineral admixtures since the loss on ignition limitations predominate for Class C.

[B] Determination of compliance or noncompliance with the requirement relating to increase in drying shrinkage will be made only at the request of the purchaser.

[C] The indicated tests for reactivity with cement alkalies are optional and alternative requirements to be applied only at the purchaser's request. They need not be requested unless the fly ash or pozzolan is to be used with aggregate that is regarded as deleteriously reactive with alkalies in cement. The test for reduction of mortar expansion may be made using any high-alkali cement in accordance with Methods C 311, Section 35.1 if the portland cement to be used in the work is not known, or is not available at the time the mineral admixture is tested. The test for mortar expansion is preferred over the test for reduction of mortar expansion if the portland cement to be used in the work is known and available. The test for mortar expansion should be performed with each of the cements to be used in the work.

10. Packaging and Package Marking

10.1 When the mineral admixture is delivered in packages, the class, name, and brand of the producer, and the weight of the material contained therein shall be plainly marked on each package. Similar information shall be provided in the shipping invoices accompanying the shipment of packaged or bulk mineral admixture.

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