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RECEIVED

MAY 2 2005

PUBLIC SERVICE COMMISSION

May 2, 2005

Judith A. Villines
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Beth O'Donnell
Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602-0615

Re: Application of Kentucky Power Company for Approval of An Amended Compliance Plan for Purposes of Recovering Additional Costs of Pollution Control Facilities and to Amend Its Environmental Cost Recovery Surcharge Tariff
PSC Case No. 2005-00068

Dear Ms. O'Donnell :

Please find enclosed an original and six copies of Kentucky Power Company's Responses to the Commission Staff's Request for Information, Second Set and KIUC's Request for Information, First set.

Upon review of the questions presented in the Requests for Information, the Company believes that it would be beneficial to have an informal conference in order better to explain and answer any remaining questions the Commission staff and Intervenors may have. If the Commission also believes such a conference would be beneficial, we will be glad to assist in scheduling such a conference.

KE057:KE113:12306:1:FRANKFORT

STITES & HARBISON PLLC
ATTORNEYS

If you have any questions, please let me know.

Sincerely,

STITES & HARBISON, PLLC

Judith A. Villines

Judith A. Villines

JAV:las

Enclosures
cc: Michael L. Kurtz (w/enclosures)
Elizabeth E. Blackford (w/enclosures)
Errol K. Wagner(w/o enclosures)
Kevin F. Duffy (w/o enclosures)

RECEIVED
MAY 2 2005
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

KENTUCKY POWER COMPANY'S SECOND	)	
AMENDED ENVIRONMENTAL COMPLIANCE	)	**Case No. 2005-00068**
PLAN AND SECOND REVISED TARIFF	)	

RESPONSES OF KENTUCKY POWER
D/B/A
AMERICAN ELECTRIC POWER

COMMISSION'S SECOND SET OF DATA REQUESTS

VOLUME I

May 2, 2005

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to the Direct Testimony of John M McManus ("McManus Testimony"", Exhibit JMM-1. For each of the 53 projects listed in this exhibit, provide the following information concerning the decisions by the American Electric Power Company ("AEP") Pool Surplus Companies to undertake the projects:

a. A listing of the options or alternative technologies that addressed the environmental problem which were available at the time the project was selected.

b. A description of the evaluation process employed by AEP and the Surplus Company to determine the selected project was the best available technology and the most reasonable alternative to deploy, based on the information available at the time the decision was made. Include copies of any written studies or analyses performed in conjunction with the evaluation. If no written studies or analyses were performed explain in detail why this step was not part of the evaluation process.

c. Copies of any regulatory commission approvals received for the project.

RESPONSE

a. A listing of options and alternative technologies generally available for meeting the NOx control requirements of the Title IV Acid Rain Program and the NOx SIP Call has previously been provided and described in previous written testimony presented before the Kentucky Public Service Commission. Please refer to the technologies described in testimony provided by John M. McManus in KPCO's First Environmental Surcharge Case No. 96-489 (pages 3, 4, 7 and 9 and Exhibit JMM-1); Michael W. Durner in Certificate of Public Convenience and Necessity Case No. 2001-093 (pages 3-4, and MWD Exhibit 1); and John M. McManus in Amended Environmental Surcharge Case No. 2002-000169 (pages 7-12).

The Continuous Emission Monitoring System installations were driven by specific Title IV Acid Rain monitoring requirements which specified the pollutants to be monitored. The systems were designed by AEP and purchased from approved vendors using a competitive bid process.

As described in the testimony provided by John M. McManus in the current case, the alternative to choosing the ESP controls upgrade at Tanners Creek Plant Unit 4 was to increase plant staffing.

b. The NOx reduction equipment evaluation process employed by AEP to determine that the selected projects represented the best choice in technology has been described in detail in previous written testimony presented before the Kentucky Public Service Commission. Please refer to the evaluation process described in testimony provided by John M. McManus in KPCO's First Environmental Surcharge Case No. 96-489, Michael W. Durner in Certificate of Public Convenience and Necessity Case No. 2001-093, and John M. McManus in Amended Environmental Surcharge Case No. 2002-000169.

c. No utility regulatory commission approvals were sought for these projects.

WITNESS: John M McManus

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

THE APPLICATION OF KENTUCKY POWER	)	
COMPANY d/b/a AMERICAN ELECTRIC	)	
POWER TO ASSESS A SURCHARGE UNDER	)	
KRS 278.183 TO RECOVER COSTS OF	)	
COMPLIANCE WITH THE CLEAN AIR ACT	)	
AND THOSE ENVIRONMENTAL REQUIREMENTS	)	
WHICH APPLY TO COAL COMBUSTION	)	
WASTES AND BY-PRODUCTS	)	CASE NO.96-489

DIRECT TESTIMONY

OF

JOHN M. MCMANUS

TESTIMONY OF

JOHN M. McMANUS

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY IN CASE NO. 96-489

Q: Please state your name, position and business address with American Electric Power.

A: My name is John M. McManus. I am the Manager of Environmental Strategy and Planning, Environmental Services Department, American Electric Power Service Corporation, a subsidiary of American Electric Power, Inc., the parent company of Kentucky Power Company d/b/a American Electric Power (AEP or the Company). My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q: Please state your educational background and business experience.

A: I received a Bachelor of Science degree in Environmental Engineering from Rensselaer Polytechnic Institute in 1976. I have been employed with American Electric Power Service Corporation since September, 1977, holding various positions in the Environmental Engineering and Environmental Affairs Departments over this period. My current responsibilities include overseeing the Company's compliance with Title IV of the 1990 Clean Air Act Amendments, the acid rain control program.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to describe the actions taken by the Company and the AEP System to comply with the requirements of the Clean Air Act Amendments of 1990 (the Act) that affect the Company. Witness Wagner describes the methods by which the Company proposes to recover the costs of these actions through the Kentucky Environmental Surcharge.

Q: Please explain generally the goals of Title IV of the Clean Air Act Amendments of 1990.

A: The primary goal of Title IV is to effect, by the year 2000, a reduction in sulfur dioxide ("SO_2") emissions of ten million tons from 1980 emission levels and a reduction in nitrogen oxide ("NOx") emissions of approximately two million tons from 1980 levels for the forty-eight contiguous states and the District of Columbia.

Q: How are the Title IV SO_2 emission reductions to be implemented?

A: The Act provides that Title IV will be implemented in two phases for SO_2 reduction. The first phase began in 1995 and extends through 1999. During Phase I, emission requirements are imposed on 261 specified coal-fired electric utility units in the country. Each of these units has been allocated a certain number of "allowances" by EPA. Each allowance is an authorization to emit one ton of SO_2. Allowances may be bought, sold, traded or banked for future use or later resale. Phase II commences on January 1, 2000 and provides emissions limitations and an allocation scheme for virtually all existing and new fossil-fired electric generating utilities in the country. Phase II caps total utility SO_2 emissions for the country at approximately 8.9 million tons annually.

Q: How are the Title IV NOx emission reductions to be implemented?

A: The NOx reduction requirements are also to be implemented in two phases. Phase I began on January 1, 1996 and applies to tangentially-fired boilers and dry bottom, wall-fired boilers at Phase I units. Those boilers must meet NOx limitations as set out in the Act and EPA rules. EPA must establish NOx emission limits for other boilers for Phase II which are to be effective in the year 2000. EPA has not yet established these limits for Phase II. Under the Phase I NOx rules, utilities are encouraged to achieve NOx reductions at Phase II units prior to the Phase II deadlines. The provision, referred to as "early election", allows Phase II units to demonstrate compliance with the Phase I NOx limitation and not be subject to a possibly more stringent Phase II NOx requirement, in the event EPA tightens the limitation. The Phase I limitation is

0.5 lb. per million BTU for wall-fired, dry bottom boilers. The proposed Phase II limit is 0.45 lb. per million BTU.

Q: Does Title IV contain new emission monitoring requirements?

A: Yes. Section 412 of the Act and its implementing regulations, 40 CFR Part 75, requires power plants to install continuous emissions monitoring systems (CEMS) by January 1, 1995 for better monitoring of SO_2 and NOx emissions.

Q: Are there other requirements of the Act with which the Company must comply?

A: Yes. The Act established a new, national air pollution permitting program, referred to as Title V permits. The Company must obtain Title V permits for its generating units. Title V also established a new air emissions fee system. Sources with a yearly combined total of more than 25 tons of volatile organic compounds, SO_2, NOx and particulate matter are assessed annual per ton emission fees by the states. By federal law the Title V program must be financed entirely through emission fees collected from air pollution sources. Those emission fees must pay all costs of administering the air permit program, and may not be used for any other purpose.

Q: What steps has the Company taken at the Big Sandy Plant to comply with the provisions of the Act?

A: The Company installed and had certified in 1994 a continuous emissions monitoring system on the Big Sandy Plant stack, serving both Unit 1 and Unit 2. This system measures SO_2, NOx, CO_2 and the volume of gas exhausted through the stack. All of these parameters are required to be measured under Title IV. The installed cost of this system was $1,301,138. In recognition of the "early election" provision of the NOx rules, the Company also installed low NOx burners on Big Sandy Unit 2 in 1994. The low NOx burners for Unit 2 cost $9,899,554 to install. There are four other units on the AEP system of the same design as Big Sandy Unit 2. When AEP installed low NOx burners at the 800 MW units at Mitchell Plant in West Virginia to meet Phase I NOx requirements, efficiencies in the design and manufacture of the burners were achieved by contracting with the original boiler vendor, Foster Wheeler Corporation, to design and install new burners at all five 800 megawatt units in the same time period. This also accommodated the scheduling of NOx control equipment retrofits on a large number of Phase II units, including Big Sandy Unit 1, to meet the Phase II deadline.

Q: Does the Company plan to "early elect" Unit 2?

A: A tentative decision to early elect Unit 2 has been made. A final decision will be made in December pending completion of modifications to the Unit 2 burners.

Q: Will the Company take further steps in the future at the Big Sandy Plant to comply with the provisions of the Act?

A: Yes. The Big Sandy units are subject to the Phase II SO_2 requirements. Thus they must comply with the Phase II SO_2 emissions limitations by the year 2000. Both units have been allocated allowances by EPA for use in Phase II. The Company will take measures to assure that the Big Sandy Plant has sufficient allowances each year of Phase II to comply with the SO_2 requirements of Title IV. The exact steps to be taken are still being evaluated. Additionally, as Witness Kyle explains in his testimony, the Company has entered into the FERC-approved AEP Interim Allowance Agreement with the other AEP affiliated utilities whereby each utility is required to maintain in inventory its Member Load Ratio share of the AEP System's unused allowances. This inventory is required to assure that the companies will have adequate allowances to comply with Title IV and the Interim Allowance Agreement. Accordingly, the Company purchases its share of allowances pursuant to the Interim Allowance Agreement.

The Company will also install low NOx burners at Big Sandy Unit 1 to comply with the Phase II NOx limitation. The burners are currently scheduled to be installed in the first quarter of 1998 at an estimated cost of $3,000,000.

Q: Has the AEP System taken steps to comply with the Act at facilities other than Big Sandy Plant that affect the Company?

A: Yes. AEP's Clean Air Act compliance plan was developed on a system-wide basis to take advantage of the flexibility offered by the SO_2 allowance program. The centerpiece of this plan is the installation of SO_2 scrubbers at the Gavin Plant in Ohio. These scrubbers were placed in service in late 1994 and early 1995 on the two Gavin units, respectively. The Phase I compliance plan results in a significant number of banked allowances for use system-wide in Phase II.

As Witness Kyle explains in his testimony, the AEP System operating companies are parties to a FERC-approved Interconnection Agreement which allows the AEP companies to acquire power from each other and prescribes the cost allocating procedure for that process. Under that agreement as described by Witness Kyle, Kentucky Power, as a capacity deficit company, is charged a capacity settlement charge. A component of that charge includes the annual charge associated with the scrubbers at the Gavin plant, including the lease payment, lime expense, waste disposal and maintenance of the scrubbers.

AEP has also taken steps to comply with the 1990 Amendments at Rockport Plant in Indiana, with which Kentucky Power has a unit power agreement. These steps consist primarily of installation of continuous emissions monitoring systems at Rockport, tentative early election of the Rockport units into the Phase I NOx program and obtaining a Title V permit. The total CEMS installation cost at Rockport Plant is $1,370,584. There is no cost associated with early election of the Rockport units.

Q: Is the Company paying emission fees under Title V?

A: Yes. Kentucky and Indiana both assess emission fees as required by Title V. The Company pays 100% of the fees associated with the Big Sandy Plant's emissions which are assessed by Kentucky. The Company is also responsible for 15% of the emission fees associated with the Rockport Plant which are assessed by Indiana.

Q: How much were the air emissions fees in 1996?

A: The air emissions fee for Big Sandy Plant was $292,967 in 1996. The Company's share of the Rockport Plant air emissions fee for 1996 is $22,500.

Q: Have you prepared a Compliance Plan for the Company?

A: Yes. As noted above, the Company's compliance plan is part of a broader AEP system-wide compliance plan. The AEP System plan was described in the Company's Integrated Resource Plan (Case No. 96-495) filed on October 21, 1996. A summary of the Company's compliance activities is provided in Exhibit JMM-1.

Q: Does this complete your testimony?

A: Yes, it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

COUNTY OF FRANKLIN

STATE OF OHIO

CASE NO. 96-489

Affidavit

John M. McManus, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

John M. McManus

John M. McManus

Subscribed and sworn to before me by John M. McManus this 15TH day of November, 1996.

Mary M. Soltesz

Notary Public

My Commission Expires 7-12-99

Exhibit JMM-1

American Electric Power-Kentucky
Environmental Compliance Plan
Pursuant to Environmental Surcharge Law

Project	Pollutant	Description	Year
1	NOx	Low NOx Burners at Big Sandy Unit 2	1994
2	NOx	Low NOx Burners at Big Sandy Unit 1	1998
3	SO_2/NOx	Continuous Emission Monitors at Big Sandy Plant	1994
4	SO_2	Scrubbers at Gavin Plant	1995
5	SO_2	Allowances Purchased	1995
6	SO_2/NOx/ Particulates	Kentucky Air Emissions Fee for Big Sandy Plant	Annual
7	SO_2/NOx	Continuous Emission Monitors at Rockport Plant	1994
8	SO_2/NOx/ Particulates	Indiana Air Emissions Fee for Rockport Plant	Annual

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

THE APPLICATION OF KENTUCKY POWER	)	
COMPANY d/b/a AMERICAN ELECTRIC POWER	)	2001-00093
FOR A CERTIFICATE OF PUBLIC CONVENIENCE	)	CASE NO. 01-
AND NECESSITY UNDER KRS 278.020 TO	)	
CONSTRUCT SELECTIVE CATALYTIC REDUCTION	)	
(SCR) NOx CONTROL TECHNOLOGIES	)	

DIRECT TESTIMONY

OF

MICHAEL W. DURNER

Q. What NOx emission reduction technology has AEP selected for the Big Sandy Units?

A. AEP has selected SCR for Unit 2. Short of shutting the unit down or switching to natural gas firing and severely curtailing generation, there is no other commercially available option that will reduce emissions to the level required by the applicable regulations. (The applicable regulatory requirements are described in the testimony of Mr. John McManus.) Even when pooling Big Sandy Unit 1 emissions with Big Sandy Unit 2 retrofitted with an SCR, the plant will not comply with the applicable limits. Additional controls will be required for Unit l. There are a variety of technologies under consideration for Unit l, including SCR.

Q. How many kinds of NOx reduction technologies did you consider for use on the AEP system?

A. Eight unique means or technologies and multiple combinations of these technologies were considered for installation on Big Sandy Unit 2. These Technologies are described and evaluated in MWD-Exhibit-1.

Q. What process did you use to determine what technology should be employed at a given AEP Unit?

A. The technologies were selected by a least incremental reduction cost method (lowest $/ton of NOx achievable on a fleet basis i.e., an optimization routine). Specifically, capital and O & M costs were developed for NOx reduction technologies on a unit-by-unit basis. The fleet dispatch was simulated using forecasted baseline data, such as expected load growth, fuel prices, heat rate and Title IV NOx emission rate. The dispatch was averaged over several years in order to void out the availability impact of scheduled outages from unit to unit, year to year. The cost effectiveness of each technology on each unit was then determined. NOx reduction technologies were then selected using a least incremental cost algorithm that identifies the least cost means of NOx reduction as a function of the depth of reduction required from the fleet of fifty units. Flexibility is built into the algorithm, as NOx reduction requirements were not definitive for some time. See MWD-Exhibit-1.

Q. Why was SCR selected for Big Sandy Unit 2?

A. SCR was selected for Big Sandy Unit 2 for two reasons. First, the application of the optimization routine results in the selection of an SCR for Unit 2 once the fleet level of reductions surpasses about 70,000 ton of NOx per Ozone Season. In other words, beyond 70,000 tons of reduction there is no other technology that is as cost effective as the installation of an SCR at Big Sandy Unit 2. In order to comply with applicable requirements, total NOx emission reductions in the range of 110,000-120,000 tons must be achieved. Second, in order for the Big Sandy Plant to meet NOx compliance within the Commonwealth of Kentucky, an SCR is required on Unit 2. Again, when pooling Big Sandy Unit 1 emissions with Big Sandy Unit 2 retrofitted with an SCR, the plant will not comply with the limits established by the regulations.

Q. What level of NOx emission reduction does AEP expect to achieve at the Big Sandy Plant?

American Electric Power
NOx Control Strategy
March 30, 2001

Introduction

The purpose of this analysis is to explain how AEP selected the NOx control technology to be placed on Kentucky Power Company's Big Sandy Unit 2 generating unit. This analysis will briefly outline the regulatory requirements necessitating NOx controls be placed onto AEP's coal-fired generating units. An overview is provided that explains how the state and federal NOx regulations affect the Big Sandy Plant's level of NOx emissions and how an optimization analysis was performed for the Big Sandy Plant and for the AEP system in order to select the appropriate NOx control technology for the affected units, including Big Sandy 2. Following the overview of the optimization analysis for Big Sandy Unit 2, the optimization procedure is discussed in more detail in connection with the development of the compliance approach for the AEP System (East). This discussion includes an explanation of the use of a production cost simulation model to provide data for the optimization and a detailed discussion of the pros and cons of the significant NOx reduction technologies that are feasible and commercially available. This discussion also includes an explanation of the various significant parameters that affect the optimization analysis. Finally, the installation plan and cost breakdown for the SCR technology to be applied at Big Sandy Unit 2 is discussed.

I. Regulatory Requirements

The U.S Environmental Protection Agency has promulgated two regulations pursuant to the Clean Air Act (as amended) that will require reduction in emissions of nitrogen oxides (NOx) from stationary sources in the Eastern U.S., including the Commonwealth of Kentucky. One rule, under Sect. 126 of the Clean Air Act, affects electric generating units and large industrial sources in the eastern half of Kentucky. The second rule, referred to as the EPA "NOx SIP Call," requires Kentucky and 18 other states to revise their State Implementation Plans ("SIPs") to establish a NOx reduction program targeted at essentially the same sources as the Sect. 126 rule. The NOx SIP Call program will affect the entire Commonwealth. Finally, Kentucky has promulgated a state-specific rule that establishes a statewide NOx emission limitation for electric generating units to address air quality in the Louisville area. All three of these programs affect American Electric Power's Big Sandy Plant in Kentucky, with the Sect. 126 and NOx SIP Call rules also affecting other AEP sources in Virginia, West Virginia, Ohio and Indiana.

The Sect. 126 rule and the NOx SIP Call program establish an emission credit trading program that allows for the development of a System compliance program. The Kentucky Louisville non-attainment SIP allows multiple sources of a company to be averaged together. However, Big Sandy Plant is the only AEP facility in Kentucky. The compliance requirements for the Sect. 126 rule and the Kentucky Louisville non-attainment SIP begin in May, 2003, although the latter may be revised to May 31, 2004. The NOx SIP Call compliance deadline is May 31, 2004. All three programs apply during the summer ozone season, from May to September. More detail on each rule is provided below.

Louisville Nonattainment Rule - The Kentucky rule to address ozone nonattainment in the Louisville area requires that all EGUs in the state reduce their NOx emission rate to a limit of 0.25 lb/mmBtu. By contrast, the Title IV NOx emission rate limits range from 0.43 lb/mmBtu to 0.86 lb/mmBtu, depending on boiler type. Although the rule is intended to address air quality in Louisville, it applies to all sources in the state, including Big Sandy Plant, which is located approximately 175 miles to the east and downwind of Louisville. The current NOx emission rates at Big Sandy Plant are 0.55 lb/mmBtu for Unit 1 and 0.57 lb/mmBtu for Unit 2. Compliance with this rule would thus require a reduction in the NOx emission rate of 55 % for Unit 1 and 56 % for Unit 2. The rule does allow a company to average it facilities together to meet the required limit. On average, Big Sandy Plant, which is the only AEP plant in Kentucky, would have to reduce its emission rate by 56 %. The compliance deadline for this rule is May 1, 2003. The compliance season would extend from May 1 to September 30 beginning in 2003. The Department of Environmental Protection has proposed that the compliance deadline be revised to May 31, 2004 to comport with the deadline for the SIP Call rule discussed below.

Sect. 126 Rule - Sect. 126 of the Clean Air Act is a provision that is intended to provide state and local air quality authorities an opportunity to petition U.S. EPA with a request for EPA to establish emission control requirements at sources that are demonstrated to contribute to nonattainment of an air quality standard in another state. In August, 1997, eight states in the Northeastern U.S. petitioned EPA with a claim that sources in states to the west were significantly contributing to nonattainment of the ozone standard in the petitioning states. U.S. EPA granted the petitions of four states (CT, MA, NY and PA) and promulgated a rule in January, 2000 establishing a NOx control program for EGUs and large industrial sources in parts or all of 12 states in the Northeast and Midwest. The compliance deadline under this rule is May 1, 2003. The Sect. 126 rule is being litigated by Midwestern states and industrial sources. A decision in this litigation is expected at any time.

Under the Sect. 126 rule, EPA is regulating total emissions of NOx from affected sources during the May through September ozone season. EPA has established NOx emission budgets for each source and will allocate NOx allowances in an approach that is similar to the SO2 allowance program under Title IV of the CAA. NOx allowances will be transferable between sources and tradable in an open market. NOx allowances can be banked and used in future years with some restrictions.

The NOx allowance allocations under the Sect. 126 rule are nominally based on a NOx emission rate of 0.15 lb/mmBtu, which is more stringent than the Kentucky limit of 0.25 lb/mmBtu. The Sect. 126 rule allocates NOx allowances to both units at Big Sandy Plant. Unit 1 is allocated 565 allowances per ozone season, and Unit 2 is allocated 1,741 allowances. An allowance is equivalent to one ton of NOx emissions. NOx emissions from the Big Sandy units are projected to be 2,282 tons for Unit 1 and 7,377 tons for Unit 2 during the 2003 ozone season. To comply with the Sect. 126 NOx allocation, emissions will need to be reduced by 75% for Unit 1 and 76% for Unit 2, or an average of 76% for the Big Sandy Plant.

NOx SIP Call Rule - Concurrent with the development and promulgation of the Sect. 126 rule, EPA promulgated a separate rule directing 21 states to revise their State Implementation Plans (SIPs) to include a cap on NOx emissions during the five month ozone season. The ostensible purpose of this rule was to address long-range transport of ozone and ozone precursors that were claimed to be causing nonattainment of the ozone standard in Northeastern states. The rule was legally challenged by several Midwestern states and industrial sources. The rule was upheld by the U.S. Circuit Court of Appeals for the District of Columbia, although that court revised the compliance deadline and reduced the geographic coverage of the program. The U.S. Supreme Court recently issued a decision declining to hear an appeal of the D.C. Circuit Court decision. The compliance deadline under this rule as it applies to EGUs is May 31, 2004.

EPA has established NOx emission budgets for each affected state with this rule. The budget applies for the ozone season. EPA has also suggested NOx budgets for EGUs and recommended that the affected states adopt a NOx emission allowance system. While the states are not required to include such a program in their SIPs, it appears that most affected states will be utilizing an allowance system for EGUs and large industrial sources.

While states have some discretion in allocating NOx allowances, the nominal NOx budget for EGUs is the same as for the Sect. 126 rule. Thus, the budget for Big Sandy Plant will require essentially the same level of NOx emission reductions as required by the Sect. 126 rule.
The Sect. 126 rule establishes a pool of allowances that are available for new sources that do not receive an allocation directly. The allowances in this pool are withheld from the budget established for EGUs. This "new source set-aside" (also referred to as a "holdback") was established at a level of 5% of the EGU budget. Under the SIP Call rule, the states have discretion as to whether to establish a new source set-aside and the size of such a pool. As part of the development of the Kentucky NOx SIP rule, there has been discussion of establishing a new source set-aside pool as large as 20% of the EGU budget. Establishment of a larger set-aside would result in Big Sandy Plant receiving fewer NOx allowances, making the NOx SIP Call rule effectively more stringent than the Sect. 126 rule.

The Kentucky Department of Environmental Protection has prepared a draft SIP revision rule to incorporate the NOx SIP Call requirements. The rule is expected to be finalized this year. The draft rule adopts the NOx allowance budget program and includes provisions to allow interstate trading of allowances. The draft rule also includes a new source set-aside pool of 5% of the EGU budget, although the possibility exists that the final rule will include a larger set-aside. The compliance date is May 31, 2004.

The Sect. 126 rule affects all AEP coal-fired power plants in Kentucky, Indiana, Ohio, Virginia and West Virginia with the exception of Rockport Plant in Indiana. The NOx SIP Call rule includes all five of these states and will require NOx reductions at all AEP coal-fired plants in these states. The level of NOx reduction that will be required for the other AEP plants is comparable to the level of reduction required at Big Sandy Plant. NOx emissions from AEP coal-fired plants have been reduced approximately 30% under the Title IV NOx program. The total NOx allowance allocation that AEP plants may receive under the Sect. 126 or NOx SIP Call programs will require an additional 75% reduction of NOx emissions during the ozone season, almost the same as Big Sandy Plant's 78% reduction requirement. Thus, while these programs allow interstate trading of NOx allowances, large reductions in NOx emissions must be made across the AEP System before the benefits of the trading program can be applied.

II. Impact of the Sect. 126 and NOx SIP Call Rules on Big Sandy Plant[1]

Big Sandy Plant, located in eastern Kentucky near Louisa, has 2 coal-fired electric generating units. Unit 1 began operation in 1963 and has 260 megawatts of net generating capacity. Unit 2 began operation in 1969 and has 800 megawatts of net generating capacity. Both units burn Eastern Kentucky coal. Both units are equipped with low NOx burners to reduce NOx emissions for compliance with Title IV emission rate limitations. Unit 2, the primary focus of this report, is one of a series of five 800 megawatt units on the AEP System. It has a wall-fired, dry bottom boiler, a supercritical steam cycle and a cold-side electrostatic precipitator for particulate emissions control.

A. Forecasted Emissions

Table 1 below outlines the effect that both Clean Air Act Amendments Title IV and the SIP Call requirements have on NOx emissions projected for the 2003 (and beyond) Ozone Season at Big Sandy. Over the last three years capacity factors have ranged between 86% and 94% on Big Sandy Unit 1 and 76% and 88% on Unit 2. These two units are forecasted to continue operating with very high capacity factors due to the relatively low priced fuel. Calculation results are presented assuming a 90% capacity factor on both units.

2003 Big Sandy Emission Projections (assumes 90% Capacity Factors)	Big Sandy 1	Big Sandy 2	Big Sandy Plant	Total Plant NOx Reduction, % Relative to pre-Title IV Emissions	Total Plant Incremental NOx Reduction, %
2003 Emission Rate (lb/mmBtu)					
Pre CAAA Title IV Controls*	1.00	1.17	1.13	0%	0%
Title IV Controls	0.55	0.57	0.57	50%	50%
SIP Call Limit (Based on Absolute tons)	0.14	0.13	0.13	88%	76%
2003 Oz. Season Heat In (1000s -mmBtu)	8,297	25,883	34,181		
2003 Ozone Season Emission (tons)					
Pre CAAA Title IV Controls	4,149	15,142	19,290	0%	0%
Title IV Controls	2,282	7,377	9,658	50%	50%
Sect. 126 Emission Limit	565	1,741	2,306	88%	76%
*AEP Estimated					

Table 1. Projected NOx Emissions for Big Sandy Plant

[1] This report refers repeatedly to the requirements of U.S. EPA's Sect. 126 rule. It should be noted that the NOx control requirements of the Sect. 126 rule and the NOx SIP Call rule are essentially the same, with the possible exception of a potentially larger "new source set-aside" or "holdback" under the NOx SIP Call program. The most significant difference between the two programs is the compliance deadline, with the Sect. 126 rule having the most pressing deadline.

In order to comply with SIP Call emissions limits, particularly during a hot summer, both Big Sandy Unit 2 and Big Sandy Plant will be required to reduce emissions over 76% from currently projected emission levels with Low NOx Burners alone.

B. Commercially Available NOx Control Technologies

There are a number of technologies that are commercially available to reduce NOx emissions. **Table 2** below identifies the NOx control options considered for Big Sandy Unit 2 and the cost-effectiveness for each approach in dollars per ton of NOx removed. These options are ordered from lowest to highest dollars per ton of NOx removed.

NOx Reduction Options	Capital Cost $/kW (Current $)	Technology Removal Efficiency %	NOx Reduction Cost $/ton-Removed	NOx Removed tons
Do Nothing	$0	0%	$0	0
OFA*	$13	20%	$1,599	1,475
OFA*/SNCR	$28	40%	$2,158	2,951
SNCR	$15	25%	$2,435	1,844
SCR	$129	90%	$2,943	6,639
OFA*/PRB Fuel Blend	$24	34%	$4,275	2,479
AEFLGR	$40	50%	$5,567	3,688
PRB Fuel Blend	$11	17%	$6,672	1,254
Gas Reburn	$32	49%	$8,445	3,647
Gas 100%	$24	68%	$28,013	5,039

*Maximum Staging on Wall Fired Supercritical Boiler

Table 2. Big Sandy 2 NOx Reduction Options

A brief description of the options considered is provided below:

- <u>OFA, or Over-Fired Air</u>
  This technology essentially starves the main burner zone of oxygen thereby helping to minimize the oxidation of nitrogen. Heat release is less concentrated as well which reduces the formation of thermal NOx.

- <u>SNCR, or Selective Non-Catalytic Reduction</u>
  This technology uses urea or ammonia reagent to chemically reduce NOx to N_2 and water vapor in the absence of catalyst. The reagent is injected within a specific temperature window inside the convection passes of the steam generator.

- OFA/SNCR
  This is a combination of over-fired air and selective non-catalytic reduction technologies.

- SCR, or Selective Catalytic Reduction
  This technology uses ammonia in the presence of a catalyst to chemically reduce NOx to N_2 and water vapor. SCR units are installed downstream of the steam generator economizer and upstream of the air preheaters.

- PRB Fuel Blend
  This NOx reduction option involves blending upwards of 40% Western Sub-Bituminous Coal from the Powder River Basin (PRB) with native coal. The combustion of PRB coal results in formation of substantially less NOx than eastern bituminous coal due to its high moisture content, high volatiles to fixed carbon ratio and lower nitrogen content.

- OFA/PRB Fuel Blend
  This option uses both OFA and PRB blending to reduce NOx.

- Gas Reburn
  This technology involves the injection of natural gas above the main burner firing zone. Approximately 20% of the heat input into the furnace is derived from the natural gas. The natural gas acts to reduce the NOx concentration of the coal combustion products. Over-fire Air is integral to this technology wherein fuel burnout is completed.

- AEFLGR, or Amine Enhanced Fuel Lean Gas Reburning
  This technology is essentially a hybrid of Gas Reburning and SNCR. 5-10% of the heat input into the boiler is derived from natural gas. A urea-based reagent is injected into the furnace with the natural gas.

- Gas 100%
  This is a complete fuel switch to natural gas.

C. Optimization Analysis Overview

An optimization algorithm was developed within AEP in order to help identify cost effective strategies and sensitivities to a host of variables that affect the system optimization, including market forecasts, unit-specific technology capital costs, and unit-specific technology incremental operating costs. The optimization identifies the least cost NOx reduction through an incremental least cost basis, (dollars per ton of NOx removed in 2005 levelized dollars), as a function of the required depth of reduction for each individual unit and the system as a whole. As a result, the specific NOx reduction technology selected for a unit is determined as much by the amount of NOx reduction that is required as by the relative cost effectiveness of options available for that unit.

Given that the overall NOx reduction required by the Sect. 126 rule exceeds 75% and that the only technology that can achieve or exceed this level of reduction is SCR, it follows logically that, in order to achieve the NOx reductions required by these emission control programs, SCR is selected as the control technology for AEP's larger and newer units. **Figure 1** illustrates the NOx removal cost (dollars per ton of NOx removed) as a function of the overall reduction required for the AEP System. The removal cost includes both capital carrying charges as well as operation and maintenance costs. In order to achieve the overall reductions required, NOx controls with costs in excess of $5,000/ton may be needed.

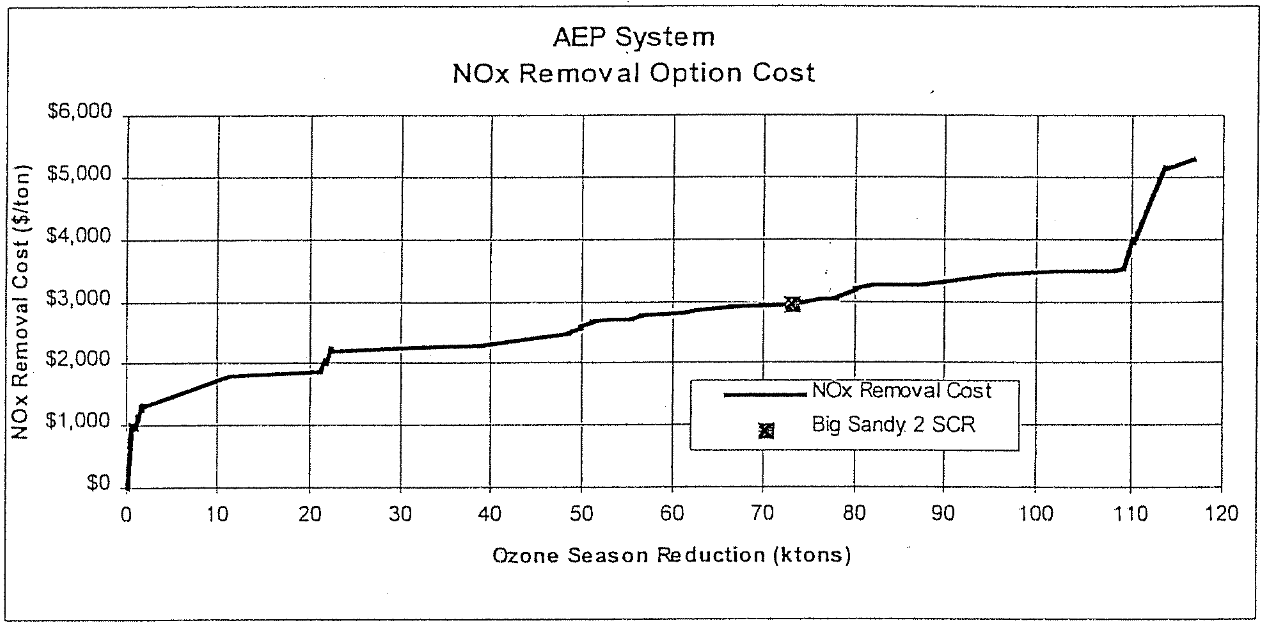

Figure 1. AEP System NOx Removal Option Cost, Current Plan

D. Technology Selection for Big Sandy Plant

The optimization calls for an SCR to be installed at Big Sandy Unit 2 as part of the overall compliance strategy as well as on a unit specific basis. The SCR NOx removal cost at Big Sandy Unit 2 is estimated at approximately $2,900/ton of NOx removed. As identified in **Figure 1,** the cost effectiveness of an SCR for Big Sandy 2 is roughly at the midpoint of the required overall AEP System reduction. As noted in the previous section, several other technologies were evaluated in the optimization for Big Sandy 2, but no other commercially available NOx removal technology can, even in combination, sufficiently reduce NOx to the required levels at Big Sandy Unit 2.

Table 3 below illustrates how SCR is selected by the optimization logic for Big Sandy Unit 2, in particular. Options are ordered from least expensive to most expensive on a dollars-per-ton-of-NOx-removed basis. The routine assigns the least cost option to a particular unit, starting with "doing nothing", at $0 cost. A desired level of NOx reduction is targeted for the system and the routine performs the selection by picking technologies according to the next least incremental costs.

NOx Reduction Option	NOx Reduction Cost $/ton-Removed	NOx Removed tons	Incremental NOx Reduction Cost, $/ton
Do Nothing	$0	0	$0
OFA*	$1,599	1,475	$1,599
OFA*/SNCR	$2,158	2,951	$2,716
SNCR	$2,435	1,844	Previous option is lower cost and more efficient
SCR	$2,943	6,639	$3,572
OFA*/PRB Fuel Blend	$4,275	2,479	SCR option is lower cost and more efficient
AEFLGR	$5,567	3,688	SCR option is lower cost and more efficient
PRB Fuel Blend	$6,672	1,254	SCR option is lower cost and more efficient
Gas Reburn	$8,445	3,647	SCR option is lower cost and more efficient
Gas 100%	$28,013	5,039	SCR option is lower cost and more efficient

*Maximum Staging on Wall Fired Supercritical Boiler

Table 3. Incremental NOx Reduction Costs for Big Sandy 2

While installation of an SCR is a necessity for plant compliance within the Commonwealth of Kentucky and a cost effective option in terms of AEP's overall NOx reduction strategy, the SCR on Big Sandy 2 is still insufficient to reduce NOx to the levels allocated for the Big Sandy Plant to meet the NOx emission reduction requirements of the state and federal regulations. As described by **Table 1**, the two units are projected to emit approximately 9,660 tons of NOx per Ozone Season (with Title IV controls, i.e., Low NOx Burners). The Sect. 126 rule allocates approximately 2,300 tons of NOx for the Big Sandy Plant. A 90% efficient SCR on Unit 2 will reduce that unit's emissions to about 740 tons per Ozone Season. Without additional controls, Big Sandy 1 is projected to emit about 2,280 tons of NOx. The sum of the unit, or total plant, emissions would be about 3,020 tons (BS 1 with LNBs and BS 2 with LNBs and SCR). Therefore, an additional reduction in NOx emissions from Big Sandy 1 of about 720 tons, (or one-third of that unit's emissions) is still necessary for the plant in order to achieve SIP Call compliance. This may be accomplished marginally by installing SNCR and Over Fire Air on Unit 1. However, this margin is slim and if so-called "holdbacks" for new sources are required, Big Sandy 1 may also require an SCR to ensure compliance.

E. Necessity for SCR at Big Sandy 2

This report addresses the need to comply with 2003 Section 126 and 2004 SIP Call NOx requirements established by the U.S. EPA, the cost effective approach taken by AEP to bring the AEP plants affected by these requirements into compliance and specifically the need to install SCR at Kentucky Power's Big Sandy Unit 2. Selective Catalytic Reduction technology will be installed on virtually **two-thirds** of the AEP East generating capacity to insure compliance. The installation of an SCR is both cost effective and a necessity to allow Big Sandy Unit 2 to operate in legal compliance with the applicable regulatory requirements. In order for Big Sandy Unit 2 to operate during the ozone season without an SCR system, a significant number of NOx allowance credits would have to be purchased, if available, from elsewhere at unknown and likely volatile prices. Beyond approximately 70,000 tons of reduction for AEP, there are no other options more cost effective than an SCR at Big Sandy 2 (see **Figure 1**). NOx reduction costs elsewhere in the AEP system will approach $5,000/ton of NOx removed. At $2,900/ton, the SCR at Big Sandy 2 is the most cost effective option available for ratepayers.

III. AEP System NOx Control Optimization Analysis

A. Introduction

For the AEP System coal-fired plants in the Midwest, the Sect. 126 rule requires that emissions of NOx be reduced from an average emission rate of 0.6 lb/mmBtu to an average emission rate of slightly below 0.15 lb/mmBtu by the 2003 Ozone season. This represents a 75% NOx reduction beyond the approximately 30% reduction that has already occurred to meet the requirements of the Title IV NOx program. The Sect. 126 program implements a limitation on total emissions of NOx and will apply throughout the System during the May through September Ozone Season. Specifically, reductions on the order of 120,000 tons are required from the AEP's Midwestern coal-fired units (20,795 MW of generating capability) during the ozone season. These units are currently projected to emit roughly 160,000 tons per ozone season with the current level of NOx controls (Low NOx Burners and staged combustion). In order to reduce System emissions by the required 75%, a significant fraction of the fleet will require additional NOx emission controls. Selective Catalytic Reduction (or SCR) is the only commercially available technology capable of achieving the required level of NOx removal. SCRs planned for the AEP System will be designed to remove between 85-93% of NOx emissions when installed on any particular unit. As a result, many AEP units will require the installation of SCR so that the average NOx level can be reduced by 75%. Other technologies available to reduce NOx emissions include over-fire air (OFA), selective non-catalytic reduction (SNCR), fuel switch to natural gas or non-Kentucky, e.g., Powder River Basin, coal, natural gas reburn, and combinations of these technologies.

B. Approach to Compliance

As U.S. EPA was developing the NOx control program to address ozone nonattainment in the eastern U.S., it became apparent that SCR control technology would be needed on a large number of coal-fired units. Therefore, in the fall of 1998 approval from the AEP Board of Directors was sought for funding of an expedited series-based engineering and design effort for SCR systems. This approval was necessary to assure preparedness in the event that EPA's NOx rules withstood legal challenge. However, the effort did not request approval of funds to purchase or erect equipment. Rather, the request was made to insure readiness and refine costs for inclusion in the AEP System NOx Optimization Strategy. While the final compliance deadline is still somewhat uncertain, AEP has adopted May 2003, the compliance date currently required in the Section 126 Rule, as the target date for compliance. Specifically, AEP is moving ahead with the presumption that the Section 126 rule will require NOx controls to be in place for the 2003 Ozone Season. Rockport Station is the only plant unaffected by these petitions, making it subject only to the May 31, 2004 compliance date of the SIP Call. AEP's Board of Directors has approved and construction projects have been announced for the installation of SCR systems at the following plants:

General James M. Gavin Plant Units 1 & 2 (Ohio)
John E. Amos Plant Unit 3 (West Virginia)
Mountaineer Plant (West Virginia)
Big Sandy Plant Unit 2 (Kentucky)

AEP has already begun construction of SCRs at the first three listed plants. In addition, SCR installations are anticipated for plants in which AEP has a partial ownership interest. These SCRs will be installed prior to the 2003 Ozone Season. The units selected to receive SCR tend to be AEP's newer and larger units that reflect economy of scale advantages over the smaller, older units. SCR systems will be required at other AEP units in order to comply with the stringent NOx control program. All told, SCR controls will be installed on approximately 14,000-15,000 MW of the 20,795 MW of AEP generation affected by this program. Schedule flexibility is limited particularly due to the short availability of craft labor forecasted in the Eastern U.S. over the next 2-3 years.

While the SCRs identified are necessary as components of the overall system compliance plan, additional controls are necessary for the remainder of the fleet. Aside from SCR, options generally considered include:

Do Nothing/Unit Curtailment
SNCR
Over-Fire Air
Flame Attemperation
Gas Conversion
Gas Reburn
Amine Enhanced Fuel Lean Gas Reburn
Powder River Basin Fuel Switch

Combinations of these technologies were included as options as well. Some options were not considered at certain installations because either the technology is already implemented, not available or physically impractical.

C. Analysis Results

The optimal investment in capital and total removal costs for NOx reductions are described by **Figures** 2 and 3, for the AEP System. AEP will need to reduce NOx emissions by approximately 120,000 tons during the Ozone Season. These Figures emphasize how costs increase with the required level of reduction. The increases are clearly non-linear. AEP will be required to invest nearly $1.6 billion to meet the NOx compliance requirements.

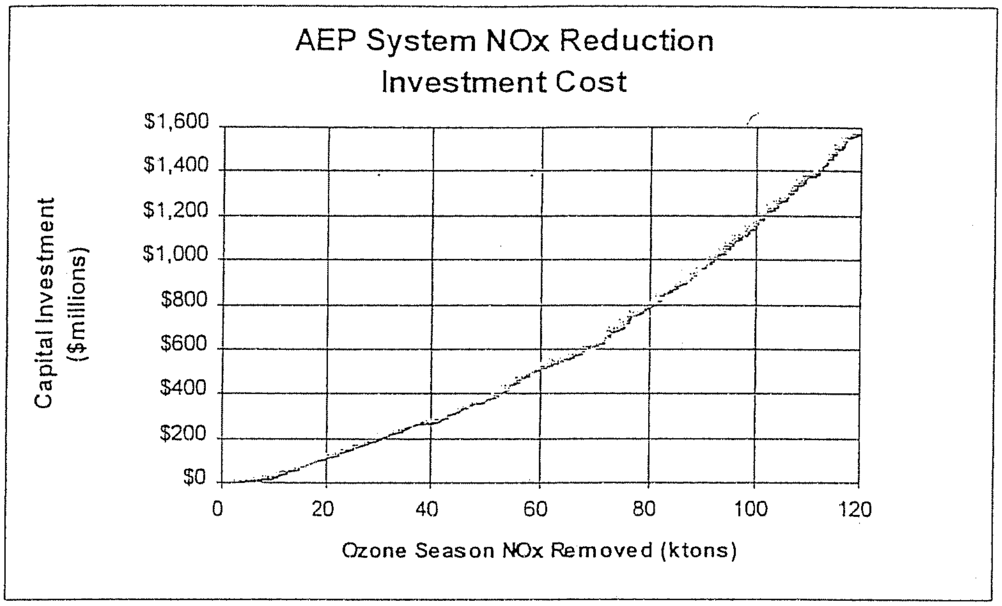

Figure 2. Projected NOx Reduction Capital Investment, Optimum

The NOx reduction algorithm optimizes the option selection identifying least cost dollars per incremental ton of NOx removed. The incremental option cost trend, as a function of the reduction depth, is represented by the upper curve in **Figure 3**. The significance of this curve is that it represents the optimum real cost of each additional ton of NOx removed as more and more NOx is removed from the system's emissions. The lower curve in **Figure 3** is simply the integrated average for the system.

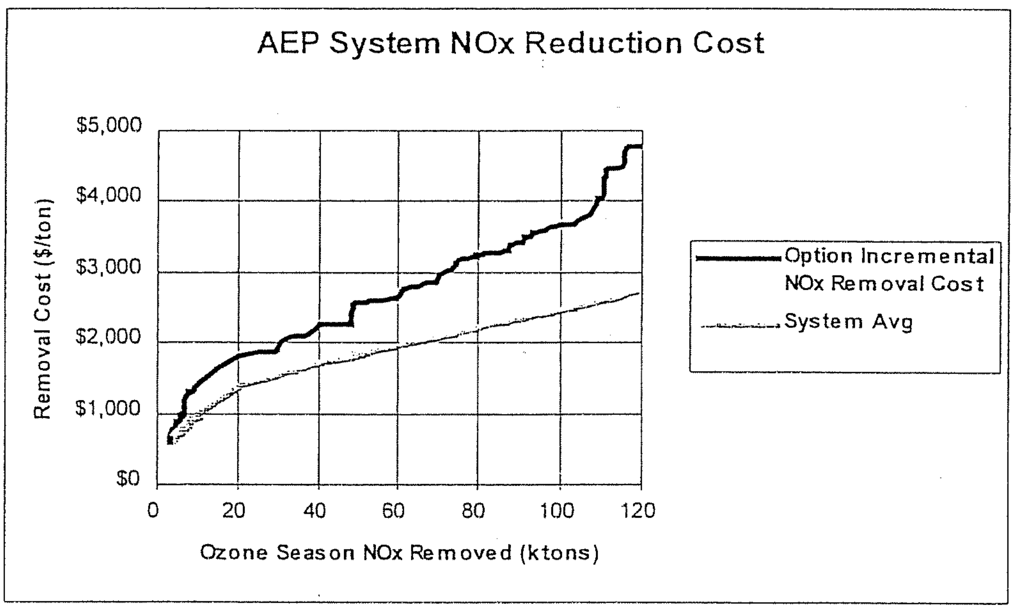

Figure 3. AEP Incremental and System Average NOx Reduction Costs, Optimum

Clearly, the cost effectiveness of reduction declines with the increasing depth of reduction. AEP's least cost strategy assigns an SCR to Big Sandy Unit 2 as a part of the least cost optimization. The incremental reduction cost beyond the next least cost option for Big Sandy Unit 2 is about \$3,200 per incremental ton of NOx removed. The total NOx removal cost for the SCR at Big Sandy 2 is about \$2,900 per ton of NOx removed. This includes capital, operating and maintenance costs. As demonstrated in Figure 1, because the required NOx reduction for the System is 120,000 tons, SCR technology is the selected least cost means of compliance for Big Sandy Unit 2. Additionally, SCR technology is the only technology that will bring Big Sandy Unit 2 into compliance with Kentucky's nonattainment regulation requiring NOx reduction.

D. Baseline Information

In order to established the required reductions necessary for the AEP System to be in compliance, a forecast was developed for each AEP-owned fossil unit. The forecast utilized current projections of unit characteristics and variable operating costs associated with dispatch in a production cost simulation model (PROMOD). Projections for NOx emissions for each unit were developed from actual data and included the assumption for continued operation of controls installed to meet compliance with Title IV, Phase II.

The resultant data inputs for the optimization were capacity factor, heat rate, and NOx emission rate. An average of multiple years was used to lessen the impact of a singular year event. Additional simulations were performed in order to evaluate the change in utilization due to the value of NOx allowances. Incorporating a dispatch cost for NOx emissions results in relatively higher production costs and reduced capacity factors for units emitting at higher NOx levels.

Many other variables enter into the optimization study including forecasted Powder River Basin and seasonal gas fuel prices (SO_2 adjusted) and NOx removal efficiency variability as a function of control technology, technology combinations, existing controls, and unit limitations.

E. NOx Reductions

As already discussed, optimization analyses were conducted for a variety of NOx level control requirements. This report specifically addresses the requirements of EPA's Sect. 126 rule.

The required NOx reduction is the difference between projected NOx emissions in the future with just Title IV NOx controls and the NOx allowance allocation established under the Sect. 126 rule. That allocation was set by EPA based on a targeted NOx emission rate of 0.15 lb/mmBtu and the average of 1995 and 1996 unit heat input values adjusted according to presumed growth requirements (defined by EPA for each state) projected out to the year 2007. The economics within the framework of this analysis are levelized to 2005 dollars, for comparative purposes. The total NOx allowance allocation for AEP's owned units is about 40,000 tons, which is the equivalent of an 85% reduction from AEP's 1990 emissions or 75% from current levels. Based on the dispatch of the units as projected in this analysis (i.e., system 72.0% Ozone Season capacity factor) this allowable emission corresponds to a system NOx emission rate of less than 0.15 lb/mmBtu.

F. NOx Reduction Technologies

Table 4 below outlines the technologies and combinations of technologies considered in the optimization. The effectiveness of each technology and combinations of technologies were developed for each unit considered in the analysis. The technologies considered in this study include: Over Fire Air (OFA), Selective Catalytic Reduction (SCR), Selective Non-Catalytic Reduction (SNCR), Gas Reburn, Steam Generator Gas Retrofit (Gas 100%), Amine Enhanced Fuel Lean Gas Reburn (AEFLGR), PRB Blending On-Site, PRB Blending Off-Site and 100% PRB fuel switch. In addition to these, a "Do Nothing" option is considered which includes technologies currently in place to meet Title IV requirements. Ozone Season unit curtailment is an implicit NOx reduction option when applying a NOx emission cost to the dispatch, particularly for units selected with minimal or no controls, i.e., "Do Nothing".

NOx Reduction Options			
1	Do Nothing		
2	Over Fire Air		
3	SCR		
4	Gas Reburn		
5	Gas 100%		
6	AEFLGR		
7	SNCR		
8	Flame Attemperation		
9	Flame Attemperation	Over Fire Air	
10	Flame Attemperation	Over Fire Air	SNCR
11	Flame Attemperation		Gas Reburn
12	PRB Blend On Site		
13	PRB Blend Off Site		
14	PRB Blend Off Site	Over Fire Air	
15	PRB Blend Off Site	Over Fire Air	SNCR
16	PRB Blend Off Site		Gas Reburn
17	100% PRB		
18	100% PRB	Over Fire Air	
19	100% PRB	Over Fire Air	SNCR
20	100% PRB		Gas Reburn

Table 4. NOx Reduction Technology Combinations

Flame attemperation is currently under study and may have particular applicability to AEP's subcritical fleet. While short term tests to date indicate that flame attemperation holds promise, it is considered experimental at this point. Therefore, technology combination "10" in **Table 4** effectively includes only "Over Fire Air" and "SNCR". Tests on representative units are planned for this year. If the promise of flame attemperation is born out with these tests, more rigorous performance assumptions will be included in the optimization analysis. Aside from these technologies, AEP will evaluate the cost effectiveness of monitoring systems that optimize combustion to the extent practical. Monitoring systems may have applicability on all or part of the fleet including units with SCR.

A range of the costs and NOx Removal Efficiencies used in the optimization is presented in **Table** 5 below.

Technology	Removal Efficiency %	Capital Cost $/kW	Total Removal Cost (typical) $/ton of NOx Removed
Over Fire Air	10-45	5-13	300-1500
SCR	85-90	63-184	2000-6000
SNCR	20-35	10-36	1500-4000
Gas Reburn	35-50	20-50	5000-15000
Gas 100%	50-85	10-45	8000-30000
AEFLGR	50	20-60	4500-10000
Flame Attemperation	10-25	2-7	600-1500
PRB Blending	15-20	10-20	3000-6000
100% PRB Switch	30-50	30-90	1000-2500

Table 5. Base NOx Reduction Technology Efficiency and Costs

Over Fire Air

Over fire air, or OFA, is the diversion of a portion of the combustion air, typically 10-30% of the total air, to a point in the furnace above the burner zone. As with low NOx burners, the concept further delays combustion, reducing thermal NOx and simultaneously minimizing oxygen partial pressure in the primary combustion zone.

AEP considered placing OFA on the 800 MW units in the mid-90's when it became evident that the newly installed LNBs would not reduce NOx to below 0.5 lb/mmBtu on those units as was required of Phase I and early elected Phase II units. AEP did not install OFA on the 800 MW units primarily because of significant reported fireside corrosion throughout the industry. Other relevant factors that weighed against use of OFA were:1) the vendor's other equipment did not meet the performance guarantee; and 2) OFA was not considered low NOx burner technology for purposes of meeting the requirements of the Title IV.

Conscious effort made to limit excess air levels in order to minimize NOx formation has resulted in significantly accelerated fireside corrosion at both Big Sandy Unit 1 (260 MW sub-critical wall-fired) and Big Sandy Unit 2 (800 MW supercritical wall-fired) to the extent that tube replacement and overlays have recently been installed. Significant water wall wastage has also been experienced on another supercritical AEP unit, which is currently undergoing weld overlay repair.

Overlay methods developed since the mid-90's have been successful in mitigating fireside corrosion and have alleviated some concern. Operating experience and research[2] has since pointed to the deposition of pyritic sulfur (FeS) in an oxidizing (and perhaps alternating oxidizing/reducing) environment rather than localized hydrogen sulfide attack as the primary cause of corrosion. Corrosion potential may actually be a combination of the fact that Fe3O4 normally found on tube surfaces is intermixed with FeS, the combination of which is more porous and less dense allowing for easier exchange of H_2S and CO to the surface metal[3]. Additionally, ash fusion temperatures are lowered when fired in a reducing environment. Molten ash deposited on the outer surface of wall deposits accelerates corrosion at the wall due to the increased rate of mixing and chemical reaction.

However, industry experience demonstrates that cyclone boilers, in particular, have fewer problems with corrosion (since most of the heavy ash is tapped and drained out the bottom of these units, and the cyclones themselves are protected by refractory and a slag layer). AEP has incorporated over-fire air in its CAAA affected sub-critical cyclone units (Kammer 1,2&3 and Muskingum River 3&4). Staging the air to maintain the burner stoichiometry at about 0.95-1.0, results in NOx reductions of between 50 and 60%. Again, a dual effect is occurring here. Incomplete combustion results in a cooler flame; less thermal NOx is generated as a result. In addition the volatiles and CO scavenge all available oxygen, thereby depleting the oxygen partial pressure and the driving force for NOx formation. In order to meet Title IV compliance, AEP has also staged combustion in its roof-fired and pulverized coal wet-bottom units.

Industry experience with overlays is being tracked, as is the reported corrosion experience. Staging can result in a NOx reduction between 10% and 45% depending on the unit type and level of staging. In fact, cyclone furnaces with gas re-burn report nearly the same reductions in NOx whether firing in a gas reburn mode or just an OFA mode. Suppliers of OFA systems now claim reductions upwards of 40%, even on pulverized coal wall-fired units firing Western Fuel, i.e., Powder River Basin Sub-Bituminous Coal. The primary differences, between the earlier systems and those now proposed, include the level of staging (10% vs. 20-30%) and the combustion residence time before OFA is introduced. Increased sub-stoichiometric residence time requires a more extensive ducting configuration at higher cost and exposes a larger fraction of the furnace wall surface to damaging reducing and alternating oxidizing and reducing gases.

Sensitivities were conducted around OFA system technology cost and removal efficiency. However, the negative impacts of increased LOI and CO, and accelerated water wall corrosion, make severe staging less attractive particularly for supercritical units, such as Big Sandy Unit 2, firing Eastern bituminous coals. Aside from the Rockport Plant (which fires PRB or a high PRB blend) and several subcritical units, the efficiency was limited to 10% on pulverized coal wall-fired units because of the aforementioned concerns. At 30% removal efficiency the technology is cost effective. However at 10% removal efficiency the economics are less favorable.

[2] AmerenUE has been operating Sioux U-2 a 500 MW supercritical cyclone fired boiler since 1997 in an over-fire air mode of operation. No corrosion problems were found as of this past spring. NOx reduction is reported to be 60%.

[3] "Fireside Corrosion in Low-NOx Combustion in Pulverized Coal-Fired Boiler", Proceedings: 1998 Low NOx Control Shop, EPRI TR 111356

Furthermore, generally OFA becomes generally uneconomic on units that require SCR in order to achieve a high NOx removal level to come into compliance.

SCR

Selective Catalytic Reduction, or SCR, is both the most capital intensive and at the same time the most effective NOx reduction technology commercially available. AEP's SCR design criterion is 90% removal efficiency with no low-end limit.

SCR uses ammonia to reduce NOx to N_2 and water vapor; vanadium oxide catalyzes the reaction. The process itself is very efficient and has a very low operating cost of about $300 per ton of NOx removed. O&M costs include catalyst replacement, reagent (ammonia), and auxiliary power.

Capital cost estimates to retrofit AEP system units with SCR have ranged from about $63 to $184 per kW in current dollars; the cost variation depends, in large part, on the degree of retrofit difficulty.

SCR is typically installed downstream of the economizer and upstream of the furnace air preheaters. Generally SCR operates above 600°F in order to avoid the formation of ammonium bisulfate, a sticky substance that can cause fouling of equipment located downstream of the SCR. The propensity for such formation occurs, logically, with increased flue gas sulfur concentrations. In order to both insure sufficient treatment residence time and prevent erosion, SCR design gas velocities are typically 20 ft/sec. Since flue duct velocities are typically 50-60 ft/sec, the SCR has an expanded flow cross-section. Critical parameters that affect SCR removal efficiency include NOx and flow distribution, ammonia distribution, and catalyst blinding and poisoning.

SNCR

Selective Non-Catalytic Reduction, or SNCR, reduces NOx to N_2 and water vapor without the assistance of a catalyst. Urea or ammonia is injected into the gas path where temperatures fall between 1700°F and 2100°F. Sensitivities of removal efficiencies were incorporated into the development of the optimization analysis. The optimization modeling assumed that SNCR was capable of reducing NOx 20% and 30%, respectively, on units greater than and smaller than 400 MW. Published results of testing indicated that the technology was capable of reductions over 50%. However, these results were from controlled tests performed on relatively small units, usually under steady operating conditions. The deeper the reductions, the higher the normalized stoichiometric ratio (NSR) and higher removal cost. Unfortunately, greater chances for ammonia slip and the formation of ammonium bisulfate occur with higher NSR.

AEP conducted the first large scale demonstration of SNCR at the 600 megawatt Cardinal Plant Unit 1 in Ohio. After some confidence was gained from the Cardinal Unit 1 tests, AEP entered into a partnering agreement with Fuel-Tech Corporation as the provider of SNCR technology. In February 2000, Fuel-Tech presented AEP with unit-series based cost estimates for AEP System generating stations. SNCR removal efficiencies are now estimated between 25% and 35% depending on the type of unit and retrofit difficulty. SNCR capital cost estimates range between $10 and $36. There are significant economies of scale with this technology and generally, the smaller the unit, the higher the capital cost. Operating costs for SNCR are about $1000 per ton of NOx removed; this essentially reflects the reagent cost. The Fuel Tech SNCR system uses a patented urea solution with additives for the reagent.

<u>Gas Reburn</u>

Gas Reburn involves the following: 1) Reducing the primary fuel heat input to 80%, 2) Introducing secondary fuel, usually natural gas, at least 250 milliseconds (15 ft above) downstream of the top burner row; and 3) Introducing over fire air at least 250 milliseconds downstream of the gas burners. Much of the OFA discussion earlier in this section pertains to this technology. Discussions have been held with both Energy and Environmental Research (EER), now a subsidiary of General Electric, and Mitsui-Babcock (MB) in order to develop costs estimates for AEP's 800 MW boilers. Both vendors believe that NOx can be reduced by about 55% (at full load). The cost for this system, and any system requiring natural gas, is very sensitive to the length of pipeline as well as generation over which that capital cost is distributed. Aside from gas delivery, another significant capital component of gas reburning is the installation of an extensive, remotely located over-fire air system. The loaded cost estimate for this system starts at about $20/kW and, depending on the remoteness of a gas supply, can run over $50/kW. Even at this price, these costs are secondary, when compared to the O&M cost of firing 20% natural gas. Within the time frame of this analysis projected gas costs have increased from about $3.65/mmBtu to $6.00/mmBtu (2005 dollars levelized over ten years). This translates to a NOx removal cost of between $3,500 and $14,000 per ton of NOx removed, for gas-coal fuel differential alone including the sulfur dioxide offset. As with over-fire air, a furnace tube repair and overlay O&M cost of $0.30/kw-yr per lbm-SO2/mmBtu is also included in the economics.

The NOx reduction capability of gas re-burn technology is derived from several sources. First, the primary burner zone heat release is reduced by 20% thereby reducing thermal NOx. Second fuel nitrogen and resulting NOx is also cut as 20% of the fuel heat input is now derived from gas. Third, although combustion at the coal burners is maintained at 10-15% excess air, once the combustion products pass through the gas burner zone, the stoichiometry is dropped to 0.9-0.95 wherein CO and volatile hydrocarbons scavenge available oxygen. Fourth, burnout with over fire-air further spreads out the heat release zone.

Most experience to date with gas re-burn has been reported on high NOx emitting, small wet bottom units. Much of the benefit is derived from the staging aspect. Emission performance data of gas re-burn systems have been compared in the past to uncontrolled furnaces operated without over fire-air. Staging with OFA ports reaps the majority of the benefit of gas reburning systems. The benefit of gas reburning over OFA may include reduced LOI, reduced potential for water wall corrosion, and possibly reduced propensity for steam generator slagging. However, the incremental economics do not justify firing gas at the current forecasted price of gas. Further, gas reburning systems are generally uneconomic for AEP's units even at originally forecasted gas prices.

The benefit of gas re-burn drops off with load as excess air levels generally increase with reduced load. Depending on the source, re-burning is no longer effective somewhere between 50-70% load. Consequently, if a unit is not dispatched near full load, the NOx reduction benefit is lost. Furthermore, the incremental economics of firing 20% gas above say 60% load will force an economically dispatched coal-fired unit to run at or below the point when gas is effective in reducing NOx. The optimization analysis assumes the technology to be capable of reducing NOx by 50% and 0% at full and 50% load respectively. For simplicity, the units were assumed to have 50% and 100% load segments and generation was distributed between the two, based on capacity factor. As already noted, the cost of gas is offset by an SO_2 allowance value of $355/ton (2005 levelized) as applied to the offset in sulfur emissions when firing gas.

Gas 100%

Firing units on 100% natural gas is a relatively inexpensive option in terms of capital investment, but a very costly one in terms of operating cost. NOx emissions from gas-fired burners are assumed to be 0.2 lb/mmBtu, which is consistent with testing conducted at AEP's Conesville Plant Unit 3 in Ohio and industry experience. In early optimization analyses AEP re-assessed the dispatch of the units according to marginal production costs against hourly forecasted market prices. Generally the dispatch was affected negligibly by all NOx reduction technology options with the exception of 100% gas firing. This option came up as a low cost alternative generally for the small wet bottom units that fire a relatively high cost (on a sulfur adjusted basis), high sulfur coal and are already dispatched at low capacity factors, typically 45-50%. At the time these analyses were performed, the baseline NOx levels for AEP's small cyclone units were very high. However, the subsequent baseline for these units was dropped owing to the success of over fire air on these types of units. Consequently, the economics for pure gas firing no longer existed other than for a couple of small high NOx emitting units. For all units where gas appeared to be an economically viable alternative, the dispatch analysis indicated that capacity factors were typically driven to 15-25%. Firing gas 100% of the time during the summer then results in operating these units essentially as "peakers". With the increase in gas prices, the economics for this option disappear altogether.

Cost estimates for gas firing were based, in part, on the retrofit at AEP's Conesville Units 1,2 & 3. (100% gas firing capability was installed on these units for SO2 compliance prior to Phase I of the Title IV program.) Gas supply pipeline costs were assumed to be $1 million/mile. Additionally there is a $1.5 million interconnect charge and a $500,000 charge for a pressure regulator. Gas delivery from the regulator and distribution into the boiler was estimated at $10/kW.

AEFLGR

Amine Enhanced Fuel Lean Gas Reburn, or AEFLGR, is the combination of gas reburning, fired without over fire air, in addition to SNCR (discussed above). This technology was developed and promoted by GRI, the Gas Research Institute. Fuel lean gas reburning is itself a means for reducing NOx but was not considered for the optimization analysis, as the reductions are similar to those of SNCR (but at higher operating cost). As an outgrowth to fuel lean gas reburning studies, GRI developed the amine enhancement concept. Fuel Tech has an exclusive license from GRI to install these systems. GRI claims a synergistic effect occurs when co-injecting gas and urea. The heat input by gas is typically 5-10% of the total; 7.5% was used in the optimization analysis. In AEFLGR, coal is fired at normal excess air levels, however, once the combustion products pass through the reburn zone, excess air levels drop to about 10%. SNCR is effective within a certain temperature window 1600°F-2100°F, more optimally between

1700°F and 1900°F. Introducing natural gas with the urea helps maintain the effectiveness of SNCR at reduced loads, when furnace gas exit temperatures decline. Removal efficiencies have been reported as high as 70% for this technology but not over the load range. A conservative value of 50% is used within the analysis with a normalized stoichiometric ratio of 1.5 (for the urea) and 7.5% gas firing.

Flame Attemperation

The concept of cooling the combustion zone to reduce flame temperature is not new. Gas turbine manufacturers have used combustor water and steam injection to reduce the formation of thermal NOx. The Rockport Plant, which fires Powder River Basin sub-bituminous coal, emits NOx at levels 40%-50% below Mountaineer, a sister unit that fires Eastern Bituminous coal. The lower NOx generation of PRB is believed to be due to lower concentrations of fuel nitrogen per mmBtu –dry basis and a low fixed carbon to volatile ratio. However, the high moisture content relative to eastern fuels (e.g., 25-30% vs. 6-8%) is believed to account for the majority of the reduction via reduced flame temperature.

Flue gas recirculation has been a means traditionally used to control heat absorption in the steam generator, primarily at part load. Gas recirculation tempers the flames by increasing the mass flow through the furnace; a side benefit is an accompanying reduction in NOx emissions.

Direct water injection was installed at AEP's Tanners Creek Plant Unit 4, a 500 MW supercritical cyclone unit, in order to help reduce NOx emissions for the Title IV program. In this installation, water is injected along the cyclone centerline. Full load NOx levels are reduced by about 25-30% when the total equivalent fuel moisture was 25% (15 gpm per cyclone, 165 gpm total).

Water and steam injection have also been used in utility boilers[4] to reduce NOx. Oil fired industrial boilers demonstrate a 15%-20% reduction in NOx with a water/fuel ratio of 0.3.

The primary air system at Rockport evaporates the majority, if not all of the surface moisture water in the mills[5]. Therefore, humidifying primary air or secondary air would have a similar tempering effect on combustion. Humidifying primary air is a simple, low cost means of trimming NOx. In terms of flame temperature reduction, it is about half as effective as spraying water directly into the hottest point of the flame. Flame stability will limit the extent to which water can be added as less volatile eastern coal is more difficult to ignite, particularly in low NOx burners. Testing of Flame Attemperation is ongoing. The maximum benefit anticipated for the AEP System results in eliminating the need for about 200 MW of SCR and 2000 MW of SNCR.

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[4] "Low Cost Techniques Reduce Boiler NOx", Chemical Engineering, February 1993

[5] When firing eastern fuel, mill outlet temperatures are maintained usually at about 150°F. However, at Rockport mill outlet temperatures usually range between 125-135°F. This is a direct result of the moisture content of PRB. At 125°F and a mill exhaust pressure of 60 in-H_2Og, the primary air saturates at about 12% moisture by volume. Assuming a 1.8:1 air to coal ratio and a coal flow of 1.45 million lbm/hr, the water vapor flow is about 200,000 lbm/hr, which correlates to about 14% of the coal by weight. Therefore roughly half the fuel water is evaporated. At 200,000 lbm/hr (400 gpm), the flame temperature is reduced by about 70°F due to sensible heat absorption alone.

PRB Firing

Since the concept of flame attemperation came about as a result of PRB firing experience, much of the previous discussion applies. The potential benefits of switching to a PRB blend or 100% PRB, include lower fuel cost, reduced NOx as well as reduced SO_2. In 1999, costs for delivering and firing PRB and/or a blend were identified for over 9200 MW of the 20,795 MW included in the optimization study. While the coal market has not seen the volatility of the natural gas market, spot prices and more importantly with regard to this option, spot price differentials between Eastern and PRB coals have fluctuated since.

Firing 100% PRB requires significant physical upgrades that typically cost on the order of \$50-100/kW. A preliminary economic assessment concluded that only two AEP units were viable candidates for firing pure PRB, namely Mountaineer Plant and Tanners Creek Unit 4. The former unit shares much commonality with Rockport and the conversion cost for that unit is estimated at \$20/kW. The SO_2 -adjusted delivered price of PRB to Tanners Creek Unit 4 has been sufficiently low and recent industry experience with PRB on cyclone units so encouraging, that it may be a candidate for complete conversion. All other units of the 9200 MW identified were considered for firing a PRB blend only. However, economics were evaluated for on-site and off-site blending as well as Ozone Season vs. year round firing. For simplicity, the optimization assumed that a 40% by weight (32% by heat) PRB fraction was blended with the planned coal for any particular unit. NOx reduction due to the blend was estimated from the Rockport vs. Mountaineer experience as well as that reported at Clifty Creek and other plants inside and outside the AEP system:

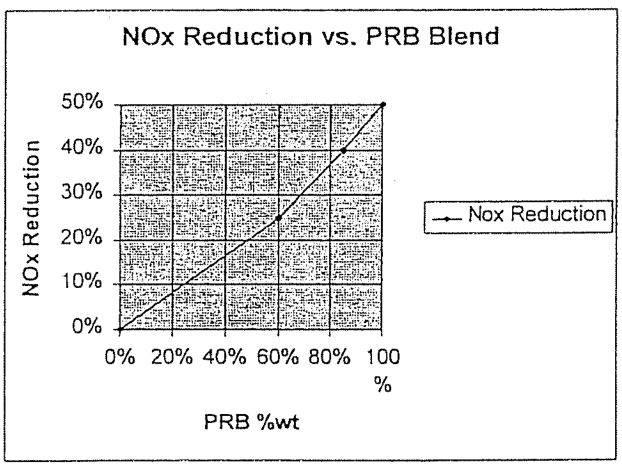

Figure 4. NOx Reduction vs. PRB Fraction

Other Technologies

AEP is actively engaged in the development of new, innovative approaches to reducing emissions from coal-fired power plants. In particular, AEP is partnering with Thermal Energy Corp. on a demonstration of the ThermaloNox system at AEP's Conesville Plant this summer. This technology relies on a conventional SO_2 scrubber to also remove NOx after the injection of phosphorous to oxidize NO to NO_2. In addition, AEP has partnered with Powerspan Corp. and FirstEnergy to demonstrate an electrocatalytic oxidation system to reduce SO_2, NOx and mercury simultaneously. These technologies have not been included in this analysis.

G. Analysis Mechanics

CAAA Title IV NOx emission rate baseline information was developed for each unit in the "System Base". Capacity factors (and heat rates) used in the optimization analysis were derived by a marginal production cost dispatch of the units.

As already identified, the optimization contains nineteen NOx reduction options and the additional option of doing nothing. For each of the nineteen reduction options, base information was developed for each specific unit regarding costs and removal effectiveness. These costs were entered in current dollars and escalated to 2005 and beyond. The analysis results are referenced to 2005 levelized dollars, levelized for the period of 2005-2014. O&M and capital were escalated at 2% per annum.

AEP's Fuel Supply provided fuel prices; gas prices are based on NYMEX Henry Hub futures (with an added delivery charge).

For each of the nineteen options, the NOx reduced as well as the levelized $2005 NOx costs were developed on a dollar per ton of NOx removed basis for each unit as applicable. The emissions removed and associated removal costs are fed into an optimization routine.

The routine performs an incremental cost optimization and orders the options from least to most expensive cost. Once the desired control level is reached, the algorithm stops. Specifically the routine orders the options for each unit according to average removal cost. Once this is established for each unit the program determines the incremental cost of the next least cost option for that unit. From this group it then selects the least cost increment option as the next to be implemented (and records the incremental reduction). The program loops in this manner until it has reached the target level of reduction[6]:

NOx removed by option "i" for unit "j", tons	dt(i,j)
NOx removed by option "i+1" for unit "j", tons	dt(i+1,j)
NOx removal cost of option "i" for unit "j", $/ton	dcdt(i,j)=
NOx removal cost of option "i+1" for unit "j", $/ton	dcdt(I+1,j)=

Incremental cost of option "i+1" option for unit "j" = $\dfrac{dcdt(i+1,j)*dt(i+1,j)-dcdt(i,j)*dt(i,j)}{(dt(i+1,j)-dt(i,j))}$

An ordered selection as a function of the NOx reduction depth and a final lineup of controls for the system is generated. Total reduction, capital cost, O&M costs, total annual costs, tallies of technology types, etc. are then calculated. The incremental and total system NOx removal cost curves are generated directly from the optimization logic output. Analysis assumptions are

[6] Note that the technology ranking order based on removal cost is unique to each unit since removal costs themselves are a function of relative capital and operating costs. In other words SCR might be the second most cost effective means for reduction on one unit but might only be the eighth most cost effective means on another.

continually updated to reflect the most current available information, be it technology removal efficiency improvements, or costs.

H. Sensitivities and Going Forward System Optimization

The analysis methodology is fairly flexible and allows for ready changes in input assumptions. Some or more of the following parameters will affect future optimization analyses:

1) Compliance Requirement

This includes required reduction levels and implementation timeline. These will be influenced by both federal and individual state law, once established. Additionally, looking to the future, US EPA's New Source Review program may further drive controls established for particular power plants. Also, legislation has been introduced in the U.S. Congress that calls for stringent NOx controls implemented on an annual basis, not just ozone season. An annual control requirement will generally make SCR a more cost effective option to implement due to the lower operating costs relative to SNCR. Allowance set asides, as they become established, will have a significant impact on planning

2) Technology Optimization & New Alternatives

Longer-term SNCR operation and effectiveness has been realized from tests conducted at Cardinal U-1. Sufficient data must be verified on different types and size units and over the load range before a technology's effectiveness is modified within the optimization routine. This is true for flame attemperation and more severe over fire air staging as well as effectiveness of these combined technologies. In addition, other technologies or combinations of technologies not considered but currently under development such as ThermaloNOx could be added to the array of options considered for the AEP System.

3) Revised Capital Costs

Capital costs for SCR have changed due to detail design efforts. The same has become evident with SNCR costs where unique configurations may add to the complexity of a retrofit. Refined costs have both increased and decreased relative to earlier estimates. With the 14,000-15,000 MW of SCR being planned, optimizations as well as unforeseen retrofit difficulties may still surface.

4) Fuel Supply

Significant changes in forecasted fuel costs including base, PRB and gas, have and will continue to be incorporated.

5) CCD Unit Influence

The analysis assumes the shared ownership of the certain units (Conesville Unit 4, Beckjord Unit 6, Stuart Units 1-4 and Zimmer, all located in Ohio) remains unchanged and prescribes SCR for Zimmer and the Stuart Units.

6) Market Conditions

The dispatch of any particular unit will change as a result of changes in forecasted market place conditions; this includes both raw fuel and electric energy market influences. Energy prices will also, of course, be affected by the NOx legislation itself as well as unforeseen environmental legislation. If emission reductions are held to absolute values and lower market price curves forecasted, then additional controls will be required since the system capacity factors will likely increase over time.

The analysis assumes that compliance levels must be met without purchased allowances as the robustness of the NOx allowance market is still very uncertain.

IV. SCR Technology at Big Sandy Unit 2

A. Major Cost Components

<u>Capital</u>

The SCR for Big Sandy Unit 2 is currently estimated to cost about $107 million (as spent) or about $133/kW (roughly $4/kW of this cost relates to removal of existing equipment). This cost is comparable to the cost of SCR at the 800 MW series of AEP units. The cost breakdown is given by:

Material	$45,236,681
Labor	$49,861,965
Engineering and Design	$ 5,517,528
AFUDC	$ 6,237,408
Total	$106,853,582

<u>Retrofit Difficulty</u>

SCR capital costs developed by the AEP SCR team vary considerably on a $/kW basis. Economies of scale present some benefit, but retrofit difficulty has a significant impact on costs. Unfortunately, the 800 MW series of units have a high degree of SCR retrofit difficulty. The SCR system must be installed downstream of the economizer and upstream of the air preheaters. The air preheaters on these units are horizontal shaft mounted in two parallel gas paths from the economizer. This configuration was originally conceived in the design of the 800 MW series in order to minimize exhaust ductwork between the economizer and precipitator. As a result, there is insufficient room to install the SCR's main and bypass ductwork and catalyst reactors between the economizer outlets and the air preheaters. In order to fit the SCR into this configuration without moving the economizer or precipitator and stack, reconfiguration and replacement of the horizontal shaft air preheaters and ductwork is necessary.

The air preheaters will be relocated further downstream of the economizer outlets and replaced with new vertically mounted air heaters. In addition, the two forced draft fans and two primary air fans must be relocated to accommodate the new air preheaters. This effort will require new foundations, structural steel and ductwork. These spatial limitations add to the labor costs of the SCR installation.

The Big Sandy site is not accessible by barge. Shipping costs are generally higher via truck and rail. Further, pre-fabricated components are limited by size and weight transport restrictions. More extensive onsite fabrication facilities will be required.

The cost of the Big Sandy Unit 2 SCR reflects the additional relocation work, spatial limitations and lack of river access. Most of the other units on the AEP system do not have such constraints, for instance the 1300 MW units have vertical shaft air heaters allowing space for the installation of the SCRs without relocation of major equipment. All of the above elevates the unit cost of the Big Sandy SCR.

Operations and Maintenance Costs

The cost of operating and maintaining an SCR system at Big Sandy Unit 2 has three components – the cost of the ammonia reagent, the cost of catalyst replacement and the cost associated with auxiliary power needs. The current estimate of this cost on a ton of NOx removed basis is $300. This figure will vary as the cost of ammonia is closely tied to the cost of natural gas, and the natural gas market is in a period of significant fluctuation. The total cost of operating and maintaining the SCR system will depend on the actual operating level of the unit and the NOx removal level. At $300/ton of NOx removed and the current estimate of removal of 6,600 tons of NOx per ozone season, the total ozone season O&M cost is estimated at $2.0 million.

B. Partnering Arrangement

Background

Given the complexity of retrofitting the latest SCR technology into various size units on the AEP system, a teaming concept was considered as the best approach to implement the NOx reduction program. AEP focused on three principal areas which required key participants: the SCR system, SCR catalyst, and SCR construction. AEP itself has the expertise and experience to provide balance of plant engineering and design, construction and project management, procurement services, and plant O&M impacts. A teaming strategy also "locked in" the essential resources needed to implement AEP's large scale program in the relative short time frame established by the U.S. EPA.

AEP evaluated at the onset of the SCR program in late 1998 the various SCR technologies provided by the three leading SCR vendors and their allied catalyst suppliers – Deutsche Babcock (DB)/Siemens, Babcock & Wilcox (B&W)/BHK, and ABB.

The evaluation focused on SCR systems installed in the dirty flue gas stream, between the economizer outlet and the electrostatic precipitators, thus termed high dust SCR systems. AEP's units are all high dust applications.

The following summarizes their experience at the time

- DB had successfully applied their SCR technology on 23 coal-fired units ranging in size from 35 MW to 630 MW, totaling 5100 MW. Siemens had accumulated over 650,000 hours of operating experience on coal fired **high dust** units such as those on the AEP system, with over 100,000 hours on units in the U.S. Siemens had provided catalyst for over 100 SCR systems totaling 24,000 cubic meters.

- B&W had successfully applied their technology on (4) 550 MW coal fired units in Taiwan. BHK, their strategic Japanese and SCR technology partner had experience with 57 coal and/or heavy oil utility units but many of which were not high dust applications.

- ABB had (7) coal fired units in Europe and **one** application in the U.S., ranging in size from 85 MWs to 250MWs. ABB did not have an alliance with a catalyst supplier.

Prior to the formation of the team, AEP reviewed DB's engineering and design costs as well as its 1999 fiscal year business plan and forecasted costs comprising its G&A, for determining an equitable reimbursement of DB's corporate G&A. Based on AEP's experience and knowledge of market conditions, AEP determined that DB's engineering and design costs were reasonable and in line with the recognized market value for the proposed work. Analysis of the plan indicated that DB's proposed G&A charges, profit margins, markups and E&D rates were reasonable discounted values for the large volume of work and the existing market conditions.

Upon review of DB's SCR experience, engineering and design capabilities, cost estimates and costing structure, in-house modeling expertise and facilities, and close alliance with Siemens, a leading catalyst manufacturer, DB was selected as the SCR partner.

Separately, negotiations were conducted with Siemens as the exclusive catalyst supplier for the AEP units. Given the large volume of catalyst required, AEP was able to negotiate favorable below market prices reflecting a "volume discount". This approach has proved economical as compared to present market prices obtained on a unit by unit basis. In support of this alliance and the increased market need for catalyst, Siemens has expanded its catalyst manufacturing capacity from 6,000 cubic meters of catalyst per year 12,000 cubic meters.

AEP's evaluation of the SCR erector focused on Babcock & Wilcox due to the long history between the two companies and the synergies developed through this relationship. B & W has successfully executed numerous AEP major construction (Gavin scrubber), maintenance, and retrofit projects under teaming agreements. B & W is one of the top employers of boilermakers in the U.S. and has a wide experience base in project management and field supervision. The company is known for creative and innovative construction technology, optimizing prefabrication and subassembly of components to minimize outage durations. Also, B & W has international and domestic experience on SCR retrofits. At the time they were performing a major SCR retrofit on a 600 MW unit for Illinois Power including air heater, FD fan, precipitator, and ductwork modifications, similar work expected on the AEP units.

Update

DB's experience base has grown considerably since the formation of the AEP team. To date, DB has almost 14,000 MW worth of installed SCRs in Europe, over 60 units with an average of 10 years of operating years with SCRs. In the U.S., DB has approximately 30,000 MWs worth of committed SCR projects for over 60 coal-fired units. Currently, DB is installing SCR on 23 U.S. units.

Other major utilities such as Duke, LG&E, PSNH, PP&L and WEPCo have teamed with DB to install SCRs on their units. This further validates AEP's teaming approach as the best method of meeting the NOx compliance.

A more detailed description of the partnering arrangement, including the scope and team objectives, is provided below.

Participants

Siemens Westinghouse
Deutsche Babcock (DB) (now Babcock Borsig Power)
Babcock & Wilcox Construction Company
American Electric Power Service Corporation

Scope

Implement AEP's Selective Catalytic Reduction (SCR) Retrofit Program in the most cost effective manner on AEP and OVEC/IKEC coal fired plants.

The base scope included development of a design basis for SCR at AEP's 1300 MW, 800 MW and 600 MW series of units. Since the original strategy was formulated, AEP continues to evaluate the need for SCRs on other AEP plants. The SCR "team" has also been approached by other utilities to provide SCR installation. In fact, the SCR "team" will be providing SCR engineering, procurement and construction services to owners of the 1300 MW Zimmer Plant in Ohio.

Team Objectives

- Reduce NOx emissions to acceptable levels while maintaining useful life and maintaining the high availability of the plants

- Be recognized as a world class team in engineering, procurement, and construction of SCR systems

- Maintain a core staff and continuity of personnel throughout the program such that "lessons learned" will be effectively addressed and integrated into successor projects and series design

- Reduce overall program costs through collaborative efforts and leveraging the expertise of participant

- Engineer, design, and construct SCR systems based on the best balance of cost effectiveness, constructability, space utilization, and minimizing disruptions to operating plants

- Develop mutually agreed upon performance evaluation criteria and incentives

- Develop innovative construction methods employing state of the art approaches on modularization and sub-assembly of components leading to minimal plant tie-in outage durations and site manpower requirements

- Jointly foster and develop efficient cost effective project labor contracts

- Recognize and incorporate safety into SCR engineering, design and construction

- Mutually establish SCR performance targets based on shared risk and reward

- Establish sub-tier contracts and cost reimbursement agreements based on a total and verifiable "open-book" philosophy, including incentives and/or shared savings approach when applicable

C. Schedule for Installation of SCR at Big Sandy

The following schedule has been developed for installation of SCR at Big Sandy 2:

- Site Preparation 7/29/01- 12/01/01
- Jobsite Mobilization 11/11/01- 2/16/02
- Onsite Steel Fabrication 12/2/01- 8/17/02
- Onsite Ductwork Fabrication 1/6/02-8/17/02
- Pre-Outage Steel Erection 3/3/02-8/31/02
- Install SCR Reactor and Ductwork, 12/22/02-2/26/03
- Tie-in Outage, 4/27/03-5/24/03

D. Conclusion

Big Sandy Plant and the other AEP System coal-fired power plants in the Midwest are faced with the requirement to comply with very stringent NOx emission limitations during the months of May to September beginning in 2003. The use of an allowance trading program as the basis for compliance provides significant flexibility in designing and implementing a compliance strategy. There exist a number of NOx control technologies that can play a role in an overall compliance plan. However, the stringency of the required NOx reductions will require widespread application of SCR technology, the most effective technology in terms of achievable NOx reductions. A thorough analysis of available technologies in the context of the required NOx emission reductions leads to the conclusion that SCR systems are needed at a number of AEP's largest coal-fired power plants, including Big Sandy Plant Unit 2. Not only is SCR required at Big Sandy Unit 2 for compliance, but it is a very cost-effective compliance measure within the overall AEP System NOx compliance program. In order to meet the May 1, 2003 compliance deadline, construction of the Big Sandy Unit 2 SCR system must commence no later than the Fall of 2001.

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

THE APPLICATION OF KENTUCKY POWER COMPANY	**)**	
d/b/a AMERICAN ELECTRIC POWER FOR APPROVAL	**)**	
OF AN AMENDED COMPLIANCE PLAN FOR PURPOSES	**)**	
OF RECOVERING THE COSTS OF NEW AND ADDITIONAL	**)**	**CASE NO. 2002-000169**
POLLUTION CONTROL FACILITIES AND TO AMEND	**)**	
ITS ENVIRONMENTAL COST RECOVERY SURCHARGE	**)**	
TARIFF	**)**	

DIRECT TESTIMONY

OF

JOHN M. MCMANUS

September 30, 2002

DIRECT TESTIMONY OF
JOHN M. MCMANUS, ON BEHALF OF
KENTUCKY POWER COMPANY,
d/b/a AMERICAN ELECTRIC POWER,
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY
CASE NO 2002-00169

I. Introduction

Q: Please state your name, position and business address.

A: My name is John M. McManus. My position is the Manager of Environmental Strategy and Compliance Planning in the Environmental Services Department of American Electric Power Service Corporation. The American Electric Power Service Corporation (AEPSC) is a wholly owned subsidiary of American Electric Power Company, Inc. (AEP) the parent of Kentucky Power Company d/b/a/ American Electric Power (AEP/Kentucky or Company). My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q: Please describe your education and business experience.

A: I earned a Bachelor of Science Degree in Environmental Engineering from Rensselaer Polytechnic Institute in 1976 and undertook graduate studies at the same location from 1976-77. I joined the AEPSC Environmental Engineering Division in September, 1977. After holding various positions in the environmental division over the years, I was appointed to my current position in January, 1997. In that position, I am responsible for overseeing AEP's compliance with Title IV of the Clean Air Act Amendments of 1990 (CAA) and for evaluating the potential for future legislative and regulatory environmental initiatives that could result in new emission control requirements for Company facilities. I am a licensed Professional Engineer in the State of Ohio.

Q: Have you testified in a hearing before this Commission previously?

A: Yes. I testified on behalf of Kentucky Power Company in Case No. 96-489, the Company's initial environmental surcharge case. I provided both written and oral testimony in that case.

Q: What is the purpose of your testimony in this case?

A: The purpose of my testimony is: 1) to describe regulatory programs for reduction of emissions of nitrogen oxides (NO_x) with which the Company's Big Sandy Plant must comply; 2) to describe the selection process for the NO_x controls that are included in the Amended Environmental Compliance Plan; 3) to describe why the projects in the Company's Amended Environmental Compliance Plan are needed to meet CAA requirements; and 4) to describe the operation of the NO_x allowance program, including the benefits from early compliance.

Q: Have you previously provided written testimony to this Commission concerning AEP/Kentucky's NO_x compliance plan?

A: Yes. I provided written testimony in April, 2001 in the Certificate of Public Convenience and Necessity Case No. 2001-093.

Q: What did that testimony address?

A: That testimony addressed the CAA's regulatory requirements for NO_x and the need for installation of an SCR on Big Sandy Unit 2 in order to meet those NO_x emission control requirements.

Q: Do you wish to adopt your testimony in the Certificate of Public Convenience and Necessity Case No. 2001-093 for purposes of this case?

A: Yes.

Q: Have you reviewed testimony of Mr. Michael Durner in Certificate of Public Convenience and Necessity, Case No. 2001-093?

A: Yes.

Q: Do you adopt it and incorporate it herein for purposes of this case?

A: Yes.

Q: For what purpose do you adopt and incorporate Mr. Durner's testimony?

A: I adopt and incorporate Mr. Durner's testimony for the purpose of explaining the NO_x control selection process used for the Big Sandy Plant environmental compliance projects.

II. The NO_x Regulatory Programs

Q: Have there been changes to the NO_x regulations and legal requirements subsequent to your testimony for the Certificate of Public Convenience and Necessity Case? Explain.

A: Yes. As described in my written testimony in the Certificate of Public Convenience and Necessity case, Big Sandy Plant is subject to more than one regulation to control NO_x emissions from the facility. Two of those regulations were promulgated by U.S. EPA and are referred to as the NO_x SIP Call rule and the Sect. 126 rule. A third regulation was promulgated by the Commonwealth of Kentucky to address ozone nonattainment issues within the Commonwealth. Since my written testimony in the Certificate case, the Commonwealth has rescinded its NO_x rule, which required reductions in NO_x emissions to a 0.25 lb/MMBtu level, and replaced it with a more stringent NO_x rule that is intended to reduce NO_x emissions to a level roughly equivalent to a 0.15 lb/MMBtu emission rate. The previous NO_x rule had a compliance deadline of May 1, 2003. The replacement NO_x rule has a compliance deadline of May 31, 2004. The replacement NO_x rule has been put in place to allow the Commonwealth to comply with U.S. EPA's NOx SIP Call rule, which requires the Commonwealth to adopt a rule requiring specific sources to meet NO_x emissions limitations by May 31, 2004. Finally, the Sect. 126 rule requires essentially the same level of NO_x emission reductions from certain sources in the eastern portion of Kentucky, including Big Sandy Plant. Since my testimony in the Certificate of Public Convenience and Necessity case, U.S. EPA has revised the compliance deadline for the Sect. 126 rule from May 1, 2003 to May 31, 2004.

Q: What are the currently applicable regulatory deadlines for NO_x control installation?

A: The action by U.S. EPA to revise the Sect. 126 compliance deadline to comport with the deadline of the state NO_x SIP Call rule results in the applicable deadline for all of these rules now being May 31, 2004.

Q: How is the NO_x compliance program established by the EPA rules structured?

A: This compliance program is designed to address an air quality concern that occurs only during the summer months, known as the "ozone season". The program requires compliance during the months of May through September, with the exception of the 2004 compliance period, which will begin May 31 of that year. For all years following 2004, the compliance period will begin May 1. The program is designed to limit total NO_x emissions from electric generating units and large industrial sources of NO_x on a broad regional basis but to provide flexibility in meeting compliance. The program utilizes NO_x allowances that can be transferred between sources to provide this flexibility. With this approach, each source will be allocated a certain number of NO_x allowances that represent on a broad basis a 75% reduction in NO_x emissions from current levels. If a source does not reduce its actual emissions to the allowance allocation level, it will have to obtain additional allowances from another source.

Q: What are the allowance allocation levels for the Big Sandy units?

A: Unit 1 has been allocated 593 allowances per ozone season beginning in 2004, and Unit 2 has been allocated 1,736 allowances. The Commonwealth will adjust the initial allocation levels in 2007 and the Big Sandy allocation levels may change.

Q: Are there any remaining issues associated with the allocation levels in Kentucky?

A: Yes. As discussed in my testimony in the Certificate of Public Convenience and Necessity case, the NO_x allowance budget for the Commonwealth includes a pool of allowances designated for new sources. This pool was originally set at 5% of the total budget for electric generating units. The Commonwealth had been considering increasing the amount of the new source set aside pool and reducing the number of allowances allocated to existing sources. However, the final Kentucky rule establishes the new source pool at the 5% level. As a result of legislation passed in the most recent session of the Kentucky legislature, the Commonwealth will auction the allowances in the new source pool. The Department of Environmental Protection will have to revise its SIP Call rule to include this auction requirement. However, this will not affect the allowance allocation for Big Sandy Plant.

Q: How does AEP/Kentucky propose to comply with the Big Sandy Plant allowance allocation level by the May 31, 2004 compliance deadline?

A: During the 2001 ozone season, actual emissions at Big Sandy Plant were 1,878 tons for Unit 1 and 6,411 tons for Unit 2. At higher capacity factors, actual emissions without additional NO_x controls would be even higher. In order for the units to individually meet the allowance allocation levels noted above, a reduction in emissions of approximately 70% for Unit 1 and approximately 75% for Unit 2 would be required, with an overall plant reduction requirement of approximately 75%. However, given the flexibility provided under the allowance program, it is not necessary to make actual emission reductions in those amounts at each unit as long as the aggregate emission reduction results in total emissions that meet the initial allowance allocation level plus any allowances that may have been obtained from other sources. While the allowance program provides some flexibility, it is worth noting that the overall NO_x reduction required, on the order of 75% from current levels across the region, is sufficiently stringent as to require some form of NO_x controls at almost all units. The controls that will be added to Big Sandy Unit 1 for purposes of NO_x control consist of an over-fire air system with water injection and furnace tube weld overlays. A selective catalytic reduction (SCR) system is being added to Unit 2 for NO_x control.

III. NOx Control Selection Process

Q: Please describe briefly the process used by AEP to determine which of the available NO_x reduction technologies to install on the generating units in the AEP System?

A: The applicable NO_x control requirements in the Commonwealth allow for the optimization of control technology through the deployment of cost-effective control equipment and interstate trading of NO_x emission allowances. This framework permits utilities with multiple units to evaluate the most prudent application of control technology and emission allowance markets to meet regulatory requirements for compliance and minimize the cost of control. Based on this compliance flexibility, AEP evaluated available technology options for each of its generating units using a broad array of technical resources including input from the steam generator original equipment manufacturers (OEMs), NO_x control equipment process suppliers and published technical papers from EPRI, utilities (both domestic and foreign) and consultants. AEP used this evaluation combined with its own experience with NO_x control technologies, to produce a cost-effective technology matrix. This matrix considered the expected and sustainable NO_x control level, the cost of installation based on industry experience and AEP project estimates, impacts to unit operating costs and potential reliability impacts, and general constructability and plant layout considerations. This analysis provided the guide to the prudent, cost-effective control options for each unit with a reasonable margin of compliance given the unknowns of the technologies. (The approach used is described in more detail in the Certificate of

Public Convenience and Necessity Case testimony of Mr. Durner that is incorporated herein.)

Q: Please describe briefly the NO_x compliance options and the effectiveness of the options that were considered as alternatives for Big Sandy Units 1 and 2.

A: A variety of possible NO_x compliance options were considered for both Unit 1 and Unit 2. The significant difference in unit capacity (Unit 1 @ 260MW and Unit 2 @ 800MW) was an important factor in determining the most cost-effective approach for each unit. A detailed discussion of these various options is available in Exhibit MWD-1 of the testimony of Mr. Durner. In brief, the options considered included:

a) <u>Purchase of NO_x Allowances and No Installation of NO_x Controls</u>. A theoretical option is to not install NO_x controls and buy the needed NO_x emissions allowances in the marketplace. The cost of NO_x allowances in the open market is expected to be driven by the next increment of control needed to achieve an average control level equivalent to a NO_x emission rate less than 0.15 lbs/MMBtu. The projected market price for NO_x allowances for 2004 have been and remain in a range between \$4,000 and \$5,000 per ton. The initial market activity for NO_x allowances has been in this range. If NO_x control technologies can be installed with a control cost below this target range, then application of technology is a more cost-effective approach and eliminates the market uncertainties as to both price and availability.

b) <u>Installation of Over-Fire Air (OFA)</u>. OFA uses a process to stage combustion of coal to reduce NO_x formation in the furnace. This is accomplished by installing ports for additional combustion air in the upper furnace above the existing coal burners. The quantity of air delivered to the existing burners is significantly reduced thereby placing the initial combustion process in a 'fuel rich' environment. This condition suppresses the flame temperature and creates limited availability of free oxygen resulting in reduced NO_x formation. The new upper furnace ports then provide the air needed to complete combustion when the partially burned fuel passes through this 'air rich' zone. The increased time for complete combustion allows for additional cooling of the combustion gases above the burner zone and assures near complete burnout of the combustion products in a safe and controllable manner. This method of NO_x control is generally expected to provide a range of reduction of 15% to 30% depending on fuel characteristics and furnace design. This technology by itself cannot achieve the reduction required at Big Sandy to meet the applicable NO_x requirements.

c) Installation of Selective Non-Catalytic Reduction (SNCR). SNCR achieves NO_x emission reduction by injecting urea slurry into the boiler upper furnace producing a chemical reaction that converts the NO_x to nitrogen and water vapor. SNCR only provides, however, a reduction in NO_x emission of approximately 20% - 30%. The process efficiency is very temperature dependent and results in un-reacted ammonia (commonly called ammonia slip) that can foul downstream boiler components. This technology by itself cannot achieve the reduction required at Big Sandy to meet the applicable NO_x requirements.

d) Installation of Over-Fire Air in Combination with Selective Non-Catalytic Reduction. OFA and SNCR can be combined to provide an overall reduction in

NO_x emissions in the range of 35 to 50%. This combined technology has several disadvantages, however, including moderate initial capital costs, high variable cost of control (e.g., urea consumption costs are high) and limited overall NO_x reduction. This combination of technologies also introduces the presence of un-reacted ammonia (similar to SNCR alone) that can foul downstream boiler components and impact unit availability. This technology by itself cannot achieve the reduction required at Big Sandy to meet the applicable NO_x requirements.

e) Installation of Selective Catalytic Reduction (SCR) Technology. SCR uses a catalyst that, in the presence of ammonia, will convert NO_x to nitrogen gas and water vapor. The use of a catalyst provides a much higher reagent efficiency and high NO_x control efficiency (greater than 85% NOx reduction). While it is the most capital intensive technology, SCR provides the highest control level for coal-fired units, and the lowest variable operating costs for units that can reasonably accommodate the SCR equipment.

f) Installation of Over-fire Air Combined with Use of Powder River Basin Coal. OFA with Powder River Basin (PRB) blended coal provides an improvement in NO_X control over OFA by using the inherent suppressed flame temperature produced by the high moisture present in PRB coal. This combination will typically provide a total NO_x reduction of 25 – 40%. This technology approach requires extensive modifications to the fuel handling, fuel preparation and boiler equipment due to the fuel's low heat value and combustion characteristics. This technology by itself cannot achieve the reduction required at Big Sandy to meet the applicable NO_x requirements.

g) Installation of Over-fired Air Combined with Water Injection Technology. OFA with water injection (flame attemperation) can achieve NO_x reductions in the range of OFA with PRB coal without the costs associated with the fuel handling upgrades. The water injection system is readily controllable to fine-tune the NO_x control levels and eliminates the potential for furnace slagging from the PRB coal characteristics. This combination of OFA with water injection will provide a NO_x reduction of 25% to 45% depending on boiler design and specific fuel characteristics. Over-fire air achieved 30-34% reduction at Big Sandy Unit 1 during the 2002 ozone season, and we expect another 7% reduction with addition of water injection. This technology by itself cannot achieve the reduction required at Big Sandy to meet the applicable NO_x requirements.

h) Installation of Amine Enhanced Fuel Lean Gas Reburn (AEFLGR) Technology. AEFLGR requires the use of natural gas as well as urea to reduce NO_x. Trials have produced mixed results (less than 50% NO_x reduction) and the variable cost of control is high. This technology by itself cannot achieve the reduction required at Big Sandy to meet the applicable NO_x requirements.

i) Fuel Blending. PRB fuel blended with local bituminous coal will achieve a NO_X reduction of 15 – 20% due to the influence of additional moisture, high volatiles and low inherent nitrogen in the PRB coal. However, blending requires upgrades to the coal handling system to control dust and assure a reliable feed system and burning PRB coal can result in excessive furnace slagging. This technology by itself cannot achieve the reduction required at Big Sandy to meet the applicable NO_x requirements.

j) Gas Reburn. Gas reburn involves the injection of natural gas above the coal flame zone. Approximately 80% of the heat input is provided from the coal with the balance from natural gas. The use of natural gas makes this an expensive control option with a 35 – 50% reduction in NO_x emissions. This technology by itself cannot achieve the reduction required at Big Sandy to meet the applicable NO_x requirements.

k) Conversion to Natural Gas. 100% natural gas conversion is a very costly control option as it requires extensive modifications to the steam generator to assure full load production of steam and greatly increases the fuel cost. A full natural gas conversion is projected to provide a NO_x emission reduction of 50 – 85% depending upon furnace design.

Q: What kinds of costs are associated with the available NO_x control technologies?

A: Each NO_x control technology has an associated cost for capitalized equipment, a cost of operation for reagent, fuel or loss of unit efficiency, and a cost for ongoing maintenance repair/replacement.

Q: How do you determine that a particular NO_x control option is cost-effective?

A: Each of these associated costs is allocated against the tons of NO_X removed to establish the incremental cost of control for the specific unit. A cost-effective control strategy blends the appropriate control technologies to achieve the lowest cost of NO_x control to meet the applicable requirements of the NO_x control program.

Q: Please describe the analytical techniques used to evaluate the cost-effectiveness of the possible NO_x control technologies for the Big Sandy Units.

A: The detailed analytical method used to evaluate the cost-effectiveness of available NO_x control technologies is described in Mr. Durner's testimony at MWD-Exhibit 1, pages 21 through 23. In brief, the analysis uses an optimization algorithm that determines the cost-effectiveness in dollars/ton for each potential control combination including buying NO_x allowances on the open market. The unit is then placed in a production cost model along with the other units in the AEP fleet and the model determines the most favorable NO_x control technologies going forward. The results are reviewed to assure a rational outcome and to provide any further engineering or regulatory insight prior to final selection. The analysis considers key variables such as capital equipment costs, reagent consumption, catalyst life, fuel supply costs and market changes in NO_x allowances.

Q: Please describe the results of the analyses performed for the Big Sandy Units.

A: The analyses resulted in a ranking of NO_x control technologies based on cost-effectiveness in terms of cost in dollars per tons of NO_x removed. The results of the ranking analysis for Big Sandy Unit 2 were included in MWD-Exhibit 1, page 5 of 28 to Mr. Durner's testimony. The results of the ranking analysis for Unit 1 are discussed in Exhibit JMM-1 of this testimony. The analysis results show that the use of SCR on Unit 2 and the use of OFA with water injection on Unit 1 provide the needed NO_x reductions. It should be noted that although the cost of the SCR for Big Sandy Unit 2 in dollars per ton of NO_x removed has increased since this analysis, the ranking results have not changed.

Q: Explain how the selected technologies allow AEP/Kentucky to meet the regulatory requirements for NO_x.

A: A NO_x reduction of approximately 75% is needed at Big Sandy for the plant to comply with its NO_x emission allowance allocation or a significant number of NO_X allowances will need to be purchased every year. The cost and the availability of NO_x allowances in future years for compliance is unknown at this time. Reliance on an uncertain marketplace is an unacceptable compliance strategy and would place the Company and its ratepayers at an unacceptable risk of non-compliance. Therefore, AEP elected to install NO_x control technologies to meet the regulatory control levels with a prudent compliance margin. Given that Big Sandy Unit 2 is over three times the size of Unit 1, a greater portion of the NO_x reduction is needed from that unit. In addition, application of the most effective NO_x control technology at Unit 2 provides greater flexibility in selecting control options for Unit 1. Selective Catalytic Reduction (SCR) technology was chosen for Unit 2 as the most cost-effective approach for that unit considering both cost and the stringency of the NO_x control requirements. Big Sandy Plant cannot cost-effectively meet the applicable NO_x control regulatory requirements without the use of SCR at Unit 2. Because SCR can achieve NO_x reductions on Unit 2 that are greater than the overall 75% needed at the plant, a less efficient and less capital intensive control technology can be used at Unit 1. After evaluating the cost-effectiveness of available options, a combination of over-fire air with water injection has been chosen for Unit 1.

Q: Have the costs that were originally projected for an SCR at Big Sandy Unit 2 changed?

A: Yes. The currently projected costs for the Big Sandy Unit 2 SCR have increased from the original estimate.

Q: If the higher costs that are now expected for the SCR at Unit 2 had been considered in the initial selection process, would a different technology have been selected for Unit 2?

A: No. As explained above, the ranking did not change in the analysis. Even though the cost of the SCR technology has increased from original estimates, it remains true that there are no other technologies that can achieve the level of reduction required for Big Sandy Unit 2 at a lower cost per ton than the SCR. Because the optimization algorithm identifies the least cost NO_x reduction through an incremental least cost basis as a function of the required depth of reduction for each individual unit, the specific NO_x reduction technology selected for a unit is determined as much by the amount of NO_x reduction that is required as by the relative cost-effectiveness of options available for that unit.

Q: Why were different NO_x controls selected for Units 1 and 2?

A: No single control technology can be implemented on both units in a cost-effective manner and achieve the required NO_x reductions. A single control technology deployed on both units will either under- or over-control the NO_x emissions. If a low control efficiency technology is selected for both units, the plant will be under-controlled, thus requiring the purchase of NO_x allowances. If the most efficient NO_x control technology (SCR) is applied at both units, the plant will be over-controlled. The appropriate solution is a mix of NO_x control technologies to assure compliance and cost-effectiveness.

IV. Need for Selected Projects

Q: What additions are being made to the Company's Environmental Compliance Plan for consideration in this proceeding?

A: For Big Sandy Plant, in addition to the NO_x allowance account, the Amended Environmental Compliance Plan contains installation of an over-fire air system with water injection and associated furnace tube overlays (as needed) on Unit 1 and installation of a selective catalytic reduction (SCR) system at Unit 2. Because the current Unit 2 electrostatic precipitator is now marginal and the installation of the SCR will affect its ability to meet its permitted particulate limits (pursuant to Title V of the CAA), the necessary upgrade to the precipitator is also included in the Amended Environmental Compliance Plan. See Application Exhibit 1.

Q: Why is the Company installing NO_x control technology when NO_x allowances can be purchased?

A: As noted above, the stringency of the NO_x reduction program that has been put in place by the Commonwealth will require that almost all regulated NOx sources will have to install some type of NO_x reduction technology. SCR is the only technology that can achieve the nominal 75% reduction level required. SCR can actually achieve removal levels exceeding 75%, allowing for the application of less efficient NO_x technologies like over-fire air on some units. The SCR system being installed on Unit 2 is designed to achieve 90% reduction in NO_x emissions. While the use of a NO_x allowance trading program provides for the opportunity to purchase allowances in lieu of installing NO_x control technology, the current availability of allowances at the level that would be required by a facility with the emissions of Big Sandy Plant is very uncertain. It is important to keep in mind that the reduction obligation begins in 2004 and continues every year into the future. A strategy that relies solely or largely on purchase of a large number of allowances must provide that number of allowances every year. In addition, the current market price for NO_x allowances useable for the beginning years of this program is in the range of $4,000 - 5,000, as reported periodically in the publication Air Daily and available from emissions brokerage services like Cantor Fitzgerald. While information on prices in the NO_x allowance market is becoming increasingly available, information on the depth of the market, or number of allowances readily available for purchase, is still very scarce, with the result being a significant amount of uncertainty over the ability of the market to meet a large, annual demand for allowances. An example of market information currently available is provided in Exhibit JMM-2, which is a copy of a recent Cantor Fitzgerald emissions trading bulletin for September 19, 2002. It can be seen in that bulletin that NO_x allowances for the 2004 vintage year are in a range of $4,600 – 4,900 per allowance. Two recent trades are also shown, both for $4,800 per allowance. One trade was for 150 allowances, the second for 50 allowances. The size of these trades is typical for this market, with very small numbers of allowances in most transactions. The purchase of NO_x allowances at current market prices instead of installing NO_x control technology would not be a cost-effective compliance approach for the Big Sandy Plant. In addition, the number of allowances that would be needed by Big Sandy Plant may not be available in what is a very thinly traded market.

Q: Is the Company seeking recovery for costs of projects that control pollutants other than NO_x? Explain.

A: Yes. An electrostatic precipitator upgrade project is included in the Amended Environmental Compliance Plan and this filing for cost recovery. The precipitator upgrade project will be needed in order for Big Sandy Unit 2 to remain in compliance with applicable Commonwealth of Kentucky requirements for particulate emissions and opacity.

Q: What particulate emission requirements apply at Big Sandy Plant?

A: Both units at Big Sandy Plant have mass particulate emission limits and visible opacity limits. The mass emission limit is 0.24 lb/MMBtu. The visible emission limit is 40% opacity. These limits are incorporated in the plant's air operating permit, referred to as a Title V permit.

Q: Do the units currently meet these limits?

A: The units currently are in compliance with the applicable limits. However, at times a reduction in operating load on Unit 2 is needed to ensure compliance if there are component upsets or failures on the electrostatic precipitator. If the precipitator were not upgraded when the SCR is installed, the Unit would not be able to meet its permitted operating limits for particulates and opacity on a consistent basis and would incur many more operating curtailments.

Q: What is the status of the Plant's current operating permit?

A: The present operating permit expires at the end of 2004, and it is expected that the new operating permit willalso contain language regarding compliance monitoring with the particulate standard. Because Big Sandy currently operates near both the opacity and particulate standards, steps must be taken to improve the ESP in order to assure compliance with the Clean Air Act requirements and the Company's Title V permit that has been issued, and will be re-issued soon, pursuant to the Clean Air Act.

V. Operation of NO_x Allowance Program

Q: When will the NO_x control systems be placed in operation?

A: The over-fire air system and water injection ports were installed on Big Sandy Unit 1 during an outage that began in late March of this year. The unit returned from the outage on May 20 with the over-fire air system in service. The remainder of the water injection system can be installed while the Unit is in service. The completion of this system is planned for later this year. The SCR system on Big Sandy Unit 2 is scheduled to be placed in service in May, 2003.

Q: Are there incentives under the Kentucky NOx rule to control NO_x emissions prior to the May 31, 2004 compliance deadline?

A: Yes. The Kentucky rule includes a provision to encourage early reductions of NO_x emissions. Under this provision, a source that reduces its NO_x emission rate below 0.45 lb/MMBtu will be eligible to apply for early reduction credits (ERCs).

Q: Will the Big Sandy units be eligible for ERCs?

A: Yes. The application of the over-fire air system on Unit 1 should result in an emission rate in a range of 0.35 – 0.38 lb/MMBtu. The application of SCR at

Unit 2 should result in an emission rate below 0.10 lb/MMBtu. Both units will be able to apply for ERCs, for reductions achieved in 2002 and 2003 for Unit 1 and for reductions achieved in 2003 for Unit 2.

Q: Are there other reasons for installing the NO_x control retrofits prior to the May 31, 2004 deadline?

A: Yes. The current schedule allows for fine-tuning of the control systems and consideration of further controls or strategies if problems are encountered that may prevent the Plant from initially reaching the expected reductions and meeting the applicable regulatory limits by the regulatory deadline.

Q. How many early reduction credits will Big Sandy Plant receive?

A. There is a fixed number of early reduction credits available under the Kentucky regulation, set at 13,520. If sources in Kentucky apply for more credits than are available in the ERC pool, the number of credits received will be some fraction of the number requested. That fraction is uncertain at this time as it is not yet clear how many other sources will apply for ERCs and how many will be requested in total for the Commonwealth.

Q: Is Big Sandy Plant the only AEP facility at which NO_x controls will be operated prior to the May 31, 2004 compliance deadline?

A: No. Each state that has a NO_x emission reduction rule has an ERC provision similar to the provision in the Kentucky rule. These provisions are intended to act as an incentive to operate emissions control equipment prior to the required compliance date with the intent of achieving an environmental benefit earlier than would otherwise occur. AEP has already begun operation of SCR systems on units in Ohio and West Virginia and installed and begun operation of an over-fire air system at a unit in Indiana to achieve early emission reductions.

Q: How will the NO_x emission allowance system work?

A: The NO_x allowance system will be operated in essentially the same way as the SO_2 allowance program. U.S. EPA will establish allowance accounts on its Allowance Tracking System (ATS) for each unit that is affected under this program. EPA will deposit in the unit accounts the appropriate number of NO_x allowances for each year of the program. At the end of each compliance period (in this case the five months from May to September), the source will demonstrate the actual amount of NO_x emissions in tons and EPA will deduct that number of NOx allowances from the unit accounts. The source owner has the obligation to ensure that there are an adequate number of allowances in the account to cover the emissions. Any allowances that remain in the account can be held, or "banked", for future use.

Q. Has Big Sandy Plant received its initial allocation of NO_x allowances?

A. Yes. The NO_x allowance accounts for affected sources in Kentucky have been activated by U.S. EPA and the units have been allocated allowances for the years 2004, 2005 and 2006. As noted above, Unit 1 has been allocated 593 allowances and Unit 2 has been allocated 1,736 allowances.

Q: Will Big Sandy Plant have sufficient allowances for compliance or an allowance surplus?

A: With the combination of an over-fire air/water injection system on Unit 1 and an SCR system on Unit 2, it is projected that Big Sandy will have a small surplus of allowances. However, the number will depend on the actual performance of the NO_x control technologies being installed and the operating levels of the units. In addition, any ERCs earned for reductions prior to 2004 can be banked for use in 2004 and 2005, providing additional compliance margin in those years.

Q: What will be done with any excess allowances in the Big Sandy accounts?

A: At this time, it is expected that the number of excess allowances will be small and that they will be carried forward in the Big Sandy accounts as a form of compliance margin for future years. If the performance of the NO_x control systems is much better than projected and a much larger number of allowances remain after each compliance period, consideration may be given to transferring some allowances to other units on the AEP system or selling allowances in the market.

Q: Does this conclude your testimony?

A: Yes.

American Electric Power
Big Sandy Unit 1 - NO_x Control Strategy
2002

Introduction

The purpose of this analysis is to discuss the NO_x control technology selected for installation on Kentucky Power Company's Big Sandy Unit 1 generating unit.

Information summarizing regulatory requirements necessitating NO_x controls and discussing subsequent optimization analyses to determine appropriate NO_x control technology for the AEP system, including the Big Sandy Plant was provided in testimony provided by Michael Durner in Certificate of Convenience and Necessity, Case No. 2001-093. Additionally, the aforementioned testimony addressed the optimization procedure with respect to the development of a NO_x compliance approach for the AEP system (East) by discussing significant parameters impacting the analysis.

Impact of the Sect. 126 and NO_x SIP Call Rules on Big Sandy Plant[1]

Big Sandy Plant, located in eastern Kentucky near Louisa, has 2 coal-fired electric generating units. Unit 1 began operation in 1963 and has 260 megawatts of net generating capacity. Unit 2 began operation in 1969 and has 800 megawatts of net generating capacity. Both units burn Eastern Kentucky coal and are equipped with low NO_x burners to reduce NO_x emissions for compliance with Title IV emission rate limitations. Unit 1, the primary focus of this report, has a wall-fired, dry bottom boiler, a subcritical steam cycle and a cold-side electrostatic precipitator for particulate emissions control.

Table 1 below outlines the impact to the Big Sandy Plant of both the Clean Air Act Amendments Title IV Program and the SIP Call requirements on NO_x emissions projected for the 2004 (and beyond) Ozone Season. Recent capacity factors have ranged from 86% to 94% on Big Sandy Unit 1 and from 76% to 88% on Unit 2. These two units are forecasted to continue operating with high capacity factors due to the relatively low priced fuel. However, the capacity factors are expected to change somewhat during the summer ozone season as a result of incorporation of NO_x allowance costs in the cost of operating the unit, with the Unit 2 capacity factor increasing slightly and the Unit 1 capacity factor decreasing by a small amount. Calculation results are presented in Table 1 assuming a 90% capacity factor for Unit 2 and a 85% capacity factor for Unit 1.

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[1] This report refers repeatedly to the requirements of U.S. EPA's Sect. 126 rule. It should be noted that the NO_x control requirements of the Sect. 126 rule and the NO_x SIP Call rule are essentially the same, with the possible exception of a potentially larger "new source set-aside" or "holdback" under the NO_x SIP Call program. The compliance deadlines for the two programs have now been made consistent (May 31, 2004).

Big Sandy Emission Projections

(Assumes Capacity Factors of 85% on Unit 1 & 90% on Unit 2)

	Unit 1	Unit 2	Plant	**Total Plant** NO_x Reduction, % relative to pre-Title IV Emissions	**Total Plant** Incremental NO_x Reduction, %
2004 Emission Rate (lb/mmBTU)					
Pre CAAA Title IV Controls *	1.00	1.17	1.13	0%	0%
Title IV Controls	0.55	0.57	0.57	50%	50%
SIP Call Limit (based on absolute tons)	0.14	0.13	0.13	88%	76%
2004 Ozone Season Heat Input (1000's mmBTU)	7837	25883	33720		
2004 Ozone Season Emissions (tons)					
Pre CAAA Title IV Controls	3919	15142	19061	0%	0%
Title IV Controls	2155	7158	9313	51%	51%
NO_x Allowance Allocation	593	1736	2329	88%	75%

Table 1. Projected NO_x Emissions for Big Sandy Plant

In order to comply with SIP Call emissions limits, particularly during a hot summer, Big Sandy Plant will be required to reduce tons of NO_x emissions by approximately 75% from projected emission levels based on utilizing only low NO_x burners.

As discussed in testimony provided by Michael Durner in Certificate of Convenience and Necessity, Case No. 2001-093, Big Sandy Unit 2 is installing SCR technology to control NO_x emissions at a design efficiency of approximately 90% removal. By utilizing SCR on the larger Unit 2, NO_x emissions allowances will be available that can be credited to Unit 1 under the cap and trade provisions of the Section 126 Petition and SIP Call rules. Nonetheless, NO_x controls for Unit 1 are still necessary, although lower cost and efficiency options can be considered because of the contribution of NO_x removal from the Unit 2 SCR control technology. The following table depicts the required Unit 1 NO_x removal if the Unit 2 SCR is operating at 90% removal efficiency.

	Unit 1	Unit 2	Plant Total
Ozone Season NO_x Emissions with Title IV Controls, Low NO_x Burners (tons)	2155	7158	9313
SIP Call Ozone Season NO_x Allocations (tons)	593	1736	2329
NO_x Reductions (tons)	1562	5422	6984
Unit NO_x Removal with SCR @ 90% (tons)			6442
Net Unit 1 Reduction Required with No Margin of Compliance (tons)			542

Table 2. Net Unit 1 NO_x Reductions with Unit 2 SCR @ 90% Removal

Compliance with the SIP Call and 126 Petition rule requirements can be achieved at Big Sandy Plant by utilizing the cap and trade provisions of those rules in conjunction with installation and operation of an SCR on Unit 2 and non-SCR NO_x control technology on Unit 1.

Unit 2 is expected to operate at a 90% capacity factor with the SCR operating at 90% removal efficiency. If Unit 2 is operating as projected and Unit 1 operates at an 85% capacity factor, then the Unit 1 NO_x reduction requirement would be 25%.

However, because the SCR removal efficiency and the capacity factors of the operating units is variable, the NO_x control technology applied to Unit 1 must also allow for a range of effective control efficiencies. The NOx removal capability of over-fire air technology in combination with water injection on Big Sandy Unit 1 is currently projected to allow for a removal efficiency of at least 35%. (Note that Table 3 below indicates a removal efficiency for OFA/water injection of 28%. While this was the original projection, it is now felt that greater than 35% removal is achievable, which will result in an even more cost-effective compliance solution.)

Commercially Available NO_x Control Technologies

A number of technologies are commercially available to reduce NOx emissions. **Table 3** below identifies NOx control options considered for Big Sandy Unit 1 and the cost-effectiveness of each in dollars per ton of NOx removed. These options are ordered from lowest to highest dollars per ton of NOx removed.

NOx Reduction Option	Capital Cost $/kW (Current $)	Technology NOx Removal Efficiency (%)	NOx Removal Cost $/ton – removed	NOx Removed (tons)
No Reductions	$0	0%	$0	0
OFA	$15	20%	$1,965	440
Water Injection	$4	10%	$2,246	220
OFA/Water Injection	$20	28%	$2,228	616
SNCR	$28	25%	$3,224	550
SCR *	$148	85%	$3,793	1870
OFA/PRB Fuel Blend	$26	34%	$4,603	748
AEFLGR	$53	50%	$4,985	1100
Gas Reburn	$40	49%	$5,310	1078
PRB Fuel Blend	$11-$21	17%	$6,011 – $6,887	374

Table 3. Big Sandy 1 NOx Reduction Options

*SCR estimate of $ 148/Kw is based on preliminary studies. A detailed design estimate was not developed and would probably be higher based on our experience with SCR cost on Unit 2.

A brief description of the options considered is provided below. More detailed descriptions of the technologies were provided in testimony provided by Michael Durner in Certificate of Public Convenience and Necessity, Case No. 2001-093.

- No Reductions
  Do not install NOx controls and buy the needed NOx emissions allowances in the marketplace. The cost of market allowances should be driven by the next increment of NOx control in the market to achieve average control levels equivalent to the NOx emission requirements. If NOx control technologies can be installed with a control cost below this target range, then application of technology is a more cost effective approach.

- OFA, or Over-Fired Air
  This technology essentially starves the main burner zone of oxygen during initial combustion, thereby helping to minimize the oxidation of nitrogen. Heat release is less concentrated as well which reduces the formation of thermal NOx.

- Water Injection
  This technology reduces the formation of thermal NOx by reducing the rate of heat release within the burner zone by lowering the peak combustion temperature.

- OFA/Water Injection
  This option uses both OFA and Water Injection to reduce NOx and allows for a range of control needed to meet compliance.

- SNCR, or Selective Non-Catalytic Reduction

This technology uses urea or ammonia reagent to chemically reduce NOx to N_2 and water vapor in the absence of catalyst. The reagent is injected within a specific temperature window inside the convection passes of the steam generator.

- SCR, or Selective Catalytic Reduction
  This technology uses ammonia in the presence of a vanadium catalyst to chemically reduce NOx to N_2 and water vapor. SCR units are installed downstream of the steam generator economizer and upstream of the air preheaters.

- PRB Fuel Blend
  This NOx reduction option involves blending upwards of 40% Western Sub-Bituminous Coal from the Powder River Basin (PRB) with native coal. The combustion of PRB coal results in formation of substantially less NOx than eastern bituminous coal due to its high moisture content, high volatiles to fixed carbon ratio and lower nitrogen content.

- OFA/PRB Fuel Blend
  This option uses both OFA and PRB blending to reduce NOx.

- Gas Reburn
  This technology involves the injection of natural gas above the main burner firing zone. Approximately 20% of the heat input into the furnace is derived from the natural gas. The natural gas acts to reduce the NOx concentration of the coal combustion products. Over-fire Air is integral to this technology wherein fuel burnout is completed.

- AEFLGR, or Amine Enhanced Fuel Lean Gas Reburning
  This technology is essentially a hybrid of Gas Reburning and SNCR. 5-10% of the heat input into the boiler is derived from natural gas. A urea-based reagent is injected into the furnace with the natural gas.

Overview of NOx Optimization Analysis

An optimization algorithm was developed within AEP in order to help identify cost effective strategies and sensitivities to a host of variables that affect the system optimization, including market forecasts, unit-specific technology capital costs, and unit-specific technology incremental operating costs. The optimization identifies the least cost NOx reduction through an incremental least cost basis, (dollars per ton of NOx removed in 2005 levelized dollars), as a function of the required depth of reduction for each individual unit and the system as a whole. As a result, the specific NOx reduction technology selected for a unit is determined as much by the amount of NOx reduction that is required as by the relative cost effectiveness of options available for that unit.

Figure 1 illustrates the NOx removal cost (dollars per ton of NOx removed) as a function of the overall reduction required for the AEP System. The removal cost includes both capital carrying charges as well as operation and maintenance costs. In order to achieve the overall reductions required, NOx controls with costs in excess of $5,000/ton may be needed.

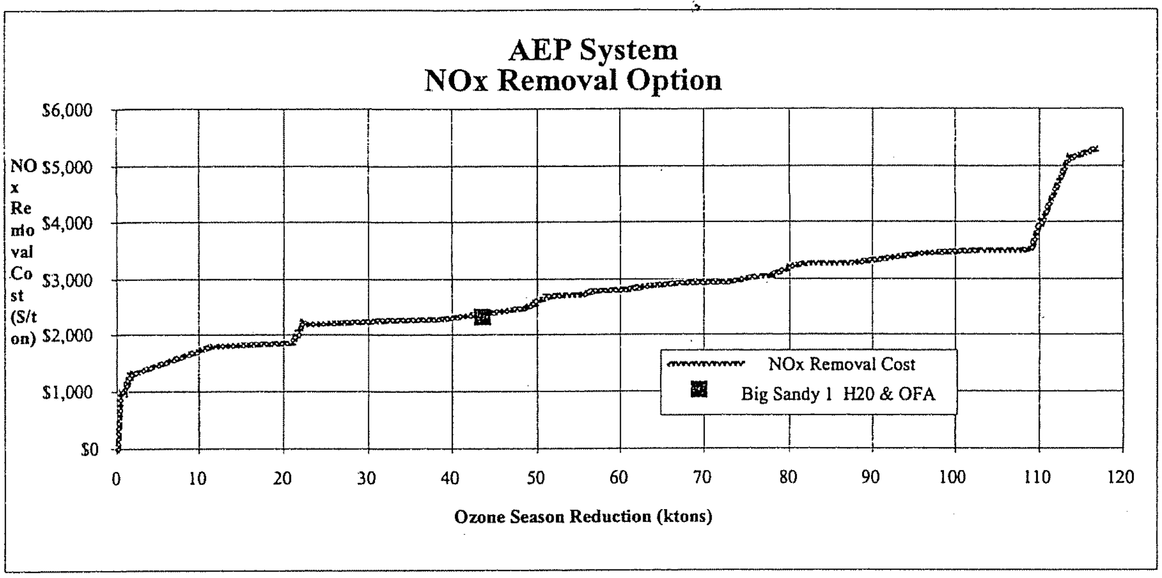

Figure 1. AEP System NOx Removal Option Cost, <u>Current Plan</u>

Technology Selection for Big Sandy Unit 1

Results of the optimization analysis indicate water injection and OFA systems on Unit 1 provide the optimal capital and removal costs for achieving the targeted reduction in NOx. The water injection and OFA NOx removal cost for Unit 1 was originally estimated at approximately $2228/ton of NOx removed. As identified in Figure 1, the cost effectiveness of water injection and OFA for Big Sandy Unit 1 is roughly at the midpoint of the required overall AEP System reduction. It is now expected that actual experience with OFA and water injection will be more effective at reducing NOx than originally thought, which will improve the cost-effectiveness.

The aforementioned Table 2 illustrates how water injection/OFA is selected by the optimization logic for Big Sandy Unit 1. Options are ordered from least expensive to most expensive on a dollars per ton of NOx removed basis. The optimization routine assigned the least cost option to a particular unit, starting with no reductions, at $0 cost. A desired level of NOx reduction was targeted for the AEP system and the routine performs the selection by picking technologies according to the next least incremental costs.

OFA and Water Injection Technology at Big Sandy Unit 1

The OFA system and water injection ports were installed during the Spring, 2002 unit outage. The unit returned to service with the OFA system in service. The remaining portions of the water injection system can be installed while the unit is in service. The water injection system installation is expected to be complete by the end of this year.

<u>Capital</u>

The water injection and OFA systems for Big Sandy Unit 1 are currently estimated to cost approximately $5.2 million, as spent, or about $20/kW.

Project	Cost Estimate	Project Total
Over-Fire Air:		
Material:	$1,973,666	
Labor:	$1,037,750	
Other:	$758,781	$3,770,197
Water Injection:		
Material:	$221,974	
Labor:	$204,649	
Other:	$224,680	$651,303
Weld Overlays:		
Material/Labor:	$650,000	
Other:	$131,000	$781,000
Grand Total:		$5,202,500

Table 4 Unit 1 Project Cost Estimates

Operations and Maintenance Costs

The cost of operating the OFA and water injection system on Big Sandy Unit 1 has two components: boiler corrosion maintenance and prevention due to the OFA system and heat rate penalties associated with the water injection system. Estimated operation and maintenance costs associated with boiler corrosion issues are approximately $109,000 annually, while costs linked to the water injection heat rate penalty are estimated at $220,000 per year.

Conclusion

Big Sandy Plant and the other AEP System coal-fired power plants in the Midwest are faced with the requirement to comply with very stringent Ozone Season NOx emission limits. The use of an allowance trading program as the basis for compliance provides significant flexibility in designing and implementing a compliance strategy. A number of NOx control technologies that can play a role in an overall compliance plan. However, the stringency of the required NOx reductions will require widespread application of SCR technology, the most effective technology in terms of achievable NOx reductions. A thorough analysis of available technologies in the context of the required NOx emission reductions leads to the conclusion that SCR systems are needed at a number of AEP's largest coal-fired power plants, including Big Sandy Plant Unit 2.

Operation of SCR technology on Unit 2 at high NOx removal efficiencies combined with NOx cap and trade programs enables other non-SCR options to be considered for reducing NOx from the smaller Big Sandy Unit 1. Results of the NOx optimization analysis for the AEP system indicate water injection and OFA systems on Unit 1 provide the optimal capital and removal costs for achieving targeted NOx reductions. The water injection and OFA NOx removal costs for Unit 1 are estimated at less than $2,228/ton of NOx dependent on the final achieved NOx removal level.

Exhibit JMM -

Cantor Fitzgerald Environmental Brokerage Services
19 Old Kings Highway South
Darien, CT 06820
Tel. 203-662-3638
Fax. 203-662-3643
www.emissionstrading.com

Emissions Trading Bulletin
NOx & SO2 Allowance Markets
9/19/02

NOx	Vintage	Bid	Offer	Trades
	1999		400	
	2000			
	2001			
	2002		630	615 for 73 tons, 630 for 200 tons, 630 for 150 tons
	2003			
	2004	4600	4900	4800 for 150 tons, 4800 for 50 tons
	2005	3800	4100	
	2003-2004			
SO2	Vintage			
	Spot	134	137	136,136,135 (2500 tons each)
Options				Nov 120 put trades 1.40

Market Comments:

For more a complete view of the NOx & SO2markets, information regarding the Bulletin, and other markets please visit <u>*www.emissionstrading.com*</u> Please let us know if we can be of assistance to you.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

STATE OF OHIO

CASE NO. 2002-00169

COUNTY OF FRANKLIN

AFFIDAVIT

John M. McManus upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

John M. McManus
John M. McManus

Subscribed and sworn to before me by John M. McManus this 23 day of September, 2002.

Notary Public

My Commission Expires 11/15/03

NOTARIAL SEAL
STATE OF OHIO

TONJA SUTTON
NOTARY PUBLIC, STATE OF OHIO
MY COMMISSION EXPIRES 11/15/03

Kentucky Power
d/b/a
American Electric Power

REQUEST

During 2001 and 2002, AEP was considering a reorganization, which would have resulted in the generating facilities of Ohio Power Company ("Ohio Power") being declared an exempt wholesale generator ("EWG"). For each project listed on Exhibit JMM-1 that is at an Ohio Power generating facility, describe the effect that possibly becoming an EWG had on the decision to undertake that project and include copies of any documents that discuss the impact that becoming an EWG would have on any of the projects.

RESPONSE

EWG status did not enter into the decision to undertake the projects listed on JMM-1.

WITNESS: Errol K Wagner

Kentucky Power
d/b/a
American Electric Power

REQUEST

Concerning the environmental costs associated with each of the projects listed on Exhibit JMM-1:

a. When did Kentucky Power become aware that it was paying the environmental costs associated with these projects through the Rockport Unit Power Agreement ("Rockport UPA") charges or the capacity equalization charges under the AEP Interconnection Agreement ("AEPIA")?

b. How long has Kentucky Power been paying the environmental costs associated with these projects through the Rockport UPA charges or the AEPIA?

c. For the environmental costs associated with the Rockport generating facilities, explain why the recovery of these costs was not addressed by Kentucky Power as part of the stipulation and settlement agreement submitted to and approved by the Commission in Case No. 2004-004201(1).

---

(1) Case No. 2004-00420, Application of Kentucky Power Company for Approval of a Stipulation and Settlement Agreement Resolving State Regulatory Matters, final Order dated December 13, 2004.

RESPONSE

a. KPCo has always known, as a party to both the AEP Interconnection Agreement and the Rockport Unit Power Agreement, that it would be responsible for its appropriate share of the environmental facilities installed at these generating facilities. KPCo has not always known precisely when particular environmental projects were placed into service and reflected in the Company's payments pursuant to these agreements because the projects have been ongoing for a number of years. KPCo became fully aware of the environmental costs associated with the payments under these Agreements in preparation for this case.

b. With respect to the environmental investment costs incurred pursuant to the AEP Interconnection Agreement, KPCo has been paying its appropriate share of the costs since the January following the in-service date of the different environmental facilities. The in-service date for each project is set forth in Exhibit EKW-1.

With respect to the environmental fixed O&M costs incurred pursuant to the AEP Interconnection Agreement, KPCo has been paying its appropriate share of those costs since the month following the in-service date of the environmental facilities. See Exhibit EKW-1.

With respect to the environmental facilities costs incurred pursuant to the Rockport Unit Power Agreement, KPCo has been paying its appropriate share of the environmental costs since the month following the in-service date of the environmental facilities. See Exhibit EKW-1.

c. The environmental costs associated with the Rockport generating facilities were not addressed by Kentucky Power Company as part of the stipulation and settlement agreement submitted to and approved by the Commission in Case No. 2004-00420 because the statute provides for recovery of these costs pursuant to the environmental surcharge mechanism. KRS 278.183. The Company has always addressed Rockport environmental costs through the environmental surcharge; the stipulation and agreement's extension of the Rockport agreement does not alter the ordinary cost-recovery procedures established by the surcharge statute.

WITNESS: Errol K Wagner

Kentucky Power
d/b/a
American Electric Power

REQUEST

Refer to McManus Testimony, Exhibit JMM-3.

a. Provide supporting documentation for the air emission fees paid in 2004 for each generating plant.

b. Provide a schedule showing the air emission fees paid for these same generating plants for calendar years 2000 through 2003. If the annual fees paid for any generating plant changed by more than 10 percent, include the reason(s) for the change.

RESPONSE

a. See attached Emission Fee Invoices as supporting documentation for the air emission fees paid in 2004.

b. See attached emissions fee schedule and associated footnotes.

WITNESS: John M McManus

West Virginia Department of Environmental Protection - Division of Air Quality

2004 CERTIFIED EMISSIONS STATEMENT INVOICE

For Assistance Call 304/926-3736
7012 MacCorkle Avenue, SE
Charleston, WV 25304-2943

KPSC Case No. 2005-00068
Commission Staff 2nd Set Data Request
Order Dated April 18, 2005
Item No. 4

Section 1

DATE DUE:
July 31, 2004

Company Name: AMERICAN ELECTRIC POWER
Facility/Source: JOHN AMOS
Company ID No.: 03-54-07900006
Federal Employer ID No.:
SIC Code: 4911

Contiguous ID No(s).

Section 2

State Fiscal Year
July 1 - June 30

Env. Contact: MICHAEL R. ROBIDA
Company: AMERICAN ELECTRIC POWER
Address: 1 RIVERSIDE PLAZA
City/State/Zip: COLUMBUS OH 43215

Env. Title: MANAGER, AIR QUALITY
Telephone: (614) 223-1270

Section 3

Did this facility operate during the last Calendar Year (Jan.-Dec.)? YES X NO __
If no, please pay the amount on Line 12.

This data is to be based on actual emissions during the last Calendar Year.

Please report all emissions. For fee calculations, each pollutant has a 4000 ton cap.

If reporting any HAP emissions, complete the HAPs Worksheet and return along with your CES and payment.

		Emissions (TPY)
1. Particulate Emissions a. Total from Column A1 of HAPs Worksheet	1a. 14.3	
b. Total Particulate emissions (TSP) (include Particulate HAPs from Line 1a.)		1b. 798.7
2. Sulfur Dioxide emissions (SO2)		2. 117380
3. Reduced Sulfur Compounds and Total Reduced Sulfur emissions		3. —
4. Nitrogen Oxide emissions (NOx)		4. 46471
5. Lead emissions (Pb)		5. —
6. Volatile Organic Compound Emissions a. Total from Column B1 of HAPs Worksheet	6a. —	
b. Volatile Organic Compounds emissions (VOC) (include VOC HAPs from Line 6a.)		6b. 223.3
7. Hazardous Air Pollutant emissions (HAPs) (include only those HAPs not already included as Particulates or VOCs from Column C1 of HAPs Worksheet)		7. 7955
8. Class I and Class II substances emissions		8. —
9. Carbon Monoxide emissions (CO) (No fee required)	9. 1866.3	
10. Add emissions from the right column ONLY (round to nearest ton)		10. 172 828 X $20.42
11. Total of Line 10 multiplied by the fee per ton		11. $265909.24
12. Minimum fee for this facility (45CSR22)	12. $10,000.00	
13. Enter the amount due (compare Line 11 to Line 12 and pay the higher amount only)		13. $265,909.24

Section 4

This form MUST be signed by a Responsible Official (see reverse side for definition)

I certify under penalty of law that I am a "Responsible Official" and, based on information and belief formed after reasonable inquiry, the statements and information contained in this statement are true, accurate and complete

Name (Please print): MARK C. McCULLOUGH
Title: VP-APCO
Signature: MCMcC
Date: 7/22/04

West Virginia Code §22-5-1 et seq. and Rule 45CSR30, "Requirements for Operating Permits"

Form Revised 6/03

Instructions	Please complete and mail the signed CES, along with a check for the correct amount to: WVDEP - Division of Air Quality, 7012 MacCorkle Avenue, SE, Charleston, WV 25304-2943. Your check should reference the facility's Company ID No. on it and be made payable to the WVDEP - Division of Air Quality. Strike through incorrect data and note the correct information on the invoice. Please return the original form; reproductions (scanned, photocopied, faxed, etc.) will be deemed incomplete and returned. Emissions from all sources at the facility are to be counted, including point source, secondary, fugitive and accidental releases This includes all Hazardous Air Pollutants (HAPs) from combustion sources. While the CES is being mailed to the attention of the individual designated in our database as the Environmental Contact. this does not necessarily mean that the Environmental Contact is authorized to sign as the "Responsible Official." The "Responsible Official" signing the CES must meet the definition listed below. Please review your CES carefully and correct any mistakes or note any changes in the facility specific information which is currently on file in the DAQ's Title V database. Please fill in any missing information. All forms should be submitted with original signatures in blue ink. For assistance with your CES, contact Jan Newton at 304/926-3736.
Responsible Official Certification	This form shall be signed by a "Responsible Official" as defined in 45 CSR §30-2.38. "Responsible Official" means one of the following: a. For a corporation: the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly-authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either (i) the facilities employ more than 250 persons or have a gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars), or (ii) the delegation of authority to such representative is approved in advance by the Director; b. For a partnership or sole proprietorship: a general partner or the proprietor, respectively; c. For a municipality, State, Federal, or other public entity: either a principal executive officer or ranking elected official. For the purpose of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., a Regional Administrator of U.S. EPA); or, d. The designated representative delegated with such authority and approved in advance by the Director.
Failure to Pay	All stationary sources which are required to obtain an operating permit under 45CSR30 shall pay fees in accordance with this Certified Emissions Statement Invoice. Operating such a facility/source without paying said fees is unlawful and may result in penalties and further legal action. Failure to pay the amount on or before July 31 will result in a penalty of five percent (5%) of the fee for each month the payment is overdue in addition to the fee itself. Any fee or penalty due the WVDEP - Division of Air Quality is a debt due the State of West Virginia and may be collected pursuant to law. Penalties for non-payment may also include civil and/or criminal penalties pursuant to W Va. Code §§22-5-6
Authority	West Virginia Code §§22-5-1 et seq. and Rule 45CSR30, "Requirements for Operating Permits."

West Virginia Department of Environmental Protection - Division of Air Quality

Hazardous Air Pollutants (HAPs) Worksheet
2004 CERTIFIED EMISSIONS STATEMENT INVOICE

Company ID Number
03-54-07900006

If reporting any HAP emissions, complete this worksheet and return along with your CES and payment.

CAS No.	Hazardous Air Pollutant (Specify by Name)	Column A Particulate (TPY)	Column B VOC (TPY)	Column C Neither (TPY)
	Arsenic	0.22		
	Beryllium	0.01		
	Chromium	0.48		
	Cobalt	0.1		
	Lead	0.21		
	Manganese	0.55		
	Mercury	0.45		
	Nickel	0.73		
	Selenium	11.5		
7647010	HCl			
7664393	HF			
	TOTAL	A1. 14.25	B1. —	C1. 7955

Include these totals in Section 3 Lines 1a, 6a or 7 where appropriate.

STATEMENT OF THE OHIO ENVIRONMENTAL PROTECTION AGENCY FOR FEE ASSESSMENT OF AIR POLLUTION EMISSIONS
(January 2003 - December 2003)

INVOICE: 07/02/04

Attention: Environmental Manager
CARDINAL POWER PLANT (CARDINAL
1 RIVERSIDE PLAZA
COLUMBUS, OH 43215

Pursuant to section 3745.11(V) of the Ohio Revised Code, enclosed is the air pollution emissions fee for CARDINAL POWER PLANT (CARDINAL OPERATING COMPANY) located in BRILLIANT

Payment is due within thirty (30) days of the invoice date.

Make Checks payable to : *The Treasurer of the State of Ohio*

Please tear off the bottom portion of this invoice and return the statement with your remittance using the enclosed envelope to: Ohio EPA
Dept. L-2711
Columbus, OH 43260-2711

IF PAYMENT IS LATE, THE PERSON RESPONSIBLE FOR THE AIR POLLUTION EMISSIONS FEE SHALL PAY AN ADDITIONAL TEN PERCENT OF THE AMOUNT DUE FOR EACH MONTH THAT IT IS LATE.

TOTAL FACILITY EMISSIONS	
PM	836.17
OC	127.19
SO2	4,000.00
NOx	4,000.00
Pb	1.40
TOTAL	8,964.76 Tons
AMOUNT DUE: @ $37.43/ton	$ 335,550.97

PLEASE DIRECT ALL INQUIRIES TO

Elisa Thomas,
Permit Management Unit (614) 644-3621
elisa.thomas@epa.state.oh.us
Be sure to reference the following:

Revenue ID	Facility ID
0000440864	0641050002

PLEASE WRITE THE ABOVE REVENUE ID NUMBER ON YOUR CHECK AND RETURN THE BOTTOM PORTION OF THIS (OR ALL) INVOICE(S) WITH YOUR PAYMENT

Please detach lower portion of invoice and return with payment to ensure proper credit.

Detach Here Detach Here Detach Here

INVOICED: 07/02/04

Revenue ID	Facility ID	Facility Name			
0000440864	T 0641050002	CARDINAL POWER PLANT (CARDINAL			
	Type Code	Check Number	Check ID	Check Date	AMOUNT DUE
For Office Use Only >	TVE03				$ 335,550.97

Total Fee Paid

Please Make Certain Address Shows Through Window

Ohio EPA
Dept L-2711
Columbus, OH 43260-2711

07/06/2004 13:16 NO.787 P005

STATEMENT OF THE OHIO ENVIRONMENTAL PROTECTION AGENCY FOR FEE ASSESSMENT OF AIR POLLUTION EMISSIONS (January 2003 - December 2003)

INVOICE: 07/02/04

Attention: Environmental Manager
GAVIN POWER PLANT
1 RIVERSIDE PLAZA
COLUMBUS, OH 43215

Pursuant to section 3745.11(V) of the Ohio Revised Code, enclosed is the air pollution emissions fee for GAVIN POWER PLANT located in CHESHIRE Ohio.

Payment is due within thirty (30) days of the invoice date.

Make Checks payable to : ***The Treasurer of the State of Ohio***

Please tear off the bottom portion of this invoice and return the statement with your remittance using the enclosed envelope to: Ohio EPA
Dept. L-2711
Columbus, OH 43260-2711

IF PAYMENT IS LATE, THE PERSON RESPONSIBLE FOR THE AIR POLLUTION EMISSIONS FEE SHALL PAY AN ADDITIONAL TEN PERCENT OF THE AMOUNT DUE FOR EACH MONTH THAT IT IS LATE.

TOTAL FACILITY EMISSIONS	
PM	686.77
OC	210.12
SO2	4,000.00
NOx	4,000.00
Pb	2.18
TOTAL	8,899.07 Tons
AMOUNT DUE: @ $37.43/ton	$ 333,092.19

PLEASE DIRECT ALL INQUIRIES TO

Elisa Thomas,
Permit Management Unit (614) 644-3621
elisa.thomas@epa.state.oh.us
Be sure to reference the following:

Revenue ID	Facility ID
0000440863	0627010056

PLEASE WRITE THE ABOVE REVENUE ID NUMBER ON YOUR CHECK AND RETURN THE BOTTOM PORTION OF THIS (OR ALL) INVOICE(S) WITH YOUR PAYMENT

Please detach lower portion of invoice and return with payment to ensure proper credit.

Detach Here Detach Here Detach Here

INVOICED: 07/02/04

Revenue ID	Facility ID	Facility Name		
0000440863	T 0627010056	GAVIN POWER PLANT		
For Office Use Only >	Type Code	Check Number	Check ID	Check Date	AMOUNT DUE
	TVE03				$ 333,092.19

Total Fee Paid

Please Make Certain Address Shows Through Window

Ohio EPA
Dept L-2711
Columbus, OH 43260-2711

West Virginia Department of Environmental Protection - Division of Air Quality
2004 CERTIFIED EMISSIONS STATEMENT INVOICE

For Assistance Call 304/926-3736
7012 MacCorkle Avenue, SE
Charleston, WV 25304-2943

Section 1

DATE DUE:
July 31, 2004

Company Name OHIO POWER COMPANY
Facility/Source KAMMER PLANT/CRESAP
Contiguous ID No(s). 05100031
Company ID No. 03-54-05100006
Federal Employer ID No.
SIC Code 4911

Section 2

State Fiscal Year
July 1 - June 30

Env. Contact MICHAEL R ROBIDA
Env. Title MANAGER, AIR QUALITY
Company OHIO POWER COMPANY
Telephone (614) 223-1270
Address 1 RIVERSIDE PLAZA
City/State/Zip COLUMBUS OH 43215

Section 3

This data is to be based on actual emissions during the last Calendar Year

Please report all emissions. For fee calculations, each pollutant has a 4000 ton cap.

If reporting any HAP emissions, complete the HAPs Worksheet and return along with your CES and payment.

Did this facility operate during the last Calendar Year (Jan.-Dec.)? YES ☒ NO ☐
If no, please pay the amount on Line 12.

Emissions (TPY)

Item		
1. Particulate Emissions a. Total from Column A1 of HAPs Worksheet	1a. 3.4	
b. Total Particulate emissions (TSP) (include Particulate HAPs from Line 1a.)		1b. 65.7
2. Sulfur Dioxide emissions (SO2)		2. 45350.6
3. Reduced Sulfur Compounds and Total Reduced Sulfur emissions		3. —
4. Nitrogen Oxide emissions (NOx)		4. 12825.6
5. Lead emissions (Pb)		5. —
6. Volatile Organic Compound Emissions a. Total from Column B1 of HAPs Worksheet	6a. —	
b. Volatile Organic Compounds emissions (VOC) (include VOC HAPs from Line 6a.)		6b. 78.5
7. Hazardous Air Pollutant emissions (HAPs) (include only those HAPs not already included as Particulates or VOCs from Column C1 of HAPs Worksheet)		7. 1790
8. Class I and Class II substances emissions		8. —
9. Carbon Monoxide emissions (CO) .... (No fee required)	9. 358.9	
10. Add emissions from the right column ONLY (round to nearest ton)		10. 60112 X $20.42
11. Total of Line 10 multiplied by the fee per ton		11. 202 872.7
12. Minimum fee for this facility (45CSR22)	12. $10,000.00	
13. Enter the amount due (compare Line 11 to Line 12 and pay the higher amount only)		13. $202,872.70

Section 4

This form MUST be signed by a Responsible Official (see reverse side for definition)

I certify under penalty of law that I am a "Responsible Official" and, based on information and belief formed after reasonable inquiry, the statements and information contained in this statement are true, accurate and complete.

Name (Please print) JEFFREY D. LAFLEUR Title VP-OPCO
Signature Jeffrey D. LaFleur Date 07/22/2004

West Virginia Code §§22-5-1 et seq. and Rule 45CSR30, "Requirements for Operating Permits" *Form Revised 6/03*

Instructions

Please complete and mail the signed CES, along with a check for the correct amount to: WVDEP - Division of Air Quality, 7012 MacCorkle Avenue, SE, Charleston, WV 25304-2943. Your check should reference the facility's Company ID No. on it and be made payable to the WVDEP - Division of Air Quality. Strike through incorrect data and note the correct information on the invoice. Please return the original form; reproductions (scanned, photocopied, faxed, etc.) will be deemed incomplete and returned.

Emissions from all sources at the facility are to be counted, including point source, secondary, fugitive and accidental releases. This includes all Hazardous Air Pollutants (HAPs) from combustion sources.

While the CES is being mailed to the attention of the individual designated in our database as the Environmental Contact, this does not necessarily mean that the Environmental Contact is authorized to sign as the "Responsible Official." The "Responsible Official" signing the CES must meet the definition listed below.

Please review your CES carefully and correct any mistakes or note any changes in the facility specific information which is currently on file in the DAQ's Title V database. Please fill in any missing information. All forms should be submitted with original signatures in blue ink. For assistance with your CES, contact Jan Newton at 304/926-3736.

Responsible Official Certification

This form shall be signed by a "Responsible Official" as defined in 45 CSR §30-2.38. "Responsible Official" means one of the following:

a. For a corporation: the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly-authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either (i) the facilities employ more than 250 persons or have a gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars), or (ii) the delegation of authority to such representative is approved in advance by the Director;

b. For a partnership or sole proprietorship: a general partner or the proprietor, respectively;

c. For a municipality, State, Federal, or other public entity: either a principal executive officer or ranking elected official. For the purpose of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., a Regional Administrator of U.S. EPA); or,

d. The designated representative delegated with such authority and approved in advance by the Director.

Failure to Pay

All stationary sources which are required to obtain an operating permit under 45CSR30 shall pay fees in accordance with this Certified Emissions Statement Invoice. Operating such a facility/source without paying said fees is unlawful and may result in penalties and further legal action. Failure to pay the amount on or before July 31 will result in a penalty of five percent (5%) of the fee for each month the payment is overdue in addition to the fee itself. Any fee or penalty due the WVDEP - Division of Air Quality is a debt due the State of West Virginia and may be collected pursuant to law. Penalties for non-payment may also include civil and/or criminal penalties pursuant to W. Va. Code §§22-5-6.

uthority

West Virginia Code §§22-5-1 et seq. and Rule 45CSR30, "Requirements for Operating Permits."

West Virginia Department of Environmental Protection - Division of Air Quality

Company ID Number 03-54-05100006

Hazardous Air Pollutants (HAPs) Worksheet
2004 CERTIFIED EMISSIONS STATEMENT INVOICE

If reporting any HAP emissions, complete this worksheet and return along with your CES and payment.

CAS No.	Hazardous Air Pollutant (Specify by Name)	Column A Particulate (TPY)	Column B VOC (TPY)	Column C Neither (TPY)
	ARSENIC	0.06		
	BERYLLIUM	0.005		
	CHROMIUM	0.61		
	COBALT	0.03		
	LEAD	0.06		
	MANGANESE	0.11		
	MERCURY	0.11		
	NICKEL	0.24		
	SELENIUM	2.2		
7647010	HCl			1700
7664393	HF			90
	TOTAL	A1. 3.43	B1. —	C1. 1790

Include these totals in Section 3 Lines 1a, 6a or 7 where appropriate.

Form Revised 6/03

West Virginia Department of Environmental Protection - Division of Air Quality

2004 CERTIFIED EMISSIONS STATEMENT INVOICE

For Assistance Call 304/926-3736
7012 MacCorkle Avenue, SE
Charleston, WV 25304-2943

Section 1

DATE DUE:
July 31, 2004

Company Name OHIO POWER COMPANY
Facility/Source MITCHELL PLANT
Company ID No. 03-54-05100005
Federal Employer ID No.
SIC Code 4911

Contiguous ID No(s).

Section 2

State Fiscal Year
July 1 - June 30

Env Contact MICHAEL R. ROBIDA
Company OHIO POWER COMPANY
Address 1 RIVERSIDE PLAZA
City/State/Zip COLUMBUS OH 43215

Env Title MANAGER, AIR QUALITY
Telephone (614) 223-1270

Section 3

Did this facility operate during the last Calendar Year (Jan.-Dec.)? YES ☒ NO ☐
If no, please pay the amount on Line 12.

This data is to be based on actual emissions during the last Calendar Year.

Please report all emissions. For fee calculations, each pollutant has a 4000 ton cap.

If reporting any HAP emissions, complete the HAPs Worksheet and return along with your CES and payment.

			Emissions (TPY)
1.	Particulate Emissions a. Total from Column A1 of HAPs Worksheet	1a. 7.8	
	b. Total Particulate emissions (TSP) (include Particulate HAPs from Line 1a.)		1b. 385.6
2.	Sulfur Dioxide emissions (SO_2)		2. 62801.8
3.	Reduced Sulfur Compounds and Total Reduced Sulfur emissions		3. —
4.	Nitrogen Oxide emissions (NO_x)		4. 31885.4
5.	Lead emissions (Pb)		5. —
6.	Volatile Organic Compound Emissions a. Total from Column B1 of HAPs Worksheet	6a. —	
	b. Volatile Organic Compounds emissions (VOC) (include VOC HAPs from Line 6a.)		6b. 114.3
7.	Hazardous Air Pollutant emissions (HAPs) (include only those HAPs not already included as Particulates or VOCs from Column C1 of HAPs Worksheet)		7. 5740
8.	Class I and Class II substances emissions		8. —
9.	Carbon Monoxide emissions (CO) (No fee required)	9. 957.4	
10.	Add emissions from the right column ONLY (round to nearest ton)		10. 100928
			X $20.42
11.	Total of Line 10 multiplied by the fee per ton		11. 255250
12.	Minimum fee for this facility (45CSR22)	12. $10,000.00	
13.	Enter the amount due (compare Line 11 to Line 12 and pay the higher amount only)		13. $255,250.00

Section 4

This form MUST be signed by a Responsible Official (see reverse side for definition)

I certify under penalty of law that I am a "Responsible Official" and, based on information and belief formed after reasonable inquiry, the statements and information contained in this statement are true, accurate and complete

Name (Please print) JEFFREY D. LAFLEUR Title VP-OPCO

Signature Jeffrey D. LaFleur Date 07/22/2004

West Virginia Code §§22-5-1 et seq. and Rule 45CSR30, "Requirements for Operating Permits"

Form Revised 6/03

Instructions

Please complete and mail the signed CES, along with a check for the correct amount to: WVDEP - Division of Air Quality, 7012 MacCorkle Avenue, SE, Charleston, WV 25304-2943. Your check should reference the facility's Company ID No. on it and be made payable to the WVDEP - Division of Air Quality. Strike through incorrect data and note the correct information on the invoice. Please return the original form; reproductions (scanned, photocopied, faxed, etc.) will be deemed incomplete and returned.

Emissions from all sources at the facility are to be counted, including point source, secondary, fugitive and accidental releases. This includes all Hazardous Air Pollutants (HAPs) from combustion sources.

While the CES is being mailed to the attention of the individual designated in our database as the Environmental Contact, this does not necessarily mean that the Environmental Contact is authorized to sign as the "Responsible Official." The "Responsible Official" signing the CES must meet the definition listed below.

Please review your CES carefully and correct any mistakes or note any changes in the facility specific information which is currently on file in the DAQ's Title V database. Please fill in any missing information. All forms should be submitted with original signatures in blue ink. For assistance with your CES, contact Jan Newton at 304/926-3736.

Responsible Official Certification

This form shall be signed by a "Responsible Official" as defined in 45 CSR §30-2.38. "Responsible Official" means one of the following:

a. For a corporation: the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly-authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either (i) the facilities employ more than 250 persons or have a gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars), or (ii) the delegation of authority to such representative is approved in advance by the Director;

b. For a partnership or sole proprietorship: a general partner or the proprietor, respectively;

c. For a municipality, State, Federal, or other public entity: either a principal executive officer or ranking elected official. For the purpose of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., a Regional Administrator of U.S. EPA); or,

d. The designated representative delegated with such authority and approved in advance by the Director

Failure to Pay

All stationary sources which are required to obtain an operating permit under 45CSR30 shall pay fees in accordance with this Certified Emissions Statement Invoice. Operating such a facility/source without paying said fees is unlawful and may result in penalties and further legal action. Failure to pay the amount on or before July 31 will result in a penalty of five percent (5%) of the fee for each month the payment is overdue in addition to the fee itself. Any fee or penalty due the WVDEP - Division of Air Quality is a debt due the State of West Virginia and may be collected pursuant to law. Penalties for non-payment may also include civil and/or criminal penalties pursuant to W. Va. Code §§22-5-6.

Authority

West Virginia Code §§22-5-1 et seq. and Rule 45CSR30, "Requirements for Operating Permits."

West Virginia Department of Environmental Protection - Division of Air Quality

Hazardous Air Pollutants (HAPs) Worksheet
2004 CERTIFIED EMISSIONS STATEMENT INVOICE

Company ID Number
03-54-05100005

If reporting any HAP emissions, complete this worksheet and return along with your CES and payment.

CAS No.	Hazardous Air Pollutant (Specify by Name)	Column A Particulate (TPY)	Column B VOC (TPY)	Column C Neither (TPY)
	Arsenic	0.15		
	Beryllium	0.01		
	Chromium	0.36		
	Cobalt	0.07		
	Lead	0.15		
	Manganese	0.41		
	Mercury	0.16		
	Nickel	0.49		
	Selenium	6.0		
7647010	HCl			5500
7664393	HF			240
	TOTAL	A1. 7.8	B1. —	C1. 5740

Include these totals in Section 3 Lines 1a, 6a or 7 where appropriate.

STATEMENT OF THE OHIO ENVIRONMENTAL PROTECTION AGENCY FOR FEE ASSESSMENT OF AIR POLLUTION EMISSIONS (January 2003 - December 2003)

INVOICE: 07/02/04

Attention: Environmental Manager
MUSKINGUM RIVER POWER PLANT
1 RIVERSIDE PLAZA
COLUMBUS, OH 43215

Pursuant to section 3745.11(V) of the Ohio Revised Code, enclosed is the air pollution emissions fee for MUSKINGUM RIVER POWER PLANT located in WATERFORD Ohio.

Payment is due within thirty (30) days of the invoice date.

Make Checks payable to : *The Treasurer of the State of Ohio*

Please tear off the bottom portion of this invoice and return the statement with your remittance using the enclosed envelope to: **Ohio EPA**
Dept. L-2711
Columbus, OH 43260-2711

IF PAYMENT IS LATE, THE PERSON RESPONSIBLE FOR THE AIR POLLUTION EMISSIONS FEE SHALL PAY AN ADDITIONAL TEN PERCENT OF THE AMOUNT DUE FOR EACH MONTH THAT IT IS LATE.

TOTAL FACILITY EMISSIONS	
PM	635.17
OC	105.53
SO2	4,000.00
NOx	4,000.00
Pb	0.99
TOTAL	8,741.69 Tons
AMOUNT DUE: @ $37.43/ton	$ 327,201.46

PLEASE DIRECT ALL INQUIRIES TO

Elisa Thomas,
Permit Management Unit (614) 644-3621
elisa.thomas@epa.state.oh.us
Be sure to reference the following:

Revenue ID	Facility ID
0000440866	0684000000

PLEASE WRITE THE ABOVE REVENUE ID NUMBER ON YOUR CHECK AND RETURN THE BOTTOM PORTION OF THIS (OR ALL) INVOICE(S) WITH YOUR PAYMENT

Please detach lower portion of invoice and return with payment to ensure proper credit.

INVOICE

Please Remit To:
IN Dept of Environmental Management
100 North Senate Avenue
PO Box 7060
Indianapolis IN 46207-7060

Page:	1
Invoice No:	000022731
Invoice Date:	02/05/2004
Customer Number:	CST100010141
Bill Type:	054
Payment Terms:	NET 30
Due Date:	03/06/2004

Customer
AMERICAN ELECTRIC POWER
MR JAMES BUTCHER
2791 NORTH US HIGHWAY 231
ROCKPORT IN 47635

AMOUNT DUE: 150,000.00 USD

$150,000
Amount Remitted

☐ Note Address Changes Above.

For billing questions, please call 317-233-0604

Line	Adj Identifier	Description	Quantity	UOM	Unit Amt	Net Amount

- TITLE V Annual Permit Fee Invoice for Calendar Year 2004. This invoice is calculated using 2002 calendar year reported emissions.
- The Office of Air quality is required by 326 IAC 2-7-19 to collect an annual permit fee for facilities operating in the State of Indiana that have a TITLE V permit.
- If you have questions on how your annual fee was determined, please contact Chet Bohannon of the Office of Air Quality at 317-233-4230.
- If you have questions on how your emissions were calculated, please contact Michele Boner at 317-233-6844.
- If you disagree with the amount of your annual permit fee, please complete a copy of the dispute sheet on the back side of this invoice.
- Please return the dispute sheet, a certified emissions statement per the requirements of 326 IAC 2-6, a copy of this invoice, and payment for the undisputed amount of your annual fee to the address stated on this invoice.
- All emission quantities listed below are in tons.

Line	Adj Identifier	Description	Quantity	UOM	Unit Amt	Net Amount
1	T147-6786-00020	Your Cap Credit	1.00	EA	(2,719,105.95)	(2,719,105.95)
2	T147-6786-00020	Base Fee	1.00	EA	1,500.00	1,500.00
3	T147-6786-00020	Volatile Organic Comp (VOC)	277.50		33.00	9,157.50
4	T147-6786-00020	Hazardous Air Pollutant(HAP)	910.65		33.00	30,051.45
5	T147-6786-00020	Sulfur Dioxide (SO2)	51,550.43		33.00	1,701,164.19
6	T147-6786-00020	Nitrous Oxides (NOx)	34,013.58		33.00	1,122,448.14
7	T147-6786-00020	Total Particulates (PM10)	144.99		33.00	4,784.67

TOTAL AMOUNT DUE : 150,000.00

Please include a copy of your invoice along with payment.
Payments received without a copy of original invoice or invoice number noted on the check will be returned.

OK To Pay
2/9/04

495-IDEM Printed on Recycled Paper Original

West Virginia Department of Environmental Protection - Division of Air Quality

2004 CERTIFIED EMISSIONS STATEMENT INVOICE

For Assistance Call 304/926-3736
7012 MacCorkle Avenue, SE
Charleston, WV 25304-2943

KPSC Case No. 2005-00068
Commission Staff 2nd Set Data Request
Order Dated April 18, 2005
Item No. 4

Section 1

DATE DUE:
July 31, 2004

Company Name: AMERICAN ELECTRIC POWER
Facility/Source: PHILIP SPORN PLANT
Contiguous ID No(s).
Company ID No.: 03-54-05300001
Federal Employer ID No.
SIC Code: 4911

Section 2

State Fiscal Year
July 1 - June 30

Env. Contact: MICHAEL R. ROBIDA
Env. Title: MANAGER, AIR QUALITY
Company: AMERICAN ELECTRIC POWER
Telephone: (614) 223-1270
Address: 1 RIVERSIDE PLAZA
City/State/Zip: COLUMBUS OH 43215

Section 3

This data is to be based on actual emissions during the last Calendar Year

Please report all emissions. For fee calculations, each pollutant has a 4000 ton cap.

If reporting any HAP emissions, complete the HAPs Worksheet and return along with your CES and payment.

Did this facility operate during the last Calendar Year (Jan.-Dec.)? YES ☒ NO ☐
If no, please pay the amount on Line 12.

		Emissions (TPY)
1. Particulate Emissions a. Total from Column A1 of HAPs Worksheet	1a. 5.53	
b. Total Particulate emissions (TSP) (include Particulate HAPs from Line 1a.)		1b. 330.7
2. Sulfur Dioxide emissions (SO2)		2. 51763.3
3. Reduced Sulfur Compounds and Total Reduced Sulfur emissions		3. —
4. Nitrogen Oxide emissions (NOx)		4. 15369.8
5. Lead emissions (Pb)		5. —
6. Volatile Organic Compound Emissions a. Total from Column B1 of HAPs Worksheet	6a. —	
b. Volatile Organic Compounds emissions (VOC) (include VOC HAPs from Line 6a.)		6b. 76.8
7. Hazardous Air Pollutant emissions (HAPs) (include only those HAPs not already included as Particulates or VOCs from Column C1 of HAPs Worksheet)		7. 2855
8. Class I and Class II substances emissions		8. —
9. Carbon Monoxide emissions (CO) (No fee required)	9. 644.8	
10. Add emissions from the right column ONLY (round to nearest ton)		10. 70396
		X $20.42
11. Total of Line 10 multiplied by the fee per ton		11. $229,990.46
12. Minimum fee for this facility (45CSR22)	12. $10,000.00	
13. Enter the amount due (compare Line 11 to Line 12 and pay the higher amount only)		13. $229,990.46

Section 4

This form MUST be signed by a Responsible Official (see reverse side for definition)

I certify under penalty of law that I am a "Responsible Official" and, based on information and belief formed after reasonable inquiry, the statements and information contained in this statement are true, accurate and complete.

Name (Please print): William F. Vineyard
Title: VP-APCO
Signature: Wm F Vineyard
Date: 7/26/04

West Virginia Code §§22-5-1 et seq. and Rule 45CSR30, "Requirements for Operating Permits"

Form Revised 6/03

Instructions

Please complete and mail the signed CES, along with a check for the correct amount to: WVDEP - Division of Air Quality, 7012 MacCorkle Avenue, SE, Charleston, WV 25304-2943. Your check should reference the facility's Company ID No. on it and be made payable to the WVDEP - Division of Air Quality. Strike through incorrect data and note the correct information on the invoice. Please return the original form; reproductions (scanned, photocopied, faxed, etc.) will be deemed incomplete and returned.

Emissions from all sources at the facility are to be counted, including point source, secondary, fugitive and accidental releases. This includes all Hazardous Air Pollutants (HAPs) from combustion sources.

While the CES is being mailed to the attention of the individual designated in our database as the Environmental Contact, this does not necessarily mean that the Environmental Contact is authorized to sign as the "Responsible Official." The "Responsible Official" signing the CES must meet the definition listed below.

Please review your CES carefully and correct any mistakes or note any changes in the facility specific information which is currently on file in the DAQ's Title V database. Please fill in any missing information. All forms should be submitted with original signatures in blue ink. For assistance with your CES, contact Jan Newton at 304/926-3736

Responsible Official Certification

This form shall be signed by a "Responsible Official" as defined in 45 CSR §30-2.38. "Responsible Official" means one of the following:

a. For a corporation: the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly-authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either (i) the facilities employ more than 250 persons or have a gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars), or (ii) the delegation of authority to such representative is approved in advance by the Director;

b. For a partnership or sole proprietorship: a general partner or the proprietor, respectively;

c. For a municipality, State, Federal, or other public entity: either a principal executive officer or ranking elected official. For the purpose of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., a Regional Administrator of U.S. EPA); or,

d. The designated representative delegated with such authority and approved in advance by the Director.

Failure to Pay

All stationary sources which are required to obtain an operating permit under 45CSR30 shall pay fees in accordance with this Certified Emissions Statement Invoice. Operating such a facility/source without paying said fees is unlawful and may result in penalties and further legal action. Failure to pay the amount on or before July 31 will result in a penalty of five percent (5%) of the fee for each month the payment is overdue in addition to the fee itself. Any fee or penalty due the WVDEP - Division of Air Quality is a debt due the State of West Virginia and may be collected pursuant to law. Penalties for non-payment may also include civil and/or criminal penalties pursuant to W. Va. Code §§22-5-6.

Authority

West Virginia Code §§22-5-1 et seq. and Rule 45CSR30, "Requirements for Operating Permits."

West Virginia Department of Environmental Protection - Division of Air Quality

Hazardous Air Pollutants (HAPs) Worksheet
2004 CERTIFIED EMISSIONS STATEMENT INVOICE

Company ID Number
03-54-05300001

If reporting any HAP emissions, complete this worksheet and return along with your CES and payment.

CAS No.	Hazardous Air Pollutant (Specify by Name)	Column A Particulate (TPY)	Column B VOC (TPY)	Column C Neither (TPY)
	ARSENIC	0.19		
	BERYLLIUM	0.01		
	CHROMIUM	0.35		
	COBALT	0.07		
	LEAD	0.17		
	MANGANESE	0.40		
	MERCURY	0.15		
	NICKEL	0.35		
	SELENIUM	3.85		
7647010	HCl			2700
7664393	HF			155
	TOTAL	A1. 5.53	B1. —	C1. 2855

Include these totals in Section 3 Lines 1a, 6a or 7 where appropriate.

INVOICE

Please Remit To:

IN Dept of Environmental Management
[illegible] Avenue
[illegible]
Indianapolis IN 46207-7060

Page:	1
Invoice No:	000022734
Invoice Date	02/05/2004
Customer Number	CST100010387
Bill Type:	054
Payment Terms:	NET 30
Due Date:	03/06/2004

Customer

INDIANA MICHIGAN POWER CO
MR KENNETH W KNOWLTON
800 AEP DRIVE
LAWRECEBURG IN 47025

AMOUNT DUE: 150,000.00 USD

$150,000.00
Amount Remitted

__ Note Address Changes Above.

For billing questions, please call 317-233-0604

TITLE V Annual Permit Fee Invoice for Calendar Year 2004 This invoice is calculated using 2002 calendar year reported emissions.

The Office of Air quality is required by 326 IAC 2-7-19 to collect an annual permit fee for facilities operating in the State of Indiana that have a TITLE V permit.

If you have questions on how your annual fee was determined, please contact Chet Bohannon of the Office of Air Quality at 317-233-[illegible]

If you have questions on how your emissions were calculated please contact Michele Boner at [illegible]-6844.

If you disagree with the amount of your annual permit fee, please complete a copy of the dispute sheet on the back side of this invoice.

Please return the dispute sheet, a certified emissions statement per the requirements of 326 IAC [illegible], a copy of this invoice, and payment for the undisputed amount of your annual fee to the address stated on this invoice.

All emission quantities listed below are in tons.

Line	Adj Identifier	Description	Quantity	UOM	Unit Amt	Net Amount
1	T029-6785-00002	Your Cap Credit	1.00	EA	(2,608,913.67)	(2,608,913.67)
2	T029-6785-00002	Base Fee	1.00	EA	1,500.00	1,500.00
3	T029-6785-00002	Hazardous Air Pollutant(HAP)	1,190.16		33.00	39,275.28
4	T029-6785-00002	Sulfur Dioxide (SO2)	64,439.15		33.00	2,126,491.95
5	T029-6785-00002	Total Particulates (PM10)	69.35		33.00	2,288.55
6	T029-6785-00002	Nitrous Oxides (NOx)	17,750.69		33.00	585,772.77
7	T029-6785-00002	Volatile Organic Comp (VOC)	108.64		33.00	3,585.12

TOTAL AMOUNT DUE : 150,000.00

Please include a copy of your invoice along with payment.
Payments received without a copy of original invoice or invoice number noted on the check will be returned.

495-IDEM Printed on Recycled Paper Original

RESPONSE 4.b

Kentucky Power Company
AEP Pool Surplus Companies
2000 - 2003 Costs Associated with Annual Title V Air Emission Fees

Generating Plant	2000 Air Emission Fees Paid	2001 Air Emission Fees Paid	2002 Air Emission Fees Paid	2003 Air Emission Fees Paid
Amos Plant	$165,710	$167,652	$170,719	$258,711[1]
Cardinal Plant	$274,230	$316,939[2]	$324,406	$324,985
Gavin Plant	$1,181	$316,351[3]	$328,192	$325,131
Kammer Plant	$10,000	$155,145[3]	$160,030	$199,780[1]
Mitchell Plant	$10,000	$160,640[3]	$165,748	$248,607[1]
Muskingum River Plant	$564	$319,859[3]	$326,828	$326,760
Philip Sporn Plant	$155,017	$160,705	$164,470	$212,002[1]
Rockport Plant	$150,000	$150,000	$150,000	$150,000
Tanners Creek Plant	$150,000	$150,000	$150,000	$150,000

[1] The fees paid by Amos Plant, Kammer Plant, Mitchell Plant, and Philip Sporn Plant in 2003 (for 2002 operations) were much higher than those paid in 2002 (for 2001 operations). The increase was a result of the West Virginia Division of Air Quality making the decision to charge fees for the emission of Hazardous Air Pollutants (HAPs) from electric utility sources. Prior to this, fees for electric utility sources in West Virginia were not base on HAPs emissions.

[2] The fees paid by Cardinal Plant in 2001 (for calendar year 2000 emissions) were approximately 15.6% higher than those paid in 2000 (for calendar year 1999 emissions). The increase was a result of a court decision in Ohio to require particulate related emission fees to be based on the emission of total suspended particulate (TSP) instead of the fraction of particulate less than 10 microns in size (PM10).

[3] The fees paid by Gavin Plant, Muskingum River Plant, Kammer Plant and Mitchell Plant in 2001 were much higher than those paid in 2000. Pursuant to Title V permitting regulations (40 CFR 70.9(b)(4), these sources (Title IV Phase I Units) were not required to pay a fee for purposes of Title V during the years 1995 through 1999, inclusive. Instead, the much lower fees paid in 2000 (for calendar year 1999 operation) were based on state operating fee programs.