

OUR CHALLENGE, THEN, IS MORE THAN A TECHNICAL ONE. WE MUST IMPROVE COAL'S REALITY, IF YOU WILL, THROUGH ADVANCED TECHNOLOGY. BUT WE MUST ALSO BRIDGE THE YAWNING GAP BETWEEN REALITY AND PERCEPTION.

AS JOHN PAUL NOTED IN HIS PLENARY SESSION REGARDING THE CEED PROGRAM, WE MUST BETTER COMMUNICATE THE STRONG EFFORTS OF THE PEOPLE IN THIS ROOM AND ELSEWHERE IN ADVANCING THE POTENTIAL OF THIS MOST NECESSARY FUEL THROUGH ADVANCED TECHNOLOGY.

WE MUST TAKE TO TASK THE JUNK SCIENCE ADVOCATES WHO WOULD HAVE YOU BELIEVE THAT THE SKY IS FALLING AND THE EARTH IS WARMING. WE MUST CHALLENGE THE FLAWED CONCEPT THAT ENERGY USE IS A SIN TO BE TAXED. AND WE MUST CONTINUE TO SHOW THAT IT IS IN THE NATION'S INTEREST TO AGGRESSIVELY PURSUE PRACTICAL, COST-EFFICIENT CLEAN COAL TECHNOLOGIES. THE PRESIDENT AND HIS ADMINISTRATION HAVE CALLED FOR A STRONGER PUBLIC-PRIVATE PARTNERSHIP IN PURSUING TECHNOLOGIES TO IMPROVE INDUSTRIAL COMPETITIVENESS. AND WE SHOULD CONTINUE TO EXPLORE THESE OPPORTUNITIES.

WE MUST ALSO COMMUNICATE THE MAJOR ROLE TECHNOLOGY HAS PLAYED IN ADVANCING THE CAUSE OF COAL IN THE PAST. FOR WHEN COAL'S FUTURE HAS LOOKED MOST BLEAK, TECHNOLOGY HAS NEVER FAILED TO LEAD TO BREAKTHROUGHS IN SAFETY, IN PRODUCTIVITY, IN EFFICIENCY AND IN THE ENVIRONMENT.

TODAY'S TECHNOLOGY HAS ASSISTED US IN PRODUCTION, WHERE WE HAVE IMPROVED PRODUCTIVITY BY 78 PERCENT SINCE 1970 AND DECREASED THE NUMBER OF MINING FATALITIES BY THE SAME PERCENTAGE.

TODAY'S TECHNOLOGY HAS IMPROVED EFFICIENCIES, ENABLING US TO OBTAIN THE SAME AMOUNT OF ENERGY FROM ONE TON OF COAL AS WE GOT FROM EIGHT TONS OF COAL EARLIER IN THIS CENTURY.

AND TODAY'S TECHNOLOGY HAS ENABLED US TO IMPROVE ENVIRONMENTAL PERFORMANCE. SINCE 1970, SULFUR DIOXIDE OUTPUT HAS DECREASED BY 27 PERCENT DURING A TIME WHEN AMERICA'S ELECTRIC UTILITY COAL BURN INCREASED BY 144 PERCENT.

THERE IS ONE MAJOR DIFFERENCE BETWEEN NOW AND 1970 REGARDING THE CLEAN AIR ACT AMENDMENTS. AT THAT TIME, WE CALLED FOR MUCH GREATER RESEARCH INTO CLEAN COAL TECHNOLOGIES BECAUSE THERE WAS A MARKED VACUUM IN THIS AREA. TODAY, AS WITNESSED BY THE ATTENDANCE HERE, THAT VACUUM IS GONE. CLEAN COAL HAS ARRIVED.

WITHOUT GROWTH IN COAL USE, AMERICA'S POWER PRODUCTION WOULD BE LIMITED TO 1970 LEVELS. AND SO, MOST LIKELY, WOULD THE ECONOMY.

EACH \$1 BILLION WORTH OF COAL PRODUCTION PRODUCES \$25 BILLION OF ELECTRICITY, \$10 BILLION IN TRANSPORTATION ACTIVITY, AND \$27 BILLION IN BUSINESS SERVICES.

THESE DYNAMICS OCCUR WITHIN AN ECONOMY THAT, IN ORDER TO GROW, WILL REQUIRE ADDITIONAL ELECTRICITY USE. LAST YEAR'S NATIONAL ENERGY POLICY ACT, FOR INSTANCE, REFLECTS A 30 TO 60 PERCENT INCREASE IN POWER DEMAND BY THE YEAR 2010. AND IT ACKNOWLEDGES THAT COAL WILL BE REQUIRED FOR AT LEAST HALF OF THE NEW BASELOAD IN THIS COUNTRY.

IN SHORT, THESE CLEAN COAL TECHNOLOGIES NOW IN DEVELOPMENT ARE CRITICAL TO AMERICA'S FUTURE IN A WORLD OF TOO LITTLE RELIABLE ENERGY. ON A GLOBAL SCALE, THEY WILL BE NECESSARY TO THE SMOOTH OPERATION OF MATURE ECONOMIES, AND CRUCIAL TO MEETING THE NEEDS OF THE WORLD'S DEVELOPING COUNTRIES.

AND SO, DESPITE DAILY CRITICISMS, THE PROSPECTS FOR COAL ARE STRONG. THAT'S MY PERCEPTION, AND I BELIEVE THAT WILL BE THE REALITY.

NOBODY EXPECTED MUCH FROM THE COAL INDUSTRY IN 1970. MANY WERE WRITING OBITUARIES. YET COAL IN THE SUCCEEDING 20 YEARS GREW AS IT NEVER HAD BEFORE.

TODAY, THE INDUSTRY CONTINUES TO BE WILLING TO PERFORM THE HEAVY LIFTING FOR A NATION'S ECONOMY. AND WE CONTINUE TO TAKE ALL STEPS NECESSARY TO REMAIN THE NATIONS LOWEST-COST, MOST ABUNDANT FUEL SOURCE.

WE ARE ALSO COMMITTED TO BRIDGING THAT GAP BETWEEN PERCEPTION AND REALITY. THE COAL INDUSTRY AND OTHERS HAVE BEGUN THIS LONG AND DIFFICULT PROCESS OF CHANGING PUBLIC OPINIONS.

NEW TECHNOLOGIES, TOO, WILL BE TRIED BOTH IN THE MARKETPLACE OF COMMERCE AND THAT OF PUBLIC PERCEPTION. I WOULD URGE EACH OF YOU, AS TECHNOLOGY DEVELOPERS, TO JOIN US WHERE YOU CAN IN EACH OF THESE AREAS.

WE ARE FAST APPROACHING THE POINT WHERE ASPIRATIONS AND CONCERNS WILL HAVE TO BE RECONCILED; WHERE TALK IS SET ASIDE AND DECISIONS BEGIN TO FLOW; WHERE TODAY'S PROMISE BEGINS TO CROSS OVER INTO TOMORROW'S REALITY.

IF A STRONG ECONOMY AND GOOD JOBS ARE A GOAL, THEN ELECTRIC POWER FROM COAL WILL BE NECESSARY. AND YOUR CONTRIBUTIONS WILL ADD TO AMERICA'S COMPETITIVENESS WHILE IMPROVING THE NATURAL ENVIRONMENT.

IF ADDITIONAL CONSERVATION OF AMERICA'S ENVIRONMENT IS THE GOAL, THEN YOUR TECHNOLOGIES ARE THE MEANS OF ACHIEVING IT WITHOUT CLEAR-CUTTING THE ECONOMY.

THIS IS WHAT PROGRESS IS ALL ABOUT...THE MARRIAGE OF RESPONSIBLE CONSERVATION AND OF SOUND ECONOMICS.

IF WE SUCCEED, WHAT KIND OF WORLD COULD WE HAVE 20 YEARS FROM NOW?

IF TECHNOLOGY AND COAL ARE ALLOWED TO DO WHAT WE KNOW THEY CAN DO -- TO REMOVE THE UNDESIRABLE ELEMENTS FROM THE FUEL WHILE RETAINING ITS GOODNESS -- IT CAN BE A WORLD WHERE:

-- AMERICA WILL NEVER AGAIN HAVE TO GO TO WAR TO PROTECT THE WORLD'S DOMINANT OIL RESERVES;

-- WHERE ELECTRIC CARS HUM ALONG OUR HIGHWAYS, FREE OF POLLUTANTS AND CARBON DIOXIDE EMISSIONS;

-- WHERE ELECTRIC-UTILITY RATES CAN BE FORECAST YEARS AND DECADES IN ADVANCE;

-- AND WHERE THE REALITY OF INEXPENSIVE, RELIABLE DOMESTIC ENERGY CONTINUES TO DRIVE THE STRONGEST ECONOMIC MACHINE ON EARTH.

THAT'S THE WORLD I SEE. AND THAT'S WHY, TO ME, THERE IS NO QUESTION BUT THAT COAL REMAINS AMERICA'S FUEL OF CHOICE ... AND FUEL OF NECESSITY.

THANK YOU VERY MUCH.

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# **Clean Coal Technology Markets Session**

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Panel Chair:  
**Herbert Wheary,**  
Chairman, Utility Advisory Committee,  
Southern States Energy Board

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Second Annual Clean Coal Technology Conference  
Atlanta, GA  
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## **EVOLUTION OF DOMESTIC UTILITY MARKET STRUCTURE INTO THE 21ST CENTURY**

**George T. Preston  
Electric Power Research Institute**

**My comments focus on the evolution of the United States domestic electric utility market structure and some of the implications of that evolution for clean coal technology markets. I'll briefly address:**

- **recent and potential future changes in the electric utility industry**
- **projected U. S. electricity demand into the next century**
- **current and advanced coal-based electric generating technologies and their competition**
- **the domestic market for CCT electricity generation.**

### **THE CHANGING ELECTRIC UTILITY INDUSTRY**

**The U.S. electric utility industry consists of over 3000 private and public companies and agencies with an aggregate power generating capacity of over 700 GW. This is the largest concentration of electricity capability in the world - larger than the next 5 countries combined. Of the U.S.' total generating capacity, 41% is coal-based, and in 1993 54% of our electricity will be produced from these plants.**

**The business environment in which the industry operates is changing rapidly.**

- **The customer is more sophisticated and more demanding.**
  - **Customers want more influence on the business direction of their utility.**
  - **Customers expect more breadth of choice in the services offered.**

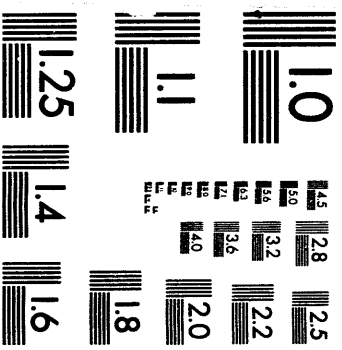
**An industry that is used to having 100% market share has nowhere to go but down, so this new muscle flexing by customers requires a nimble response (Hayes, 1991).**

- **The composition of the industry - the number and character of its participants - is changing.**
  - Utilities are evaluating and deciding among a spectrum of organizational structures, ranging from the traditional vertically integrated to completely horizontally linked or separate unbundled organizations. The United Kingdom adopted the latter model - swallowing the whole pill in a very short transition time except for nuclear generation.
  - New players - non-utility generators (NUGs), including independent power producers as well as those affiliated with regulated utilities - have entered the generation side of the industry and have accounted for over 50% of new generating capacity additions since 1990. This market share of capacity additions is likely to persist well into the first decade of the 21st century.
  - Several significant mergers and acquisitions have occurred or have been tried in the past few years, with more to come as utilities seek synergies to cut their fixed costs and remain competitive. Examples include PacifiCorp - Pacific P&L and Utah P&L; Centerior - Cleveland Electric Illuminating and Toledo Edison; Midwest Resources - Iowa Power and Iowa Public Service; Western Resources - Kansas P&L and Kansas G&E.
  - The "regulatory compact" is cracked, if not broken, as Alfred Kahn, a far-sighted regulator, observed in 1988: "The industry also has been opened in various ways to unregulated competition, but very partially, and in ways that have given rise to all sorts of distortions, inefficiencies, and inequities . . . . Whichever path the future takes, the companies have every right and obligation to demand elimination of the distortions inherent in partial deregulation . . ." (Kahn, 1988).
- **The regulatory framework is changing.**
  - The National Energy Policy Act has created new electric generation opportunities.
  - Increased transmission access will broaden the market potential for IPP and APP (affiliated power producer) generation.
  - Environmental regulation is still evolving, with increasing emphasis on pollutant prevention and externality-based cost incentives.
  - Under integrated resource planning (IRP), many utility companies will not be able competitively to build, or even own, new generating capacity.



- **The financial rules and corporate objectives are changing.**
  - Electricity is still the product, but increasingly it is viewed by customers and the more perceptive companies as an energy service, not a commodity.
  - Corporate earnings come from multiple sources.
  - Corporate growth no longer depends on sales growth.
  - Sustained low interest rates are putting pressure on common stock dividends. (Wang, 1993)
- **It is simplistic to say that any of these changes is driven unilaterally by any other. They all influence each other, but the corporate attitude toward electricity generation as a business is changing, driven by all of the above.**
  - Generation is moving outside the rate base as IPPs and APPs account for over 50% of new capacity additions. However, most of the added capacity has been for peaking and cycling duty. Little baseload capacity will be added in the 1990s - meaning that installed baseload generation will continue to dominate electricity revenues.
  - For many reasons influenced by the driving factors cited above, IPPs and APPs tend to be the early implementers of new advanced generating technologies, out of proportion to their relative presence in the industry.
  - Utility corporate decisions about plant upgrades and maintenance investments will be determined by an asset management decision philosophy that looks beyond the "obligation to serve" and considers a broader definition of corporate value.

**Economic life vs physical life.** One implication of asset management based decisions is that the classic 30-year book life - assumed for many fossil generating plants at their commissioning - is becoming irrelevant. Plants can be designed and operated to have physical lives well beyond 30 years - even an "undefined" physical life; but if competition, downward price pressure and tightening environmental requirements along with technology advancements make a physically healthy but obsolete plant economically inoperable, then designing and maintaining it to be physically capable of a long life was not a viable business strategy. This is why the issue of relicensing nuclear plants has lost some urgency in recent years; even with years remaining on their 40-year licenses, several nuclear plants have closed. (Wang, 1993)



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## U. S. ELECTRICITY NEEDS

Growth in electricity demand will likely continue, since electricity is the most versatile energy source at the point of use. The U. S. Energy Information Administration's Annual Energy Outlook 1993 projects that electricity energy and load demand will increase at a 1.3 - 1.9% annual rate from 1990 to 2010 depending on the strength of the U. S. economy, the proportion of electricity relative to total U. S. energy consumption, the impact of higher efficiency industrial technologies and energy savings from demand-side management. Energy demand growth at even the lowest rate of 1.3% annually will require adding about 150 GW of new capacity between 1990 and 2010. This compares to an installed base of about 730 GW. A 1.9% growth rate implies about 250 GW of new capacity.

EIA and others expect that 50% or more of the generating capacity added between now and 2000 will be natural gas fired, to serve intermediate and peak load requirements. As reserve margins decline and existing base load capacity becomes more fully utilized toward the end of the decade, coal-based generation additions will likely become more significant - according to EIA, 36-62% of all capacity additions during 2000-2010.

Compared to the EIA projections of need, the announced plans of utilities and other electricity generators are relatively consistent in terms of types of capacity to be added, although the amounts of capacity on the drawing boards are far less than the EIA projected demand.

- The *Power Engineering* survey of North American utilities identifies 69 GW of planned additions, of which 30 GW is coal, 15-18 GW gas, and 11 GW nuclear. The largest planned coal-fired units are 675-720 MW, and most of these show startup dates after 2005 (Smock, 1993).
- NERC data show planned U.S. (48 states) additions for 1993-2001 of 73 GW including 8.5 GW coal-fired, 40.7 GW oil or gas-fired by utilities (fossil steam, combustion turbine and combined cycle) and 14.2 GW by NUGs.
- Utility Data Institute shows 1990-2000 planned U. S. additions totaling 113 GW: 52.5 GW utility including 12.4 GW coal-fueled, and 60.6 GW non-utility including 11 GW coal-fueled (UDI, 1993).

Some of the data are net of annual planned plant retirements; but as implied earlier, a significant number of plants are likely to be retired early due to competitive pressures shortening their economic life. And these "early retirements" generally have not been reflected in utility forecasting (Wang, 1993).

## U. S. UTILITY GENERATING TECHNOLOGIES, 1993 TO ?

Investment decisions and, indirectly, the structure of the U. S. domestic utility market itself will be affected by the technological success of numerous development and demonstration programs now in progress.

**Conventional fossil steam boilers.** As implied earlier, the bulk of the electric generating capacity running in 2000 is running today, much of it baseloaded. Until recently the presumption has been that existing baseload capacity would be the benchmark for generating technology performance as well as economics. However, as explained earlier, new legislative and regulatory approaches (e.g. externalities, renewable energy production credits) and advanced lower-cost technologies could drastically shorten the economic life of much of this existing capacity base.

**State-of-the-art power plant (SOAPP).** Modern materials, component designs and emission control technologies are the basis of advanced steam condition (4500 psi, 1050°F double reheat) supercritical coal-fired plants with thermal efficiency in the 39-42% range. These plants could exploit some of the flue gas clean-up technologies demonstrated in the early rounds of the DOE Clean Coal Technology program.

**Pulverized coal combined cycle air turbine/steam turbine plant with thermal efficiency over 47%.** This is high-efficiency developing technology with potential for significant capital cost reductions.

**Coal gasification combined cycle with 2500°F combustion turbines.** The consortium-funded 100 MW Cool Water demonstration in the mid 1980s was the cleanest coal-based generating plant ever to operate up to that time. Three major suppliers now offer commercial IGCC plants using 2300° F ("F series") combustion turbines.

**Advanced pressurized fluidized bed combustion** applies the design, operating and materials lessons learned from several early utility-scale AFBC commercial plants and PFBC demonstration plants to achieve efficiencies in the 44-46% range while side stepping hot-gas filter material limitations through clever cycle design. This is developing technology that will be tested by Southern Company with DOE and EPRI funding support.

**Combustion turbine combined cycle.** As discussed earlier, through much of the 1990s combustion turbines - first "heavy frame" and then aeroderivative machines - and advanced cycles based on combustion turbine concepts are expected to account for most new generating capacity. The 2500°F combustion turbines for these plants will be available by about 2000 to provide thermal efficiency of 54% (LHV) in combined cycle service. DOE's Advanced Turbine

Systems program is aimed at developing machines to reach combined cycle thermal efficiencies of 60% or more.

With 50-60 GW of planned combustion turbine additions in the next decade, the prognosis for long-term availability of gas at assured prices is an important factor. This can be summarized as:

- There is plenty of gas in the ground.
- Gas producers and distributors are confident of their ability to deliver. Some will sign 10 or 15 year ("long-term") supply contracts with specific escalation terms.
- The producer industry recognizes an issue concerning their ability to provide gas in the potentially required quantities at \$4/MBtu or less. Success in this will depend in part on technology advances to keep production costs from rising.
- Utilities that are adding significant combustion turbine capacity (and also IPPs, if they bear the risks) are not taking anything for granted, and many are buying gas storage capacity.
- There is an effective cap of about \$4/MBtu on the price of gas, because at that level, integrated coal gasification combined cycle economics can beat out natural gas combined cycle in many utility generation situations.

**Distributed generation** means modular units in the 10 kW to 2 MW size range to meet localized electricity demand and replace "economy of scale" with "economy of production." Examples include solar photovoltaic cell arrays, internal combustion engines, small gas turbines, fuel cells, and batteries. Distributed generation will not replace the need for future large-scale central-station generation; however, the utility business-strategic benefits of distributed generation will have major impacts on siting philosophy, rate making and the competitive environment.

## **MARKET FOR DOMESTIC COAL-BASED GENERATION**

The recent galloping changes in the U.S. electric utility industry, projections of electric power needs for the next ten years, and perspectives on the status of the generation technologies to be available, support the following observations about the prospects for broad implementation of clean coal technologies in the domestic market.

- NERC projections indicate that utility coal-based generating capacity will be only 5.5 GW greater in 2002 than now, in contrast to gas-fired and dual fuel fired which will be a total of 50 GW greater in 2002 than now.
- The requirement for integrated resource planning (IRP will be required in 45 states by 1995) will add to the list of options to be considered - i.e. it will open the competitive door to - demand-side management, inter-utility power purchases, and plant refurbishments. Inter-utility power purchases facilitated by increased transmission access will make it more difficult for smaller utilities to stay in the generation business - i.e. to add new generating capacity of their own, whether coal-based or other fuel source.
- In today's utility business environment, regardless of thermal efficiency, reliability or environmental performance, a clean coal technology that can be competitive only if its capital costs are levelized over a 30 year period, will not succeed. The half-life of technology advancement today is so much shorter that we must re-think everything we thought we knew about power plant investment horizons.
- In the 1990s and even after 2000, NUGs and the technologies that are suitable for distributed generation will hold the advantage of less risk through smaller-size capacity increments, compared to clean coal technologies or other coal-based options that depend on economy of scale to "make the numbers."
- Several key competitive issues face new coal-based technologies in the near-term power generation market. These include credible demonstration, costs competitive with natural gas options, and capability to meet continually tightening environmental regulations and externality challenges.
- The capital cost for most current or advanced coal-based technologies is in the range \$1300-1700/kW - which at today's gas prices can't compete with natural gas fired plants that cost \$500-700/kW. The coal technologies become competitive when natural gas reaches a sustained price of \$4-\$5 per MBtu or when one or more of the technically attractive clean coal options are developed sufficiently to be offered at reduced capital costs. Either or both of these could occur after 2000.

## CONCLUSION

The U. S.' enormous low-cost coal resource base will continue to provide over half of the nation's electricity well after year 2000. For the balance of the decade, however, due to competitive pressures and the shortening half-life of technology advances, the low capital cost of natural gas generation options will make gas the predominant fuel for new capacity additions or repowering. This provides a

window in which to demonstrate advanced high-efficiency lower cost coal-based generating technologies.

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**OPPORTUNITIES IN INTERNATIONAL  
DEPLOYMENT OF CCTs**

**Barry K. Worthington  
Executive Director  
United States Energy Association**

**(The comments of Mr. Worthington were not  
available at the time of publication.)**



**INTEGRATED RESOURCE PLANNING:  
ITS IMPACT ON SUPPLY-SIDE OPTIONS**

**Steven A. Fluevog  
Project Engineer  
Georgia Power Company**

**(The comments of Mr. Fluevog were not  
available at the time of publication.)**



## **Talking Points for Clean Coal Conference- IPP Perspective**

**P. Chrisman Iribe  
U.S. Generating Company  
September 8, 1993**

### **I. Background on IPP Industry and U.S. Generating**

#### **Historical Growth (1978 - 1993)**

- IPP industry has grown from 0-6% of U.S. electric capacity in 15 years
- 7-10% of IPP industry coal based, over 70% is natural gas based
- U.S. Generating has over 1200 MW of coal fired projects in construction or operation all permitted in last 3.5 years.

### **II. Market Trend in Coal Combustion Technologies**

- A. Distinct Consumer (utility is IPP customer) preference for low cost - competitively procured electricity is pushing the historical new technology "test-bed" (i.e., the rate based utility) off the stage.**
- B. Societal pressures for cleaner and "smaller" electricity facilities (smaller scale cogen sites in urban air sheds make clean projects easier to permit) further limits growth in solid fuel combustion.**
- C. Typical cost advantage of solid fuel consumption even with clean-up has been offset by efficiency advances in combustion turbine technology.**
- D. Gas costs now will have to more than double in real terms from current level to give coal even the appearance of competitiveness.**

### III. Clean Coal Technology Commercialization Issues

1. Can we with existing technology make clean coal projects that:
  - are almost as clean as gas plants  $\text{SO}_x$ ,  $\text{NO}_x$  and particulate. (In reality comparison of new plant emissions should not be made between fuels but compared to existing fossil plants whether oil, gas and coal that are in reality 2-5 times dirtier).
  - can use waste water and zero discharge systems
2. Problem areas are:
  - High  $\text{CO}_2$  emission
  - Solid waste concerns (ash)
  - Air toxics could be a problem

Note: Today, natural gas fired turbine generation is nearly twice as efficient and even with 60 days of No. 2 oil firing generates between 1/6 and 1/4 the regulated pollutants as a coal fired facility (see table which follows).

### IV. What needs to be improved if clean coal technology commercialization can go forward

1. Need to improve efficiency of use (e.g., gasification) and thus reduce  $\text{CO}_2$  emissions
2. Need to develop safe, commercial opportunities to use ash
3. Must continue to improve on particulate removal
4. Must do all of these without increasing capital costs

### V. Potential Market today - next 5-10 years

1. Replacing older utility units (repowering) in domestic market
2. International in regions where there are limited gas infrastructure and/or substantial coal resources

### VI. Commercialization Challenges - Conclusions

1. Loss of utility as test-bed for commercialization
2. IPP financing will inhibit commercialization of CCT
3. Need to develop or find a mechanism for risk sharing with beneficiaries of the new technology i.e., major role for government, large trade associations, equipment and fuel suppliers
4. Project financing or lower equity commitments truly limits all but the surest technologies or the most profitable technology applications in order to offset commercialization risks

## Relative Emissions

	240MW Coal	240 MW Gas*
SO <sub>2</sub>	1,500	425
NO <sub>x</sub>	930-1,600	400
CO <sub>2</sub>	2,200	970
Part.	170 T/YR	100 T/YR

\*Include 60 days of oil firing.

Source: U.S. Generating Company - 1993





**FOREIGN MARKETS AND A CASE STUDY  
OF INTERNATIONAL DEPLOYMENT  
OF CCTs**

**Roger Naill  
Vice President  
Applied Energy Services, Inc.**

# World Bank Standards

- Compliance with "World Bank Standards" will likely be required to obtain funding from multi-lateral agencies.

<b>COMPARISON OF EMISSION RATES FOR COAL-FIRED PLANT (lb/MMBtu)</b>			
<b><u>Pollutant</u></b>	<b><u>World Bank</u></b>	<b><u>European Community</u></b>	<b><u>U.S. (BACT)</u></b>
SO <sub>2</sub>	0.9 no standard removal	0.9 ≥60% removal	0.31 ≥95% removal
NO <sub>x</sub>	0.7	0.52	0.11
TSP	no standard	0.079	0.015

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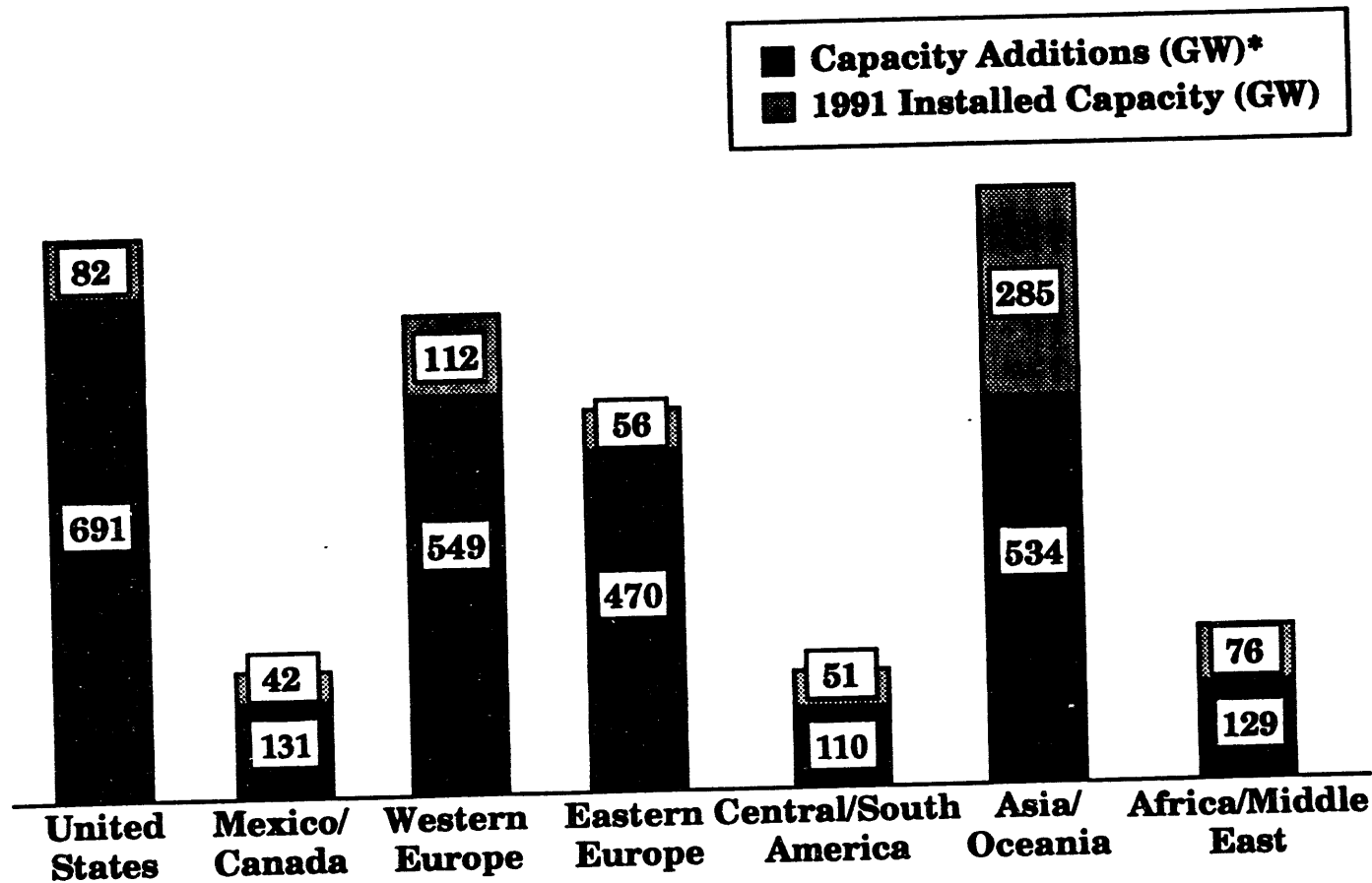
## **How To Get "Clean Coal" Into Foreign Markets?**

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- **Make country or World Bank emission standards more stringent.**
  - **Lower the cost of clean coal to be competitive with conventional technologies.**
  - **Find "third party" sources of funding for the incremental cost of clean coal technologies.**
-

# World Power Markets

## Installed Capacity and Planned Capacity Additions, 1991-2000 (Gigawatts)



Note: Capacity additions include plant retirements and repowerings.  
Sources: RCG/Hagler, Bailly Inc., and American Tractabel

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# Environmental Performance of Coal Options

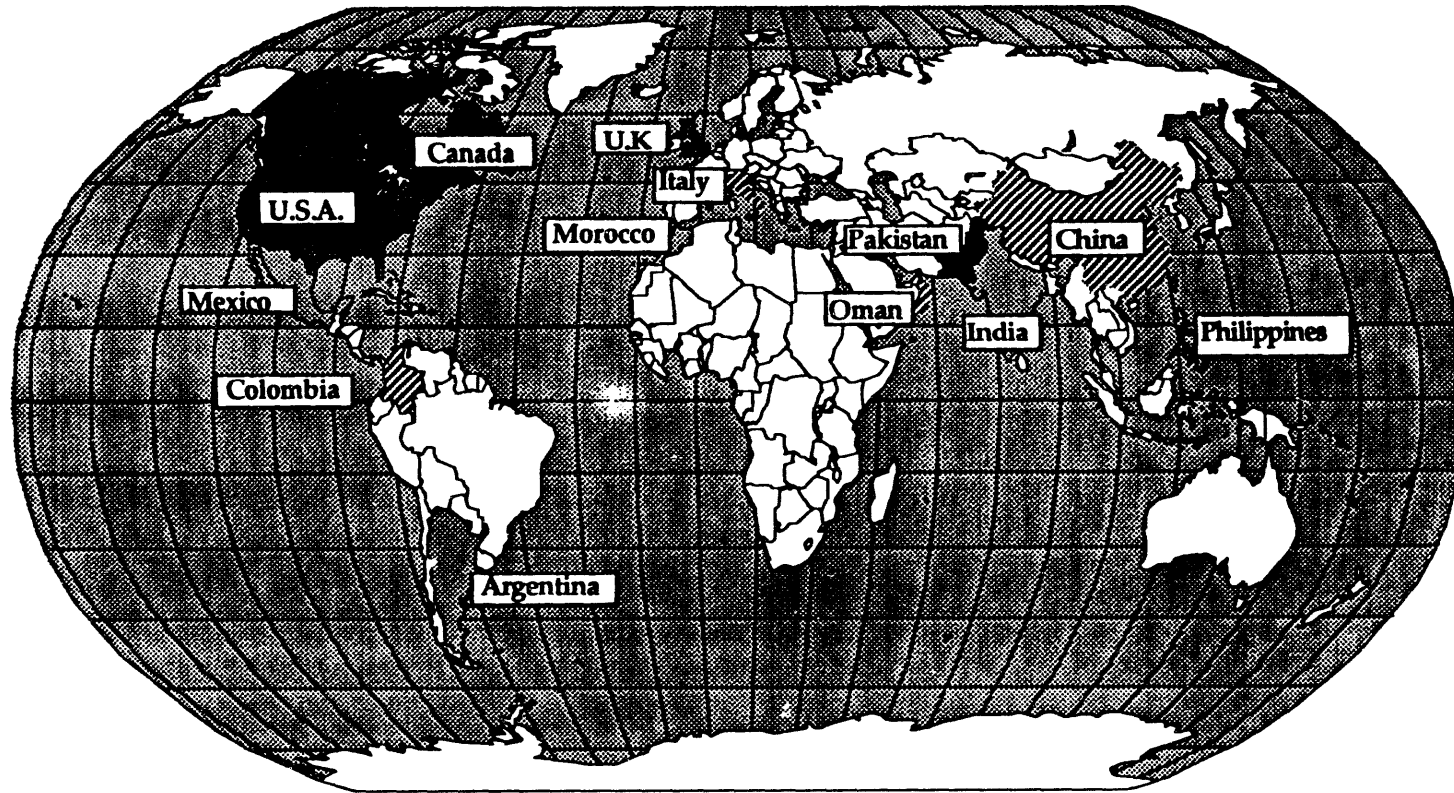
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	<b>Heat Rate (Btu/kWh)</b>	<b>NO<sub>x</sub> (lb/MMBtu)</b>	<b>SO<sub>2</sub> (lb/MMBtu)</b>	<b>CO<sub>2</sub> (% of PC)</b>
<b>CONVENTIONAL PC</b>	<b>9550</b>	<b>0.5</b>	<b>4.4</b>	<b>100%</b>
<b>PC W/DRY SCRUBBER</b>	<b>9800</b>	<b>0.2</b>	<b>0.44</b>	<b>103%</b>
<b>PC W/WET SCRUBBER</b>	<b>10,100</b>	<b>0.2</b>	<b>0.22</b>	<b>106%</b>
<b>CFB</b>	<b>10,000</b>	<b>0.1</b>	<b>0.09</b>	<b>105%</b>
<b>IGCC</b>	<b>9200</b>	<b>0.1</b>	<b>0.04</b>	<b>96%</b>

**Assume: 2.5% sulfur; 11,500 Btu/lb coal.**

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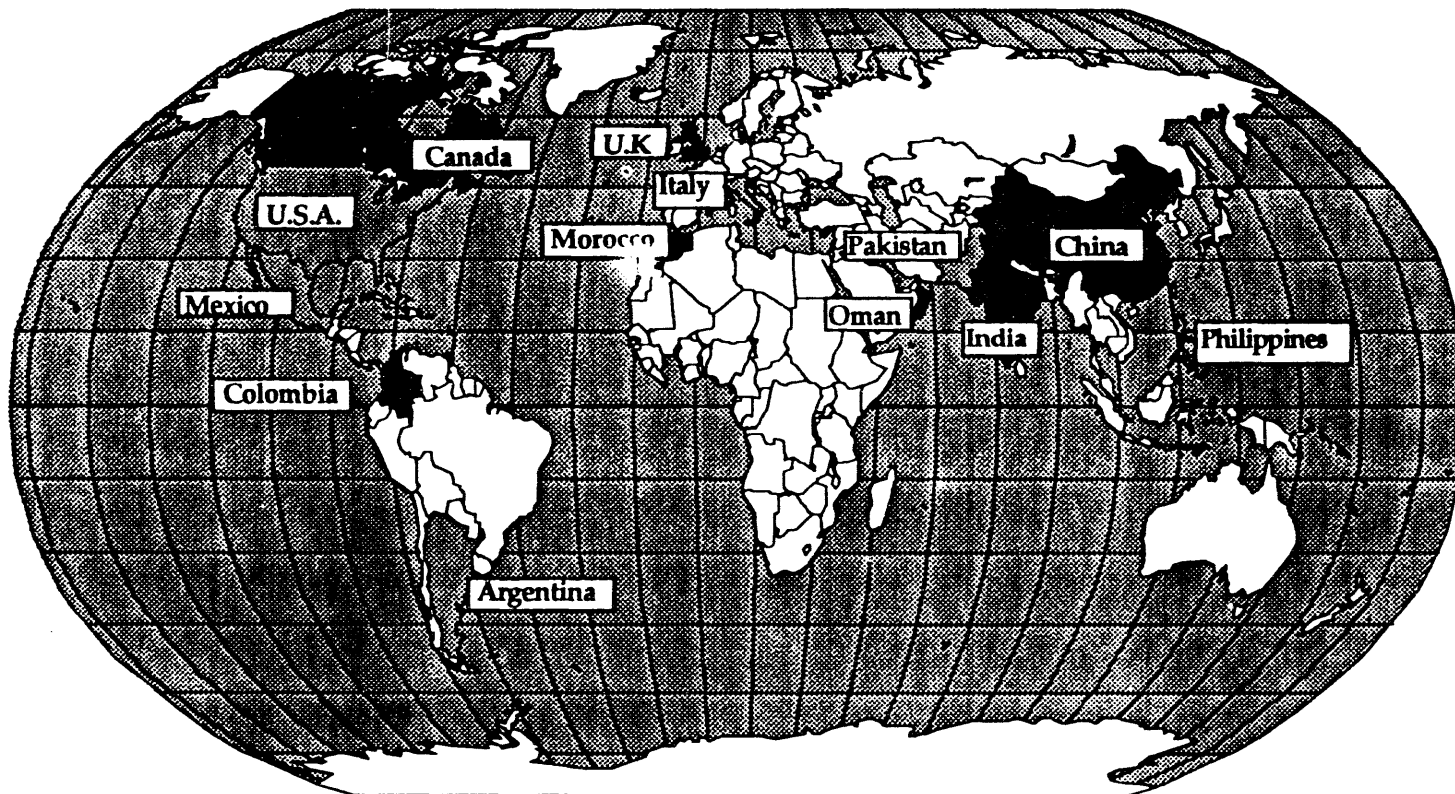
# Country Credit Risk



- Few Risks
- ▨ Some Risks but Overall Quite Stable
- Caution
- Risky

Source: Economist Intelligence Unit and Institutional Investors Credit Risk Ratings

# IPP Potential Market Size\*

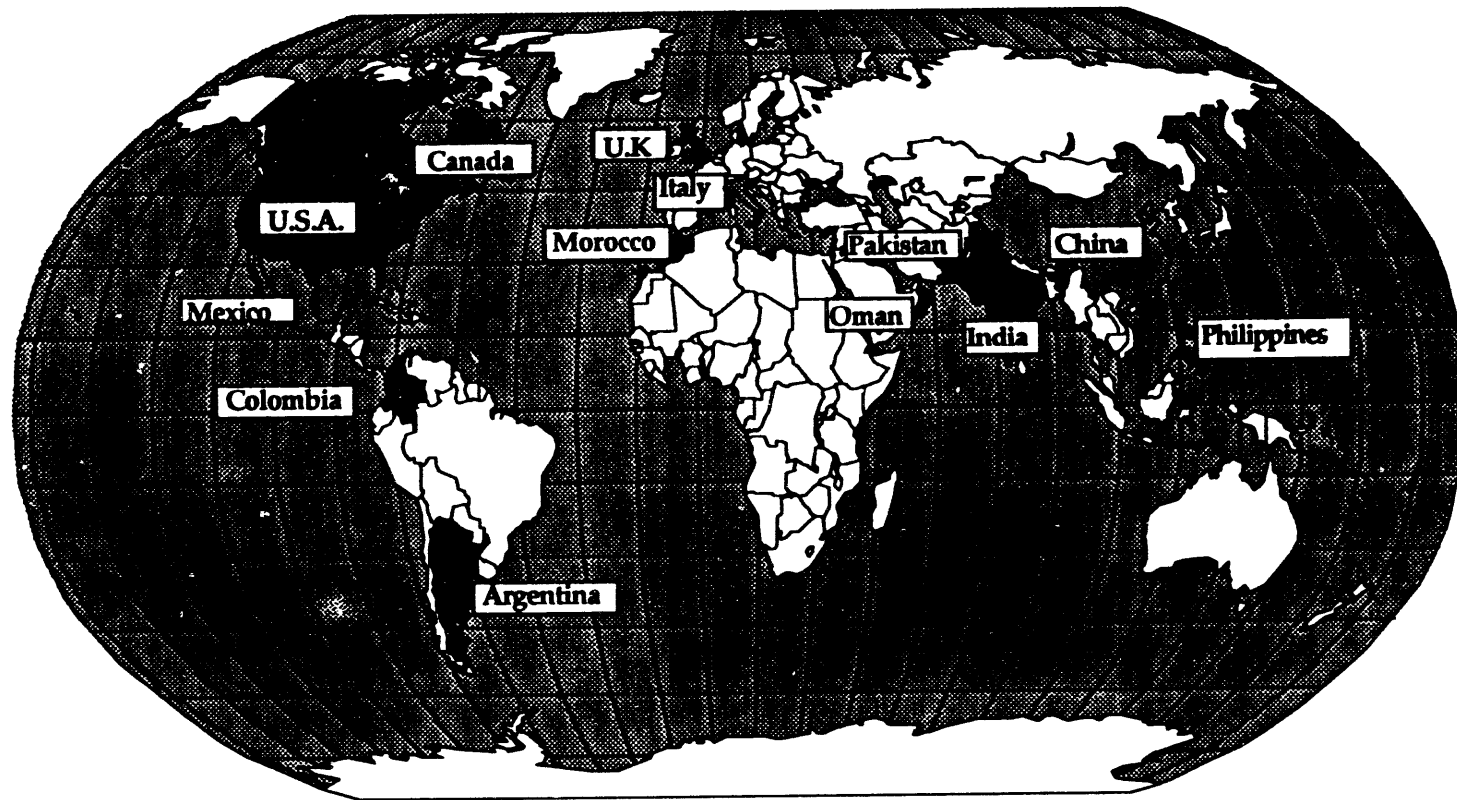


- Large
- Medium
- Small

\* IPP market size analysis includes planned capacity additions and planned asset sales

Source: International Private Power Quarterly

# Government Actions Encouraging IPP Development

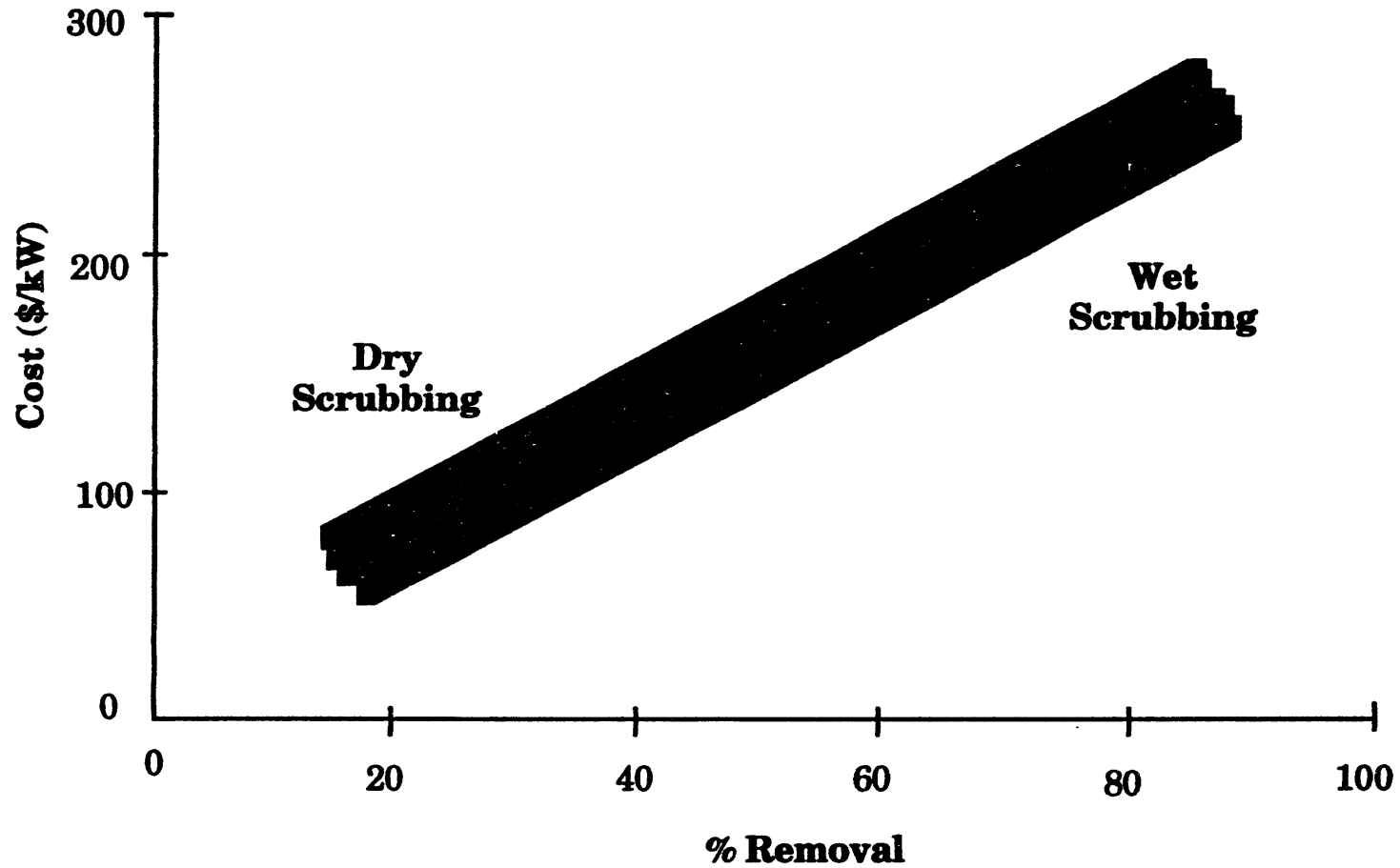


- Mature market, government encourages IPP development
- Government encourages IPPs, but only to a limited extent
- Immature market, few actions encouraging IPPs as of yet

Sources: International Private Power Quarterly, AES project developers, and various other articles

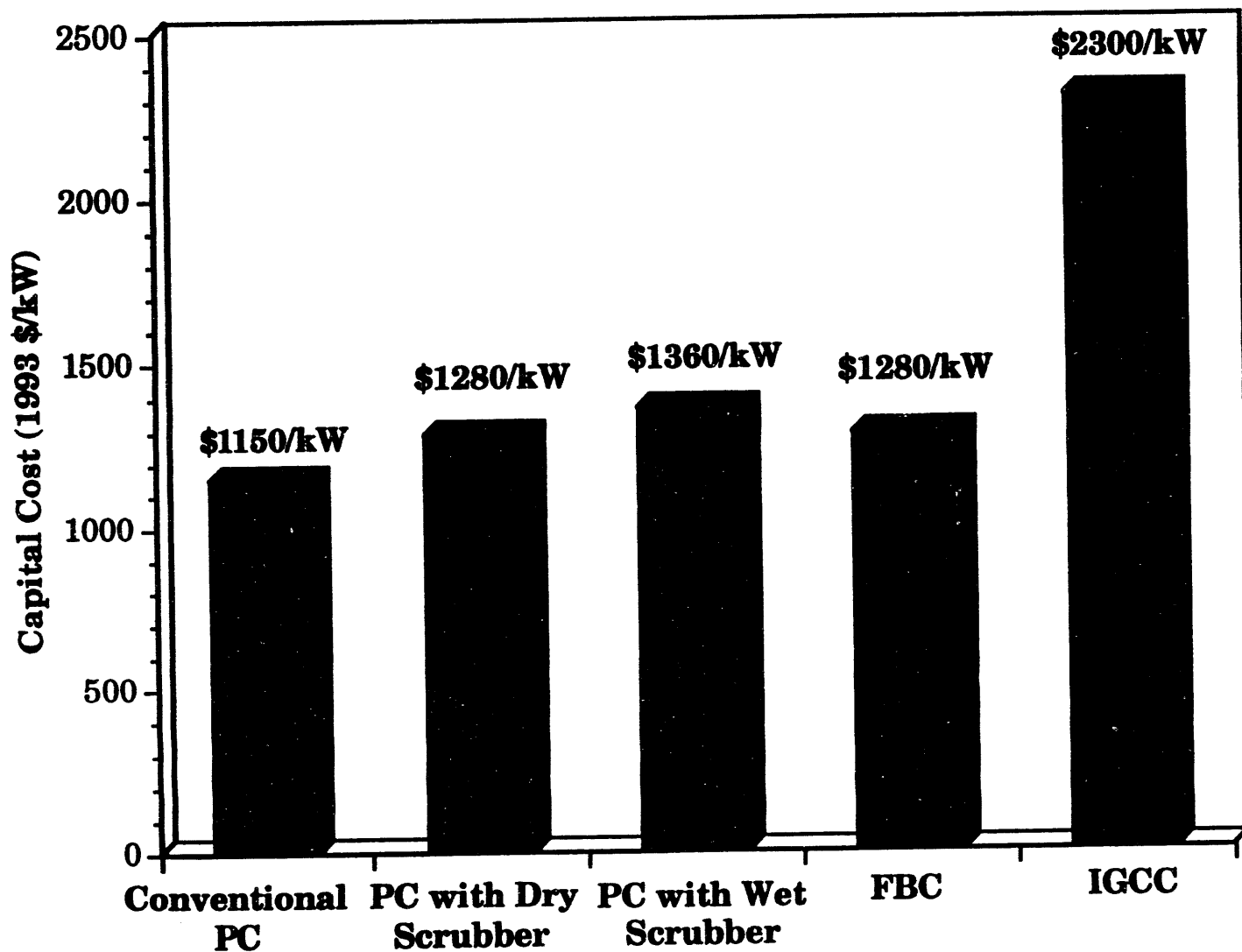


# Cost of SO<sub>2</sub> Removal



Source: Battelle Labs. Includes both capital and NPV of operating costs.

# Cost of Clean Coal vs. Conventional Coal Options



Source: AES experience with vendors.

**A CASE STUDY:  
THE COMMERCIAL DEPLOYMENT OF  
PURE AIR'S CLEAN COAL TECHNOLOGY**

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## **ABSTRACT**

Northern Indiana Public Service Company (NIPSCO) has chosen an unique approach to comply with air quality regulations at its Bailly Generating Station. The utility has entered into a 20-year agreement with Pure Air to design, engineer, construct, fabricate, own, operate, maintain and finance the FGD project. Pure Air, a general partnership company between Air Products and Chemicals, Inc. and Mitsubishi Heavy Industries America, Inc., was selected by the U.S. Department of Energy (DOE) under the Clean Coal Technology Demonstration Program to install an advanced co-current, wet flue gas desulfurization (FGD) system at the Bailly Generating Station. The project combines the most advanced features of Mitsubishi's 95+ units worldwide (over 27,000 MW installed) and an innovative commercial arrangement into a single project to demonstrate substantially lower capital and operation costs when compared to conventional FGD designs. This paper briefly discusses the progress and performance of the project to date and then describes Pure Air's deployment strategy for this technology.

## **BACKGROUND**

In the spring of 1988, with Clean Air legislation soon to be enacted, Northern Indiana Public Service Company (NIPSCO) and Pure Air, a general partnership of Air Products and Chemicals, Inc. and Mitsubishi Heavy Industries America, Inc., began discussions to determine what role flue gas desulfurization (FGD) could play in helping NIPSCO achieve compliance with the anticipated new SO<sub>2</sub> emission standards. The two companies submitted a proposal to the U.S. Department of Energy (DOE) and subsequently this project was selected for \$63 million of funding under Round Two of the agency's Clean Coal Technology Demonstration Program.

### **Innovative FGD Ownership**

In October of 1989, Northern Indiana signed a flue gas processing agreement with Pure Air, whose scope includes the following: design, engineer, fabricate, construct, finance, own, operate and maintain an Advanced FGD facility adjacent to the Bailly generating station. Pure Air also assisted in the development of gypsum sales options and development of the eventual gypsum contract as part of its services to Northern Indiana.

### **Project Objectives And Accomplishments**

The fundamental objectives of the project, as originally outlined by NIPSCO and Pure Air, were to achieve the required SO<sub>2</sub> emission reductions and minimize waste production at the least cost. The goal was to realize cost savings of roughly 50 percent compared to conventional FGD approaches by employing the following:

- **Single 600 MW module which will reduce costs. Use of a single 100% capacity absorber module will demonstrate that spare modules are no longer necessary due to the high reliability of the module design.**
- **Co-current, single loop absorber with in-situ oxidation producing high quality gypsum while operating with a wide range of high sulfur coals. Oxidation will be accomplished by an innovative air rotary sparger system.**
- **The FGD supplier will own and operate the plant for 20 years or more and provide ongoing performance guarantees which will reduce operating risk and cost to utilities and their customers.**
- **Sale of commercial grade gypsum to a wallboard manufacturer.**
- **Direct injection of powdered limestone.**
- **High sulfur dioxide removal efficiency up to 95%.**
- **Wastewater Evaporation System (WES) which will reduce water disposal problems inherent with many U.S. power plants.**
- **Multiple boilers to a single absorber module which will significantly reduce costs at power plants with multiple boiler units.**

Additionally, NIPSCO, Pure Air, and the DOE are in the process of employing an additional feature using Pure Air's proprietary technology for producing PowerChip™ gypsum. PowerChip gypsum is an agglomerated product using typical gypsum produced from an FGD facility and which can be substituted directly for natural rock gypsum in wallboard and cement manufacture. This eliminates any capital investment for the use of FGD gypsum by the end user. Unlike, the "pelletizing" process employed in Europe, PowerChip gypsum can be produced economically [approximately \$2.50/ton (including capital) versus \$8-10/ton for pelletizing].

## **MARKET FORCES**

When considering the flexibility that utilities are given in complying with the SO<sub>2</sub> emission reduction requirements of the Clean Air Act Amendments of 1990, it is clear that traditional approaches to installing air pollution control systems must be modified to successfully compete in this new market. The "command and control" philosophy inherent in the New Source Performance Standards regulations dictated air that pollution control systems be built and operated regardless of the cost per ton of SO<sub>2</sub> removed. The Clean Air Act and the focus on least cost planning in an increasingly competitive power industry require a low cost, low risk, reliable compliance strategy for achieving environmental objectives.

Just as the actual FGD system awards in Phase I were significantly below most expectations, the demand in Phase 2 will be a function of how cost-effectively FGD technology can compete with other compliance options. Least cost will become the overwhelming driving force in making compliance decisions, just as it is today in making decisions as to how to generate new power in a very competitive marketplace.

## **SO<sub>2</sub> Emission Allowances**

Emission allowance trading provisions allow the transfer of emission rights from facility to facility and from utility to utility or independent power producers. Estimates show that emission allowance trading has the potential of reducing the costs of achieving SO<sub>2</sub> emission reduction requirements by 25 percent or more. The trading system permits utilities and independent power producers to buy, sell, and bank allowances, which the EPA has allocated to individual utility generating units. This new type of trading commodity is a license that grants the bearer the right to emit one ton of SO<sub>2</sub> per year. As a commodity, emission allowances will become a product themselves, a form of currency. Each ton of SO<sub>2</sub> emitted by a facility will have a value in the sense that if it were not emitted it could have been traded or sold to another facility.

It may be more cost-effective, for example, for one generating unit to overcomply and credit or sell its excess emission allowances to another facility which, in turn, may find it less costly to buy allowances than to install an expensive control system or switch fuels. Because of the newness of the emission allowance approach, it will be important for utility commissions to establish some form of review and certification procedure so that power generators can reflect the value of such allowances in their compliance plans. Several Midwestern states have in fact already passed legislation directing their commissions to review and approve such compliance plans.

## **Cost Analysis**

In developing a least cost strategy utilizing FGD technology, it is critical to assess the potential impact of all cost elements. The use of advanced technology, the potential derates of 10-15% by fuel switching, by-product utilization, and most importantly, generating and crediting the value of emission allowances, are key strategies in compliance costs. For example, analysis of the cost of building and operating an FGD system at a hypothetical 500 MW generating unit located in the Midwest, burning 4.5 percent sulfur coal and using advanced FGD technology with an own and operate arrangement, by-product sales and emission allowances is shown in Exhibit 1. A graph depicting the impact of each element and a relative comparison to fuel switching is shown in Exhibit 2. The cost of building and operating a traditional FGD system would be over 50% higher than the compliance cost, which can be achieved by combining the potential savings of each element.

The cost per ton of SO<sub>2</sub> removed based on achieving 95% SO<sub>2</sub> removal efficiency, selling gypsum by-product at \$2/ton and selling or crediting emission allowances at \$300/ton, is calculated at \$236/ton SO<sub>2</sub> which is equivalent to a fuel delta of \$0.80/MMBtu. By comparison, the cost of using a conventional FGD system removing 90 percent, making a disposal grade by-product, and without crediting the value of allowances is \$373/ton SO<sub>2</sub> or \$1.26/MMBtu. The reduction of costs which can be achieved by combining the savings of each of these factors is not only important to optimizing the cost of using FGD technology, they are essential to determining whether or not FGD is the least cost compliance alternative. In order for our hypothetical

Midwest generating unit to switch to compliance grade fuels, the plant would likely need to abandon the use of local high sulfur coal which it was designed to burn and import low sulfur coal from the West or Southern Appalachian coal regions. Coal price forecasts indicate that the cost delta for low sulfur compliance coal delivered to a Midwestern generating station will run approximately \$0.70/MMBtu on a 30 year levelized basis versus the cost of burning local coals in such units. The transportation delta alone accounts for 50 percent of this differential. In addition, even minor plant retrofits such as precipitator upgrades required to allow the burning of low-sulfur coals would increase the levelized cost to \$0.85/MMBtu. This analysis would indicate that without combining the benefits of advanced technology, by-product utilization and emission allowances, it is likely that fuel switching would be a lower cost compliance strategy.

Looking at the sensitivity of key cost variables such as the value of emission allowances, the sulfur content of the fuel burned, and the impact of landfilling gypsum by-product show a substantial change in the cost per ton of SO<sub>2</sub> removed, but demonstrate that combining the cost savings potential of each element is still essential to achieving the least cost compliance strategy. Exhibit 3 shows the cost per ton of SO<sub>2</sub> removed drops to approximately \$175 per ton if excess allowances were valued at \$600 per ton versus \$300 per ton. Exhibit 4 shows the cost per ton of SO<sub>2</sub> removed increases to approximately \$425 per ton if the sulfur content of the coal were 2% versus 4.5%. Exhibit 5 shows that landfilling by-product at a disposal cost of \$8 per ton increases the cost per ton of SO<sub>2</sub> removed to approximately \$275.

### **Least Cost Implications**

The implications of these factors are equally important to retrofit and new plant markets, since the cost of achieving SO<sub>2</sub> emission requirements cannot be viewed simply in terms of the cost of installing and operating a mandated control technology. Use of low sulfur fuels, use of control technologies, and the purchase of emission allowances will all be viable, cost effective compliance alternatives. Along with the cost and performance risks of building, financing, operating, and maintaining an air pollution control system, the cost or value of buying, selling, or transferring emission allowances will become a critical factor in making FGD a least cost compliance alternative. The ability of suppliers to provide more than just equipment may become a key determinant in the ability of the marketplace to capitalize on the potential value of these factors.

It is likely that the provisions of the new Clean Air Act legislation will over the long term drive the marketplace for FGD systems to develop a least cost approach to SO<sub>2</sub> compliance which will incorporate many of the following factors:

- Reduced capital and operating costs through use of advanced technology.
- Third party financing, ownership, operation, and maintenance alternatives to capitalize on specialization, risk reduction, and economies of scale.

- Production and sale of commercial gypsum by-products.
- Creation and credit, lease, or sale of emission allowances from high removal (95 percent plus) systems.

Least cost for control technologies and all other compliance alternatives will be measured on a total cost basis expressed in terms of dollars per ton of SO<sub>2</sub>. By capitalizing on the opportunities to reduce the capital and operating costs of FGD systems and generating excess emission allowances, the potential exists to meet or exceed the expectations of achieving the Clean Air Act Amendments requirements for SO<sub>2</sub> emission reductions at costs 25% lower than those which would have been incurred with a traditional "command and control" mandate. The ability of power producers, system suppliers, utility commissions, and fuel suppliers to work together to create and implement innovative strategies will be essential to capturing the full potential of the opportunities provided by this legislation.

## DEPLOYMENT

The deployment of any Clean Coal Technology process has evolved beyond the standard competitive bid, turnkey methodology. The concept of "Allowances" embodied in the Clean Air Act Amendments of 1990 increases the flexibility and complexity of any SO<sub>2</sub> reduction decision making process by a U.S. electric utility. The strongest competitors to Pure Air are in reality non-scrubbing alternatives available to utilities. As discussed earlier, the concept of Least Cost in the absence of "Command and Control" regulation creates whole categories of decisions. Additionally, the value of Allowances and externalities, such as future costs of disposal, are ever increasingly being taken into account in a Least Cost analysis. Pure Air intends to deploy our technology to not only those utilities with SO<sub>2</sub> emission reduction requirements necessitated by Phase II of Acid Rain but also those utilities contemplating the addition of base loaded coal-fired generating capacity.

The former group is deciding between being a buyer or producer [for selling or banking] Allowances. Once they have decided to be a producer of Allowances they must determine whether to purchase low sulfur coal or SO<sub>2</sub> reduction technology. By packaging large, highly efficient AFGD systems, the taking of risk of gypsum sale and/or disposal and limestone procurement and with the Own-and-Operate concept Pure Air is offering a long-term least cost solution to a utility. Allowances and their future value will play a significant role in the actual decision and will remain an on-going parameter in the operation of any Acid Rain FGD system. As the value of an SO<sub>2</sub> Allowance ebbs and flows, a utility can choose to produce Allowances or emit SO<sub>2</sub> based on marginal costs.

The latter group of utilities will be competing with gas-fired IPP's for the construction [and inclusion in their capital rate base] of coal-fired, base loaded capacity. An FGD system will be required under "Command and Control" regulation and will represent a



major portion of the total cost of a grassroots coal-fired power plant. By employing the above mentioned concepts Pure Air can reduce the cost of a coal-fired, base load plant to assist the utility in making a least cost decision that allows them to construct their own coal-fired capacity. Without the employment of extreme measures most coal-fired, base loaded capacity that is required to compete with gas-fired IPP capacity will not be constructed due to current market prices of gas and gas-fired IPP capacity. Thus, once again the real competitor is a utility decision process not an alternate FGD vendor.

Lastly, a market is developing on the gulf and eastern coasts for fuel conversion of under-utilized oil-fired capacity to base loaded Orimulsion-fired operation. Orimulsion fired units will require SO<sub>2</sub> reduction and because these units do not have significant Allowances, highly efficient AFGD systems will be necessary. Due to the nature of these conversions from oil to Orimulsion, fuel savings will go to the benefit of the ratepayer while the risk of any capital expenditures will flow to the shareholders. Consequently, by incorporating the capital and operating costs (i.e., Own-and-Operate) into the cost of the fuel by either the fuel supplier or an other third party, the risk can be removed from the shareholders while the conversion can take place to the benefit of the ratepayer. This type of project can significantly reduce the average cost of production for a utility thus making them more competitive in their service territory. This will then bring benefit to their shareholders through increased power sales.

## **SUMMARY**

As of this report, the facility is operating as expected. The AFGD facility has demonstrated sustained capability to remove in excess of 95% of the SO<sub>2</sub> from Units #7 and #8, has a 99.9% availability rate, and is producing a commercial-grade gypsum that is 98% pure, and being used to manufacture wallboard.

## **LEGAL NOTICE/DISCLAIMER**

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**TABLE 1  
AFGD DEMONSTRATION TEST SCHEDULE**

<u>Test No.</u>	<u>Coal Sulfur</u>	<u>Schedule</u>
1	2.0% to 2.5%	Fall 1994
2	2.5% to 3.0%	Fall 1993
3	3.0% to 3.5%	Fall 1992 (Complete)
4	3.5% to 4.0%	Spring 1993 (Complete)
5	4.0% to 4.5%	Spring 1994
6	Optimal Conditions	Spring 1995

**TABLE 2  
ADVANCED FGD PROJECT COST SUMMARY**

	<u>Budget</u>	<u>Actual/Estimate</u>
Phase I (Design)	\$ 16,251,000	\$ 20,876,000
Phase II (Construction)	\$ 93,142,000	\$ 85,654,000
Phase III (Operations)	\$ 41,104,000	\$ 43,067,000
Subtotal	\$150,497,000	\$149,597,000
PowerChip™ Gypsum	\$ 1,210,898	\$ 1,210,898
Total	\$151,707,898	\$150,807,898

**TABLE 3  
OPERATIONS SUMMARY FOR PURE AIR SCRUBBER  
AT BAILLY STATION**

	<u>Expected</u>	<u>Achieved</u>
SO <sub>2</sub> Emissions	90% removal or 1.2 lb/MMBtu, whichever is less stringent	Averaged 95% (during DOE test up to 98+%, or 0.382 lb/MMBtu)
Power Consumption		
24-hour average	≤8,650 kW	5,962 kW
instantaneous	≤9,650 kW	6,128 kW
Facility Pressure Drop		
24-hour average	≤13.5 IWC	6.66 IWC
instantaneous	≤14.5 IWC	7.55 IWC
Particulate Emissions (g/SCFD)	No net increase	0.04 inlet 0.0071 outlet

W2650aWCB

8/19/93

**Exhibit 1**

**500MW FGD Economics (Capital + O&M)**  
**Allowance Value = \$300/Ton**

<b>(1990\$)</b>	<b>30 Year Levelized Costs</b>		
	<b>Annual Costs (\$MM)</b>	<b>\$/Ton SO<sub>2</sub></b>	<b>\$/mmBTU</b>
<b>Conventional FGD* (EPRI Cost Model)</b>	<b>37.6</b>	<b>373</b>	<b>1.26</b>
<b>Advanced FGD, Own &amp; Operate</b>	<b>33.3</b>	<b>329</b>	<b>1.12</b>
<b>Advanced FGD, Own &amp; Operate, Byproduct Sale</b>	<b>29.8</b>	<b>295</b>	<b>1.00</b>
<b>Advanced FGD, Own &amp; Operate, Byproduct Sale, Emission Allowance Sale (90% SO<sub>2</sub> Removal)</b>	<b>26.4</b>	<b>261</b>	<b>.88</b>
<b>Advanced FGD, Own &amp; Operate, Byproduct Sale, Emission Allowance Sale (95% SO<sub>2</sub> Removal)</b>	<b>23.9</b>	<b>236</b>	<b>.80</b>

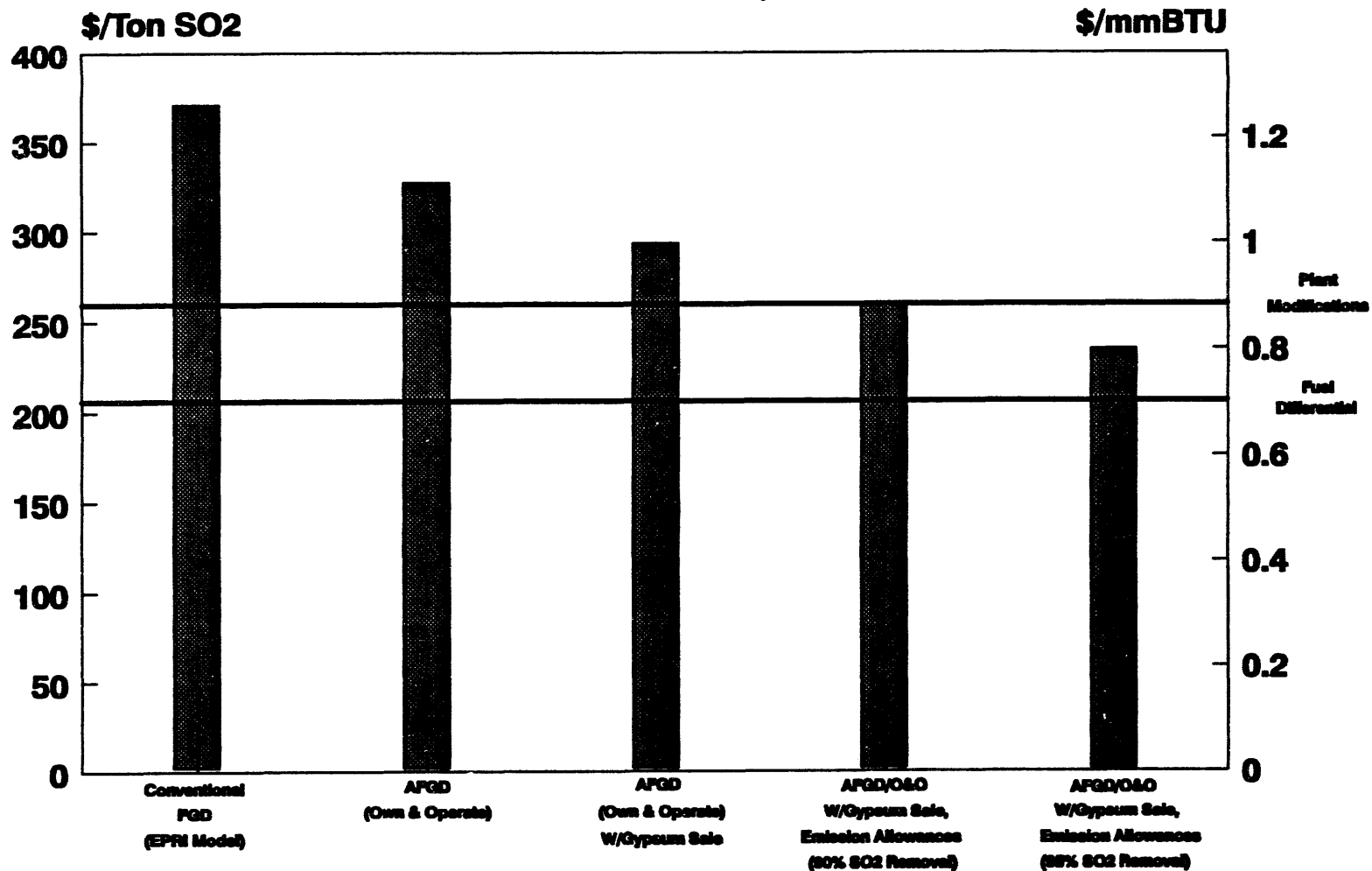
**\*Derived using EPRI's "Retrofit FGD Cost Estimating Guidelines", March 1990**

Exhibit 2

# Flue Gas Desulfurization Economics

## 500 MW Plant - 30 Year Levelized Costs

Allowance Value = \$300/Ton



**Exhibit 3  
Flue Gas Desulfurization Economics  
500 MW Plant - 30 Year Levelized Costs  
Allowance Value = \$600/Ton**

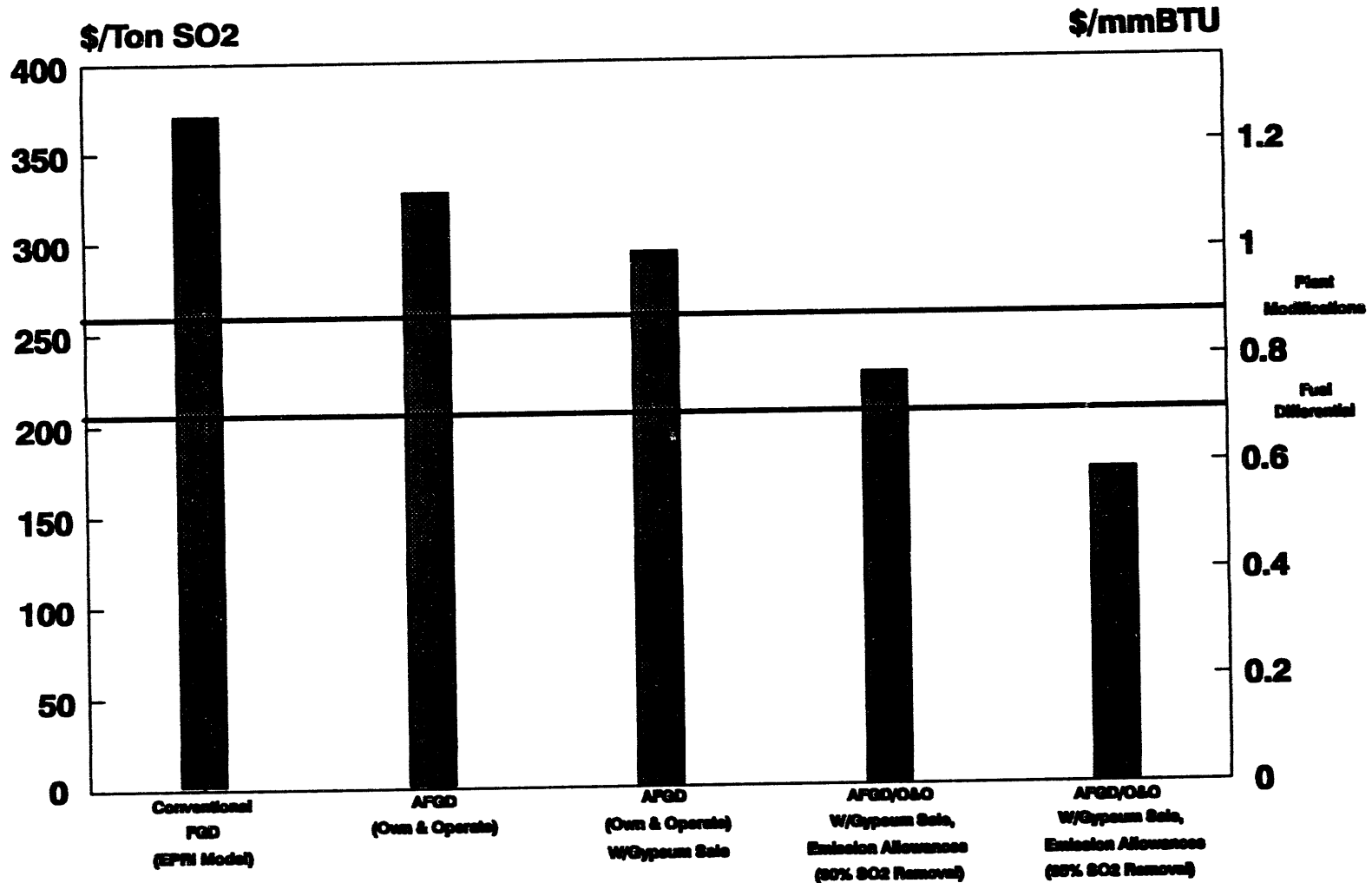
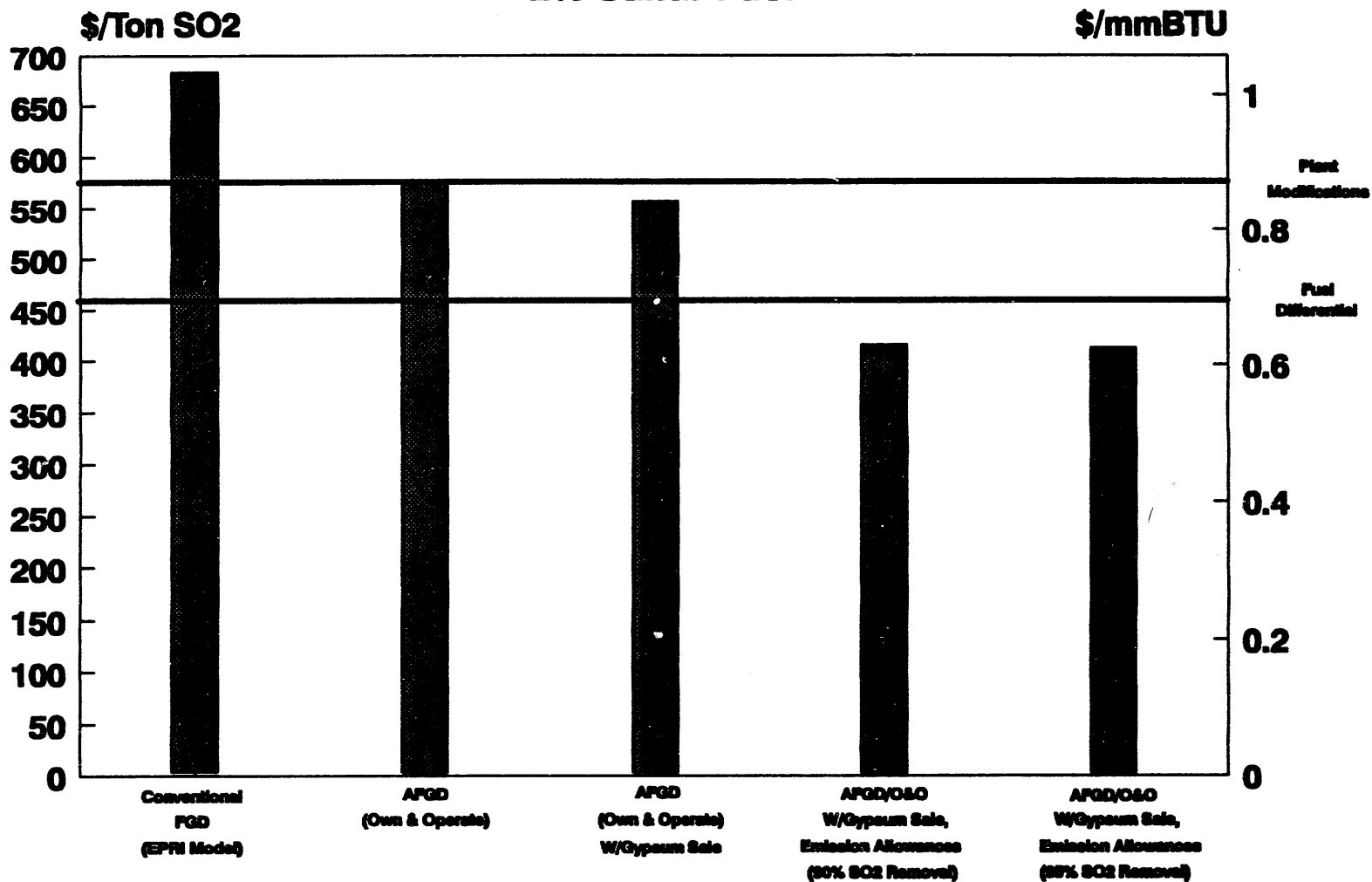


Exhibit 4

# Flue Gas Desulfurization Economics

## 500 MW Plant - 30 Year Levelized Costs

### 2% Sulfur Fuel







**IMPACT OF FEDERAL ENERGY POLICY ON  
UTILITY PLANNING**

**Ray Billups**  
**Manager, Industry Structure Issues, Governmental Affairs**  
**Southern Company Services, Inc.**

**(The comments of Mr. Billups were not  
available at the time of publication.)**



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# **Session 1**

## **NO<sub>x</sub> Control Technologies**

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Co-Chairs:

**Arthur L. Baldwin,**

Pittsburgh Energy Technology Center/  
U.S. Department of Energy

**William E. Fernald,**

Office of Clean Coal Technology/  
U.S. Department of Energy

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# **PERFORMANCE AND OPERATING RESULTS FROM THE DEMONSTRATION OF ADVANCED COMBUSTION TECHNIQUES FOR WALL-FIRED BOILERS**

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## **ABSTRACT**

This paper discusses the technical progress of a U. S. Department of Energy Innovative Clean Coal Technology project demonstrating advanced wall-fired combustion techniques for the reduction of nitrogen oxide (NO<sub>x</sub>) emissions from coal-fired boilers. The primary objective of the demonstration is to determine the long-term performance of advanced overfire air and low NO<sub>x</sub> burners applied in a stepwise fashion to a 500 MW boiler. A 50 percent NO<sub>x</sub> reduction target has been established for the project. The focus of this paper is to present the effects of excess oxygen level and burner settings on NO<sub>x</sub> emissions and unburned carbon levels and recent results from the phase of the project when low NO<sub>x</sub> burners were used in conjunction with advanced overfire air.

## TABLE OF ABBREVIATIONS

<b>AOFA</b>	<b>Advanced Overfire Air</b>
<b>ASME</b>	<b>American Society of Mechanical Engineers</b>
<b>C</b>	<b>carbon</b>
<b>CF/SF</b>	<b>Controlled Flow/Split Flame</b>
<b>Cl</b>	<b>chlorine</b>
<b>CO</b>	<b>carbon monoxide</b>
<b>DAS</b>	<b>data acquisition system</b>
<b>DOE</b>	<b>United States Department of Energy</b>
<b>ECEM</b>	<b>extractive continuous emissions monitor</b>
<b>EPA</b>	<b>Environmental Protection Agency</b>
<b>EPRI</b>	<b>Electric Power Research Institute</b>
<b>F</b>	<b>Fahrenheit</b>
<b>FC</b>	<b>fixed carbon</b>
<b>FWEC</b>	<b>Foster Wheeler Energy Corporation</b>
<b>H</b>	<b>hydrogen</b>
<b>HHV</b>	<b>higher heating value</b>
<b>ICCT</b>	<b>Innovative Clean Coal Technology</b>
<b>lb(s)</b>	<b>pound(s)</b>
<b>LNB</b>	<b>low NO<sub>x</sub> burner</b>
<b>LOI</b>	<b>loss on ignition</b>
<b>(M)Btu</b>	<b>(million) British thermal unit</b>
<b>MW</b>	<b>megawatt</b>
<b>N</b>	<b>nitrogen</b>
<b>NO<sub>x</sub></b>	<b>nitrogen oxides</b>
<b>NSPS</b>	<b>New Source Performance Standards</b>
<b>O, O<sub>2</sub></b>	<b>oxygen</b>
<b>psig</b>	<b>pounds per square inch gauge</b>
<b>PTC</b>	<b>Performance Test Codes</b>
<b>RSD</b>	<b>relative standard deviation</b>
<b>S</b>	<b>sulfur</b>
<b>SCS</b>	<b>Southern Company Services</b>
<b>SO<sub>2</sub></b>	<b>sulfur dioxide</b>
<b>UARG</b>	<b>Utility Air Regulatory Group</b>
<b>VM</b>	<b>volatile matter</b>

## **INTRODUCTION**

This paper discusses the technical progress of one of the U. S. Department of Energy's Innovative Clean Coal Technology (ICCT) projects demonstrating advanced combustion techniques for the reduction of nitrogen oxide (NO<sub>x</sub>) emissions from wall-fired boilers. This demonstration is being conducted on Georgia Power Company's Plant Hammond Unit 4, a 500 MW, pre-NSPS (New Source Performance Standards), wall-fired boiler. Plant Hammond is located near Rome, Georgia, northwest of Atlanta.

This project is being managed by Southern Company Services, Inc. (SCS) on behalf of the project co-funders: The Southern Company, the U. S. Department of Energy (DOE), and the Electric Power Research Institute (EPRI). In addition to SCS, Southern includes the five electric operating companies: Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Savannah Electric and Power. SCS provides engineering and research services to the Southern electric system. The ICCT program is a jointly funded effort between DOE and industry to move the most promising advanced coal-based technologies from the research and development (R&D) stage to the commercial marketplace. The goal of ICCT projects is the demonstration of commercially feasible, advanced coal-based technologies that have already reached the "proof-of-concept" stage. The ICCT projects are jointly funded endeavors between the government and the private sector in which the industrial participant contributes at least 50 percent of the total project cost. The DOE is participating through the Office of Clean Coal Technology at the Pittsburgh Energy Technology Center (PETC).

The primary objective of this demonstration is to determine the long-term effects of commercially available low NO<sub>x</sub> combustion technologies on NO<sub>x</sub> emissions and boiler performance. Short-term tests of each technology are also being performed to provide engineering information about emissions and performance trends [1]. Achieving 50 percent NO<sub>x</sub> reduction using combustion modifications is the goal of this project.

Following a brief unit and technology review, this paper focuses on (1) results of efforts to establish the relationship between NO<sub>x</sub> emissions and unburned carbon and (2) recent results from the low NO<sub>x</sub> burner (LNB) plus advanced overfire (AOFA) test phase.

## **UNIT AND TECHNOLOGY REVIEW**

Georgia Power Company's Plant Hammond Unit 4 is a Foster Wheeler Energy Corporation (FWEC) opposed wall-fired boiler, rated at 500 MW gross, with design steam conditions of 2500

psig and 1000/1000°F superheat/reheat temperatures, respectively. The unit was placed into commercial operation on December 14, 1970. Prior to the LNB retrofit, six FWEC Planetary Roller and Table type mills provided pulverized eastern bituminous coal (12,900 Btu/lb, 33% VM, 53% FC, 72% C, 1.7% S, 1.4% N, 10% ash) to 24 pre-NSPS, Intervane burners. The burners are arranged in a matrix of 12 burners (4W x 3H) on opposing walls with each mill supplying coal to four burners per elevation.

During a spring 1991 unit outage, the Intervane burners were replaced with FWEC Controlled Flow/Split Flame (CF/SF) burners. In the CF/SF burner, secondary combustion air is divided between inner and outer flow cylinders (Figure 1). A sliding sleeve damper regulates the total secondary air flow entering the burner and is used to balance the burner air flow distribution. An adjustable outer register assembly divides the burner's secondary air into two concentric paths and also imparts some swirl to the air streams. The secondary air that traverses the inner path, flows across an adjustable inner register assembly that, by providing a variable pressure drop, apportions the flow between the inner and outer flow paths. The inner register also controls the degree of additional swirl imparted to the coal/air mixture in the near throat region. The outer air flow enters the furnace axially, providing the remaining air necessary to complete combustion. An axially movable inner sleeve tip provides a means for varying the primary air velocity while maintaining a constant primary flow. The split flame nozzle segregates the coal/air mixture into four concentrated streams, each of which forms an individual flame when entering the furnace.

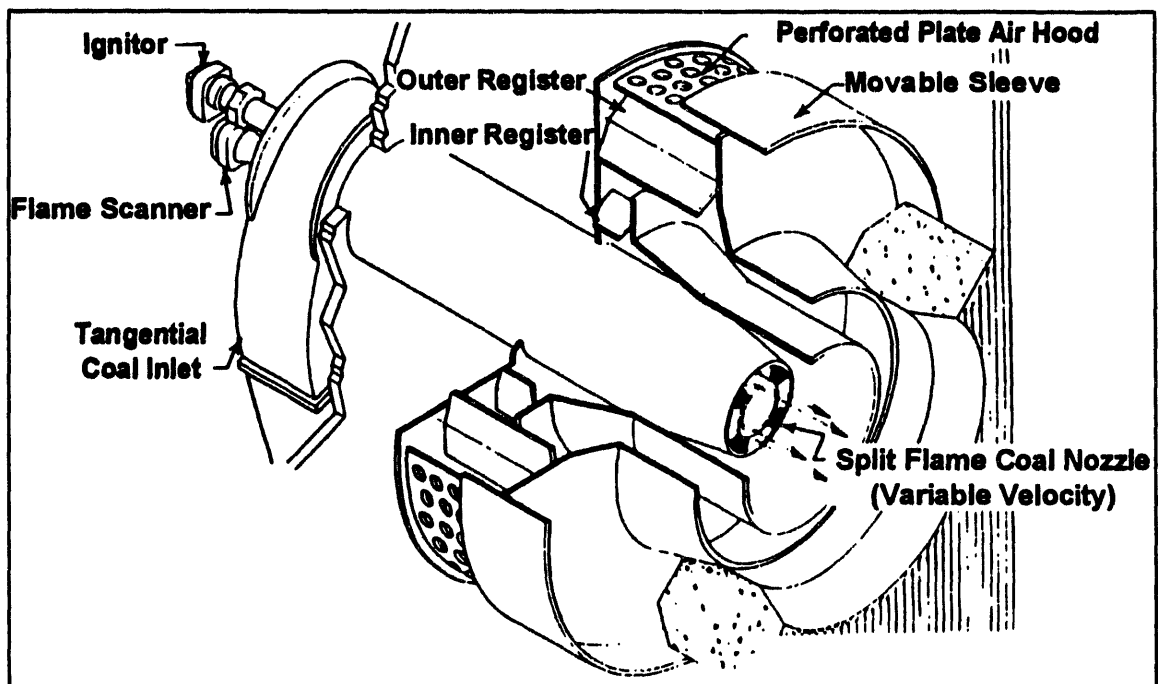


Figure 1. FWEC CF/SF Low NO<sub>x</sub> Burners



This segregation minimizes mixing between the coal and the primary air, assisting in the staged combustion process.

As part of this demonstration project, the unit was also retrofit with an Advanced Overfire Air (AOFA) system (Figure 2). The FWEC design diverts air from the secondary air ductwork and incorporates four flow control dampers at the corners of the overfire air windbox and four overfire air ports on both the front and rear furnace walls. Due to budgetary and physical constraints, FWEC designed an AOFA system more suitable to the project and unit than that originally proposed. Six air ports per wall were proposed instead of the as-installed configuration of four per wall.

During the course of the demonstration, the unit was also retrofitted with four Babcock & Wilcox MPS 75 mills (two each during the spring 1991 and spring 1992 outages). The unit is equipped with a coldside ESP and utilizes two regenerative secondary air preheaters and two regenerative primary air heaters. The unit was designed for pressurized furnace operation but was converted to balanced draft operation in 1977.

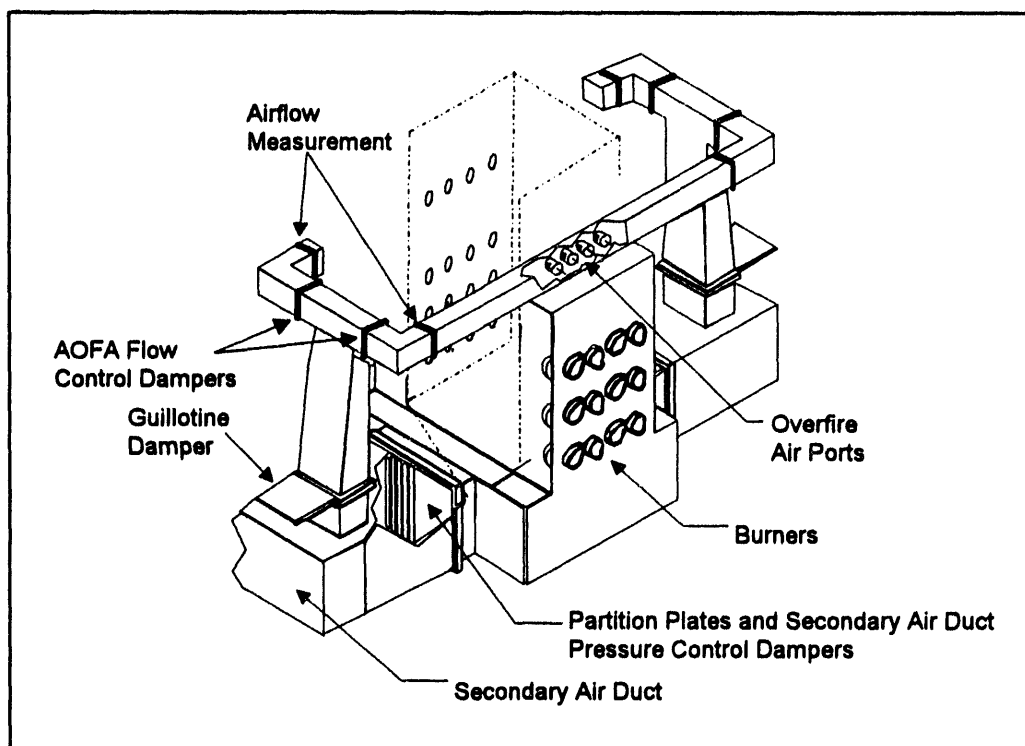


Figure 2. FWEC Advanced Overfire Air System

## REVIEW OF PRIOR TESTING

Baseline, AOFA, and LNB test phases have been completed (Table 1). Short-term and long-term baseline testing was conducted in an "as-found" condition from November 1989 through March 1990. Following retrofit of the AOFA system during a four-week outage in spring 1990, the AOFA configuration was tested from August 1990 through March 1991. The FWEC CF/SF low NO<sub>x</sub> burners were then installed during a seven week outage starting on March 8, 1991 and continuing to May 5, 1991. Following optimization of the LNBs and ancillary combustion equipment by FWEC personnel, LNB testing was commenced during July 1991. However, due to significant post-LNB increases in precipitator fly ash loading and gas flow rate and also, increases in fly ash LOI which adversely impacted stack particulate emissions, the unit was run below 300 MW from September to November 1991 [2]. Following installation of an ammonia flue gas conditioning system, the unit was able to return to full load operation and complete the LNB test phase during January 1992.

Phase	Description	Date
0	Pre-Award Negotiations	
1	Baseline Characterization	8/89 - 4/90
2	Advanced Overfire Air Retrofit (AOFA) & Characterization	4/90 - 3/91
3A	Low NO <sub>x</sub> Burner Retrofit (LNB) & Characterization	3/91 - 1/92
3B	LNB+AOFA Characterization	1/92 - 8/93
4	Digital Controls	9/93 - 6/95
5	Final Reporting and Disposition	6/95 - 12/95

Table 1. Project Schedule

Given the extended LNB test phase, insufficient time was available to complete the full requirements of the LNB+AOFA test phase prior to the spring 1992 outage; therefore it was decided to collect abbreviated data prior to this outage and comprehensive data following the outage. Following the outage, it was found that the AOFA had exacerbated the stack particulate emissions and the unit was again load limited, this time to 450 MW. While efforts were made to resume full load operation, special tests (i.e., NO<sub>x</sub> vs. LOI) were performed and long-term data collected. On March 30, 1993, Hammond Unit 4 resumed full load operation and comprehensive testing in the LNB+AOFA configuration began.

## NO<sub>x</sub> VS. LOI TESTING

The NO<sub>x</sub> versus LOI testing was conducted between October 12 and 28, 1992. The primary purpose of these tests was to determine the effects of various burner settings and mill operation on NO<sub>x</sub> emissions and unburned carbon levels in the fly ash. To assess the effects of each parameter, the test matrix was designed so that a single parameter was varied each test day and all

other parameters were held constant to the extent possible. The parameters tested were (1) excess air, (2) mill coal flow bias, (3) burner sliding tip position, (4) burner outer register position, and (5) burner inner register position. The range of values tested is shown in Table 2. Mill characterization (i.e., primary air and coal through each mill; coal and air distributions; and particle size determination in each coal pipe) was also performed as part of this test program. Unless specified otherwise, all tests were run at the following conditions: (1) nominal 450 MW, (2) all mills in service with equal flows, and (3) overfire air flow set to 200,000 lb/hr (600,000 lb/hr of overfire air is normal for LNB+AOFA operation at this load). The tests were conducted at reduced loads to adhere to stack particulate compliance limits while overfire flow was maintained at the reduced level to prevent excessive slagging or overheating of the AOFA ports. Because of the different operating conditions (load and overfire air flow rates), the absolute values of emissions are difficult to correlate with previous test phase results; however, the intent of this test segment was to perform sensitivity studies, and the influence of the independent variables on NO<sub>x</sub> emissions and LOI at the tested condition should be indicative of the sensitivities at full load with LNBs and no overfire air.

Parameter	Nominal Value	Range Tested	
		Low	High
Excess Air	4%	2.8%	5.0%
Sleeve Damper	7" Outer burner columns 4" Inner burner columns	Not Adjusted	Not Adjusted
Inner Register	~15%	Nominal	Nominal + 40%
Outer Register	~60%	-20% of nominal	+20% of nominal
Sliding Tip	+4 inches	+2 inches	+4 inches
Mill Bias	No bias	Upper Mills +10% Lower Mills -10%	Upper Mills -10% Lower Mills +10%

**Table 2. Hammond 4 / NO<sub>x</sub> vs. LOI Tests / Parameters Tested**

Figure 3 shows the range of the NO<sub>x</sub> and LOI values which resulted from this testing. NO<sub>x</sub> emissions and LOI levels varied from approximately 0.44 lb/MBtu to 0.57 lb/MBtu and 10 percent to 3 percent, respectively. With the exception of the excess O<sub>2</sub> tests, the NO<sub>x</sub> (in lb/MBtu) and LOI values shown in this figure are adjusted to a nominal 4 percent excess O<sub>2</sub> operating level using the slopes of the NO<sub>x</sub> and LOI vs. O<sub>2</sub> curves found during these tests. This adjustment was made to compensate for the test to test variations in excess O<sub>2</sub> levels. As expected, excess O<sub>2</sub> level had a considerable effect on both NO<sub>x</sub> and LOI (Figure 4). For the other parameters considered, within the range of adjustments tested, mill bias and sliding tip position had the greatest influence on NO<sub>x</sub> and LOI (Figures 5 and 6). As can be seen from these graphs, there is some flexibility in selecting the optimum operating point and making

tradeoffs between NO<sub>x</sub> emissions and fly ash LOI; however, much of the variation was the result of changes in excess O<sub>2</sub>.

This can be seen more clearly in Figure 7 in which all the sensitivities are plotted. This figure shows for excess O<sub>2</sub>, mill bias, inner register, and sliding tip, any adjustments to reduce NO<sub>x</sub> emissions are at the expense of increased LOI. In contrast, the slope of the outer register characteristic suggests that an improvement in *both* NO<sub>x</sub> emissions and LOI can be achieved by adjustment of this damper. However, due to the relatively small impact of the outer register adjustment on both NO<sub>x</sub> emissions and LOI, it is likely that the positive NO<sub>x</sub> / LOI slope is an artifact of process noise. It should be stressed that Figures 3 and 7 are parametric plots and that neither NO<sub>x</sub> or LOI are independent variables.

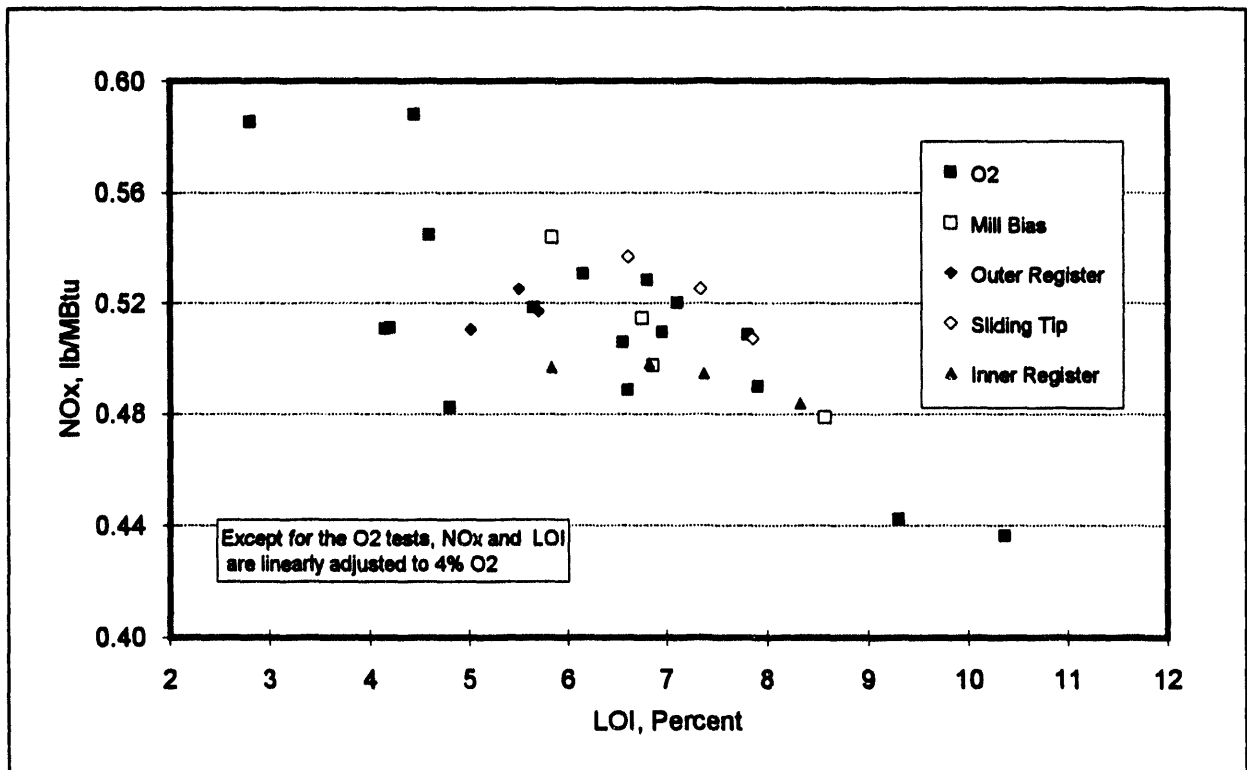


Figure 3. Hammond 4 / NO<sub>x</sub> vs. LOI Tests / All Tests

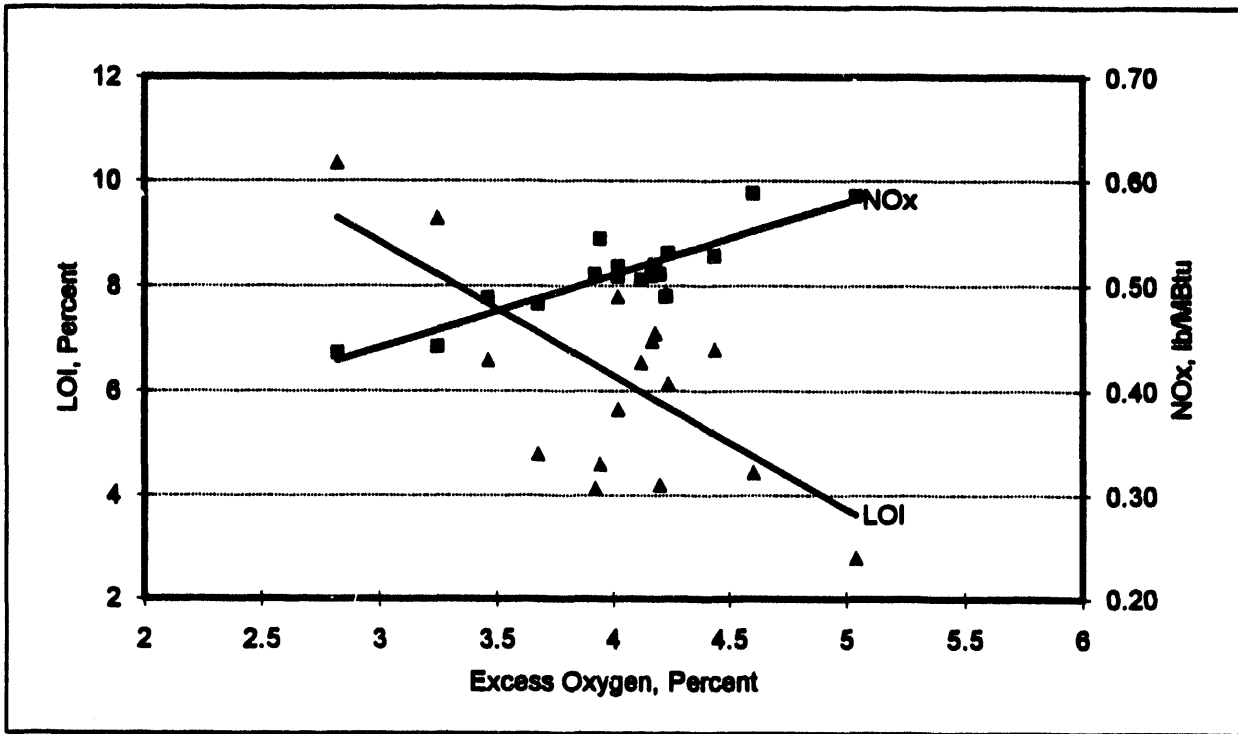


Figure 4. Hammond 4 / NOx vs. LOI Tests / O<sub>2</sub> Sensitivity

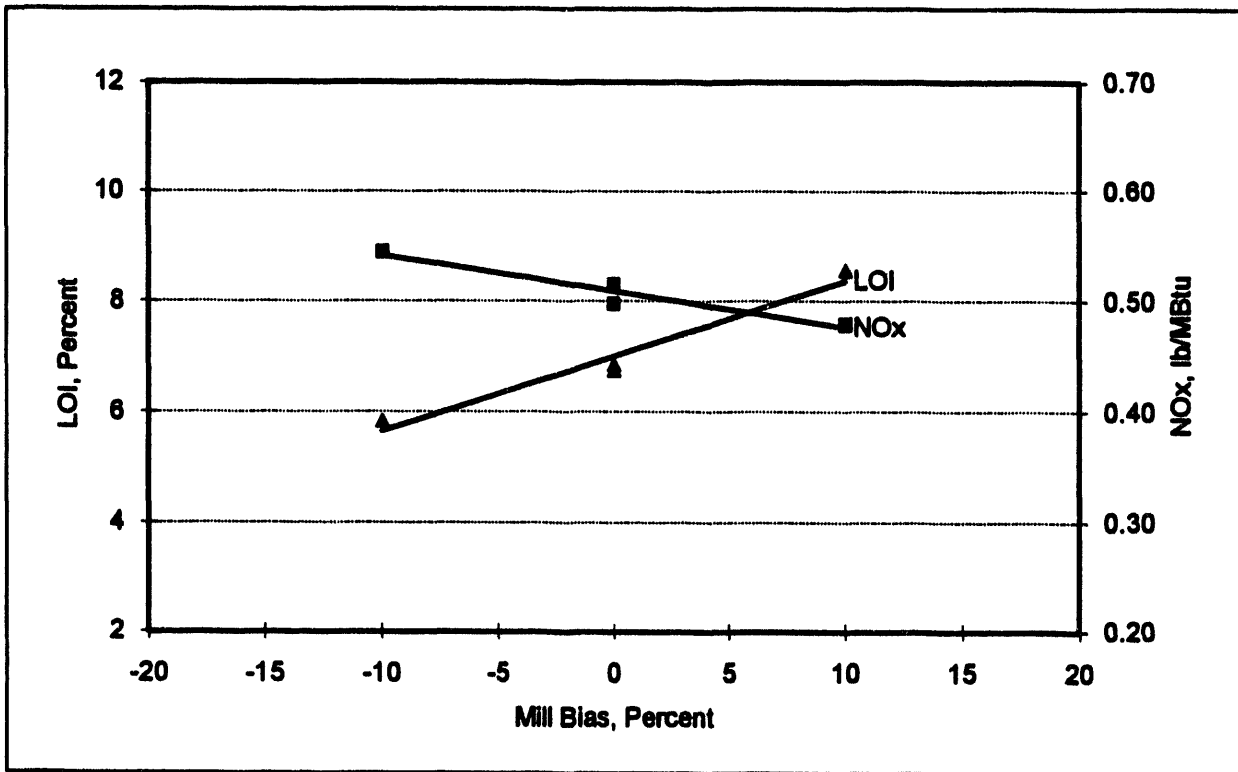


Figure 5. Hammond 4 / NOx vs. LOI Tests / Mill Bias Sensitivity

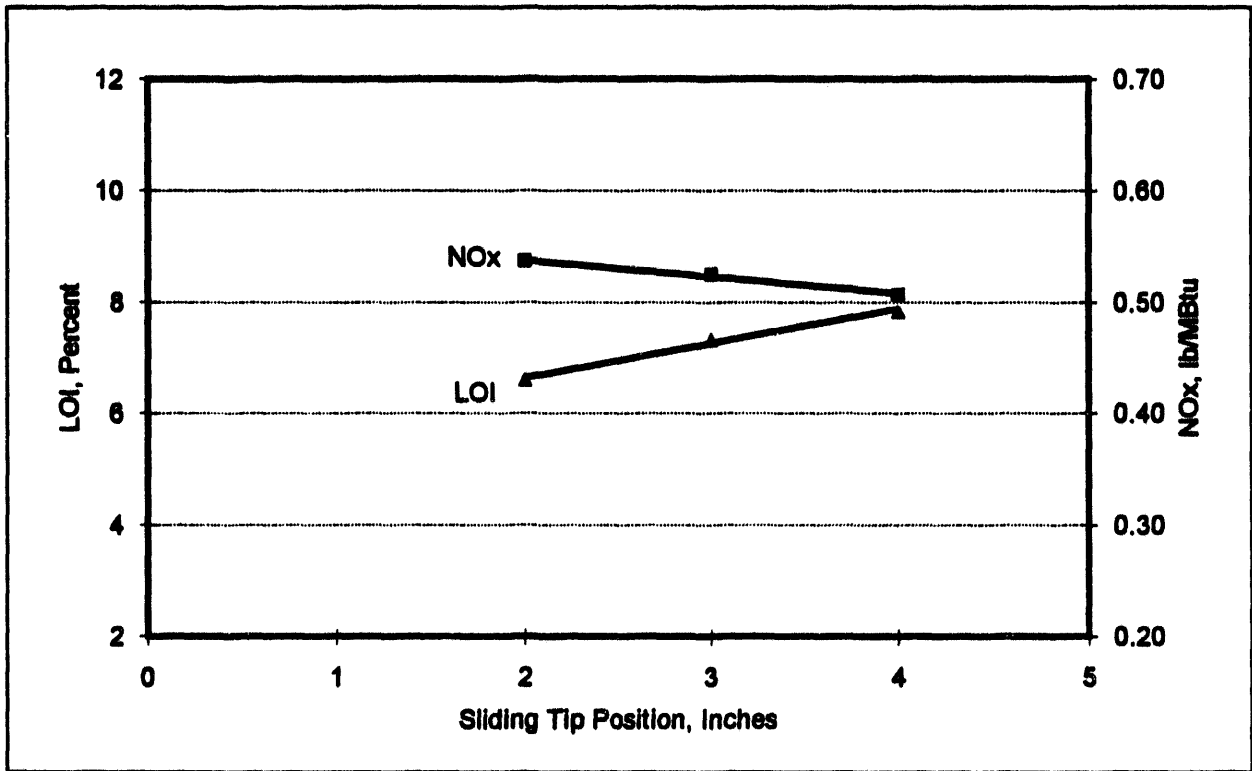


Figure 6. Hammond 4 / NOx vs. LOI Tests / Sliding Tip Position

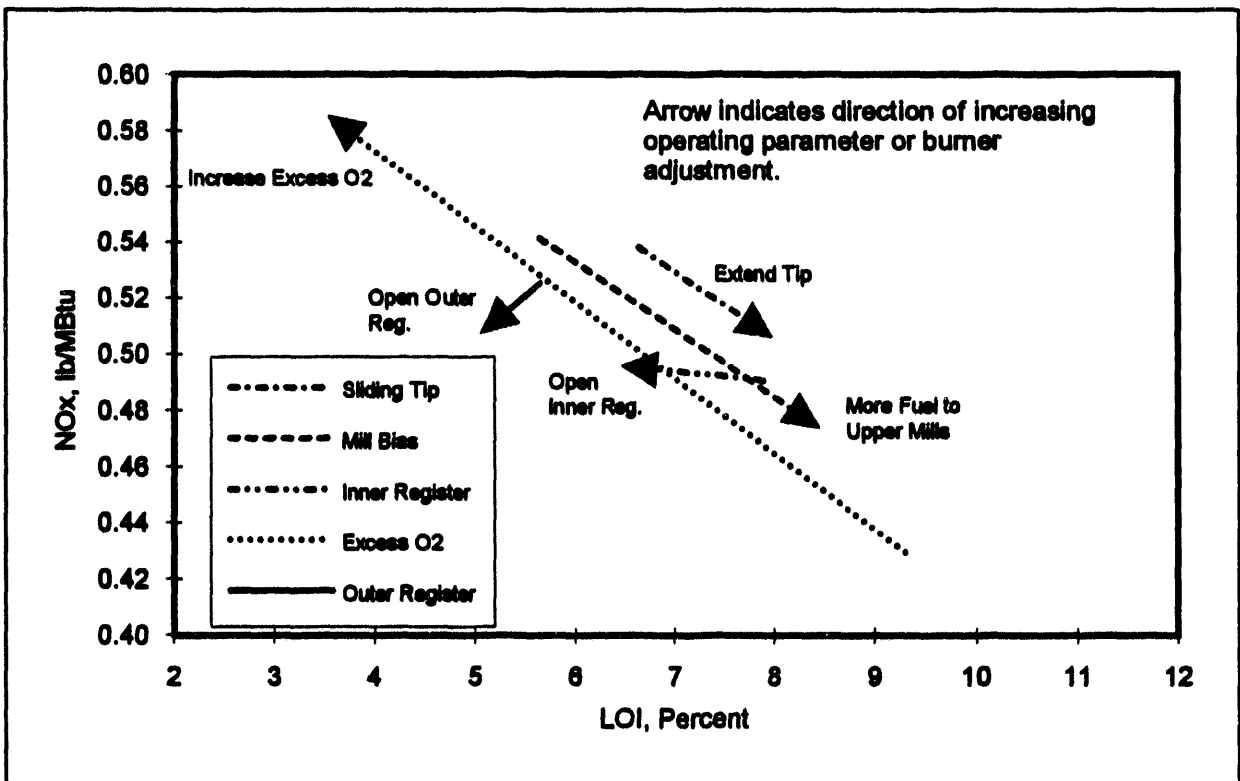


Figure 7. Hammond 4 / NOx vs. LOI Tests / All Sensitivities

## LNB+AOFA CHARACTERIZATION

Following completion of the LNB test phase during January 1992, testing in the low NOx burner and advanced overfire air configuration was to begin with completion scheduled for late March 1992. However, due to delays associated with increased stack particulate emissions following the LNB installation, testing in the LNB+AOFA configuration could not be completed prior to the spring 1992 outage during which two new mills were to be installed. To obtain operating data prior to this outage, abbreviated testing (designated 3B') in the LNB+AOFA configuration was performed during February and March 1992. Following the spring 1992 outage, the unit ran at reduced loads (less than 450 MW) until spring 1993 to maintain stack particulate compliance. During this period, long-term data were collected and the NOx vs. LOI tests (discussed above) were performed.

Following resumption of full load operation on March 26, 1993, FWEC personnel re-optimized the unit starting March 30, 1993 and continuing through May 6, 1993. As shown in Figure 8, burner settings, with the exception of the burner tips, are similar to those used for the NOx vs. LOI test segment. The AOFA flow schedule is also shown in Figure 8. Since the AOFA is not automatically controlled, the operator must manually maintain not only the total overfire air flow rate but also balance the flows to the four corners of the AOFA windbox. This task has proven difficult during long-term, normal unit dispatch.

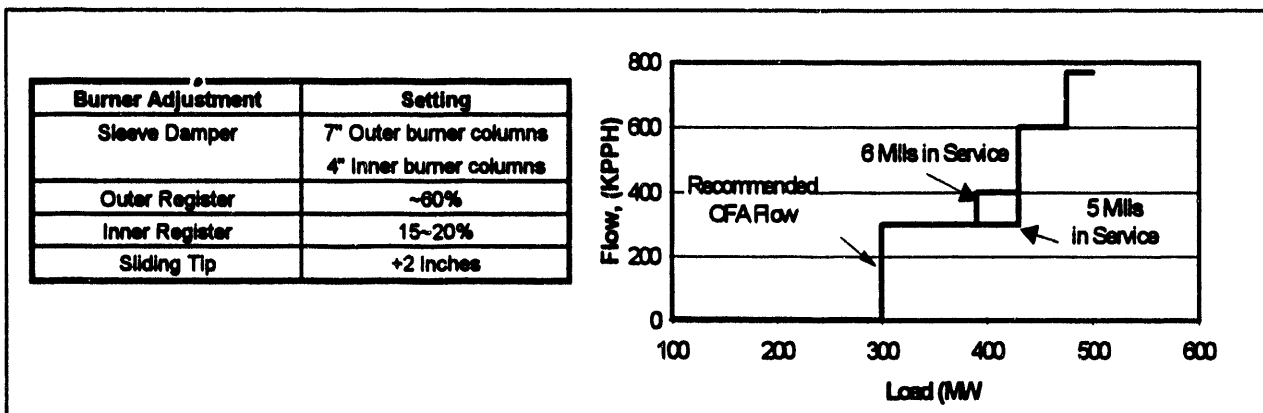


Figure 8. LNB+AOFA Burner Settings and AOFA Schedule

Subsequent to the re-optimization, comprehensive testing using LNB plus AOFA began. As of June 30, 1993, sixty-seven (67) diagnostic and performance tests have been conducted. As shown in Figure 9, full load NOx emissions are approximately 0.43 lb/MBtu with corresponding fly ash loss-on-ignition (LOI) values of 8 percent. At low loads (300 MW), NOx emissions and LOI are approximately 0.32 lb/MBtu and 5.5 percent, respectively. Also shown in Figure 9 are

the results from the February-March 1992 testing. NO<sub>x</sub> emissions for the latest round of testing are considerably below the NO<sub>x</sub> levels found in these earlier tests. The additional NO<sub>x</sub> reduction is most likely the result of re-optimization of the combustion system allowing lower excess air operation for the most recent testing (approximately 4 percent vs. 3.7 percent).

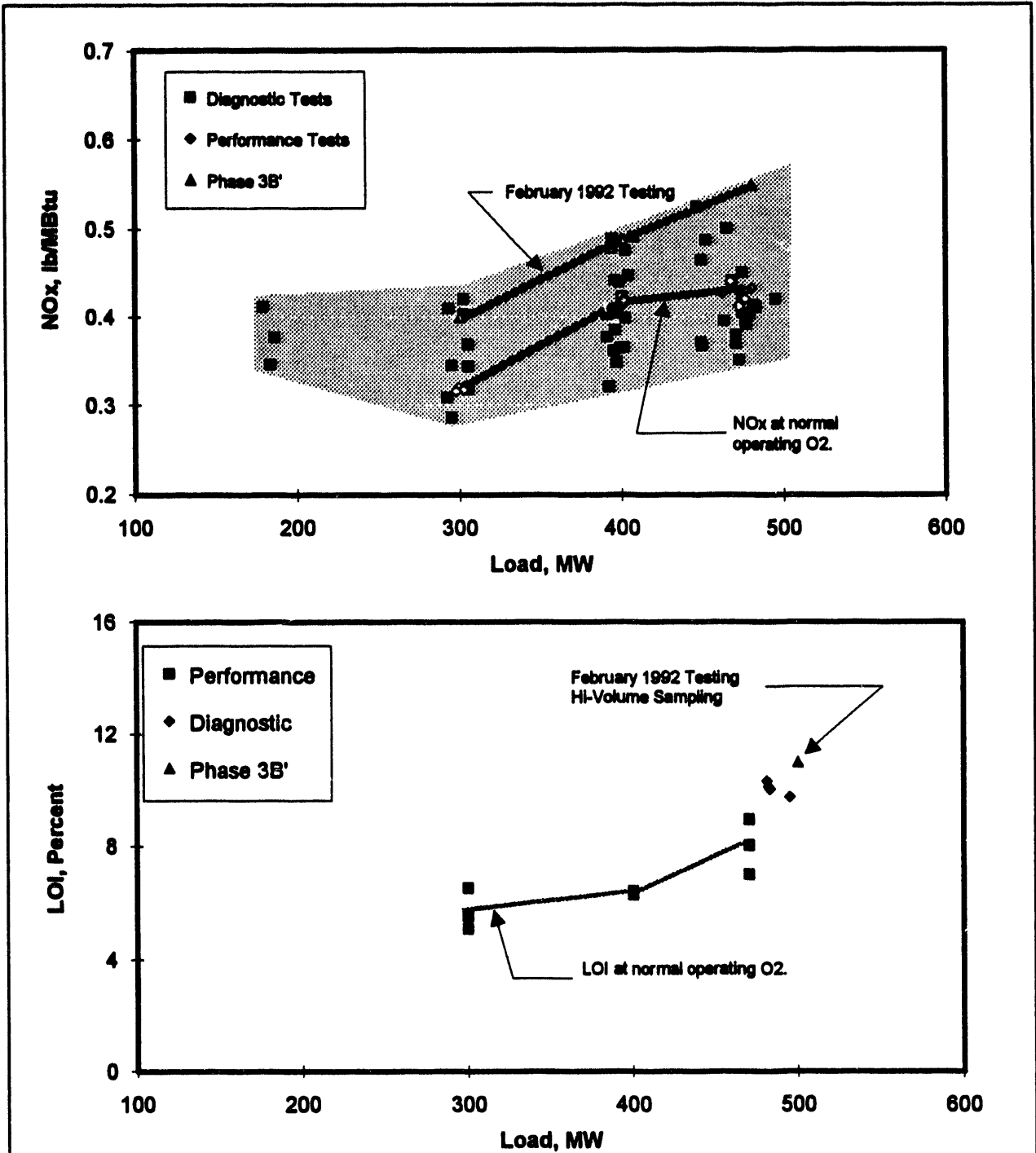


Figure 9. LNB+AOFA Short-Term NO<sub>x</sub> Emissions and Fly Ash Loss-On-Ignition



Long-term testing of the LNB+AOFA is in progress and is scheduled to continue until August 1993. As of June 30, 1993, twenty-nine (29) days of valid long-term data have been collected. Full load, long-term NOx emissions are approximately 0.42 lb/MBtu, which is consistent with that found during the performance testing (Figure 10). However, at 300 MW, long-term NOx emissions are near 0.37 lb/MBtu, nearly 0.05 lb/MBtu higher than the short-term emissions at the same load with approximately the same excess air and AOFA flow rate. The cause of this disparity is unknown. Despite this difference, the short-term data is within the 90th percentile range of the long-term data. As with the short-term data, a substantial difference exist between the current long-term NOx emissions and those previously recorded. This difference is again likely the result of re-optimization of the combustion system. Approximately 60 days of long-term data will be collected in this configuration; therefore, the final results may change when the complete data set is analyzed.

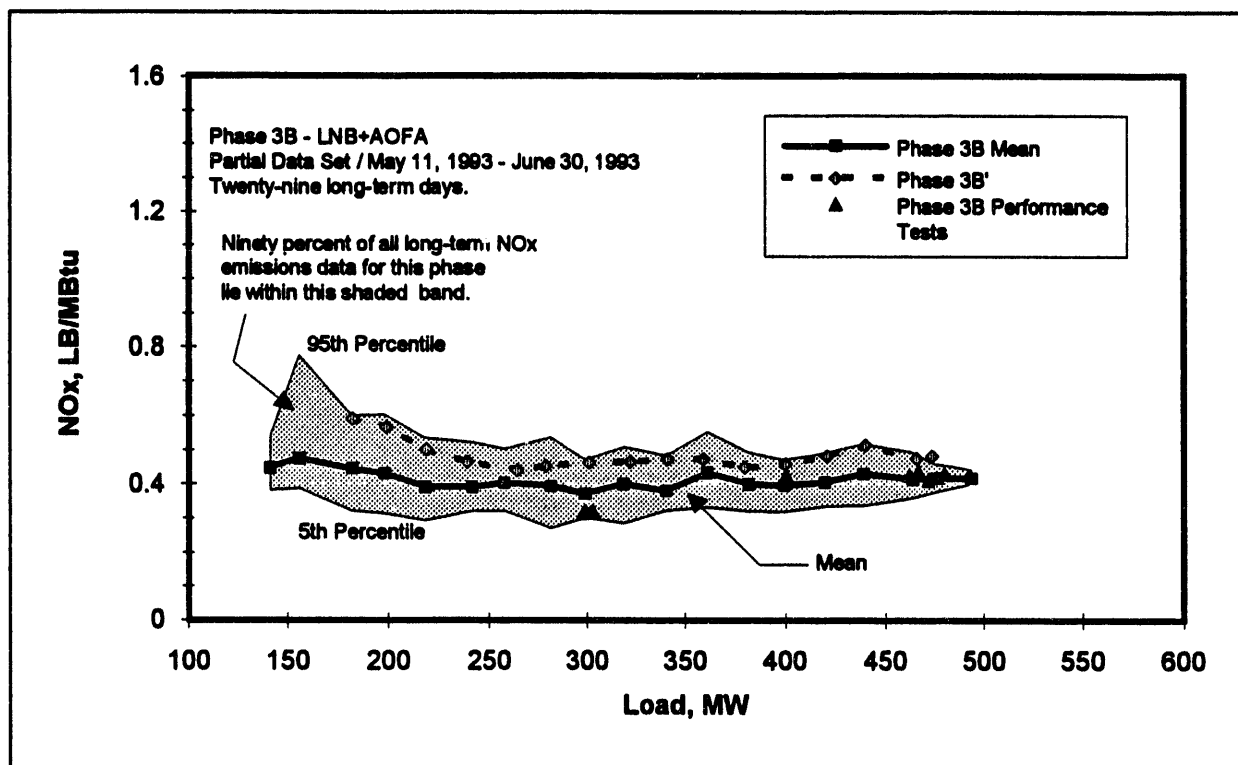


Figure 10. LNB+AOFA Long-Term NOx Emissions

## DATA COMPARISON

As previously discussed, baseline, AOFA, and LNB test phases have been completed. Testing in the LNB+AOFA configuration is scheduled for completion in August 1993. The following paragraphs compare the results from these phases.

## NOx Reductions

Figure 11 compares the baseline, AOFA, LNB, and LNB+AOFA long-term NOx emissions data for Hammond Unit 4. Baseline testing was performed in an "as-found" condition and the unit was not tuned for NOx emissions for this test phase. For the AOFA, LNB, and LNB+AOFA test phases, following optimization of the unit by FWEC personnel, the unit was operated according to FWEC instructions provided in the design manuals. As shown, the AOFA and LNBs provide a long-term, *full load*, NOx reduction of 24 and 48 percent, respectively. For the LNBs, the NOx reduction averaged approximately 50 percent over the load range; however, the effectiveness of the AOFA system decreased with decreasing load. For the baseline, AOFA, and LNB phases, the NOx vs. load characteristic is based on normal operation of the unit in excess of 51 days. The full load, long-term NOx emissions reduction in the LNB+AOFA configuration *with the partial data set* is approximately 65 percent at full load. These results may change when the complete data set is analyzed.

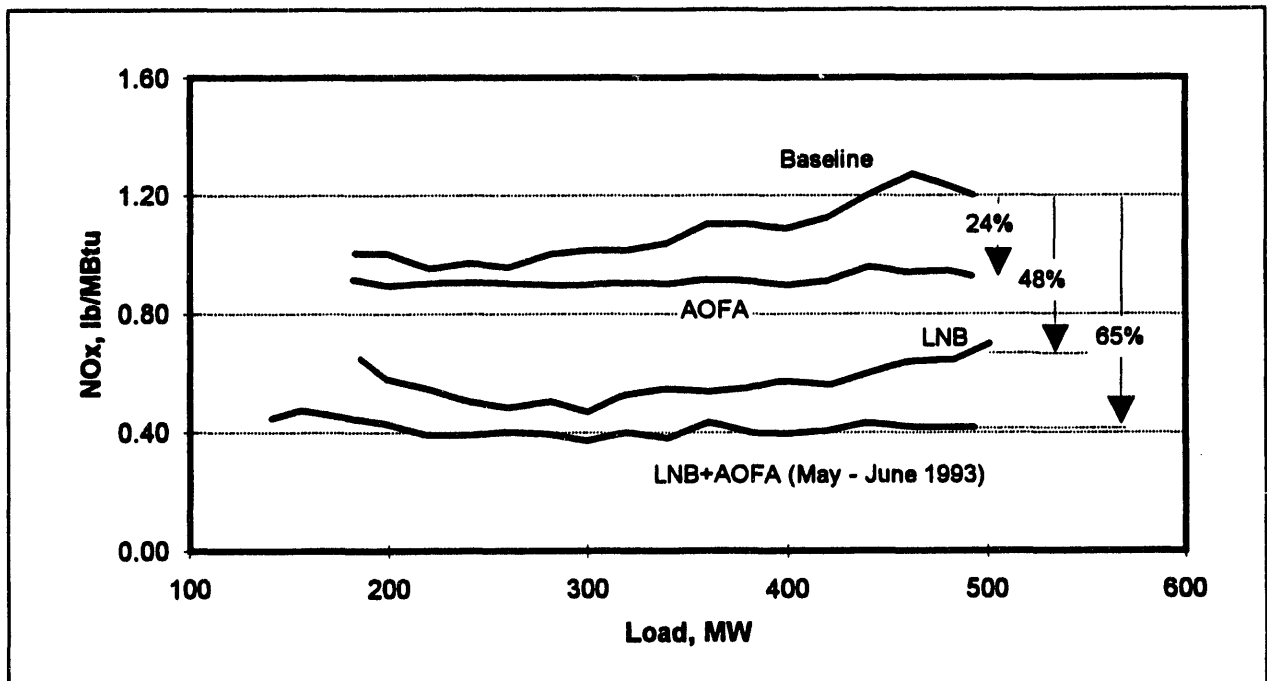


Figure 11. Hammond 4 / Long-Term NOx Emissions

The NOx emissions averaged over the baseline, AOFA, and LNB test phases are shown in Table 3. Since NOx emissions are generally dependent on unit load, the NOx values shown in this table are influenced by the load dispatch of the unit during the corresponding test frame. Results from the LNB+AOFA test phase will be determined at the end of the long-term data collection period.

Unit Configuration	Baseline		AOFA		LNB	
	Mean	RSD,%	Mean	RSD,%	Mean	RSD,%
Number of Daily Averaged Values	52	-	86	-	94	-
Average Load (MW)	407	9.4	386	17.9	305	17.7
Average NOx Emissions (lb/MBtu)	1.12	9.5	0.92	8.6	0.53	13.7
Average O2 Level (percent at stack)	5.8	11.7	7.3	12.6	8.4	7.7
NOx 30 Day Achievable Emission Limit (lb/MBtu)	1.24	-	1.03	-	0.64	-
NOx Annual Achievable Emission Limit (lb MBtu)	1.13	-	0.93	-	0.55	-

Table 3. Long-Term NOx Emissions

### LOI Performance

The fly ash loss-on-ignition (LOI) values increased significantly for the AOFA and LNB test phases and similar increases have been experienced in the LNB+AOFA testing (Figure 12). These LOI increases were evident over the load range. The LOI measurements were made during each performance test using EPA's Method 17 at the secondary air heater outlet [3]. As shown in Table 4, mill performance was generally better in the AOFA, LNB, and LNB+AOFA test phases than during baseline. The improvement in coal fineness was likely responsible for the reduction in fly ash LOI levels during the May-August 1993 LNB+AOFA test phase. Although it is commonly recognized that fuel fineness can have a pronounced effect on fly ash LOI, results from Plant Smith, Plant Gaston, and other sources indicate the direct impact of fuel fineness on NOx emissions is small [4,5,6]. As previously reported, the post LNB retrofit increase in fly ash LOI along with increases in combustion air requirements and fly ash loading to the precipitator, has had an adverse impact on the unit's stack particulate emissions [2].

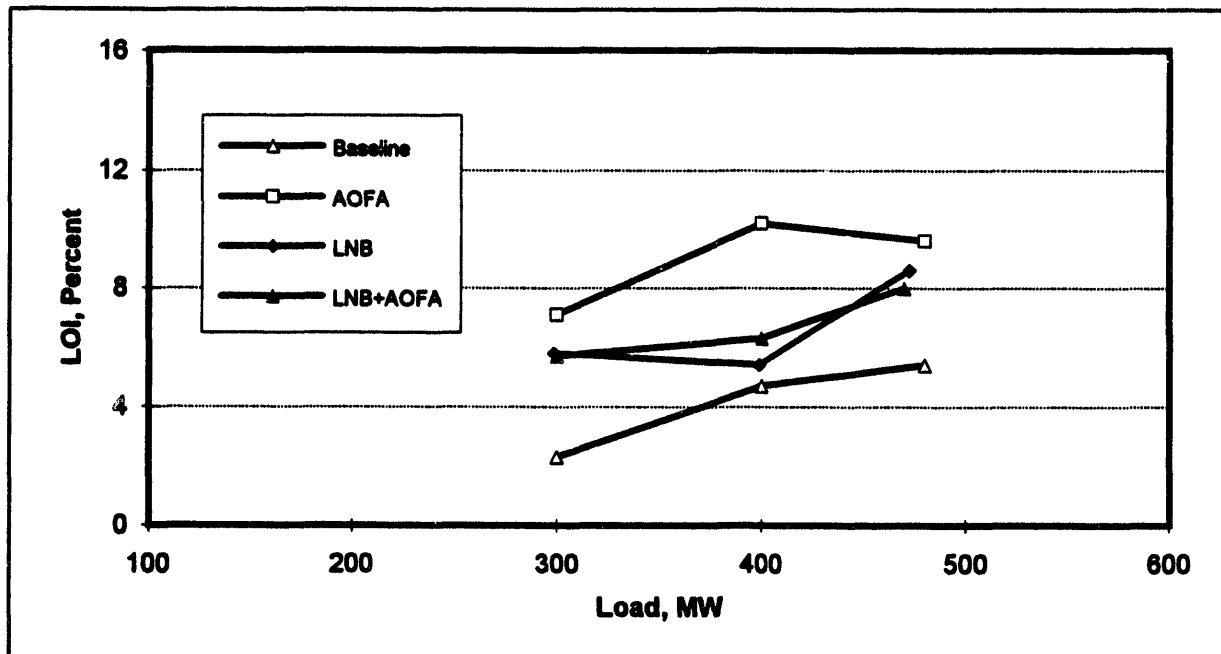


Figure 12. Hammond 4 / Fly Ash LOI

Technology	Coal Fineness	
	Passing 200 Mesh Percent	Remaining 50 Mesh Percent
Baseline	63	2.8
AOFA	67	2.6
LNB	67	1.4
LNB+AOFA	74	0.6

Table 4. Hammond 4 / Mill Performance Summary

### Excess O<sub>2</sub> Levels

Long-term, economizer outlet O<sub>2</sub> levels for the AOFA, LNB, and LNB+AOFA test phases were generally higher than the corresponding baseline values (Figure 13). This change in O<sub>2</sub> level for these configurations is mostly attributable to an increase in combustion air requirements for the low NO<sub>x</sub> combustion configurations; however, factors unrelated to the retrofits, such as leakage in the furnace backpass, can also affect these levels. The impact of this leakage and varying O<sub>2</sub> levels on emissions and unit performance will be investigated and discussed in future reports.

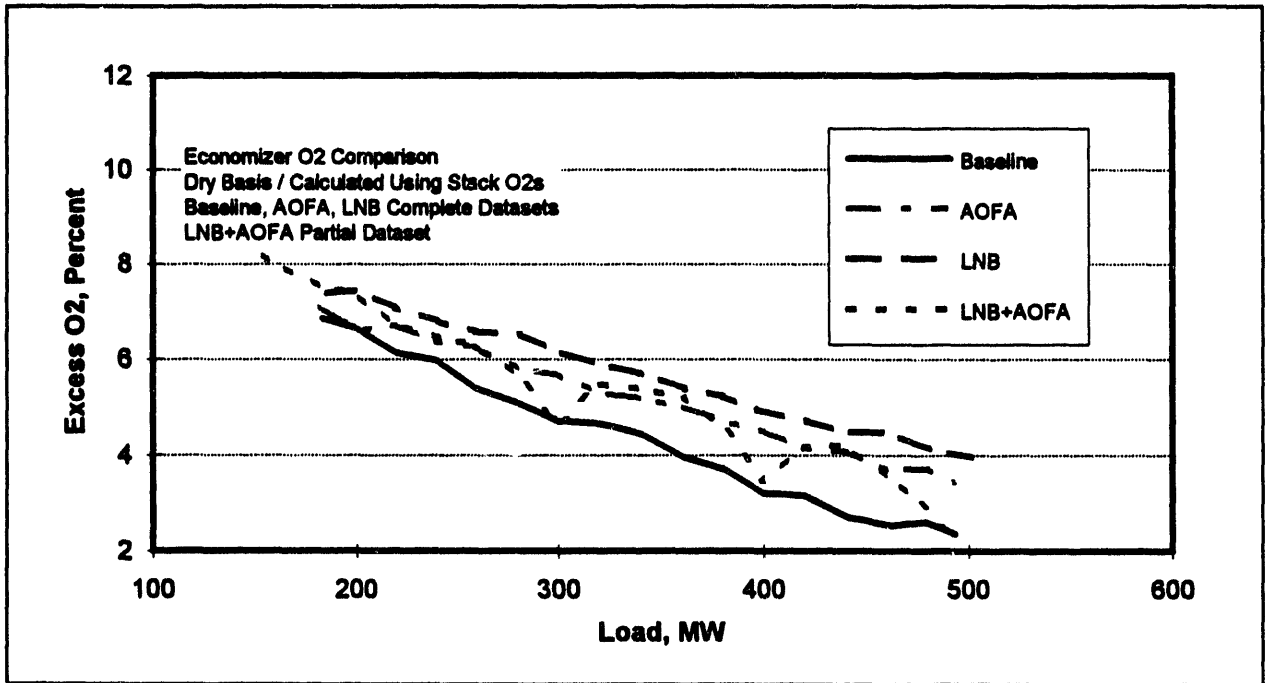


Figure 13. Hammond 4 / Economizer O<sub>2</sub>

## CONCLUSIONS

In conclusion, the results to date at Plant Hammond indicate:

- NO<sub>x</sub> emissions have been reduced to about 50 percent of baseline values by using low NO<sub>x</sub> burners alone. These reductions were sustainable over the long-term test period and were consistent over the entire load range. At Hammond, preliminary results indicate AOFA used in conjunction with the LNBs provide approximately 15 percent additional NO<sub>x</sub> reduction benefit over LNB alone.
- For all low NO<sub>x</sub> combustion configurations, the unit experienced significant performance impacts including increases in excess air and fly ash LOI.
- At Hammond 4, operational and burner adjustments which favorably impacted NO<sub>x</sub> emissions adversely affected fly ash unburned carbon levels.

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## **Measurement of Air Toxic Emissions from a Coal-Fired Boiler Equipped with a Tangentially-Fired Low NOx Combustion System**

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### **ABSTRACT**

This paper presents the results of measurements of chemical emissions from a coal-burning, tangentially-fired, utility boiler equipped with a hot-side electrostatic precipitator and a low NOx firing system. The tests were conducted in response to Title III of the 1990 Amendments to the Clean Air Act which lists 189 chemicals to be evaluated as "Air Toxics". The project was jointly funded by the Electric Power Research Institute and the U.S. Department of Energy under an existing Innovative Clean Coal Technology Cooperative Agreement managed by Southern Company Services. Field chemical emissions monitoring was conducted in two phases: a baseline "pre-low NOx burner" condition in September 1991 and in the LNCFS Level III low NOx firing condition in January 1992. In addition to stack emissions measurements of both organic and inorganic chemicals, plant material balance evaluations were performed to determine the efficiency of the hot-side ESP at controlling emissions of air toxics and to determine the fate of the target chemicals in various plant process streams.

## **ABBREVIATIONS**

<b>AAS</b>	<b>atomic absorption spectroscopy</b>
<b>ABB CE</b>	<b>Asea Brown Boveri Combustion Engineering Services</b>
<b>As</b>	<b>arsenic</b>
<b>Btu</b>	<b>British Thermal Units</b>
<b>C</b>	<b>carbon or centigrade</b>
<b>Cl</b>	<b>chlorine</b>
<b>Cr</b>	<b>chromium</b>
<b>CVAAS</b>	<b>cold-vapor atomic absorption spectroscopy</b>
<b>CVAFS</b>	<b>cold-vapor atomic fluorescence spectroscopy</b>
<b>DNPH</b>	<b>dinitrophenylhydrazine</b>
<b>DOE</b>	<b>United States Department of Energy</b>
<b>EPA</b>	<b>United States Environmental Protection Agency</b>
<b>EPRI</b>	<b>Electric Power Research Institute</b>
<b>ESP</b>	<b>electrostatic precipitator</b>
<b>F</b>	<b>Fahrenheit or fluorine</b>
<b>FC</b>	<b>fixed carbon</b>
<b>GC/MS</b>	<b>gas chromatography / mass spectroscopy</b>
<b>H</b>	<b>hydrogen</b>
<b>Hg</b>	<b>mercury</b>
<b>HGAAS</b>	<b>hydride generation atomic absorption spectroscopy</b>
<b>HHV</b>	<b>higher heating value</b>
<b>ICCT</b>	<b>Innovative Clean Coal Technology</b>
<b>ICP</b>	<b>inductively coupled argon plasma emission spectroscopy</b>
<b>K</b>	<b>potassium</b>
<b>lb(s)</b>	<b>pound(s)</b>
<b>LNCFS</b>	<b>Low NO<sub>x</sub> Concentric Firing System</b>



## **ABBREVIATIONS (continued)**

<b>m</b>	<b>meter</b>
<b>max</b>	<b>maximum</b>
<b>min</b>	<b>minimum or minutes</b>
<b>N</b>	<b>Newton or nitrogen</b>
<b>NOx</b>	<b>nitrogen oxides</b>
<b>O</b>	<b>oxygen</b>
<b>P</b>	<b>phosphorous</b>
<b>PAH</b>	<b>polycyclic aromatic hydrocarbons</b>
<b>PETC</b>	<b>Pittsburgh Energy Technology Center</b>
<b>PISCES</b>	<b>Power Plant Integrated Systems: Chemical Emissions Studies</b>
<b>POM</b>	<b>polycyclic organic matter</b>
<b>ppm</b>	<b>parts per million</b>
<b>S</b>	<b>sulfur</b>
<b>SCS</b>	<b>Southern Company Services</b>
<b>SRI</b>	<b>Southern Research Institute</b>
<b>T-fired</b>	<b>tangentially-fired</b>
<b>UV</b>	<b>ultraviolet</b>
<b>VM</b>	<b>volatile matter</b>
<b>VOST</b>	<b>volatile organic sampling train</b>
<b>µg</b>	<b>micrograms</b>

## **INTRODUCTION**

This paper provides recent technical results on the release of chemical emissions from a U. S. Department of Energy (DOE) Innovative Clean Coal Technology (ICCT) project test site demonstrating advanced tangentially-fired (T-fired) combustion techniques for the reduction of NO<sub>x</sub> emissions from a coal-fired boiler. During the project, all three levels of the ABB Combustion Engineering Services (ABB CE) Low NO<sub>x</sub> Concentric Firing System<sup>1</sup> (LNCFS) were evaluated. Chemical emissions tests were conducted before and after the installation of LNCFS Level III. Testing for the project was conducted at Gulf Power Company's Plant Lansing Smith Unit 2 near Panama City, Florida.

The ICCT project was managed by Southern Company Services, Inc., (SCS) on behalf of the project co-funders: the DOE, The Southern Company, and the Electric Power Research Institute (EPRI). The chemical emissions tests were funded by EPRI and DOE and conducted by Southern Research Institute (SRI). In addition to SCS, The Southern Company includes five electric operating companies: Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Savannah Electric and Power. SCS provides engineering, procurement, and research services to The Southern Company. The DOE is participating through the Office of Clean Coal Technology at the Pittsburgh Energy Technology Center (PETC).

The primary objective of this demonstration project was to determine the long-term effects of commercially available low NO<sub>x</sub> combustion technologies for T-fired boilers. However, this paper focuses on the results of the measurement of chemical emissions. The emissions of primary concern are those being addressed by the EPRI PISCES (Power Plant Integrated Systems: Chemical Emissions Studies) program. Most of these species are found among the "Air Toxics" listed in Title III of the 1990 Amendments to the Clean Air Act. The PISCES air toxics list is shown in Table 1. The substances in the measurement inventory include metallic and nonmetallic elements and organic compounds. Sampling and analytical methods, the test results, and inconsistencies in the results are presented in this paper.

## **UNIT DESCRIPTION**

Plant Lansing Smith Unit 2, owned and operated by Gulf Power Company, uses a T-fired boiler (aspect ratio = 1.5 width/depth) rated at 180 MW with the capability to provide loads of up to 200 MW. The boiler is a Combustion Engineering radiant reheat, natural circulation steam generator which came on line in 1967. It is designed for continuous indoor service to deliver 1,306,000 pounds of steam per hour at normal rated load, a pressure of 1800 psig, and a temperature of

1000°F at the superheater and the reheater outlets. Five CE-Raymond bowl mills equipped with exhausters at the outlet of each mill deliver pulverized coal (66.5% C, 9.9% H<sub>2</sub>O, 4.6% H, 1.4% N, 2.8% S, 6.3% O, 8.5% ash, 0.1% Cl; HHV = 11,886 Btu/lb, FC = 46.0%, VM = 35.6%) through 20 tangential coal nozzles with 5 nozzles stacked vertically in each corner of the furnace. The unit is equipped with Ljungstrom air preheaters and two forced-draft fans which deliver all the combustion air to the boiler. Exhaust gases are treated with both hot- and cold-side electrostatic precipitators (ESP). Although originally designed for pressurized furnace operation, the unit was converted to balanced-draft operation in 1976.

## **TEST DESCRIPTION**

Chemical emissions were measured at Plant Smith on two occasions. Each test period required one week to complete. During the first period, tests were conducted with the LNCFS Level II technology in service. However, to simulate a baseline firing condition, the separated overfire air system was closed and the offset air nozzles were placed in line with the fuel nozzles. These baseline tests were conducted in September 1991.

During the second test period (January 1992), chemical emissions were measured with the LNCFS Level III in service. The LNCFS Level III technology is equipped with separated overfire air, close coupled overfire air, and offset air nozzles (Figure 1). During other portions of the test program, the long-term NO<sub>x</sub> reduction capabilities of the LNCFS Level III system were measured. At full load (180 MW), NO<sub>x</sub> reduction was 45 percent compared to the baseline emissions level (Figure 2). As unit load decreased, NO<sub>x</sub> emissions increased to baseline levels.

In each week of testing, samples were collected during two separate modes of ESP operation. For each test period, three tests were conducted with only the hot-side ESP energized and one test was conducted with both the hot- and cold-side ESPs energized. Each test required from 10 to 16 hours to complete.

The goals of the chemical emissions tests were to obtain the information required to answer the following questions:

- How are chemical emissions altered by the LNCFS Level III?
- How effectively does the hot-side ESP control chemical emissions?
- How much additional reduction in chemical emissions takes place when the cold-side ESP is energized?

The sampling plan was designed to include material balance checks of elements in fuel and discharge streams throughout the plant as well as in input and output streams across the ESPs and air heater. Discharge streams include the pyrite rejects, bottom ash, part of the bottom ash sluice water, economizer ash, ESP hopper ash, and stack gases. The sampling locations are diagrammed in Figure 3.

## **AIR TOXICS SAMPLING AND ANALYTICAL METHODS**

Solid materials in bulk deposits (such as the ash discharged from the water-sealed furnace or ash deposited in hoppers) were collected at various intervals each day as grab samples. Daily composites of each material served for analysis. The individual solids collected for analysis included coal prior to pyrite removal, pyrite waste, bottom ash, economizer ash, and ESP ash. The coal composite was prepared from hourly samples from each feeder. The pyrite hoppers were inspected once per shift. All other solid samples were collected and composited once per day.

Gas streams entering the hot-side ESP or leaving the cold-side ESP (and then entering the stack) were sampled by methods developed by EPA or based on EPA sampling principles<sup>2</sup>, and previously adopted as protocols for the PISCES program<sup>3</sup>. Table 2 lists the major sampling methods employed. This table also lists the collection media for the samples to be analyzed. An exception to EPA-based methodology was evaluated as an alternative method for sampling mercury in the vapor state. This method employed solid sorbents consisting of a quartz wool filter, followed by two KCl-soda lime traps, followed by two iodated carbon traps as recently described by Bloom<sup>4</sup>.

The analytical laboratories employed, in general, the methods that have been used in prior PISCES projects. Table 3 lists the analytical methods. Mercury from the solid sorbents was determined by cold-vapor atomic fluorescence spectroscopy (CVAFS), whereas mercury from the EPA train was determined by cold-vapor atomic absorption spectroscopy (CVAAS).

## **DATA ON METALS**

### **Partitioning**

Whether a trace metal occurs as a component of the ash or as a component of the gas phase is obviously an important factor insofar as control of its emission in an ESP is concerned. Significant conclusions with respect to this matter were possible, even though the Multi-Metals sampling train is limited in its ability to discriminate between the fractions of an element in the solid and gas phases. This limitation exists because the filter in the sampling train is maintained at

250 °F and thus it can easily collect an element that occurs as a vapor at a higher temperature in the duct being sampled. (The inlet gas temperature to the hot-side ESP was about 700 °F, and the outlet gas temperature from the cold-side ESP was about 325 °F.)

Two metals, mercury and selenium, were shown to be present predominantly in the vapor state at the outlet of the ESP, even given the limitation of the Multi-Metals sampling train. Mercury is volatile in various chemical states, both elemental and oxidized. The more conclusive evidence on the vapor state of mercury came from the samples collected with the solid sorbents, which explicitly avoided the collection of particulates. The fact that the concentrations of total mercury were comparable using the two methods provides complementary evidence of the vapor state. The concentrations of mercury found in the gas stream at the outlet of the ESPs ranged from 80 to 120 percent of the concentrations expected based on the mercury concentrations in the coal and firing rates of the coal. Selenium created persistent analytical problems, causing the material balance for selenium to be indeterminate. However, much of the selenium was found in the impingers behind the filter of the Multi-Metals train which substantiated a high volatility.

Arsenic is a metal that is appreciably volatile as the trioxide, and, in theory, might have been emitted from the stack in a vapor phase. In this study however, arsenic was shown conclusively to have been predominantly in the solid phase which was controlled by the ESP.

Concentrations of certain trace metals in ash samples that were separated from the gas phase at different temperatures indicated that metals other than mercury and selenium were in the vapor state before the gas reached the ESPs. Arsenic and antimony, for example, were much more concentrated on particulate filter samples taken out of the system at lower temperatures; presumably, therefore, they were in the vapor state at the higher temperatures.

## **Speciation**

The chemical speciation, or oxidation state, of certain metals is of particular interest. In the case of mercury, emissions data regarding the ratio of the elemental form to the ionic form can be applied to plume chemistry and atmospheric deposition rates to provide insight on affected geographic locales. In the cases of chromium and arsenic, one oxidation state is considered to be very toxic, while a second is non-toxic or much more benign. However, in all cases of speciation measurements, the sampling and analytical procedures are still at various levels of development, and the potential for sampling artifacts is great. Many of the species display a wide range of measured concentrations, and probably a wide range of accuracy. All arsenic speciation data, for example, are especially suspect.

**Mercury.** As stated above, mercury is volatile in various chemical states. At 300 °F, for example, elemental mercury, Hg(0), has the highest volatility, while the chloride, HgCl<sub>2</sub>, has a volatility that is just slightly lower<sup>5</sup>. Organomercury compounds, such as methylmercury, also have appreciable volatilities. Table 4 shows the distribution of mercury that was found in one of the sets of samples from the ESP outlet. The oxidized mercury, presumably HgCl<sub>2</sub>, represented about 80 percent of the total, elemental mercury about 20 percent, and methylmercury only about 0.02 percent. The total concentration, 9.22 µg/Nm<sup>3</sup>, represents a material balance of 110 percent of the mercury supplied in the coal.

**Chromium.** Chromium in the hexavalent state is a carcinogen, while trivalent chromium is generally regarded as a non-toxic. The fraction of total chromium in ash samples that could be extracted in an aqueous alkaline medium and identified as Cr(VI) was determined by use of diphenylhydrazide as a calorimetric reagent<sup>6</sup>. In the ash entrained at the ESP inlet, 5-10 percent of the total chromium was in the hexavalent state. In the fine particulates that were not collected by the ESP but that remained entrained at the ESP outlet, the percentage of chromium measured in the hexavalent state was less definitely determined, but it appeared to be enriched in excess of 25 percent. However, the absolute concentration of Cr(VI) in the outlet stream from the ESP was very low since the removal efficiency for total chromium by the ESP was greater than 97 percent.

**Arsenic.** Arsenic can be toxic in both the trivalent and pentavalent forms. To the degree that the element could be extracted from ash in water, the quantities in the two oxidation states were determined by performing hydride generation atomic absorption spectroscopy (HGAAS) determinations on extracts acidified with citric acid (giving trivalent As alone) or with HCl (giving both oxidation states)<sup>7</sup>. Pentavalent arsenic was dominant in all the samples analyzed.

### **Control by Electrostatic Precipitation**

With the cold-side ESP de-energized, the hot-side ESP in operation alone removed all but about 0.6 percent of the entrained fly ash during baseline testing. The hot-side and cold-side ESPs in combination gave no measurable improvement during the baseline testing. However, during the low NO<sub>x</sub> testing, the hot-side unit alone allowed a penetration of 1.0 percent compared to 0.6 percent for the combination.

Despite the predominance of most of the trace metals in the particulate phase, the observed ESP penetration by most of them was significantly more than 0.6-1.0 percent. Some examples of penetration on a percentage basis for metals that were predominantly in the particulate phase are as follows: arsenic, 1 percent; cobalt, 2 percent; manganese, 1-3 percent; molybdenum, 4 percent.

The finer ash particles appear to be enriched in the trace metals, probably as a result of metal deposition of surfaces at some time during transit of the gas stream from the furnace to the ESPs. Some removal of elements found in the gas phase at the ESP inlet at 700 °F might have occurred on cold surfaces in the air heater between the ESPs. However, this occurrence is not confirmed by the experimental data.

### **Material Balance**

**Overall system.** The absence of information on mass flow rates of certain process streams, such as the rate of discharge of bottom ash, prevented a strict assessment of material balance. There was reason to believe, however, that for most of the metals the total elemental flow rate in the gas stream at the inlet to the hot-side ESP should have represented 80-100 percent of the elemental flow rate in the coal. The mass of ash entrained in this gas stream was approximately 80 percent of that in the coal (a figure in conformity with the rule of thumb that a pulverized-coal boiler will divide fly ash and bottom ash in an 80/20 ratio). There were no target elements that were profoundly enriched in the bottom ash. Thus, elements confined to the particulate phase should have been found at a level that was 80 percent of that supplied by the coal, and elements divided between the particulate phase and the gas phase, or found exclusively in the gas phase, should have been found at levels ranging from 80 to 100 percent.

Table 5 lists the ranges of trace metal "recoveries," that is, total elemental flow rates at the ESP inlet expressed as percentages of elemental flow rates in the coal. For the majority of the elements, the recoveries straddle the target value of 80 percent. In some cases, however, the range is so far biased from the expected range that the data cannot be truly said to represent recoveries. For example, such ranges as 131-256 percent and 26-46 percent for lead in the two test series reveal such serious analytical difficulties for coal and/or ash that neither set of results for lead can be regarded as meaningful. The inconsistencies almost certainly occur in the analytical procedures and not in recovery of a representative sample of the material entrained in the flue gas.

**ESP system.** Material balance could be determined more exactly insofar as the ESP system was concerned. Inlet and outlet mass flows in the gas stream were directly measured. The ash concentrations, corrected to 4 percent O<sub>2</sub>, were 7.29 g/Nm<sup>3</sup> at the ESP inlet versus 0.038 g/Nm<sup>3</sup> at the ESP outlet during baseline testing, and 7.73 g/Nm<sup>3</sup> at the ESP inlet versus 0.079 g/Nm<sup>3</sup> at the ESP outlet during the low NO<sub>x</sub> testing. The mass flow rate of collected hopper ash was not measured; but, it could be calculated as the difference between mass flows in the inlet and outlet ducts. Table 6 compares the trace element closures between the baseline and low NO<sub>x</sub> testing based on a ratio between the calculated accumulation rates of elements in the hoppers with the

difference between inlet and outlet duct flow rates. Generally, the closures across the ESP system signify better data quality than the recoveries at the ESP inlet.

### **Influence of Plant Variables on Emissions**

The emission of trace metals was not affected in major ways either by converting the boiler to low NO<sub>x</sub> combustion or by operating with one or both ESPs. There was some evidence that low NO<sub>x</sub> combustion suppressed the fraction of total chromium that was present in the hexavalent state, which would be desirable.

### **DATA ON NON-METALS**

Among the four non-metals considered, only phosphorus was found predominantly in the ash. In the fly ash deposited in the ESP hoppers, phosphorus in the form of P<sub>2</sub>O<sub>5</sub> represented 0.22 percent of the total mass. In the coal ash obtained by laboratory ignition of the coal, P<sub>2</sub>O<sub>5</sub> represented 0.23 percent of the total mass. Thus, not much phosphorus could have been in the vapor state, and none was found, even though P<sub>2</sub>O<sub>5</sub> or H<sub>3</sub>PO<sub>4</sub> are reasonably volatile compounds.

Sulfate in the fly ash from the ESP hoppers accounted for about 5 percent of the sulfur in the coal. On the other hand, SO<sub>2</sub> collected as sulfate found in the impinger solutions of the train for acid gases represented about 90 percent of the sulfur in the fuel.

Fluoride and chloride were not found in the fly ash. These halogens were collected in the train for acid gases at concentrations averaging 80 percent of the fluorine in the coal or 108 percent of the chlorine in the coal, presumably due to their occurrence as HF and HCl gases. These recoveries were for the ESP outlet; the recoveries were more variable and less complete at the inlet. Table 7 lists average concentrations of HF, HCl, and SO<sub>2</sub> for the flue gas at the ESP outlet based on the amounts of the elements collected in the impingers of the sampling train. The emission of the non-metals predominantly as gases was not influenced perceptibly either by low NO<sub>x</sub> combustion or operating with one or two ESPs.

### **DATA ON ORGANIC COMPOUNDS**

#### **Volatile Compounds**

Volatile organic compounds were defined, effectively by the sampling and analytical methods used, as compounds boiling below 100 °C. Not all compounds thus defined could be collected and analyzed, however. One of the notable exceptions was formaldehyde, which was not detected



in samples from the volatile organic sampling train (VOST), but which was detected by the alternate procedure with a different collection medium, dinitrophenylhydrazine solution (DNPH).

The principal objective with respect to the analysis of volatile compounds in the flue gas was to determine the concentrations of benzene and toluene. The gas chromatography/mass spectroscopy (GC/MS) method employed, however, had the capability of determining many more compounds. The computer program used for data analysis is able to identify a total of 40 compounds on the basis of chromatographic retention time and ion spectra. Of these 40 compounds, 24 are included among the 189 compounds in Title III of the 1990 Amendments to the Clean Air Act. During the testing, a total of 19 identifiable volatile compounds were detected. However, some of the 19 compounds identified were clearly extraneous, being introduced into the sampling media by accident and not being contributed by the source being sampled. The quality of the volatile organic data was further diminished by the presence of a number of unidentifiable chromatographic peaks.

The detected compounds included several aromatic hydrocarbons that are related structurally to benzene and toluene: the three isomeric xylenes, ethyl benzene, and styrene. Table 8 lists the average concentrations and standard deviations therein for benzene and toluene, which were the more concentrated aromatic hydrocarbons. The most striking aspect of the data, apart from the variability of the concentrations, is the high concentration of benzene recorded in one sampling experiment around  $10,000 \mu\text{g}/\text{Nm}^3$  (that is, around 3 ppm by volume). This level of concentration may or may not be real. The variations of benzene concentrations over time should have been seen by a total hydrocarbon analyzer that was in use, but the emissions were not confirmed.

Low NO<sub>x</sub> combustion was expected to increase the emissions of volatile hydrocarbons. Since increases in unburned carbon in fly ash often accompany low NO<sub>x</sub> combustion, increases in hydrocarbon emissions would logically also occur. Paradoxically, however, if low NO<sub>x</sub> combustion made any change in the emission of volatiles, it was to suppress the emission of these compounds. The ESPs did not have a consistent effect on these emissions.

### **Semi-Volatile Compounds**

Semi-volatile organic compounds range from examples with boiling points near 100 °C to examples with very high molecular weights, such as benzo(a)pyrene with a boiling point around 500 °C. The latter compound is an example of polycyclic aromatic hydrocarbons (PAHs). The presence or absence of PAH emissions from utility boilers is an issue of importance in PISCES work and was also addressed in this investigation.

A group of 16 PAHs were the primary targets for measurement. Only one of these compounds was detected with any significant frequency: naphthalene, which is the PAH with the most simple structure and lowest molecular weight. This compound occurred at concentrations near the limit of detection, around  $10 \mu\text{g}/\text{Nm}^3$  (note that this figure is three orders of magnitude below that sometimes seen for benzene).

Two compounds of lower molecular weight and higher volatility were seen consistently: phenol and benzoic acid (which is not on the list of 189 air toxics). The concentrations of these compounds were  $100\text{-}600 \mu\text{g}/\text{Nm}^3$  at the ESP inlet and thus much higher than that of the PAHs. The concentrations were significantly less at the ESP outlet. As with volatiles, many unidentifiable chromatographic peaks were detected. The total emission of semi-volatiles was evidently increased by low NOx combustion, as expected, yet contrary to the effect seen with volatiles.

The emissions of semi-volatiles were possibly suppressed by the ESPs. This effect might be attributed to the presence of the compounds in the adsorbed state on precipitated ash except for the fact that no organic matter could be found on the ash recovered from the ESP hoppers. If the hopper ash analyses are correct, it is conceivable that oxidation by ozone in the corona regions of the ESPs removed organic compounds.

### **Aldehydes and Ketones**

Two compounds were detected: formaldehyde and acetone. These are the most simple compounds in the two classes concerned. The concentrations at the ESP inlet ranged from  $20\text{-}200 \mu\text{g}/\text{Nm}^3$  for formaldehyde and from  $1\text{-}20 \mu\text{g}/\text{Nm}^3$  for acetone. The concentrations were consistently lower at the outlet. One logical explanation that can be offered for the apparent effect of the ESPs is that ozone oxidation occurred, just as may have occurred with the semi-volatile compounds.

No information on the effect of low NOx combustion on the emissions of these compounds was obtained because the samples for baseline operation were analyzed incorrectly and disposed of before the error was discovered.

## **CONCLUSIONS**

### **Effects on Chemical Emissions Due to LNCFS Level III Conversion**

The change from normal firing of pulverized coal to low NOx firing did not produce sharp changes in the emissions of elementary substances. This is hardly surprising for metals, which generally occur in the fly ash in oxidation states only problematically related to the conditions of oxidation in

the boiler. One exception occurred with a trace metal that can exist in different oxidation states; hexavalent chromium apparently was suppressed by low NO<sub>x</sub> firing. The absence of changes in emissions of the non-metals of concern as a consequence of low NO<sub>x</sub> firing is not surprising either; the principal forms of these elements are phosphate in the ash and HF, HCl, and SO<sub>2</sub> in the flue gas.

The shift to low NO<sub>x</sub> firing was expected to influence the emissions of organic compounds because the emissions of such substances are an effect of incomplete combustion. If elementary carbon is not burned completely, as seems to be the case, hydrocarbons and other organic compounds are not likely to be burned completely either. The effect of low NO<sub>x</sub> firing on these compounds, unfortunately, cannot be described simply or unambiguously from the results of this testing. The data appear to present the anomaly of opposing effects: reduced emissions of volatiles such as benzene and other simple aromatics, and increased emissions of semi-volatiles, possibly from unidentified compounds.

### **Control of Chemical Emissions by Hot-Side and Cold-Side ESP's**

The hot-side and cold-side ESPs removed approximately 99.5 percent of the particulate material entrained in the flue gas at the ESP inlet. Since most of the trace metals were associated with the particulate phase, most of the trace metals were controlled by the ESPs. However, the ESPs failed particularly at controlling mercury and selenium, which were largely in the vapor state. From the point of view that the main control of total particulate matter occurred at 700 °F in the hot-side ESP, however, the control efficiency for most of the trace metals may be regarded as unexpectedly high.

The data suggest that some organic compounds were removed from the flue gas through the ESPs and air heater. This effect may have been due to the presence of the vapors on solids that were precipitated. It may have also been due in part to the oxidation of the vapors to undetected residues, because of the presence of the vigorous oxidant ozone in the corona regions within the ESPs.

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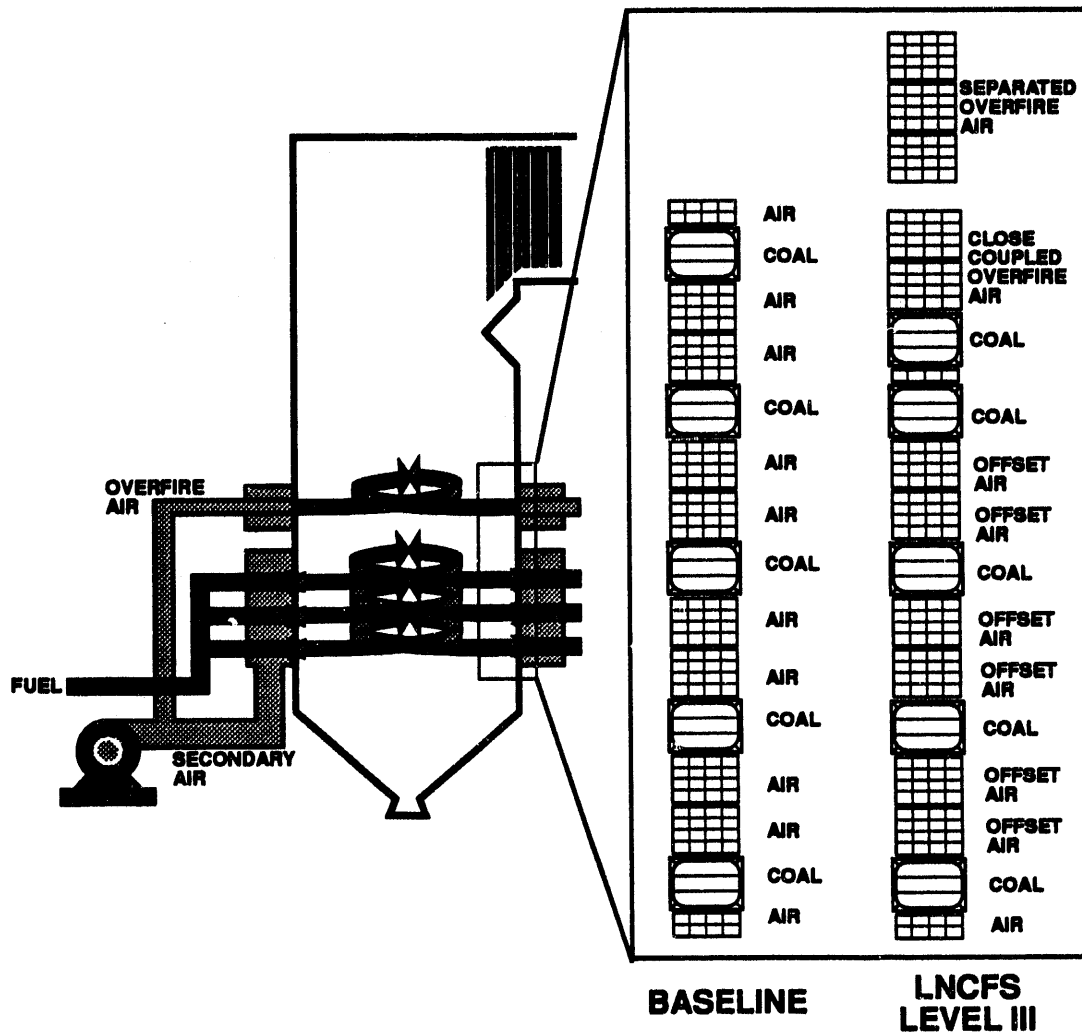
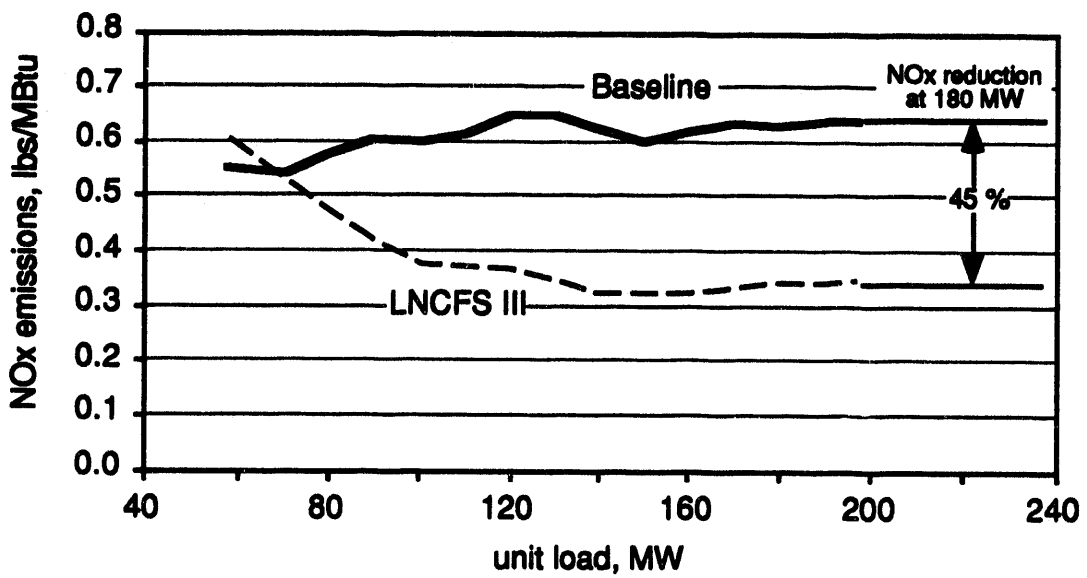


Figure 1. Low NOx Concentric Firing System Level III



**Figure 2. NOx Reduction with LNCFS Level III**

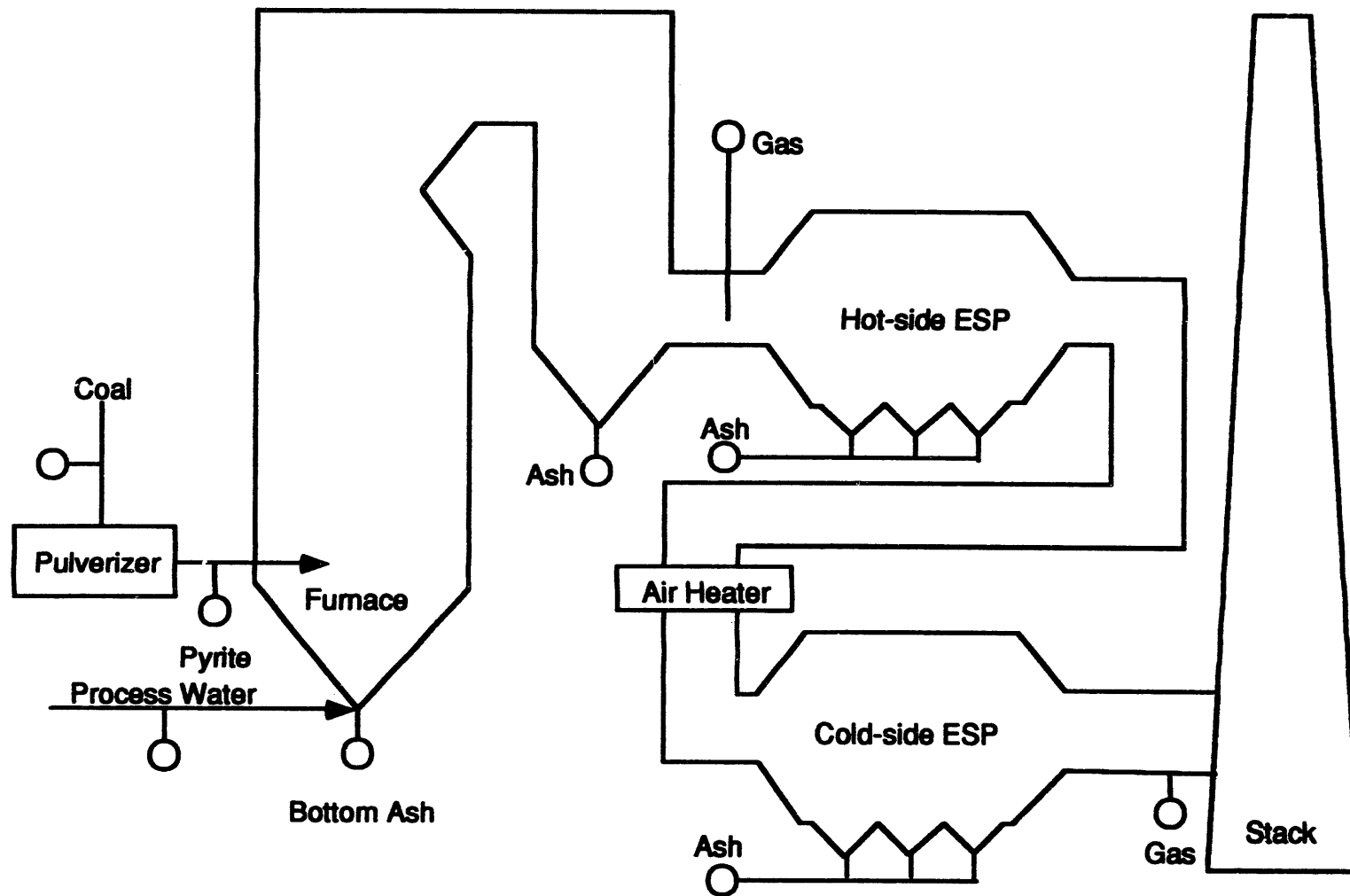


Figure 3. Layout of Sampling Locations

**Table 1. PISCES Air Toxics List**

<b>Inorganic Chemicals</b>	<b>Polynuclear Aromatic Hydrocarbons (PAH) *</b>	<b>Polycyclic Organic Matter (POM) *</b>	<b>Volatile Organic Compounds</b>
Arsenic	Acenaphthene	1,2-Diphenylhydrazine	Benzene
Barium	Acenaphthylene	1-Chloronaphthalene	Toluene
Beryllium	Anthracene	1-Naphthylamine	Formaldehyde
Cadmium	Benzo(a)anthracene	2-Chloronaphthalene	
Chlorine (Cl-)	Benzo(a)pyrene	2-Naphthylamine	
Chromium	Benzo(b)fluoranthene	3,3-Dichlorobenzidine	
Cobalt	Benzo(g,h,i)perylene	4-Aminobiphenyl	
Copper	Benzo(k)fluoranthene	4-Bromophenyl phenyl ether	
Fluorine (F-)	Chrysene	4-Chlorophenyl phenyl ether	
Lead	Dibenzo(a,h)anthracene	Benzidine	
Manganese	Flouranthene	Butylbenzylphthalate	
Mercury	Fluorene	Dibenzofuran	
Molybdenum	Indeno(1,2,3-cd)pyrene	Dibenz(a,j)acridine	
Nickel	Naphthalene	Diphenylamine	
Phosphorus	Phenanthrene	n-Nitrosodiphenylamine	
Selenium	Pyrene		
Vanadium	2-Methylnaphthalene		
	3-Methylcholanthrene		
	7,12-Dimethyl- benzo(a)anthracene		

\* Semi-Volatile Organic Compounds



**Table 2. Methods for sampling flue gas stream**

<b>Analyses</b>	<b>Sampling apparatus</b>	<b>Sampling media</b>
Metals: As, Ba, Be, Cd, etc.	Method 5-type train known as the EPA Multiple Metals Train	Filter HNO <sub>3</sub> -H <sub>2</sub> O <sub>2</sub> impingers H <sub>2</sub> SO <sub>4</sub> -KMnO <sub>4</sub> impingers
Non-metals: F, Cl, S, P	Method 5-type train for "acid gases" or "anions"	Carbonate-bicarbonate-peroxide impingers
Volatile organic compounds	So-called "VOST" (Volatile Organics Sampling Train)	Tenax and charcoal absorbers; water condensate
Semi-volatile organic compounds	So-called "Modified Method 5 Train"	Filter XAD resin Water-filled impingers
Aldehydes, ketones	Method 5-type train with trapping compound DNPH	Impingers containing dinitrophenylhydrazine (DNPH)

**Table 3. Analytical methods for solids and flue-gas constituents.**

<b>Analytes</b>	<b>Methods</b>
<b>Metals</b>	
Ba, Be, Co, Cr, Cu, Mn, Mo, Ni, V	Inductively coupled argon plasma emission spectroscopy (ICP)
Cd, Pb <sup>a</sup>	Graphite furnace AAS (GFAAS)
As, Se, Sb	Hydride generation AAS (HGAAS)
Hg	Cold-vapor AAS (CVAAS)
<b>Non-metals</b>	
S as sulfate	Ion chromatography
F as fluoride	Ion-specific electrode
Cl as chloride	Ion chromatography
P as phosphate	Ion chromatography or colorimetry
<b>Volatile organics</b>	Gas chromatography/mass spectroscopy (GC/MS)
<b>Semi-volatile organics</b>	Gas chromatography/mass spectroscopy (GC/MS)
<b>Aldehydes, ketones</b>	High performance liquid chromatography with UV detection

<sup>a</sup>And others if required for sensitivity

**Table 4. Illustrative data on mercury  
(baseline test at the ESP outlet, only hot-side ESP operating)**

Form of mercury	Concentration, <sup>a</sup> µg/Nm <sup>3</sup>
Particulate	Not determined
Vapor	
Hg(0)	1.85
Hg(II)	7.37
Methylmercury	0.0021
Total, all forms	9.22

<sup>a</sup>Data are averages from three sampling experiments.

**Table 5. Recoveries<sup>a</sup> of metallic elements in the gas stream entering the hot-side ESP**

Element	Baseline testing	Low NOx testing
	Min. Max., %	Min. Max., %
Antimony	Indeterminate <sup>c</sup>	Indeterminate <sup>c</sup>
Arsenic	81-120	Indeterminate <sup>c</sup>
Barium	69- 88	168-179
Beryllium	54-103	22-113
Cadmium	76-346	26-166
Chromium	128-173	67-112
Cobalt	64-145	Indeterminate <sup>c</sup>
Copper	47- 81	22- 37
Lead	131-256	26- 46
Manganese	91-121	64- 90
Mercury <sup>b</sup>	100-134	70-106
Molybdenum	97-179	84-105
Nickel	86-124	86-121
Selenium	59- 61	49- 98
Vanadium	55- 74	56- 61

- a Recovery is the percentage of element in the coal found in the gas stream. The data are from three tests in each series with the cold-side ESP de energized.
- b All data except for mercury are for the ESP inlet; the data for this element are from the outlet and are believed correct for the inlet since a negligible fraction of this element was in the particulate state.
- c Results that are shown as indeterminate can be illustrated in this way: The concentration of antimony in the coal has to be reported as giving a flux of <5.0 g/min, a value consistent with the value based on the coal but still not providing a figure for recovery.

**Table 6. Material balance across the ESP system.**

<b>Element</b>	<b>Closure,<sup>a</sup> %, Baseline testing</b>	<b>Closure,<sup>a</sup> %, Low NOx testing</b>
Antimony	<40	95
Arsenic	132	161
Barium	60	200
Beryllium	>69	36
Cadmium	95	211
Chromium	131	134
Cobalt	117	133
Copper	109	104
Lead	99	138
Manganese	114	123
Mercury	<57	<30
Molybdenum	107	89
Nickel	117	102
Selenium	Indeterminate	5
Vanadium	111	123

<sup>a</sup> Closure is the percentage of the element removed from the gas stream that is found in the hopper ash. The data on removal are based on inlet and outlet concentrations plus flow rate. The data on hopper accumulation rate are based on the solids analysis plus the amount of entrained solids that is collected in the hot-side ESP. The data given here are averages for four tests in each series, one test with both ESPs operating and three tests with only the hot-side unit operating.

**Table 7. Concentrations of acid gases and corresponding recoveries of non-metallic elements in the coal.**

<b>Gas</b>	<b>Concentration, ppm</b>
HF	6.7
HCl	117
SO <sub>2</sub>	2080

**Table 8. Concentrations of benzene and toluene.**

<b>Test series</b>	<b>Sampling time, min</b>	<b>Benzene</b>		<b>Toluene</b>	
		<b>ESP Inlet</b>	<b>ESP Outlet</b>	<b>ESP Inlet</b>	<b>ESP Outlet</b>
Baseline	40	--	500±200	--	20±20
	10	2800±1300	1980± 20	310±320	13±14
	2	10,000	3500±1500	4300	50±67
Low NOx	10	160±220	1090± 430	7.1±2.6	6.6±3.4
	5	230±280	1200± 590	2.4±2.3	5.7±3.0
	2	310±260	1850±1930	3.0±6.0	6.7±7.1

<sup>a</sup> Data are averages and standard deviations except for sampling times that yielded on single results.