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Proceedings of the Joint Symposium on Stationary Combustion NO$_X$ Control

Volume V
Addendum

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Proceedings of the Joint Symposium on Stationary Combustion NO_X Control

Volume V
Addendum

Symposium Cochairmen
Robert E. Hall, EPA
and
J. Edward Cichanowicz, EPRI

Prepared for

U.S. ENVIRONMENTAL PROTECTION AGENCY
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Washington, D.C. 20460
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These proceedings document more than 50 presentations given at the
Joint Symposium on Stationary Combustion NO_x Control held October 6-9,
1980 at the Stouffer's Denver Inn in Denver, Colorado. The symposium was
sponsored by the Combustion Research Branch of the EPA's Industrial
Environmental Research Laboratory-Research Triangle Park and the Electric
Power Research Institute (EPRI). The presentations emphasized recent
developments in NO_x control technology. Cochairmen of the symposium
were Robert E. Hall, EPA, and J. Edward Cichanowicz, EPRI. Introductory
remarks were made by Dan V. Giovanni, Program Manager for Air Quality
Control, Coal Combustion Systems Division, EPRI, and the welcoming address
was given by Roger L. Williams, Regional Administrator, EPA Region VIII.
Stephen J. Gage, Assistant Administrator for Research and Development,
EPA, was the keynote speaker. The symposium had 11 sessions:

I: NO_x Emissions Issues
        Michael J. Miller, EPRI, Session Chairman

II: Manufacturers Update of Commercially Available Combustion
        Technology
        Joshua S. Bowen, EPA, Session Chairman

III: NO_x Emissions Characterization of Full Scale Utility
        Powerplants
        David G. Lachapelle, EPA, Session Chairman

IV: Low NO_x Combustion Development
        Michael W. McElroy, EPRI, Session Chairman

Va: Postcombustion NO_x Control
        George P. Green, Public Service Company of Colorado,
        Session Chairman

Vb: Fundamental Combustion Research
        Tom W. Lester, EPA, Session Chairman

VI: Status of Flue Gas Treatment for Coal-Fired Boilers
        Dan V. Giovanni, EPRI, Session Chairman

VII: Large Industrial Boilers
        J. David Mobley, EPA, Session Chairman

VIII: Small Industrial, Commercial, and Residential Systems
        J. David Mobley, EPA, Session Chairman

IX: Environmental Assessment
        Robert P. Hangebrauck, EPA, Session Chairman

X: Stationary Engines and Industrial Process Combustion Systems
        Robert E. Hall, EPA, Session Chairman

XI: Advanced Processes
        G. Blair Martin, EPA, Session Chairman

VOLUME V

TABLE OF CONTENTS

INTRODUCTORY REMARKS
Dan V. Giovanni, Manager
Air Quality Control Program, EPRI

It is my pleasure today to welcome you on behalf of EPRI to the Joint Symposium on Stationary Combustion NOx Control. This is the third in a series of symposia with which EPRI has been associated and it may prove to be the most important.

NOx emissions from stationary sources have been controlled to date through manipulation of the combustion process using conventional furnace and burner designs. To achieve significantly lower NOx levels it will be necessary to employ heretofore unconventional combustion systems or post-combustion treatment processes. New technologies such as these inherently increase the risks undertaken by manufacturers and operators of stationary combustion equipment. Capital and operating costs will increase and overall system reliability may be jeopardized.

To help offset these risks, successful research and development programs are necessary. During the next few days we will be hearing and discussing results from ongoing EPRI and EPA projects, as well as, many private programs undertaken in the U.S., Japan, and Europe. I encourage your active participation in the symposium. Thank you.

WELCOMING ADDRESS

Roger L. Williams, Regional Administrator, VIII
U.S. Environmental Protection Agency

Good Morning. It is my pleasure to welcome you to Denver and to this symposium on nitrogen oxides control. The joint sponsorship of this symposium by the Electric Power Research Institute and the Environmental Protection Agency provides the clear message of the need and desire for a close working relationship between energy and environmental interests. Later this week another workshop will be held here in Denver that will have a broader theme, designed to assist the Energy Community in understanding the many programs and authorities administered by the EPA. This seminar beginning on Wednesday is titled, "Conference on Environmental Regulations Relating to Energy."

Hardly a week goes by that there isn't a major energy conference or workshop here in Denver. Estimates indicate that there are more than 600 energy companies now residing in Denver. Denver is rapidly becoming known as the "Energy Capital" of the West. The development of Western United States vast energy resources is a vital ingredient in the National Energy Plan. EPA is committed to doing its part in support of the Nation's goal of energy self-sufficiency. These cooperative workshops are an important part toward that end.

Conversion of oil and gas fired utility boilers to coal is an important part of the energy supply equation and should proceed expeditiously. Almost 3 million barrels per day of oil equivalent could be displaced. Conversion of industrial boilers where possible should also proceed. EPA's role under the Power Plant and Industrial Fuel Act of 1978 and the Clean Air Act Amendments of 1977 is one of assuring that these conversions occur in an environmentally acceptable manner. Continued research into cost effective methods to reduce NOx emissions from stationary source combustion, such as papers presented at this symposium are a key to the environmental acceptance of these conversions.

All new steam electric power plants constructed in the United States will be coal fired or nuclear. The abundance and availability of cheap surface mineable coal in the West has provided an attraction for the utility industry. This attraction has resulted in a substantial increase in EPA Region VIII Office activities in the form of EIS reviews, issuance of surface water discharge permits, and air quality (PSD) permits to construct and operate. Since January 1, 1978 we have issued more than 308 energy related permits. We are presently averaging one Regional energy related action per working day and this pace is projected for the next five years. Most permitting applications have been approved with reasonable environmental safeguards, a few permits have been denied. Since the PSD concept was adopted in the Clean Air Act Amendments of 1977, my Office has received applications for and issued PSD permits to eleven power plants with a total combined generating capacity of almost 10,000 Megawatts. This will raise the Rocky Mountain Regions generating capacity to about 29,000 MW. I believe that this indicates that while environmental standards impose tough requirements in the form of new source performance standards, best available control technology, and PSD ambient air quality increments, the program cannot be labeled as a major inhibiting force against energy development as some people have chosen to do. Appropriate siting combined with good controls result in adequate energy development coupled with proper environmental protection.

The protection of environmentally sensitive areas must share an equal place at the table along with the development of energy resources. Region VIII states have been blessed with a dichotomy. While we have abundant energy resources -- 50% of the Nation's coal and uranium resources and essentially all of the oil shale and tar sands resources -- we also have the cleanest air and water in the Nation, 10 million acres of Class I National Parks and

Wilderness areas, wild and scenic rivers, unique wetlands, prime agricultural land, endangered species and habitat and some of the Nation's clearest visibility. It is heartening to see increasing emphasis on energy conservation measures and on the development of renewable energy resources. It is also encouraging to note that electric power demand increased by only 2.1 percent in 1979 over 1978. That is a major improvement over the industry's historic 7 percent annual growth rate.

It is clear from a review of your program and the experience assembled in this room, that this conference will be a major success and have a significant impact in the field of combustion research and environmental control.

We are very pleased to have the opportunity to co-sponsor this seminar with the Electric Power Research Institute here in Denver and look forward to the continued cooperation between your Industry and EPA towards a better life.

Welcome and I wish you much success for your seminar.

Thank you.

SOLVING THE NO$_x$ CONTROL DILEMMA
(Keynote Address, October 6, 1980)

Dr. Stephen J. Gage
Assistant Administrator for Research and Development
U.S. Environmental Protection Agency

To someone who is inclined to believe that the Federal Government
spends its time searching for ways to make life difficult for the private
sector, it would be easy to assume that we get a perverse delight out of
instructing industry to burn more coal, while insisting at the same time
that air quality be maintained. Such instructions sound almost like a
Zen koan...one of those paradoxical word puzzles a Zen Master will use
to confound his students and spur them toward enlightenment. "Without
getting your robe wet, remove a stone from the bottom of the sea."
"Without moving a muscle, stop the clanging of the bell across the
river."

There's no getting around the fact that coal is a dirty fuel,
contaminated with a variety of substances found to be harmful to human
health and the environment. How on earth can we possibly triple the
burning of coal by the year 2000, yet keep our air breathable?

We in EPA are aware of the dilemma industry faces. Far from
sitting back with an inscrutable smile as you scramble to find solutions,
we consider your problem our own. We are not in the business of assigning
koans...that job will be left to the Zen Masters. But in the past
decade, we have become enlightened about one thing: achievement of
these twin goals is possible...at a reasonable cost...through the
development of effective control technologies. Environmental degradation
need not follow on the heels of a dramatic increase in coal use. The
nation can have economic growth, achieve energy independence, and at the

5

same time maintain a high quality of life that so closely depends on the quality of our environment. Working together with industry, EPA has made and is continuing to make considerable progress in developing cost-effective ways of controlling coal's pollutants.

One success story has been sulfur oxide control, thanks to the development of flue gas desulfurization techniques. Although the first commercial use of FGD control systems took place in the early 1930's, the technology is only now becoming widely used, after ten years of extensive research, development and demonstration programs sponsored by EPA, the Tennessee Valley Authority, and the Electric Power Research Institute. As a result of these programs, FGD systems can now remove up to 90 percent of SO_2 emissions reliably and economically. Industry and utility companies, which in the early days of FGD development viewed the technology with a skeptical eye, are now adopting the process. At last count, 73 FGD units were in operation, with 127 units in design or under construction. Once all these units are operating, over a quarter of the current total U.S. coal-fired capacity will be equipped with FGD. Because of this growing acceptance of FGD, the total amount of sulfur oxides emitted to the atmosphere will remain constant or even decrease slightly from 1975 to 2000. This represents a tremendous victory for pollution control technology.

The history of particulates control is similarly cheering. Although the total amount of particulates generated between 1975 and 2000 is projected to double because of increased coal use, particulate emissions from coal combustion by electric utlities and industrial boilers will decline. This decline will be made possible by the widespread use of

6

modern, high-efficiency electrostatic precipitators. In the future, more advanced ESP's will likely attain the same level of performance at half the cost. And, while there is still work to be done in improving removal methods for fine particles and the difficult-to-remove ash typically produced from Western coals, the already established technologies of wet scrubbing and baghouses may provide the answers we're looking for. The bulk of the particulates problem has been licked.

What I mainly want to talk to you about today is a third air pollutant from coal combustion that may present us with our biggest air pollution challenge during the 1980's and beyond: nitrogen oxides. While sulfur oxide emissions are expected to decrease or remain constant between now and the year 2000, and while particulate emissions will decrease, nitrogen oxide emissions could easily double during this period...unless more effective control methods are developed. At present, about half the current NO_x emissions come from stationary sources, but by 1985, due to the trend toward greater combustion of coal, stationary sources may be responsible for 70 percent. Of the emissions from stationary sources, over half are contributed by utility and large industrial boilers alone. These large boilers emit an estimated 6 million tons of NO_x every year. Without controls, a single coal-fired boiler may spout 120 tons of NO_x into the atmosphere every day.

EPA is extremely concerned about the NO_x trends in this country. As a result, we have mobilized a significant portion of our research and development machinery toward combatting such emissions. In each of the last three years, through 1980, EPA has spent $12 million on developing methods of controlling NO_x pollution. In 1981 and 1982, funding will

continue at this high level, for a total expenditure of $60 million over the five-year period from 1978 to 1982. This level of funding should leave no doubt of EPA's dedication to the NO_x control effort.

Until recently, the effects of NO_x on humans and their environment has not been sufficiently appreciated. At last year's conference on EPA's Interagency Energy/Environment R&D Program, someone stood up and asked why EPA was devoting so much time and money to NO_x control. "NO_x makes your eyes burn," he said, "but sulfur oxides can kill you." Well, as a matter of fact, we now know that NO_x can do a great deal more than cause eye irritation. Long-term exposure to even low levels of NO_x can reduce resistance to respiratory infections such as bronchitis, pneumonia and influenza, and high-level, short-term exposure can have a variety of pronounced adverse health effects. The available evidence indicates that human health can be impaired by exposure to nitrogen dioxide concentrations approaching or falling within the range of recorded ambient air NO_2 levels.

Also of great concern are the environmental effects of NO_x once it has been transformed into other pollutants in the atmosphere. NO_x is a precursor of photochemical oxidants...the air pollutants most damaging to agriculture and forestry in the United States. Elevated concentrations of ozone, which is the chief ingredient of smog, have become a regional problem throughout the country, causing widespread damage to crops on both coasts. Oxidants have caused harm to agricultural crops, forest, and native vegetation in Southern California as well as widespread damage to crops in the East, and have become a new stress on ecosystems

8

in the Southwest.

Probably the most alarming environmental effect of NO_x is its role in the formation of acid rain, which is developing into what may be one of the most serious environmental threats of the century. As you heard, acid rain is formed when the gases of nitrogen and sulfur oxides combine with water vapor molecules in the atmosphere and are transformed into nitric and sulfuric acids. These acids are returned to earth by rain or snow or in dry form, sometimes hundreds or even thousands of miles from their sources, and can cause extensive ecological damage.

In New York's Adirondack Mountains, for example, acid rain has killed all of the fish in half of the high-altitude lakes. In Norway, the losses to salmon fisheries attributable to acid rain are estimated to be in the tens of millions of dollars. Acid rain may also be playing a part in the decline in forest growth observed in the Northeastern United States. In the eastern part of the U.S. and in Canada, there are extensive areas which are particularly susceptible to acidification because of the lack of natural buffering capacity in soils and water. In much of the West, the alkaline nature of the soils and lakes acts to neutralize acid rain, so the effects are not as pronounced there. But even in the West, ominous signs of vegetation damage have appeared.

NO_x accounts for 30 to 50 percent of the acid rain problem in the East, depending on the season. In the West, acid rain may be composed of up to 90 percent nitric acids formed from NO_x. Even as sulfur oxides are brought under control, the jump in NO_x emissions ensures that the acid rain threat will remain with us.

As required by the Clean Air Act, EPA has set a National Ambient Air Quality Standard for nitrogen dioxide, based on the level required

9

to protect the public health and welfare. This standard is currently
pegged at 100 micrograms per cubic meter of air, or .05 parts per
million, on an annual average basis. Several of our largest cities,
including Los Angeles, Chicago, Denver, New York, and Salt Lake City,
are currently exceeding this standard. In fact, many industiralized
cities have short-term levels of nitrogen dioxide that reach several
times the NAAQS.

EPA is ready and willing to work with you in attaining the ambient
air and stationary source standards. A teamwork approach was successful
when we were confronted with the need to reduce sulfur oxides and
particulates. The same approach can work with NO_x control. I would
also like to make a special point of welcoming our international friends
to join us in this cooperative effort. As one who has appreciated the
significant contributions made by the Jpaanese and, more recently, the
Germans in advancing FGD technology, I am encouraged by the active
participation of the highly capable engineers from Japan and West Germany
as well as from Canada and the European Common Market.

The NO_x problem is, however, a tough nut to crack. It doesn't
yield to the solutions that worked so well for sulfur oxide and particulates
control. Physical coal cleaning, which can be used on some coal to
reduce sulfur and ash content, has no effect on coal's nitrogen content,
because the nitrogen is chemically bound to the coal. "Denitrogenation" --
that is, chemically removing nitrogen from coal -- is prohibitively
expensive at present, and at any rate does not address the problem of
thermal NO_x, which is formed by molecular reaction in superheated

combustion air. Flue gas treatment for NO_x control has been used with a fair amount of success in Japan on oil-fired boilers, but there are major financial and technical hurdles to applying that technology to coal-fired units. Even the coming age of synthetic liquid fuels made from coal, which may consume 120 million tons of coal in 1990 and 300 million tons in 2000, offers little hope for NO_x control -- in fact, the concentration of fuel nitrogen may be increased when coal is converted to a liquid.

However, the picture is not nearly as bleak as it may at first appear. There is an answer that is both cost-effective and energy-efficient. By modifying the conditions under which combustion takes place, an existing coal-fired power plant can reduce its NO_x emissions by 40 to 50 percent, which is generally enough of a reduction to meet current New Source Performance Standards for utility and large industrial boilers. When applied to new burner designs, combustion modification may reduce NO_x emissions by another two-thirds, yielding a total NO_x control of up to 85 percent. This means that NO_x emissions from coal burners can be reduced to the level found in oil burners. Yet, because combustion modification involves changes only in burner design, the cost is quite small -- less than one-half of one percent of the boiler cost. And, because we are ensuring that the new burners are as efficient as the older designs, the operating cost is nearly zero. Levels of other pollutants, such as particulates and hydrocarbons, are also reduced, because the total combustion process is optimized.

EPA's work in developing new low-NO_x burner designs is the center-piece of its NO_x control effort. As early as 1971, EPA's Combustion

11

Research Branch at Research Triangle Park in North Carolina was experimenting with burners that produced a slower fuel-air mixing and a cooler flame than the traditional turbulent diffusion flame. We discovered that by suppressing flame temperatures and delaying the mixing of fuel and air, both thermal and fuel NO_x formation was hindered. Pilot scale work has proven that the technology is sound -- NO_x emissions were reduced to below 200 ppm.

The next step is to evaluate the low-NO_x burner's performance at as close to practical size as possible, in order to encourage industry acceptance of the technology. Two projects currently underway have this aim in mind; they will allow full-scale field evaluation of the low-NO_x burner.

One project will employ two industrial boilers in the range of 30 to 150 thermal megawatts, while the other will involve two utility boilers in the range of 100 to 300 megawatts. For each boiler, a prototype burner will first be constructed and then tested in an experimental facility. After the uncontrolled emissions of each host boiler has been measured, the low-NO_x burners will be installed and adjusted. Then, EPA will conduct a long-term evaluation of the burners, including environmental assessment and analysis of boiler operation. This will include corrosion testing, since slagging and fouling from coal ash is always a worry when burner design is altered. Finally, a guideline manual will be prepared to explain the technology.

The goal of these projects, which will be completed in late 1982, is not <u>only</u> to show that the new burners <u>do</u> indeed reduce NO_x emissions, but, that in doing so, they also equal or improve the thermal efficiency

of conventional boilers...that carbon emissions are not increased...and, that corrosion is prevented. One encouraging observation has been that increasing the scale of the low-NO_x burner toward practical size appears to make the technology more effective.

To aid EPA in the evaluation of these projects, and also to help keep the projects on the track toward commercialization, a technical review panel composed of representatives of boiler manufacturers, utilities, and research organizations will be on hand to offer advice and criticism. To provide a broader perspective on potential users, there will also be a technology transfer panel consisting of government agency representatives and trade association members.

The low-NO_x burner is being tested with a wide variety of U.S. coals. Initial tests indicate that it is effective even with high-nitrogen-content coals. Experiments with burning high-nitrogen residual fuel oils using low-NO_x technology provide both a worst-case scenario for conventional oils and a preview of what may be achievable with high-nitrogen coal and shale-derived oils. At pilot scale, the low-NO_x burner reduced NO_x emissions from these residual oils by 50 to 75 percent of what they would be if burned in a conventional boiler.

The results of all of EPA's tests with this new technology have met or exceeded program goals, so we feel comfortably optimistic about the kind of performance we will see when it is adopted commercially. In fact, we're very much encouraged by the results being obtained on a 700-mwe boiler in West Germany, an experiment which you will be hearing

about tomorrow morning.

What we've learned in applying combustion modification techniques and innovative burner designs to utility and large industrial boilers is also being applied to other combustion sources. These include small-scale industrial boilers, gas turbine engines, and residential oil furnaces. A new oil-fired furnace design we've been working on not only reduces NO_x by 65 percent, but reduces oil consumption an average of 15 percent. These are the kind of results we really enjoy seeing: increases in efficiency as well as improved pollution control.

A particularly exciting new control technology, which can be retrofitted to many existing coal-fired boilers with only minor modifications and which reduces sulfur oxide emissions as well as NO_x, is the limestone injection/multi-stage burner, or LIMB for short. The LIMB technology may be able to remove 50 to 70 percent of sulfur oxides at the same time that it reduces NO_x by 50 to 80 percent. And it can accomplish this at a cost for SO_2 control equipment of only $30 to $40 per kilowatt, as opposed to the average of $150 per kilowatt that wet scrubbing requires. Although the LIMB has only reached the bench/pilot scale stage of development here in the U.S., Germany is currently operating a 60 megawatt electric boiler using the technology, so we know that it works on a larger scale.

The idea of combining limestone injection for SO_2 control with a low-NO_x burner is not a new one. In 1967, UOP, building on earlier limestone injection experiments by Combustion Engineering, injected

14

limestone into an arch-fired burner, which is a naturally low-NO$_x$ burner. SO$_2$ emissions were reduced by 50 percent at a stochiometric ratio of 1.3.

The 60 megawatt prototype limestone injection boiler in Germany, which I mentioned earlier, has been operating for one year. It fires West German lignite, and utilizes flue gas recirculation to minimize peak temperature and NO$_x$ formation. At present, it is achieving 50 to 90 percent SO$_2$ removal at stochiometric ratios of 2.5 to 5.0. Retrofit capital costs for this technology are only $3.00 per kilowatt.

EPA has proposed a five-year research, development, and demonstration program that will bring the LIMB technology up to commercial scale. In the first year, EPA will characterize reactions and furnace conditions; evaluate impacts on furnace operation; and test the technology with a wide range of coal types and calcium-based sorbents. Next will come a year of field evaluation, in which EPA goals will be to demonstrate sulfur removal efficiency, optimize performance variables, determine if there are any adverse boiler side effects such as slagging, plugging and corrosion, and obtain design and cost data. Both wall-fired and tangentially-fired units will undergo testing. Another year will be spent installing the LIMB technology on full-sized boilers, which will then be subjected to two years of performance optimization and long-term evaluation. The total tab for the LIMB program will amount to $16.5 million, which will be a bargain if LIMB fulfills its initial promise. The development effort will be co-sponsored by EPA and the Department of Energy.

I've been talking a lot about EPA's plans for developing NO$_x$ control methods, and the sort of projects we have underway. But, I'm

not forgetting the crucial role industry must play in this mission. EPA has the resources to provide the fundamental research and the testing of new control technologies, but we must rely on industry to provide the host sites that allow technologies to be tested under real-life conditions. And, we must depend heavily upon the commercial expertise and engineering experience of boiler manufacturers if a technology is to progress beyond the demonstration stage.

There's always an element of risk for the private sector when it invests in new equipment and new technologies. Control processes that look promising on the drawing board or during small-scale experiments don't always pan out when they are put into practical use. But we at EPA believe that with the kind of cooperation between government and industry we have enjoyed up to now, and with an equitable sharing of the risk which is, after all, inherent in all innovation, we can solve the pollution control challenges that we face.

For the rest of today and in the course of the next two days, you will be hearing about a lot of new ideas, new techniques, and new technologies aimed at keeping nitrogen oxides out of the air. Personally, I am very excited about these developments. A number of them will have far-reaching effects. For example, the low-NO_x burner or the LIMB technology may provide the technical fix for what will be an increasingly difficult political problem we will be having with our Canadian neighbors over our acid rain export to Southern Canada. Already these control methods have advanced from being just a gleam in an engineer's eye to successful operation in the laboratory, in pilot plants, and in a few

small combustors. I'm willing to bet you that when we gather together

ain in a year, many of these technologies will be starting to move into

the commercial market, working to produce electricity, generate power,

and heat homes. And we'll all be able to breathe a little easier.

AIR QUALITY CONTROL FROM A STATE REGULATOR'S VIEWPOINT
(Luncheon Address, October 8, 1980)

L. Michael Henry, Chairman
Colorado Air Quality Control Commission

Ladies and Gentlemen, I am very honored to be here, but I must say that
I am also considerably intimidated - for two reasons.

First, as I believe you know, I am substituting as a speaker for United
States Senator Gary Hart from Colorado. I am intimidated because I
certainly have nowhere near the knowledge and stature of Senator Hart on
air quality issues.

We are very proud in Colorado that Senator Hart is respected so much in
the national government to be the Chairman of the National Commission on
Air Quality. He has also played a vital role in fighting to reinstate high
altitude standards for automobile emissions. As you know, our mile-high
altitude in Denver and much higher altitudes in our mountain communities
contribute very significantly to automotive air pollution due to incomplete
gasoline combustion at higher altitudes. In addition, Senator Hart has
helped focus national attention on Colorado's deep concern about the pros-
pect of economic and environmental problems resulting from projected
massive development of the oil shale industry in the Piceance basin in
northwestern Colorado. Senator Hart held a large public hearing in western
Colorado on the oil shale development proposals of Exxon about five weeks
ago. For some reason our Colorado Air Quality Control Commission was
not notified of that meeting and, being a feisty Commission, we did send
Senator Hart a message of complaint about this failure of communication.
I cannot quite put out of my mind the possibility that Senator Hart was trying
to punish me for this complaint by suggesting that I be thrust as a speaker
before such an august meeting of international experts in stationary source
control. Seriously, I do appreciate his suggestion that I might have some
words of interest to you.

Secondly, I am very intimidated to be addressing you as a complete
scientific lay person and amateur. I was very lucky to complete one course
in high school physics and one course in high school chemistry. I have
retained very little of those courses except for a deep respect for the
discipline of those hard sciences. I am even less knowledgable in the laws
of medical science or mechanical engineering or computer sciences, and
I hope you will keep this in mind in any questions you might have.

Much of what I would like to talk to you about relates to the relationship
between a citizen non-scientific regulatory commission as we have in
Colorado and the regulated industries and the affected public.

In Colorado we have a 9-person part-time Air Quality Control Commission
all appointed by the Governor. We are paid the grand sum of $40 a day
for each day of work with a ceiling of $1,284 per year. We have regular
meetings twice a month and numerous committee meetings with groups
such as yours every month. Our Colorado statute requires the Governor
to give consideration to appointing persons with appropriate scientific,
technical, industrial, labor, agricultural, and legal training or experience,
although no specific number of members needs to be from any specific
background. The current members of our Commission include one lawyer,
one lawyer=businessman, one woman rancher, one woman Chamber of Com-
merce representative and former City Council woman, two civically-active
League of Women Voter members, one medical doctor, one professor of
Engineering, and one engineer with a large manufacturing company.

Our current political makeup, which never is reflected in any of our votes,
is three Democrats, three Republicans, and three unaffiliated members.

Our statutory obligations include the functions of preparing a comprehensive
State Implementation Plan (SIP) to assure attainment and maintenance of the
National Ambient Air Quality Standards, preventing significant deterioration
and the preparing of emission control regulations.

We are very proud that the State Implementation Plan (required by the
Federal Clean Air Act) which was submitted by Colorado to the Environmental
Protection Agency in early 1979 was the first plan submitted by any state.
We are not quite so proud that our State Implementation Plan was the first
also to bring sanctions from the Environmental Protection Agency due to the
failure of our Legislature to pass in a timely fashion legislation for inspection
and maintenance of automobiles in our non-attainment areas. These Environ-
mental Protection Agency sanctions have since been lifted after the Legislature
did finally pass such Inspection and Maintenance legislation.

19

In the two and one-half years since I have been a member of the Colorado Commission, I have been extremely impressed with the quality and diligence and good common sense of the members of our Commission. Many have suggested that the State would be better served by having full-time paid members of the Regulatory Commission who would either be scientists or at least persons who can afford time to be scientifically and rigorously trained on the job. I certainly do wonder sometimes myself whether a deeper scientific training would have helped me be a better policy maker, particularly in the middle of public hearings when acronyms and medical phrases and chemical formulas and computer modeling results and engineering terms are thrown at us with scarcely any interconnecting English sentences.

On reflection, however, I believe that we do have a very workable system of regulatory air quality control in Colorado for four reasons:

First, we do have very competent technical permanent staff for the analyses of permit applications, for air monitoring, for planning and analysis of overall state strategies and for inspection and enforcement of our regulations. The trouble is that we do not have enough staff or enough funding to retain competent staff, partly due to a seven percent annual increase in State spending limitation which has been passed by our Legislature. The entire State Air Pollution Control Division has approximately seventy full-time staff, some of whom provide administrative support for the technical personnel. We have a budget of approximately 2.6 million dollars of which 10% is passed through to local health departments.

In addition to Colorado's spending limitations in a time of double-digit inflation we are also very concerned about future uncertainties in Federal Environmental Protection Agency budgeting in the next several years. We are very pleased however, with the staff resources which we have, given the limited staff numbers and the fiscal limitations we must live with.

Second, we have an enormous reservoir of public concern in Colorado about air quality control to spur us on. Very many people first came to Colorado around the turn of the last century on doctors' orders so that our pure air would ease the problems of people with tuberculosis and other respiratory diseases before they died. The fact is that many survived for very many years in our clean air. We have had a population boom for the last many years with many tourists and military short-term visitors attracted by our great weather and scenery and air to remain permanently in Colorado. None of these people are going to sit quietly by while our air deteriorates. Many times at our hearings, unfortunately my opinion, we hear very little from these people - as most of them have neither the scientific background nor the economic resources to spend time in testifying. However, we do feel a deep obligation to heed those who recall us to our heritage of clean air and

respect for our "purple mountains majesty" (as one public witness told us a couple of months ago). Many environmental groups do come however, and provide significant detailed analyses to us, which serves as a useful counterbalance to the great scientific resources of industrial representatives.

Third, we do have what I believe to be a very cooperative and mutually respectful attitude in Colorado between our Regulatory Commission and our major industries. All of our industries have a stake in maintaining Colorado as a healthy and attractive environment and all, with very few exceptions have recognized this obligation.

Fourth, we do have what I believe to be a very capable and constructive and common-sense Commission even given some of our technical weakness. We consult prior to drafting regulations with affected industry and with citizens and local governments and are very thoughtful about all of our final regulations. We are attempting now to develop a new approach to rule-making to respond to an EPA's regulation to protect visibility in Class I mountain parks areas which will come down in November. We have concluded that we would all be better served by a regulation which has been drafted jointly by the State and affected industry and the public at the beginning rather than having adversarial polarized groups at the public hearing yelling not only at each other, but at the Regulatory Commission. We are attempting to bring the resources of environmental groups and industries into the early stages in a calm atmosphere not only to defuse the process, but to capture the energy and resources and creativity of all groups, especially industry, when the resources of the State technical staff are limited, as I have said.

I think we all must recognize that when regulated industry has a role in finding solutions, certainly the outcome is much more practical and sensible. Those working deeply in an industry certainly know better than anyone else the unique problems of that industry. I am very favorable to the "bubble" concept, which is just now being applied to several industrial sources to allow the industry itself to find creative ways to reduce the overall emissions from that industrial site without outsiders attempting to establish regulations for every individual source inside the location.

I certainly commend the Environmental Protection Agency and the Electrical Power Research Institute for conducting this first joint symposium, which also reflects an understanding and need for cooperation between industry and regulators.

I will give you just a few comments on some of our specific Colorado problems:

At the time that our State Implementation Plan was submitted in early 1979, different parts of Colorado violated all of the National Ambient Air Quality

Standards except for sulfur dioxide. In Denver our 1977 average annual of NOx was .054 parts per million when the national standard is an annual average not to exceed .05 parts per million. In Denver during 1977, 37 percent of our nitrogen oxides (both NOx and NO_2) were from automobiles. Approximately 50% from large stationary sources; and approximately 10% from space heating. In 1982, our predictions are for approximately the same contributions toward our nitrogen oxide emissions, with a slight increase in the percentage to be emitted from space heating.

The fact that our nitrogen oxides are emitted by three different large factors differs from the situations we have with our other pollutants. In Denver, 93% of our carbon monoxide is contributed by automobiles, 85% of hydrocarbons are contributed by automobiles and 75% of our Total Suspended Particulates are contributed by automobiles. With the multiple contributors of nitrogen oxides, the control strategies are more complicated than if the greatest part of the pollutant came from one source.

In Colorado we are also facing a great deal of work and study to prepare regulations to protect our visibility in Class I areas. As I indicated, we in Colorado feel an enormous obligation to protect our mountain beauty. The task will be especially difficult due to the fact that visibility-measurement is not at all a fully-developed science.

Another very large problem facing us relates to the development of the oil shale industry in northwestern Colorado. We are extremely conscious that the entire nation is looking toward northwestern Colorado as a very valuable source of oil shale and also coal, but the scale of some of the proposed oil shale developments is absolutely overwhelming. Exxon, for example, has recently proposed an eight-million barrel per day development in the next several years. Most of our state officials and industry representatives believe that a 1.5 million barrel per day oil shale industry is much more realistic. Even so, the population increases and the energy capability to serve not only the industrial processes but the needs of the added people themselves, pose enormous problems for northwestern Colorado. In addition, the proposed MX missle system will also need approximately 180 megawatts of new power to serve not only the missile system itself, but the added population in western Colorado and eastern Utah.

One of our other major endeavors in Colorado relates to automobile inspection and maintenance. The Legislature finally did pass implementing Legislation in May of 1980. The program will be operational in full beginning in January of 1982. Many of us are concerned that our inspection and maintenance program will have little if any effect on reducing visible pollutants. Although most of us are most concerned about health-related pollutants, we believe that many members of the public are most keenly aware of the visible effects

which damage our mountain views. We will thus be feeling considerable public pressure to control the visible pollutants as aggressively as we do the invisible pollutants.

In other words, we have plenty of work to do in Colorado; and, given our history and our recent activites, I have every confidence that we will be able to handle our problems. With cooperation from industry, we will be able to do even better. I am very glad that you have offered me the opportunity to speak to you, and I trust that your visit to Colorado will be pleasant. Thank you very much.

REGULATORY PRESSURES FOR INCREASED NO_x CONTROL

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REGULATORY PRESSURES FOR INCREASED NO_x CONTROL

Electric utilities have had little concern with nitrogen oxide emissions. Particulates and sulfur oxides have received a great deal more attention. New and likely regulations will change this situation soon and could cost the electric utility industry as much as $11 billion (1).

I want to discuss the significance of impending and likely NO_x regulations upon the electric utility industry as well as the impact of other new laws upon the choice of an NO_x control technology.

The Clean Air Act Amendments of 1977 request a short-term ambient standard for NO_2. No standard has yet been set, but current discussion centers upon a one-hour average NO_2 ambient concentration of 0.125 - 0.50 ppm (2). Although this limit will be more restrictive than current SO_2 standards, small and medium-sized coal-fired power plants can probably satisfy the NO_2 limit (1). If we assume a one-hour standard of .25 ppm NO_2 and assume that all NO_x is converted to NO_2, then a 500 MW(e) power plant in flat terrain and complying with new source performance standards can easily conform to this standard if background levels of NO_2 are not already high. (See Table 1.) The same is also true for 1000 MW(e) plant. Significant background levels of NO_2 and uneven terrain would make it more difficult to satisfy the regulation.

Relaxation of the 100% NO_x to NO_2 conversion rate would make it easier to satisfy the regulation. A coal-fired power plant 1500 MW(e) or larger could not, however, meet a one-hour standard of .25 ppm even if it satisfied new source performance standards. Additional NO_x control would be needed.

A second requirement of the 1977 Clean Air Act Amendments is the Prevention of Significant Deterioration (PSD) provision for NO_2. The format for these regulations is not yet known, and several alternatives are under study. If, however, an increment format similar to that established for SO_2 and particulate matter is chosen, it will present significant constraints upon the electric utility industry. The allowable PSD increments for SO_2 and particulate matter are generally 25% of the ambient standards for Class II areas. For Class I areas the increments are about 2 - 5% of the ambient standards. If similar percentages were applied to the NO_2 standards, the impacts on power plant siting, size, and control technology choice could be great. For example, the NO_x emission from a 500 MW(e) coal-fired power plant satisfying new source performance standards would lead to concentrations which would exceed the increment by 50 percent. (1) We assume flat terrain and total conversion of NO_x to NO_2 in this calculation. Uneven terrain would lead to greater constraints, and relaxation of the total

conversion assumption would reduce the constraints a bit. The only way to satisfy the PSD regulations would be to construct very small coal-fired power plants with capacities less than about 300 MWe or to introduce controls which would reduce NO_x emissions beyond new source performance standards limits. The hypothesized Class I increments for NO_2 would require that 500 MWe power plants complying with new source performance standards be sited at least 100 km from Class I areas. Again smaller power plants or greater NO_x control could reduce the 100 km distance.

The Clean Air Act Amendments also provide for legislation to improve and minimize visibility impairment. Visibility regulations are imminent and could present significant constraints for power plants sited near Class I visibility areas. A relatively small amount of NO_2 in a power plant can lead to perceptible brownish coloration of the plume. In fact, preliminary results from the VISTA study undertaken jointly by EPA and several private groups, indicate that NO_2 is the most important contributor to plume coloration in the Southwest. (3) Visibility regulations will then certainly address NO_x emissions. According to one set of tentative criteria (4), a coal-fired power plant as small as 750 MWe may require flue gas treatment of NO_x if the

plant is sited in the visual range of the Class I visibility
area. (1) The visual range is 100 to 200 km in the West;
in the East it is from 15 to 50 km. (5)

There are two additional environmental concerns which
could lead to increased pressures for decreased NOx emissions.
The nitrogen oxides, along with hydrocarbons, are precursors to
ozone formation. Oxidant control in the past has relied heavily
upon hydrocarbon emissions control, but future controls may
also require additional NO_x limitations. This is of
particular concern in those 16% of U.S. counties which
violate the oxidant standard (6). These counties, in general,
are the sites of the major urban areas in the U.S. Power
plants upwind of these areas might anticipate demands for
increased NO_x control. In some places, such as California,
demands have already been formulated.

The acid rain problem is receiving a lot of attention,
and there is some public clamor to control acid rain. Because
nitrogen oxides may be responsible for up to 30 - 40% of
the acidity of rainfall in the Northeast U.S. (7), any
efforts to control acid rain will probably involve some
control of nitrogen oxide emissions from stationary sources.

All five of the planned and potential regulations can
have tremendous impacts upon the electric utility industry,
particularly in its planning of new plants. The regulations

will impact coal-burning power plants most, although synfuel
plants can also be significantly impacted. At a time when
nuclear power plants were more popular, the increased
restrictions and costs imposed by these regulations could
lead to a greater share for nuclear of new power plants.
Given the current mood, this is unlikely to happen. Alternative
coal types are not likely to influence NO_x emissions
significantly, but shale oil and coal liquid could yield
greater NO_x emissions than fuel oil. (1) Hence these
regulations could influence fuel choice and the demand for
shale oil and synthetic fuels. The regulations could lead
to smaller power plants as they may be allowed with existing
and inexpensive controls and they may be sited more easily.
If, however, a PSD increment for NO_2 is set as outlined above,
the maximum allowable power plant size, 300 MWe for a
coal-fired plant, may be too small for utility consideration.
Siting will also be impacted. New power plants can expect
to be sited further from Class I areas and probably further
from oxidant non-attainment areas.

Greater NO_x emissions control can allow power plants
to satisfy the above regulations without decreasing size
or siting flexibility. The potential PSD increments
could, however, even pose problems for larger power plants
using the most advanced available control technology.

The increased costs of the control technologies will be weighed against size and siting in planning new power plants.

There is another factor, however. The most advanced control technologies are new and largely untested. Before these new technologies are chosen, we must make sure that they do not introduce any new risks to the environment and that they satisfy regulations in addition to those which they are designed to help meet. Table 2 gives a partial list of those regulations which require compliance of new technologies with some minimal level of risk; moreover, there are concerns with some of the substances which have been mentioned in connection with the NO_x control technologies. The Clean Air Act Amendments under section 112 (NESHAP), for example, are concerned with airborne carcinogens including polycyclic organic materials (POM). It is unclear whether or not combustion modification leads to increased POM emissions. The Clean Water Act Amendments are concerned with ammonia and nitrosamines along with many other toxics. It is unclear as to which if any quantities of these substances may be released to the environment with selective catalytic reduction. The Occupational Health and Safety Act is concerned with the risk of occupational exposure to vanadium, a catalyst in selective catalytic reduction.

The risks associated with this use of vanadium have not

yet been estimated. The Hazardous Materials Transport

Act is concerned with the risk of transporting ammonia

as well as other substances. The risk of ammonia transport

associated with selective catalytic reduction is unknown.

Other legislative acts raise other concerns.

These examples illustrate the complexity of the current

regulatory environment and the necessity to consider a much

broader set of regulations than previously. This is

particularly true for the NO_x control technologies. Relatively

little experience is available at the operational level.

As these technologies are tested for efficacy of NO_x

control, they must also be examined to insure that they

do not introduce any new risks to the environment and that

they can comply with the entire regulatory spectrum. The

failure to identify and correct any deficiencies during

the development of the technologies can only lead to greater

costs and problems. The uncertainty attached to any new

technology must be weighed by utilities in deciding how to

comply with the new NO_x regulations. There is a price

attached to uncertainty. In this case one could imagine

technologies which may be obsolete before they are constructed

or the need to build one gismo on top of another à la Rube

Goldberg. Practices for the use of the technologies may have

to be altered as well. All of these will require more money,

lots of it. The result may be that utilities will give

more weight to siting solutions and smaller power plants
in the near term than they would have given in a simple
regulatory environment.

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TABLE 1: Power Plant Abilities to Satisfy a 1-hour NO_2 Standard of 0.25 ppm

Standard of 0.25 ppm, Power-plant* abilities to satisfy standard with a 1-hour NO_2

Power Plant Size	Maximum Concentration as % of Standard
500 MW(e)	40%
1000 MW(e)	80%
1500 MW(e)	120%

* coal-fired power plant satisfying New Source Performance Standards located in flat terrain

TABLE 2:   Partial List of Regulations Requiring
           Risk Assessment

o   Clean Air Act Amendments

-    NESHAP (National Emissions Standards for

     Hazardous Pollutants

o   Clean Water Act

o   Occupational Safety and Health Act

o   Hazardous Materials Transport Act

o   Resource Conservation and Recovery Act

o   Toxic Substances Control Act

o   Federal Railroad Safety Act

o   Ports/Waterways Safety Act

o   Safe Drinking Water Act

DEVELOPMENT AND REVISION OF AIR QUALITY STANDARDS
WITH SPECIAL ATTENTION TO THE NO_2 STANDARD REVIEW

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ABSTRACT

This paper describes the process for review of National Ambient Air Quality
Standards. Special attention is given to the issues facing the Environmental
Protection Agency in assessing the need for and nature of possible modifications
to the NO_2 ambient air quality standards. The legal requirements for the
Clean Air Act Amendments of 1977 are discussed as they apply to this review
and to the decision process in making a standard choice. The paper describes
not only the importance of the scientific basis for selecting a standard but
also the role of the policymaker and the judicial process. Criteria document
development, the scientific review process, the preliminary staff position
paper and the public review process are all described. Finally, the critical
elements in the upcoming NO_2 standard decision are identified and discussed.

INTRODUCTION

The development of National Ambient Air Quality Standards (NAAQS) is a step-by-step process followed by the Environmental Protection Agency (EPA) that includes: (1) the assessment of scientific information, (2) generation of a consensus within the scientific community on the veracity of this assessment, (3) an exchange of views and information with the public sector following proposal of a standard, and (4) promulgation and enforcement of a final rule. EPA's charter for this review process is the Clean Air Act and related amendments passed by the United States Congress. This paper reviews the requirements of this legislation, how the Agency has implemented these requirements, and a brief status update of the NO_2 standard review.

BACKGROUND

Seven National Ambient Air Quality Standards have been established under the provision of the Clean Air Act Amendments. Substances for which these standards have been set are presented in Table 1 and include carbon monoxide (CO), hydrocarbons (HC), lead (Pb), nitrogen dioxides (NO_2), sulfur oxides (SO_x), particulate matter (TSP), and ozone (O_3). All of these standards with the exception of ozone and lead were originally set in 1971. The 0.12 ppm ozone standard is the result of the 1978-79 review and revised the old 0.08 ppm oxidant standard, while the lead standard was promulgated in October 1978 after litigation brought against the Agency by the Natural Resources Defense Council.

Following promulgation of the original standards, a number of reviews of the air quality criteria were conducted by the National Academy of Sciences (NAS). For example, the NAS reviewed the basis for all of the standards for Congress in 1974, and another NAS study was prepared on the criteria for sulfur oxides for the Senate Committee on Public Works in 1975. EPA also contracted with NAS to review the scientific basis for each of the criteria pollutants, resulting in NAS reports completed in 1977 and 1978.

The NAS reviews found that there was insufficient new scientific information to justify changing the existing standards, although in several instances revisions to ambient air quality criteria were recommended.

LEGISLATIVE REQUIREMENTS

The goal of the Clean Air Act is to protect the public health and welfare and enhance the quality of the nation's air. Under the Act, the Federal government is responsible for establishing, on a nationwide basis, ambient air quality standards that are stringent enough to protect the public health with an adequate margin of safety. In order to provide for attainment of these standards, the States are responsible for specifying emission limitations and other programs for individual sources through State implementation plans (SIP's).

The first step in establishing an ambient air quality standard is a finding by the Administrator of the Environmental Protection Agency that a particular pollutant causes or contributes to air pollution which, in the words of the Act, "may reasonably be anticipated to endanger the public health or welfare." Within 12 months after the listing of a pollutant under section 108(a) of the Clean Air Act, the Administrator must publish an air quality criteria document which will form the scientific basis for the ambient air quality standard. The criteria document must contain the "latest scientific knowledge useful in indicating the kind and extent of all identifiable effects on public health or welfare."

Simultaneously with publication of the criteria document, the Administrator must propose primary and secondary national ambient air quality standards, as appropriate. A primary standard is one that, in the Administrator's judgment, is required to protect the public health with an adequate margin of safety. Costs of attainment are not a germane consideration in setting the primary standard, although such costs are to be considered in the development of SIP's. A secondary standard is one that adequately protects the public welfare. Public welfare is defined as including, but not limited to, effects on soils, water, crops, vegetation, man-made materials, animals, wildlife,weather, visibility, climate, damage to and deterioration of property, and hazards to transportation, as well as effects on economic values and on personal comfort and well-being. After providing a public

comment period and hearing, the Administrator is required to promulgate final standards; standards are usually promulgated within 6 months of his initial proposal.

The 1977 amendments require that all existing criteria documents be reviewed at 5-year intervals by a newly created Clean Air Scientific Advisory Committee (CASAC) of EPA's Science Advisory Board (SAB). An independent body made up of scientists and engineers with substantial scientific and technical expertise, the SAB is chartered by the Administrator to provide critical review of scientific matters before the Agency, as well as independent advice. (The SAB's authority to comment on draft criteria documents was statutorily established by the Environmental Research Development and Demonstration Authorization Act of 1978.) In addition to the establishment of the CASAC, section 109(d) of the 1977 Act further directed the Administrator to complete reviews of all existing standards and criteria before the end of 1980 and at no longer than 5-year intervals thereafter, and to revise the criteria and standards, as appropriate, based on those reviews.

Once an ambient standard is promulgated, responsibility under the Clean Air Act shifts from the Federal government to the States. Within 9 months after promulgation, each State is required to prepare and submit a State implementation plan (SIP) to EPA for approval. These SIP's must contain emission limitations and must describe all other measures necessary to attain the primary standard "as expeditiously as practicable" but not later than 3 years after EPA approval and to attain the secondary standard within a reasonable time.

CONSIDERATIONS IN ESTABLISHING AIR QUALITY STANDARDS

When the Agency undertakes either to establish or revise a standard, questions often arise concerning what the Administrator must consider in establishing a primary standard. Section 109(d) of the Clean Air Act requires that national primary ambient air quality standards be set at a level allowing for an adequate margin of safety, which the Administrator judges is adequate to protect the public health. The statute and legislative history[2] make it very clear that the standards are to be solely health based, designed

to protect the most sensitive group of citizens (but not necessarily the most sensitive members of that group) against adverse health effects. The task of deciding which health effects are adverse is a difficult one, and to accomplish it the Administrator must exercise his judgment as allowed by the Act in the investigation of the range of health effects of a pollutant and in the consideration of the risks disclosed by the investigation. In addition, the requirement of a margin of safety and the precautionary nature of the Act indicate that the standards must protect against uncertain, as well as certain, effects.

In the process of setting the primary standards, the Administrator must typically deal with two different kinds of issues: (1) which effects on a continuum of known effects should be regarded as adverse? and (2) what degree of additional protection is required to protect against uncertain harms--those not yet identified by research, or identified but not yet fully understood?

Any attempt to determine that level of pollutant exposure at which the effects are adverse to the sensitive population faces an immediate problem: investigation of the effects typically reveals that while there are levels above which "adverse effects" clearly exist, it is not generally possible to identify sharp "thresholds" for such effects. Rather, expanding scientific knowledge and better analytical techniques have made it clear that pollutant effects typically exist as a continuum, ranging from clearly serious health effects at high pollutant concentrations, to physiologically detectable effects of uncertain significance, to effects which are too subtle to measure.

Even though Congress was aware that there is no sharp "breakpoint" between a "no-effect" level and a level where the effect is clearly adverse, it still required that standards be set and that the standards be set at the point where there is no adverse effect for the sensitive population. The fact that health effects exist on a continuum creates a difficulty in identifying that level. In addition, the term "adverse" itself is difficult to define in the abstract. At different points in the continuum are levels of pollutants at which the effects will be conceded to be "adverse" by any given person. That point will vary, however, since medical judgments about what is "adverse" will vary with the information available to the

41

person and his or her viewpoint. In a given case, determination of what health effects are adverse may be as much an exercise of informed judgment as a factual injury.

In recognition of this, Congress in section 109(b)(1) of the Clean Air Act explicitly provided that the Administrator is to exercise his judgment in setting the standard. Though relying heavily on scientific advisors for technical evaluation of data and for those judgments that are essentially scientific in nature, the Administrator alone is responsible for considering risks and determining at what pollutant concentration the health effects on the sensitive population should be regarded as adverse. Medical experts may differ as to which particular health effects are adverse, but the statute gives the Administrator the responsibility of making that judgment.

RECENT SUPPORT FOR EPA'S APPROACH TO STANDARD SETTING

On the 27th of June 1980, the United States Court of Appeals, upheld the principal elements of EPA's standard-setting philosophy in its decision on the lead standard.[3] The court specifically supported EPA's contention that: (1) costs cannot be considered in selecting primary or secondary standards and, (2) the Administrator's authority and responsibility for making reasoned judgments in protecting public health in the face of incomplete or uncertain evidence. Two cites from the court decision amply verify this judgment.

Statutory Authority

"Furthermore, we agree with the Administrator that requiring EPA to wait until it can conclusively demonstrate that a particular effect is adverse to health before it acts is inconsistent with both the Act's precautionary and preventive orientation and the nature of the Administrator's statutory responsibilities. Congress provided that the Administrator is to use his judgment in setting air quality standards precisely to permit him to act in the face of uncertainty. As we read the statutory provisions and the legislative history, Congress directed the Administrator to err on the side of caution in making the necessary decisions. We see no reason why this court should put a gloss on Congress' scheme by requiring

42

the Administrator to show that there is a medical consensus that the effects on which the lead standards were based are 'clearly harmful to health'. All that is required by the statutory scheme is evidence in the record which substantiates his conclusions about the health effects on which the standards were based. Accordingly, we reject the Lead Industry Association's (LIA) claim that the Administrator exceeded his statutory authority and turn to LIA's challenge to the evidentiary basis for the Administrator's decisions."

Cost and Economics Role in Standard Setting

"The petitioners' first claim is that the Administrator exceeded his authority under the statute by promulgating a primary air quality standard for lead which is more stringent than is necessary to protect the public health because it is designed to protect the public against 'subclinical' effects which are not harmful to health. According to petitioners, Congress only authorized the Administrator to set primary air quality standards that are aimed at protecting the public against health effects which are known to be clearly harmful. They argue that Congress so limited the Administrator's authority because it was concerned that excessively stringent air quality standards could cause massive economic dislocation.

In developing this argument, St. Joe contends that EPA erred by refusing to consider the issues of economic and technological feasibility in setting the air quality standards for lead. St. Joe's claim that the Administrator should have considered these issues is based on the statutory provision directing him to allow an 'adequate margin of safety' in setting primary air quality standards. In St. Joe's view, the Administrator must consider the economic impact of the proposed standard on industry and the technological feasibility of compliance by emission sources in determining the appropriate allowance for a margin of safety. St. Joe argues that the Administrator abused his discretion by refusing to consider these factors in determining the appropriate margin of safety for the lead standards, and maintains that the lead air quality standards will have a disastrous economic impact on industrial sources of lead emissions.

This argument is totally without merit. St. Joe is unable to point to anything in either the language of the Act or its legislative history that offers any support for its claim that Congress, by specifying that

the Administrator is to allow an 'adequate margin of safety' in setting primary air quality standards, thereby required the Administrator to consider economic or technological feasibility. To the contrary, the statute and its legislative history make clear that economic considerations play no part in the promulgation of ambient air quality standards under Section 109."

This court decision would appear to lay to rest arguments questioning the role of economics in standard setting and the Administrator's responsibility in making choices under uncertainty.

STANDARD DEVELOPMENT PROCESS

Criteria Document

Figure I illustrates the various steps in the standard development process. The first step in the process is to review criteria, and develop a revised criteria document where appropriate. Main responsibility for production of the document rests with the Environmental Criteria and Assessment Office (ECAO/RTP) in EPA's Office of Research and Development (ORD). The first phase of the documentation process is to plan and initiate document preparation procedures. This phase includes assembling an internal EPA task force and recruiting outside experts as consultants to aid in writing the document. Together, these groups develop a work plan and define a schedule for production of the document.

The next step includes accumulating and analyzing literature and writing initial rough drafts of document chapters. Hard copies of every article cited are obtained and kept on file for public inspection at ECAO facilities. The actual writing of the drafts is carried out by ECAO staff, other EPA research scientists, or non-Agency consultants, depending upon the avialability of authors with the required expertise. These activities result in the production of an initial working draft of the document.

Following this phase, a workshop is held, where non-Agency experts meet with the document preparation team, which includes authors of the draft chapters, to provide preliminary peer review of the document contents and to assist in its revision. Post-workshop revisions lead to the production of a first external review draft of the document. This draft is circulated to

the public and CASAC for review and comment. The document is reviewed by CASAC at a public meeting.

Following the public review meeting, ECAO staff members undertake indepth cataloging of public and CASAC comments on the first external review draft. All comments from CASAC, the public, and other reviewers are passed on to the appropriate authors and are given consideration in revising the document. Each comment and its disposition is considered and entered into a docket, which is available for public inspection. Consideration of comments and appropriate revision of the document text result in a second external review draft.

The revised and reprinted draft is normally submitted to the public and the CASAC again for external review, and an effort is made to achieve final closure on the document with the CASAC. If no substantive critcisms are received as a result of this cycle of review or remain outstanding after this cycle, then the CASAC/SAB indicates, in a written report to the Administrator, that such is the case, confirming the CASAC's evaluation of the document as being of appropriate quality for use as the scientific basis for the related air standard.

STAFF PAPER

Once the criteria document has been reviewed by the public and the CASAC and the document is nearing its final form, the Agency staff prepares a paper, which evaluates the key studies in the criteria document and identifies critical elements to be considered in the review of the standard. The staff paper identifies those studies that the staff believes should be used in making the best scientific judgment on the level at which adverse effects signal a danger to public health in the sensitive population. In addition, the paper provides a discussion of the uncertainties in the medical evidence and of other factors that the staff believes should be considered in selecting an adequate margin of safety and a final standard level. In addition, the paper evaluates studies that the staff believes should be used in making the necessary scientific judgments on the level at which adverse effects signal a danger to public welfare. The paper does not present a judgment on what concentration level should be established for

45

the standard. The paper _does_ help bridge the gap between the science con-
tained in the criteria documents and the judgment required of the Administrator
in setting ambient standards.

The staff paper is reviewed externally by the public and the CASAC. A
public meeting is held with the CASAC to receive their comments and the
comments of the public. Once the paper has been reviewed by the CASAC, the
scientific judgments made in the paper form the basis for the staff's
recommendation to the Administrator on any revisions to the standard. Our
initial experience with the review of the CO staff paper[4] was extremely
good. The CASAC members were very positive in their comments, and they
found the paper to be an excellent vehicle for conveying the staff's view
of how studies presented in the criteria document should be used in setting
standards.

Assessing and interpreting the scientific evidence is a very complex
undertaking. For example, the CO criteria document contained over 200
references on the human health effects of CO. Reviewing these studies,
determining which are the most relevant to standard setting, and finally
interpreting the scientific evidence from the relevant studies are very
difficult and challenging tasks which the Agency must undertake each time
a standard is reviewed. This is even more difficult because there is often
considerable disagreement in the scientific community over how the studies
should be interpreted. The preparation of the staff paper and its review
by the public and the scientific community are our way of ensuring that the
staff's interpretation of the scientific evidence is sound and that the
Administrator has available to him a properly interpreted data base for his
decision making on air standards.

REGULATION DEVELOPMENT

The first general principle of the regulation development process is
the extensive and continuous participation by various EPA offices. Participatory
decision making continues to be important at EPA because systematic review by
offices other than the office with primary responsibility provides several
types of valuable input. Scientists and engineers check data and analyses;
lawyers check procedures, clarity, and consistency with the law; and other

program managers evaluate how proposed regulations would affect their programs. This process starts when the lead office, which has the responsibility for the standard, invites Assistant Administrators, the General Counsel, Regional Offices, and Staff Offices to send representatives to participate in a work group in developing a regulation.

The work group advises and assists the lead office in preparing a proposed regulation. The initial review of the regulation is by the Steering Committee. This committee is a continuing group representing the six Assistant Administrators' staff. Following Steering Committee reviews, proposed regulations are reviewed by all Assistant Administrators, General Counsel, and chief Staff Office directors. When consensus is not reached at a particular level, the disagreement is spelled out, and the matter is taken to a higher level for review. When consensus is reached on major issues at lower management levels, the lead office identifies for senior management the nature of the issue and the consensus that has been reached. As a result, final decisions remain with publicly responsible appointed officials at the top of the Agency.

The Agency also places a high priority on public participation in our standard review process. EPA has provided for public and scientific review of our criteria documents and staff papers. Ample public review is provided for during rulemaking under section 307(d) of the Clean Air Act, as added by the 1977 Amendments, including establishment of a public docket, provision for a public hearing, and an opportunity to submit written comments. The final regulation includes the Agency's response to the public comments.

The Agency process has worked extremely well in practice and was used as the model for regulatory reform as presented in Executive Order 12044. The process ensures both outside public review and top Agency management review during the standard development process. The result has been an open and objective decision-making process that gives consideration to opposings viewpoints.

At this stage of the NO$_2$ standard review process, EPA has completed a draft criteria document that covers concerns for both a short and a long-term air quality standard. The document is currently undergoing review by the CASAC and is expected to receive a favorable endorsement from that group. A meeting will be held with the CASAC group to discuss not only the veracity of the criteria document but also EPA's preliminary ideas on how the scientific evidence will be used in making a decision on NO$_2$ standards.

To provide insight into how this process may progress, Tables 2 and 3 are included as a representation of the critical studies expected to play a major role in selecting the standard. As can be seen from Table 2, clinical studies report a variety of effects at concentrations ranging from 0.1 ppm to 2.5 ppm. These effects include subtle responses such as elevated reaction to a bronchial constrictor agent at 0.1 ppm to significant and measurable pulmonary function decrements in the range 0.7 to 2.0 ppm. Other responses such as symptomatic effects and slight pulmonary function impairment have been observed at intermediate concentrations. A decision which has yet to be made by EPA, is just what level of response and associated concentration, should be considered as an indicator of an adverse health effect. EPA is soliciting counsel on this issue from the CASAC and from the public and other interested parties.

A second series of studies which will bear on the standard decision are the so-called "gas stove studies." These studies seem to indicate that young children suffer an elevation in the frequency of respiratory illness at NO$_2$ concentrations of about 0.4 to 0.6 ppm. Unfortunately, a key piece of information is missing from the gas stove studies, in that the exact air quality distributions are unknown. It is not clear whether the 0.4 - 0.6 peak concentrations are for very short (minutes) periods of time, or for longer periods (hours). It is also uncertain whether the observed response is due to a single peak concentration, to several peak concentrations, or to the long-term chronic exposure over a several-month period. Some evidence does

48

exist, however, from animal studies, that it is the repeated short-term peak concentrations that are most responsible for the reported insult.

A third area of major concern are the animal studies reporting a decreased resistance to disease at NO_2 concentrations of 0.5 ppm and above. These studies are, in turn, supported by other animal work showing less pronounced effects at considerably lower concentrations. These effects, such as destruction of lung tissue are considered by some investigators, precursors to the elevated disease levels shown at higher concentrations. Just how EPA will use these studies in arriving at a final standard decision, will not be decided until after discussions with the CASAC and after there has been an opportunity to receive public input on this important issue.

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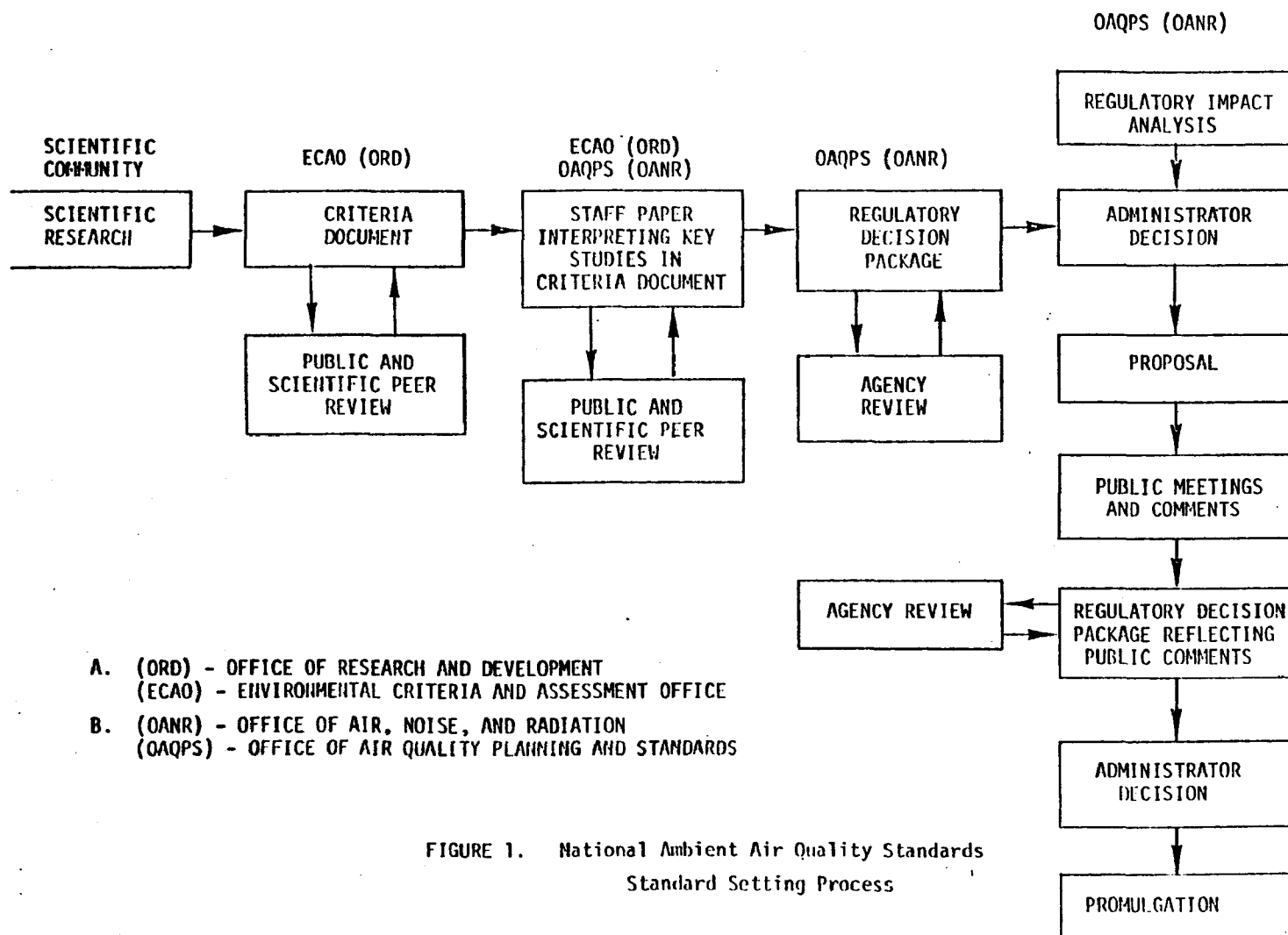   1979.)

OAQPS (OANR)

| SCIENTIFIC COMMUNITY | ECAO (ORD) | ECAO (ORD) OAQPS (OANR) | OAQPS (OANR) | |

REGULATORY IMPACT ANALYSIS

SCIENTIFIC RESEARCH → CRITERIA DOCUMENT → STAFF PAPER INTERPRETING KEY STUDIES IN CRITERIA DOCUMENT → REGULATORY DECISION PACKAGE → ADMINISTRATOR DECISION

PUBLIC AND SCIENTIFIC PEER REVIEW

PUBLIC AND SCIENTIFIC PEER REVIEW

AGENCY REVIEW

PROPOSAL

PUBLIC MEETINGS AND COMMENTS

AGENCY REVIEW ← REGULATORY DECISION PACKAGE REFLECTING PUBLIC COMMENTS

ADMINISTRATOR DECISION

PROMULGATION

A. (ORD) - OFFICE OF RESEARCH AND DEVELOPMENT
   (ECAO) - ENVIRONMENTAL CRITERIA AND ASSESSMENT OFFICE

B. (OANR) - OFFICE OF AIR, NOISE, AND RADIATION
   (OAQPS) - OFFICE OF AIR QUALITY PLANNING AND STANDARDS

FIGURE 1.   National Ambient Air Quality Standards
                    Standard Setting Process

51

TABLE 1. NATIONAL AMBIENT AIR QUALITY STANDARDS

Pollutant	Primary Standards	Averaging Time	Secondary Standards
Carbon monoxide	10 g/m^3 40 g/m^3	8-hour[a] 1-hour[a]	Same as primary
Hydrocarbons (Non-methane)	160 µg/m^3	3-hour[a] (6 to 9 a.m.)	Same as primary
Lead	1.5 µg/m^3	Quarterly average	Same as primary
Nitrogen oxides	100 µg/m^3	Annual (arithmetic mean)	Same as primary
Particulate Matter (TSP)	75 µg/m^3 260 µg/m^3	Annual (geometric mean) 24-hour[a]	60 µg/m^3 [b] 150 µg/m^3
Ozone	235 µg/m^3	1-hour[c]	Same as primary
Sulfur oxides	80 µg/m^3 365 µg/m^3 ---	Annual (arithmetic mean) 24-hour[a] 3-hour[a]	--- --- 1300 µg/m^3

[a] Not to be exceeded more than once per year.

[b] Guide to achieving the 24-hour standard.

[c] The standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above 235 µg/m^3 is equal to or less than 1.

52

TABLE II. KEY STUDIES

Compilation of Effects Reported in Selected Human Studies Examining Nitrogen Dioxide Exposures

NO_2 Concentration, ppm	Exposure Durations	Study Population	Reported Effect(s)*	References
0.1	1 hr.	20 asthmatics	Effect of bronchoconstriction enhanced after exposure to NO_2 in 13 of 20 subjects. Neither effect observed in 7 of 20 subjects. A bronchoconstrictor (carbachol) was used.	Orehek, 1976
0.5	2 hrs.	10 healthy adults 7 chronic bronchitics 13 asthmatics	1 healthy and 1 bronchitic subject reported slight nasal discharge. 7 asthmatics reported mild symptomatic effects. Bronchitics and asthmatics showed no statistically significant changes for all pulmonary functions tested when analyzed as separate groups, however small, but statistically significant changes in quasistatic compliance were found when analyzed as a single group.	Kerr, et al., 1979
0.5 to 5.0	approx. 15 min.	63 chronic bronchitics	Significant increase in airway resistance at or above 1.6 ppm	Von Nieding et al. 1971
0.6	2 hrs.	15 healthy exercising adults	No physiologically significant changes in cardiovascular, metabolic, or pulmonary function after 15, 30, or 60 minutes of exercise.	Folinsbee et al., 1978
0.7 to 2.0	10 mins.	10 healthy adults	Increased inspiratory and expiratory flow resistance of approximately 50% and 10% of control values measured 10 mins. after exposure.	Suzuki and Ishikawa, 1965
1.0	2 hrs.	16 healthy adults	No statistically significant changes in pulmonary function tests with exception of small changes in forced vital capacity (1.5% mean decrease; $p < .05$). Respiratory symptoms slightly increased after exposure to NO_2, but change not statistically significant compared to controls.	Hackney, 1978
1.0 and 2.5	2 hrs.	8 healthy adults	Increase in airway resistance at 2.5 ppm but not at 1.0 ppm	Beil and Ulmer, 1976
1.0 to 2.0	2½ hrs.	10 healthy adults	Alternating exercise and rest produced significant decrease for hemoglobin, hematocrit, and erythrocyte acetycholinesterase.	Posin, et.al., 1978

TABLE III. COMPILATION OF REPORTED EFFECTS ASSOCIATED WITH EXPOSURE TO NITROGEN DIOXIDE
IN THE HOME IN COMMUNITY STUDIES INVOLVING GAS STOVES

Concentration[a] (ppm)	Study Population	Reported Effects	Reference(s)
Frequent peaks 0.4-0.6 (gas), maximum peak 1.0 (gas), 95th percentile 24 hr avg in activity room 0.02-0.06 (gas) 0.01-0.05 (elec)	8,120 children, ages 6-10, 6 different cities, data also collected on history of illness before age 2	Significant association between history of serious respiratory illness before age 2 and use of gas stoves. Small but statistically significant decreases in pulmonary function (FEV_1 and FVC) in children from gas stove homes.	Speizer et al., 1980
NO_2 not measured at time of study	2,554 children from homes using gas to cook compared to 3,204 children from homes using electricity, ages 6-11	Bronchitis, day or night cough, morning cough, cold going to chest, wheeze, and asthma increased in homes with gas stoves	Melia, et al., 1977
NO_2 not measured in same homes studied	4,827 children, ages 5-10	Higher incidence of respiratory symptoms and disease associated with gas stoves	Melia, et al., 1979
Kitchens: .005-0.317 (gas) .006-0.188 (elec) Bedrooms: 0.004-0.169 (gas) 0.003-0.037 (elec)	808, ages 6-7	Higher incidence of respiratory illness in gas-stove homes	Florey, et al. 1979 Companion papers to Melia et al., 1979; Goldstein et al., 1979
Sample of Households 24 hr avg 0.005-0.11 (gas) 0-0.06 (elec) 0.015-0.05 (outdoors)	128 children, ages 0-5 346 children, ages 6-10 421 children, ages 11-15	No significant difference in reported respiratory illness between homes with gas and electric stoves in children from birth to 12 years old	Mitchell et al., 1974 See also Keller et al., 1979
Peak hourly 0.25-0.50 (gas), max hr 1.0 (gas)	Housewives cooking with gas stoves compared to those cooking with electric stoves.	No increase in respiratory illness	U.S. EPA, 1976
24 hr avg 0.005-0.11 (gas) 0-0.06 (elec) 0.015-0.05 (outdoors)	Housewives cooking with gas stoves, compared to those cooking with electric stoves. 146 households	No evidence that cooking with gas is associated with increase in respiratory disease	Keller, et al. 1979
See above for monitoring data	Members of 441 households	No significant difference in reported respiratory illness among adults in gas vs electric cooking homes	Mitchell, et al., 1974 See also Keller et al., 1979

[a]Exposures in gas stove homes were to NO_2 plus other gas combustion products.

54

ACID RAIN ISSUES

By:

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ABSTRACT

The U.S. Environmental Protection Agency (EPA) is concerned about the effects of acid rain because the acidity of precipitation falling on the U.S., Canada, and Scandinavia has been increasing for the past two decades. An annual average precipitation of pH of 4.0 to 4.5 is not uncommon in the eastern U.S., southeastern Canada, and western Europe.

Acid rain also has become more widespread in the past twenty years. Once confined to urban and industrial areas, the effects of acid rain are now being experienced in places as remote from industry as northern Minnesota and Florida.

Although all the consequences of acid deposition are not well understood, a growing body of evidence suggests that acid rain is responsible for substantial adverse environmental effects. These include the acidification of lakes, rivers and groundwaters, injury to aquatic species, acidification and demineralization of soils, reduction of forest productivity, damage to crops, and deterioration of buildings and man-made materials. In addition, the effects of acid rain on metallic elements in soil, aquatic ecosystems, and drinking water systems may affect human health adversely.

Current EPA authority generally focuses on control of the groundlevel concentrations of the precursor pollutants of acid rain. Control of these concentrations will not necessarily impact the level of acid rain which is more a function of the total precursors emitted into the air in a region over an extended period of time.

In order to reduce SO_2 and NO_x emissions, EPA in cooperation with the Department of Energy, is evaluating alternative emissions reductions strategies. These strategies focus primarily on utility and industrial boilers.

(Paper not submitted for Proceedings)

STATE OF CALIFORNIA PERSPECTIVE
ON NO$_x$ CONTROL FOR STATIONARY SOURCES

By:

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57

ABSTRACT

The California NOx control program is directed toward the achievement and maintenance of air quality standards not only for nitrogen dioxide, but also for ozone, total suspended particulate and visibility. In addition to stringent controls on mobile sources, controls on existing stationary sources and best available control technology (BACT) on new sources are needed in non-attainment areas. In these non-attainment areas, the state is encouraging local districts to adopt controls on refinery boilers and heaters, industrial boilers, gas turbines, stationary I.C. engines, glass plants and cement plants, in addition to existing controls on power plants. The state considers selective catalytic reduction (SCR) to be BACT for most natural gas and oil fired combustion sources, and that (SCR) will be BACT for coal-fired power plants. We also believe that combustion modification techniques can be improved so that SCR may be unnessary on some sources.

If this meeting had been held in Los Angeles instead of the

beautiful City of Denver, most of you who live outside of Los

Angeles would probably have wondered to themselves whether or not

it would be smoggy in Los Angeles during the meeting. Furthermore,

those of you who work at reducing air pollution would probably have

the feeling that you are doing something to reduce the smog

problem.

Los Angeles and other California cities have severe air pollution

problems. I want to talk to you today about that air quality

problem and what the California State Government is doing about

it.

The federal annual average air quality standard for nitrogen

dioxide of 100 micrograms per cubic meter or 0.053 part per

million has been violated for many years in the South Coast Air

Basin or as it is otherwise known the Los Angeles Metropolitan

Air Quality Control Region. The State of California one hour

standard for nitrogen dioxide of 0.25 part per million is also

violated in the South Coast Air Basin. In Kern County, in

California, ambient concentrations of nitrogen dioxide have also

been steadily increasing and almost approaching the air quality
standards for nitrogen dioxide as a result of the installation
of many hundreds of steam generators used to produce heavy oil
by steam injection into the reservoir.

As most of you probably know, oxides of nitrogen also participate
in the photochemical process which produces oxidants, among which
is ozone. The ozone standard is widely violated in many areas in
California, particularly in the South Coast Air Basin. While it
is generally considered that control of emissions of hydrocarbons
are necessary to achieve the ozone standard, it can also be shown
that control of emissions of oxides of nitrogen can result in
reduction in ozone concentrations under some circumstances and
particularly in rural areas.

Oxides of nitrogen are also converted, in part, to nitrates in the
atmosphere and form one of the constituents of total suspended
particulate. This is generally known as secondary particulate.
In the South Coast Air Basin, and in most urban areas, conversion
of sulfur oxides, oxides of nitrogen and hydrocarbons to particulate
accounts for a major part of the total suspended particulate. The
federal and state annual average and 24-hour standards for total
suspended particulate are also widely violated in many areas
particularly in the South Coast Air Basin and other urban centers.

Achievement of the standards for TSP could not be made unless the precursors of the secondary particulate portion of the total TSP were controlled. For this reason, we believe that NOx control is necessary to achieve the TSP standards, particularly in urban areas.

The secondary particulate is very effective in reducing visibility since the particles are close to the light scattering size range. Therefore, NOx control is one of the essential steps that must be taken in order to improve visibility.

In California, the program to control NOx is separated into two elements: mobile source control and stationary source control. The California Air Resources Board has the primary responsibility for controlling emissions from mobile sources and the local air pollution control districts have the primary responsibility for controlling emissions from stationary sources. However, the Air Resources Board is required by law to ensure that the local air pollution control districts adopt and enforce measures needed to achieve the state and federal air quality standards. If the local air pollution control districts do not adopt such regulations, the Air Resources Board is empowered to adopt the necessary regulations for the local districts.

The Clean Air Act provides that the State of California can receive a waiver from the EPA vehicular emissions standards to adopt more stringent standards. The Air Resources Board has adopted more stringent standards for NOx emissions than has EPA. However, our ability to reduce NOx emissions further from vehicular sources has just about reached its limit, given the state of the art. To achieve the ambient air quality standards, it will be necessary to further reduce emissions from existing stationary sources and to require offsets for emissions from new stationary sources.

All of the air pollution control districts in which the large coastal, ocean water cooled power plants are located have adopted regulations to limit emissions of oxides of nitrogen from power plants to 225 ppm when burning oil and 125 ppm when burning natural gas. There is some variation from these levels, particularly for smaller power plants. In addition, in the South Coast Air Quality Management District emissions from large industrial boilers are also limited to 225 ppm when burning oil or coal and 125 ppm when burning natural gas. Of particular importance to utilities in the South Coast Air Basin, a regulation has been adopted which requires further reduction in power plant NOx emissions.

This rule, which is presently stayed and will be reconsidered at a hearing at Los Angeles next month, introduces the new concept of setting limits on total system-wide emissions in the air basin,

rather than setting limits on emissions from individual units. This concept, which is similar to EPA's bubble concept, allows a utility to reduce emissions at the lowest cost. The rule, which is probably the most stringent in the United States, requires a 90 percent reduction in total system-wide emissions from levels that would have occurred if all of the units had been burning oil. This reduction must be achieved by 1988 or 1990, depending on the option chosen. It also requires the two large utilities, Southern California Edison and the Los Angeles Department of Water and Power, to demonstrate by the end of 1982, on the equivalent of 100 megawatts or more of capacity, equipment designed to achieve a ninety percent reduction in NOx emissions. To comply with that requirement, Southern California Edison plans to start installing selective catalyic reduction equipment soon to treat one half of the flue gas stream on a 215 megawatt unit at its Huntington Beach plant. A paper to be delivered at this meeting will discuss that install-ation.

The rule contains four options for compliance. The first two options have two stages of reduction. The first option requires about a 50 percent reduction from oil burning emission levels by the end of 1983, and a 90 percent reduction by 1990. The second option requires about a 40 percent reduction from oil

63

burning emission levels by the end of 1983, and a 90 percent
reduction by 1988. The third option, which was basically proposed
by the Los Angeles Department of Water and Power, has a single
stage of reduction, 90 percent by 1990.

The fourth option, which was basically proposed by the Southern
California Edison Company requires an evenly stepped reduction
in annual average emissions each year until 90 percent is achieved
in 1990 plus a 75 percent reduction in peak emissions. The last
two options require installation of controls as early as feasible.
All of these options allow the reduction in emissions by any method,
including reduced burning of natural gas and fuel oil. For example,
if a nuclear power plant were brought on line, it would be considered
as replacing oil and gas burning and therefore, would be a way of
reducing NOx emissions. However, it is anticipated that selective
catalytic reduction will be required on some units to meet the final
requirements of the rule. We believe that selective catalytic
reduction is a proven method of controlling NOx.

In Kern County, where I previously mentioned the increasing
concentrations of nitrogen dioxide, a rule has been adopted which
limits emissions of oxides of nitrogen from oil field steam gener-
ators. That rule has several innovative features. Firstly, it
has three stages or levels of control. The first stage of 0.3
pound of NOx per million Btu of heat input must be met by July 1,

1982. The second stage of 0.25 pound of NOx per million Btu of heat input is only applicable if the ambient concentration of nitrogen dioxide reaches 0.20 ppm on a one-hour average or 0.045 parts per million on an annual average. The third stage of 0.14 pound of NOx per million Btu of heat input is only applicable if the ambient concentration of nitrogen dioxide reaches 0.25 parts per million on a one-hour average or 0.053 parts per million on an annual average. If the second and third stages are not triggered by air quality changes, emissions reductions made to meet the first stage of the rule can be banked and used as offsets. Furthermore, emissions may be averaged over the central or the western areas of the county such that the total emissions from all existing steam generators shall be no more than if each steam generator were in exact compliance with the rule. It is expected that the first and second stages of the rule can be achieved by the use of combustion modifications. The oil companies and the burner manufacturers have been taking aggressive steps to develop means to comply with this rule. In particular, North American Manufacturing, the supplier of most of the burners used in the steam generators in Kern County, has developed a combustion modification which results in reduction of NOx to well below the requirements of the first and second stages of the rule. The North American combustion modification package is being tested on three separate steam generators, one

each at three large oil producers. The cost of the control package

has been reported to be less than $35,000. At the current oil

prices, the saving in the cost of fuel in two years would be more

than the cost of the equipment. Also, it is our information that

more than 100 units are on order. If the third stage of the rule

is triggered by an air quality change, it is anticipated that unless

further reductions are achieved with combustion modifications,

Thermal DeNOx may be required on some steam generators in order to

comply with the emissions limit of 0.14 pound per million Btu of

heat input.

Concern has been expressed that the use of low NOx burners and

Thermal DeNOx in tandem may result in problems of: 1) the temper-

ature in the transition section of the boiler changing because

of the reduced excess air requirements of the low NOx burner and

2) the emitting of a blue plume because of the formation of

ammonium sulfate in the scrubber. To investigate these problems,

Getty Oil Company is conducting a year-long experiment on a 50

million Btu per hour scrubber-equipped steam generator which will

be equipped with a low NOx burner and Thermal DeNOx.

To effect further NOx reductions required to meet the air quality

standards, the Air Resources Board is working with local air

pollution control districts for measures to control emissions

from refinery boilers and heaters, industrial boilers, utility

gas turbines, internal combustion engines, glass plants and cement kilns. For refinery heaters we are looking at a limit of about 0.06 pound of NOx per million Btu of heat input, which is a reduction of about 50 percent. We expect that the limit for existing refinery and industrial boilers will be about 0.1 pound of NOx per million Btu of heat input. We believe that such levels can be achieved by the use of combustion modification techniques. For utility gas turbines, we believe limits of 0.18 to 0.28 µg/Joule (25 to 40 ppm) could be achieved by the use of water injection but in the long range we anticipate that catalytic combustion will be developed so that NOx can be controlled to very low levels. For internal combustion engines, we have proposed a limit of 0.75 grams per horsepower hour, a limit which would probably require SCR or other catalytic means. Our investigations indicate that NOx can be reduced from glass plants by modification of combustion additional electric boost, new furnace designs and flue gas treatment including Thermal DeNOx, SCR and potentially wet scrubbing. It is anticipated that either singularly or in combination, these control techniques will enable the Glass Industry to control NOx emissions by 60 to 70 percent from uncontrolled levels. Work on development of measures to control NOx emissions from cement kilns has just begun with a workshop being held on October 8 in Los Angeles.

67

Major new sources in non-attainment areas are required to use Best Available Control Technology to control NOx and in addition to offset any emissions by reducing emissions from other existing facilities. In our opinion, SCR is well proven for natural gas and oil fired boilers and heaters.

Except for an 830 million Btu per hour heat input boiler operated by Kerr McGee, there are no coal-fired power plants in California. To meet future requirements, Pacific Gas & Electric Company has proposed the construction of two 800 megawatt coal-fired units in Northern California. In addition, Southern California Edison and others have proposed the construction of three 500 megawatt coal-fired units in Southern California. We are pressing for the installation of selective catalytic reduction on these units. We believe that by the time these units go into operation in the late eighties, SCR will have been proven on coal-fired power plants in Japan.

As you can see, we have a very aggressive NOx emission control program in California, probably the most aggressive in the nation. Many of you may feel that we are expecting too much, but history has shown us that industry can rise to meet the challenge of stringent regulations. We are deeply appreciative to those of you here who have designed and developed ways to reduce emissions of oxides of nitrogen and other pollutants and those of you in industry who have led the way to get these methods or devices proven in practical operations. We still need your help. There is a lot to be done. Thank you for your attention.

FOSSIL STEAM GENERATOR NO$_x$ CONTROL UPDATE

By:

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ABSTRACT

Since the Second NO_X Control Seminar of 1978, much additional information has been collected concerning actual NO_X emissions from fossil fuel power plants equipped with B&W Dual Register Burners/Compartmented Windbox furnace systems for a wide range of both bituminous and subbituminous coals. These field results from actual units firing coal, oil and/or gas have demonstrated NO_X reductions of up to 60 percent compared to units without NO_X control. This presentation will show our controlled NO_X emission level experience and the present status of B&W's advanced NO_X control systems to meet the more restrictive NO_X emission levels expected in the future.

ACKNOWLEDGEMENTS

The 1971 federal New Source Performance Standards limited NO_x emissions for most fossil fuels for the first time. Prior to the federal controls, local air quality districts had established emission limitations in polluted areas. For example, Babcock & Wilcox instituted a NO_x reduction program in 1957 at the request of utilities firing gas and oil fuels in the south coast air quality district. The program led to successful application of two-stage combustion and a patent granted to B&W in 1959 for the process. This early work was followed by the selective use of gas recirculation to the burner to reduce peak flame temperatures and further reduce NO_x emissions. These approaches were successfully retrofitted to the larger California units in the late 1960s and early 1970s, resulting in up to 60 percent NO_x emission reduction.

In 1970, extensive work commenced on the development and application of a combustion system to limit NO_x emissions while firing pulverized coal. Previous to the New Source Performance Standards, our mission as designers was to maximize turbulence in the combustion zone, which would optimize carbon utilization and, thereby, reduce the furnace residence time required to obtain acceptable carbon utilization. Such an approach resulted in extremely high input burner zones, small furnaces with high heat release rates, and the application of our turbulent cell burner. This optimized combustion system successfully obtained the goal of maximum carbon utilization and, unfortunately, generated high levels of nitrogen oxide emissions. The kinetics involving the air/nitrogen to NO_x transformations were understood well enough from our gas and oil experience to provide direction in developing a new combustion system that would limit free oxygen available in the flame zone and reduce peak flame temperatures.

Our thoretical combustion model indicated what we wanted to achieve in a burner design to inhibit NO_x formation and at the same time continue to maximize carbon utilization. We postulated that a fuel rich jet mixing with secondary air at a controlled rate would reduce the peak flame temperature and control the oxygen availability. This model was utilized to develop the Dual Register Burner. The hardware development of that concept indicated that a spreader device of some type was required to maintain homogenous particle distribution and avoid pitfalls similar to those encountered in operation without impellers. Also required was some means of balancing coal line pressure drop variations caused by different

lengths of coal pipes being fed by the same pulverizer.

The mixing device selected initially was the venturi. While subjected to erosion, the venturi was not subjected to high temperatures and therefore would not coke or fall off. The overall primary air/fuel flow to each burner was maintained by a permanent, calibrated orifice located in each coal line between the pulverizer and the burners. The orifices were sized to equalize the calculated line pressure drops for the various coal pipe lengths from each mill.

The remaining combustion air (secondary air) was introduced through two concentric air zones which surround the coal nozzle. The air flow to each air zone was independently controlled through an outer air zone register and inner air sleeve.

In addition to a mixing device (venturi diffuse) to obtain proper particle distribution, some means had to be provided on the air side to control the flame front location. Spin vanes were added to the inner air zone to control axial/tangential secondary air velocity. The optimum vane position was found to be a function of the fuel being fired.

These two additions to the model resulted in the "Dual Register Pulverized-Coal Burner" (Figure 1).

By controlling the mixing of coal and air in a Dual Register Burner, the combustion process can be initiated at the burner throat and the zone of completion can be varied in the furnace chamber. This method of delayed combustion reduces combustion intensity and acts to reduce peak flame temperatures at each burner. Thus, the peak temperature in the furnace is lowered, minimizing the thermal conversion of combustion air nitrogen to NO_x. In addition, a larger percentage of the furnace zone water-cooled surface is utilized during the combustion process to further lower the peak temperature in the flame. Finally, through controlled fuel and air mixing, the oxygen availability is minimized during the process, thereby reducing fuel nitrogen conversion.

72

The Dual Register Burner lowers NO_X by delaying combustion, not by staging. Previous work on pulverized-coal firing has shown that two-stage combustion is an effective method for NO_X reduction.[1] However, in reviewing overall unit performance, the Dual Register Burner has the following benefits over staging techniques:

1. The furnace is maintained in an oxidizing environment to minimize slagging and reduce the potential for furnace wall corrosion when burning high sulfur bituminous coals.

2. More complete carbon utilization occurs through better air/coal mixing in the furnace.

3. Lower oxygen levels are required when total combustion air is admitted through the burners rather than above the burner zone.

RETROFIT

A retrofit system for the E. C. Gaston plant, Southern Electric Generating Company, demonstrated NO_X reductions of up to 50 percent, unstaged, compared to levels obtained with the high turbulence circular burners which were replaced. The correlation of heat available per square foot of adjusted burner zone surface, which had been developed and utilized for commercial commitments on gas and oil fuels, has been utilized for coal with good results. In fact, the prediction curves generated by our NO_X experiments on the retrofit at the E. C. Gaston unit provide the basis upon which all NO_X emission guarantees were granted. Initial retrofit data obtained in 1972, and retested in 1974 and 1976, provided the only projection of expected NO_X emissions with the new burner until units equipped with the new system actually went into commercial operation. The first of these New Source Performance Standards designs was declared commercial late in 1975, the second and third in 1976, and at present we have 26 operating pulverized-coal-fired units that were sold to meet the New Source Performance Standards. Data obtained from 24 units tested correlate extremely well with the projections generated by the Dual Register Burner retrofit at the Gaston plant. Presently, we have 1800 burner years of experience with the Dual Register Burner system. Modifications have been made to improve primary air/coal mixing and decrease pressure drop in the primary air system, improve the operability of the spin vanes, and change the manner in which

inner air is introduced from a swirl type assembly to a streamline sleeve type
assembly. These functional improvements have been field tested both in test
tunnels and in actual operating units and indicate a further gain in stability
and NO_x reduction. Presently, 14,237 MW of New Source Performance Standard
coal units supplied by Babcock & Wilcox are in service. Most of these units
have been fitted with a complete combustion system for low NO_x, including the
Dual Register Burner, the Compartmented Windbox and larger furnaces (Figure 2).

PRESENT PRACTICE

The 1979 New Source Performance Standards promulgated on June 11, 1980, further
reduced NO_x emissions requirements for bituminous coal to 0.6 lbs of NO_x per
million Btu input and for subbituminous coal to 0.5 lbs of NO_2 per million Btu
input. In addition, most of the synthetic fuels coming from coal are limited
to 0.5 lbs NO_x per million Btu input. These new reduced levels and the proposed
research goals for 1985 implementation pose new challenges for the designers,
manufacturers, and suppliers of low NO_x combustion systems. Figure 3 indicates
the NO_x emissions measured on all of our bituminous-fired steam generators
tested which were equipped with the low NO_x combustion system and indicates
how their emissions relate to the New Source Performance Standards of 1979.
The majority of units are meeting the new 0.6 level even though they were
designed to meet the old 0.7 level. However, new designs must be developed to
provide some operating margin between the regulated limit of NO_x emissions and
the actual expected level of NO_x emissions and insure that some operational
flexibility is available. Figure 4 indicates our experience with units equipped
to meet New Source Performance Standards while firing subbituminous coal and
compares those levels to the new regulations. In all cases except one, units
designed to meet the 0.7 former standard are meeting or exceeding the new
standard of 0.5. The one exception, operating at high levels of excess air,
does exceed the design standard of 0.7. We anticipate a further tightening of
the subbituminous New Source Performance Standards and, once again, are developing
systems to further reduce NO_x emissions on these fuels.

74

FUTURE WORK

Previous efforts successfully resulted in NO_X reductions of 50 percent from uncontrolled emission levels. Future development (Figure 5) currently under way is expected to result in 85 percent reductions in NO_X emissions from uncontrolled levels. The most developed of these systems, the Low NO_X Combustor (LNCS), conceived by B&W and funded jointly by EPRI and B&W, is a first step in the second generation combustion modification approach to NO_X reduction. The LNCS is a deep staging approach with stoichiometry held at the 65 to 75 percent range in the flame zone. The industry has been and will continue to be concerned with applying two-stage concepts to pulverized-coal containing high iron and greater than 2 percent sulfur levels.[2] Concern within B&W is based upon many years of witnessing uncontrolled furnace corrosion resulting from localized reducing atmospheres. Our position is that coals with high iron and sulfur are not suitable for classical two-stage combustion in the generally accepted method where a portion of the secondary furnace is subjected to reducing conditions and, thereby, potential corrosion. The LNCS approach is to isolate the reducing zone in small, controlled primary furnaces that could be either separately cooled to maintain low metal temperatures, made of a more corrosion resistant material, or designed to be replaceable. During the Second EPRI NO_X Control Technology Seminar in 1978, we reported[1] on results of the LNCS 4 million Btu Model. Now, the results of the 50 million Btu LNCS prototype are available. Model and prototype data correlate, and the feasibility study, now being finalized, will be submitted to EPRI at the end of October. One result reported in the feasibility analysis is that the total surface area required for heat transfer on the small individual primary furnaces, when added together, exceeded 30 percent of the total furnace surface area. Thus, the reducing zone isolation approach taken initially looses validity and an alternative approach has been substituted. The venturi furnace (Figure 6) is the present application of the Low NO_X Combustor concept. Advantages of that embodiment are that the components (such as ducts, windboxes, etc.), are all standard components, and the circulation system is standard. We can continue with known designs, such as the Dual Register Burner system, simply modified for adaptation into the LNCS. The next step in this development is to locate a field retrofit and obtain the associated external funding to cover the costs.

Our next step in low NO_X combustion modification development work would be the coupling of the "planetary burner concept," advanced by Babcock-Hitachi K.K. under CRIEPI funding, within the B&W LNCS. The overall stoichiometry of the combined concept is limited to approximately 70 percent in the primary furnace, but individual burner level stoichiometry is varied to achieve the planetary concept.[4]

The lowest rows of burners would operate at a stoichiometry of 0.8 to 0.85; the highest row of fuel input nozzles would operate at less than 0.50. The flames of the relatively fuel-lean lower levels pass through the extremely fuel-ruch reducing flame. Laboratory-scale demonstrations have indicated that NO_X formed in the lowest zone is decomposed as it passes through the reducing zone, with radical products such as NH, CH present reduced to N_2, CO_2, and H_2O. Above the primary combustion furnace, the secondary air ports increase stoichiometry to the 117 to 120 percent range required for total combustion of the fuel. This approach is similar to work reported by M. Heap, L. Muzio, and J. Beer, on char and fuel rich flame reduction.[5] Our emission goal for joining these two concepts is 110 ppm on coal. That combined concept has been tested recently on a full size utility unit located in New Mexico and initial data indicates promising reductions. Once again, the advantage of this type of combustion modification is that all of the components, circulation, and air duct configurations are standard and well-known to us as boiler designer and manufacturer and to our users. The area of greatest concern to us as designers is the mixing requirements at the secondary air introduction point above the primary combustion furnace. Our extensive experience in gas tempering port design, and the subsequent mixing in the furnace, used extensively to control furnace exit gas temperatures provides an excellent data base for us to utilize for the secondary air/flue gas mixing problem.

When only seven units had been tested in the field, we had excellent fuel nitrogen correlation with the resulting NO_X emissions and reported it in 1978. However, the more units we tested, the more varied were the nitrogens in those fuels and the more it became obvious that we were not able to correlate NO_X emissions with nitrogen in the fuel to any great extent.

To further reduce NO_x emissions with combustion modifications, we must better understand the fuel-nitrogen transformation. B&W has funded a program at its Alliance Research Center to further investigate various nitrogen level coals in an attempt to understand the parameters that influence percent conversion and continue to follow the work of Dave Pershing at the University of Utah[6] (Figure 7).

In the event that New Source Performance Standards are applied to existing units in localized non attainment areas, our successful retrofit on the E. C. Gaston plant indicates that it is possible to retrofit a combustion modification. Combustion modifications for NO_x reduction continue to be both fuel and site specific with each case requiring study. What modification was reasonable at the Gaston plant with the Dual Register Burner system might not be reasonable at another plant with a different fuel. As an alternative approach to reduce NO_x resulting from combustion modifications, B&W is under contract to the EPA to develop and apply their Distributed Mixing Burner concept to actual burner hardware which can be retrofitted to a U.S. utility unit.[5]

CYCLONE FURNACES

Cyclone units that have gone into service recently, but were not subjected to the New Source Performance Standards because none had been promulgated for North Dakota lignites, have achieved NO_x emission levels lower than those presently established by the New Source Performance Standards for Northern lignites. One new cyclone unit firing bituminous coal entered service during 1979 under the exemption granted to units firing at least 25 percent mine waste along with their base coal. The unit has been in operation for approximately 15 months. NO_x levels have not been measured because the client is complying with the requirement for using 25 percent mine waste and therefore, is exempt from the NSPS. One other 450 MW cyclone unit is scheduled for initial service early in 1981, firing a North Dakota lignite. Retrofits to existing units firing typical cyclone low fusion coal are not practical. The two-stage approach has been field demonstrated both at the Board of Public Utilities, Kansas City, and at Basin Electric's Leland Olds Unit #2 and showed significant NO_x reduction.

In the North Dakota lignite case, Basin Electric required extensive amounts
of supplementary fuel to maintain flame temperatures high enough
to insure tapping of the slag. The Board of Public Utilities experiment
was successful while the Utility fired natural gas with NO_x reductions of
50 percent obtained under staged conditions. However, the base fuel for
that Unit and the majority of all our cyclone furnaces utilize a fuel
containing sulfur above 3 percent and iron above 18 percent in the ash.
The combination of these elements in a molten slag pool, under reducing
conditions, will result in immediate catastrophic loss of tube metal,
subsequent to failures, and molten slag tapping through the floor of the
cyclone and the steam generator. The application of two-stage techniques
to cyclones firing typical cyclone suitable coal is, of course, possible
and NO_x reductions would result; but the effects in an extremely short
time would be catastrophic and we do not recommend the applications of two
staging to cyclone furnaces (Figure 8).

The number of B&W New Source Performance Standards units firing oil in service
in the United States is 17 and represent 6343 MW. Only one unit is presently
under construction and none have been sold for domestic siting since 1974.
The approach that has been utilized since 1959 involves classic two
staging, gas recirculation through the windbox to reduce flame temperature.
and BOOS (burners out of service) to optimize the staging and reduce the
excess air levels required to maintain a clean smokstack. Initially,
we investigated the effect of atomizer (mixer) design upon NO_x generation
and, as expected, the atomizer producing the largest mean particle sizes produces
the lowest NO_x. The design approach used for the Dual Register Coal
Burner indicated that reduced peak flame temperatures and reduced turbulence
are important criteria to incorporate in any combustion system to reduce
NO_x (Figure 9).

The parallel flow burner was developed for oil and gas firing on New
Source Performance Standards units because it did not depend upon turbulence
to enhance the mixing and obtain acceptable burnout. The philosophy
behind its design is streamline development and slow mixing coupled with
better atomization. The independence of swirl requirements in this
design make it possible to operate at extremely low excess airs over the

78

load range than had been possible with a swirl register assembly. There are approximately 2,000 burner years' experience with this approach, and when coupled with either gas recirculation or two staging, proves to be adequate to meet the New Source Performance Standards for both oil and gas.

In 1975, the Dual Register Oil Burner was developed and retrofitted to the Mandalay Unit 1 of the Southern California Edison system. Prior to the retrofit, utilizing two-stage combustion, it was possible to reach 340 ppm NO_x emissions on 0.3 percent N_2 at 2 percent O_2. Following the Dual Register Oil Burner retrofit and utilizing two-stage combustion, NO_x could be reduced to 210 ppm. It appeared possible to obtain up to a 35 percent reduction resulting simply from the combustion system utilized. The data also indicated no reduction at all at times and, therefore, the value of the retrofit and data are questioned. Additional retrofits were made at five Florida Power Corporation plants. Florida Power Corporation's concern centered around dust emissions and meeting the Performance Standards in Florida for 0.1 lbs of dust per million Btu input. The retrofitted burners met that level. We were permitted to test for NO_x emissions in 1980 and found levels of 200 ppm. No baseline NO_x levels are available. This level was obtained with full stoichiometric air to the burners (no staging, BOOS, or gas recirculation). Fuel nitrogens averaged 0.3 percent during the test series.

The first steam generator initially designed for the Dual Register Oil Burner is owned by Hawaiian Electric, designated as Kahe Unit 6, rated for 140 MW and currently in the prestart-up, stretchout period. Kahe Unit 5 is a duplicate unit which utilizes NO_x ports and circular (high turbulence) burners to meet an old state NO_x emission standard of 300 ppm, in effect at the time of its construction. Kahe Unit 6 is required to meet the federal New Source Performance Standards, and has been supplied with the Dual Register Oil Burner and no NO_x ports. We expect to better the NSPS for oil on this unit (Figure 10).

Babcock-Hitachi has developed the Dual Register Oil Burner one step further by injecting gas recirculation, undiluted, into the primary flame zone. They refer to this device as the Primary Gas Dual Register Oil and Gas Burner. This combustor, when coupled with staging and gas recirculation in the secondary air, has resulted in retrofit, NO_X emission levels as great as 85 percent below uncontrolled levels. Application of this combustor, coupled with a primary combustion furnace (LNCS) and operating in the planetary mode similar to what is presently under test for pulverized coal, will result in even lower commercially obtainable NO_X emissions than presently possible (Figure 11).

Research and Development plans for the 1980s will concentrate in three major NO_X areas. The first area is that of the fuel nitrogen correlations which govern the NO conversions on both solid fuels and liquid fuels. The second major area is to continue our successful efforts in combustion modification, retrofitting the LNCS and demonstrating total unit performance, and retrofitting the Distributed Mixing Burner and demonstrating total unit performance. The third area concerns Synthetic Fuels and includes SRC I and II, coal/oil mixtures, coal/water mixtures, chars, and other liquifaction products from coals. We have gained extensive experience with the SRC I and II fuels under EPRI and DOE funding for both the field retrofit portion and laboratory characterizations. In addition to the NO_X emissions, the burning, fouling, slagging and handling characteristics of these fuels must be classified to allow us to design combustion systems to handle them.
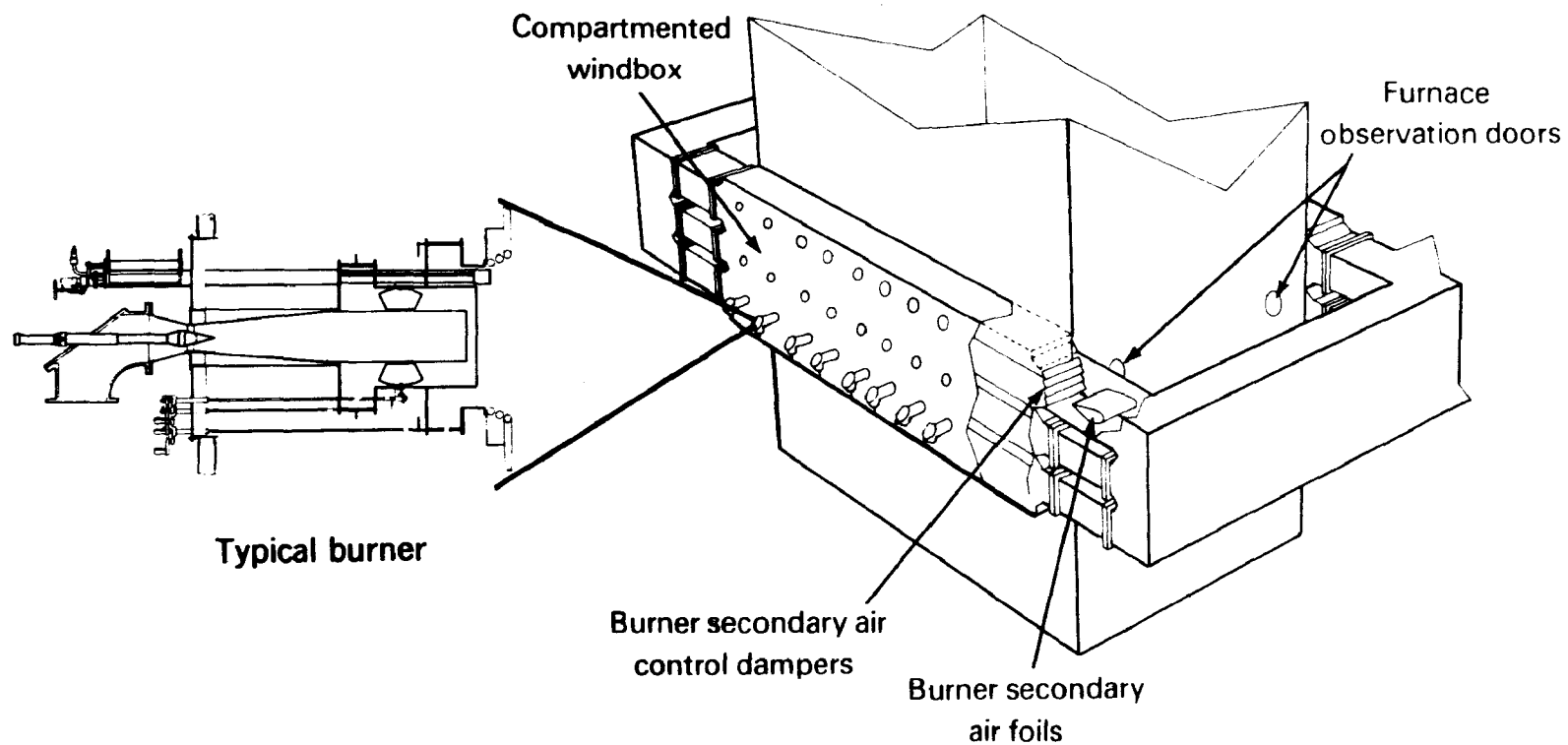
SUMMARY

Results from the 24 pulverized coal units tested to date show that the Dual Register Burner/Compartmented Windbox furnace system is an effective tool for NO_X emission control. NO_X levels 40 to 60 percent lower than those achievable with the high turbulence circular burner system are obtained through limited turbulence combustion. At the same time, carbon utilization has been maintained at levels comparable to those obtained

utilizing a high turbulence circular burner. Actual data collected for both fuel classes demonstrate NO_X emission levels to be within the 1978 NO_X limits established by the EPA New Source Performance Standards. Additional work in the area of combustion modifications, fuel nitrogen correlations and new fuel investigations must be continued to meet the anticipated tighter NO_X emission limitations expected over the next six years.

In the short term, through 1985, it is anticipated that we will have applied our Dual Register Burner/Compartmented Windbox furnace system to 150 utility steam generators with an approximated capacity of 67,500 MW. Typically, these units have generated half the NO_X they would have if the New Source Performance Standards of 1971 had not implemented emission controls. We are prepared with proven combustion modification retrofits to apply to units in non attainment areas on a base by base basis and plan to continue working with both EPRI and EPA to develop our lower NO_X concepts for commercial applications from combustion modifications in the late 1980s.

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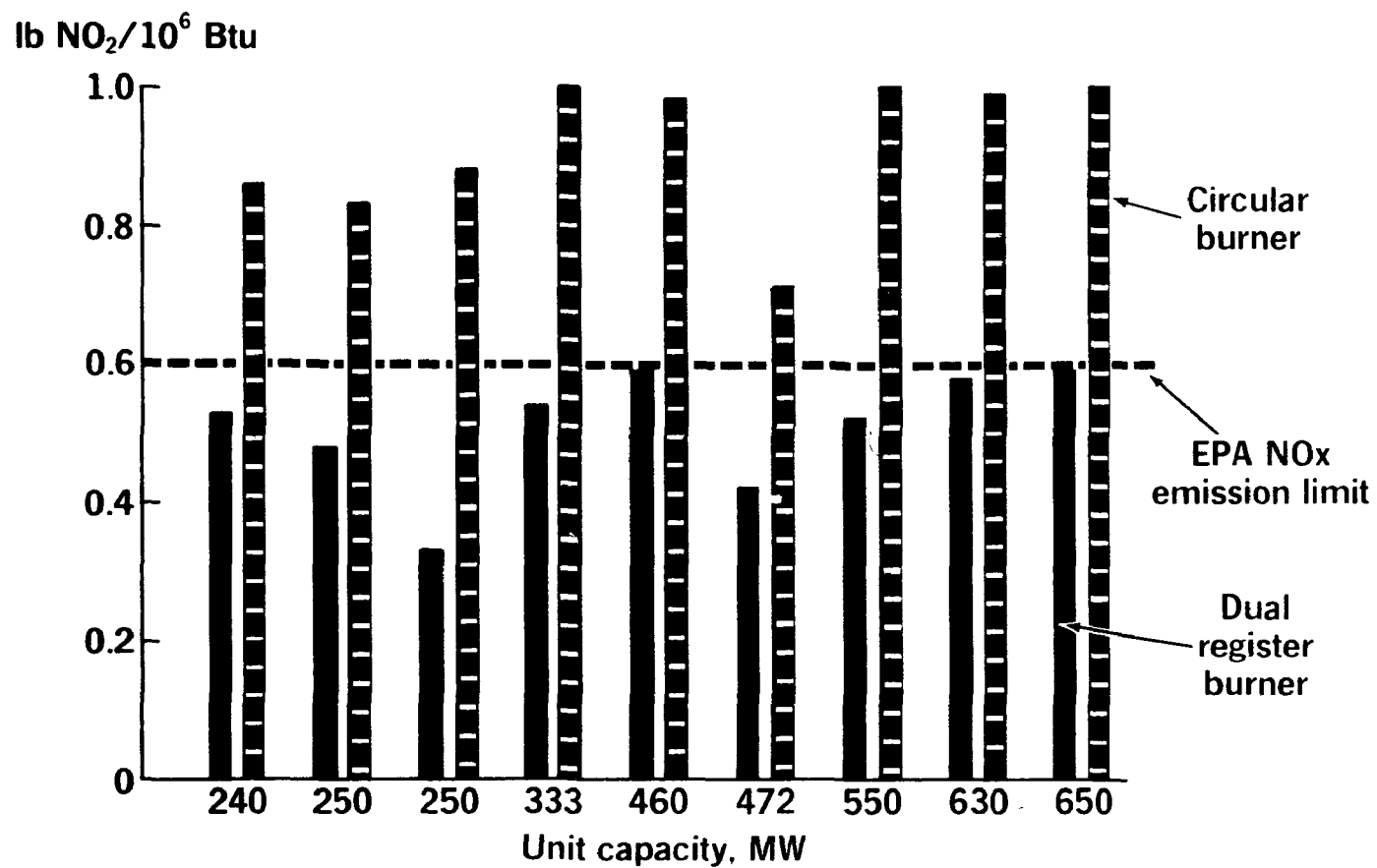
Compartmented
windbox

Furnace
observation doors

Typical burner

Burner secondary air
control dampers

Burner secondary
air foils

Dual Register Burner/Compartmented Windbox system
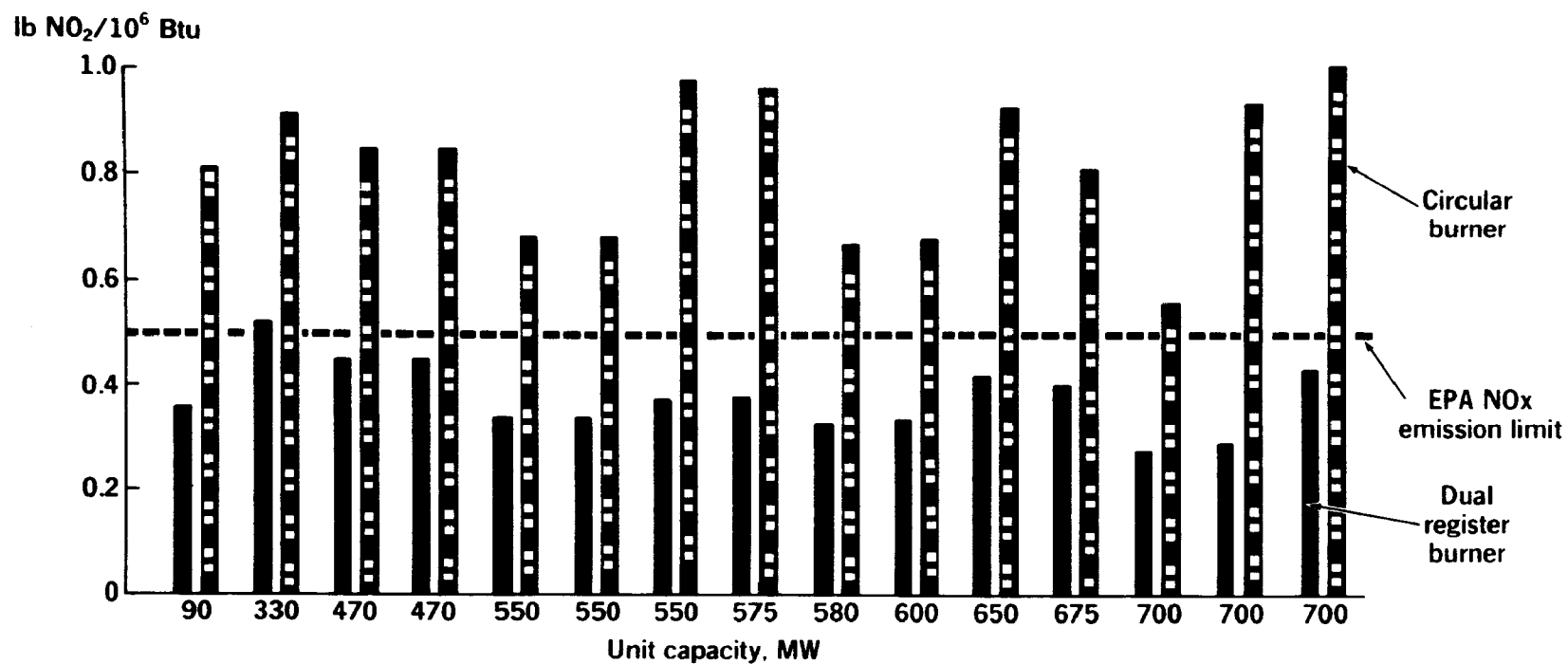
Figure 1
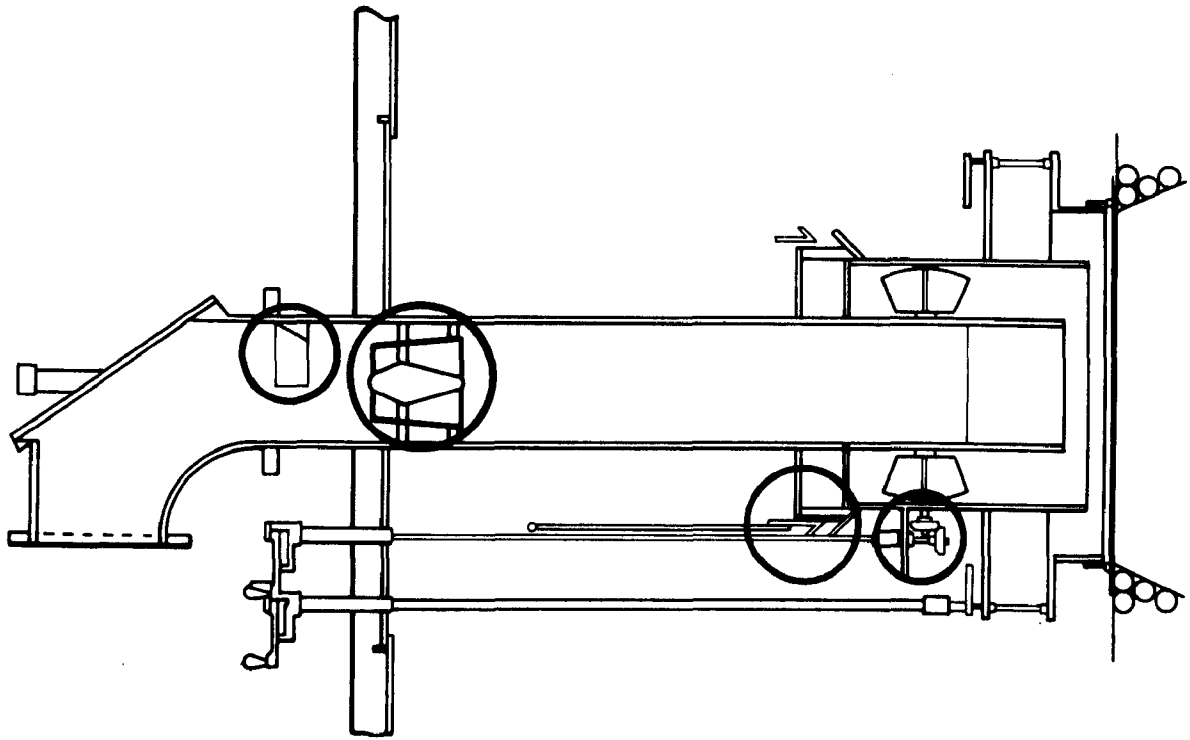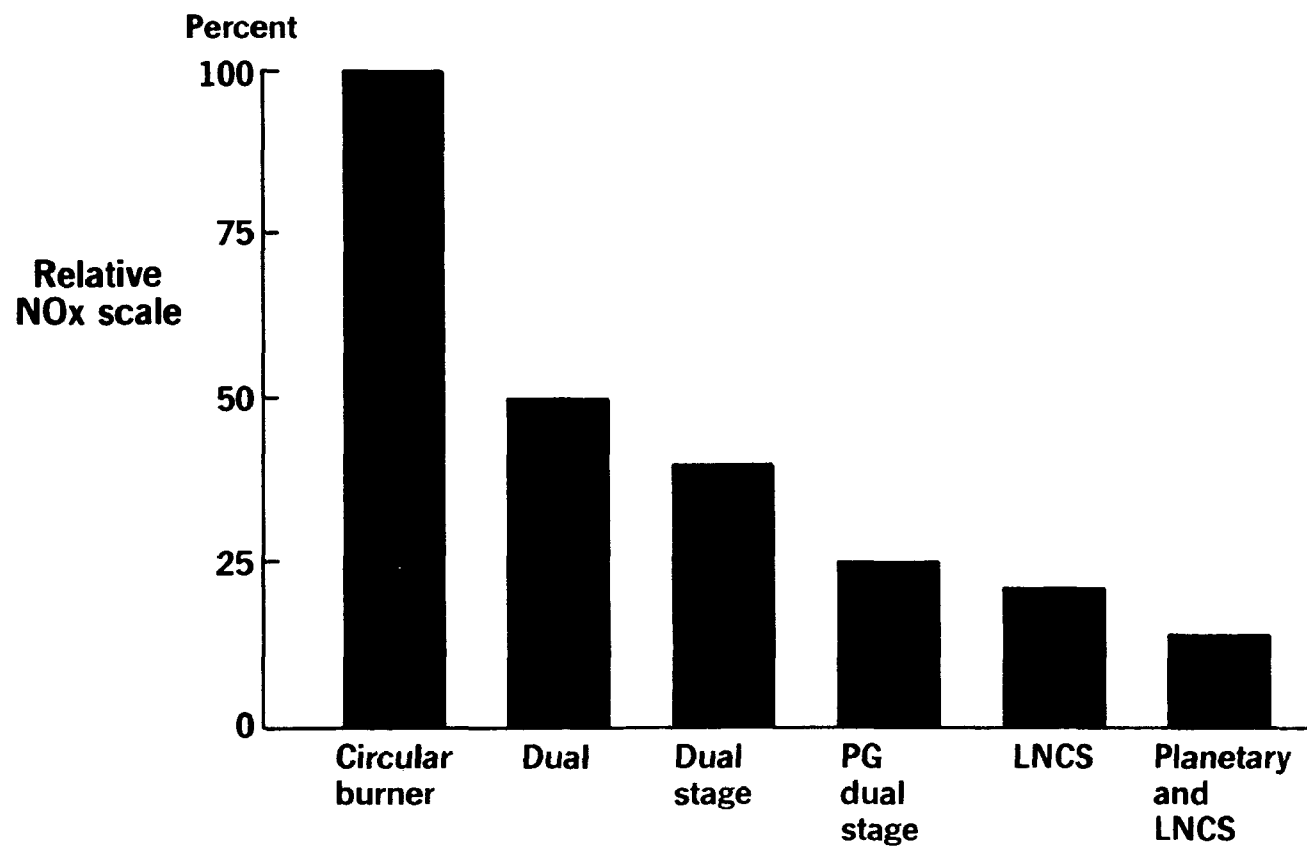
Dual Register Burner

Figure 2

Comparison of NOx emissions from circular burners
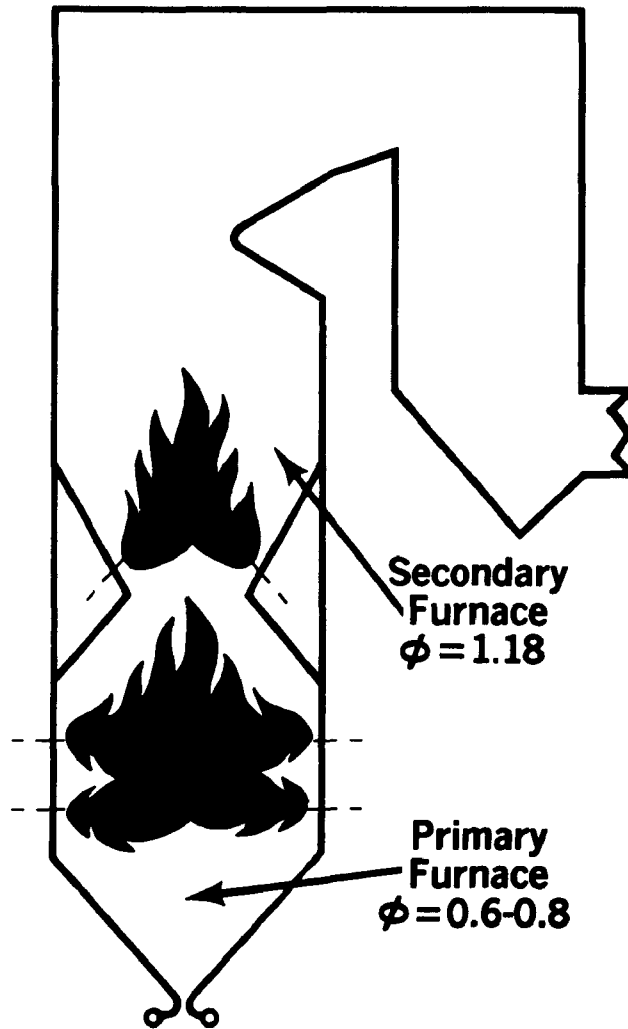and Dual Register Burners with bituminous coal

Figure 3

Comparison of NOx emissions from circular burners
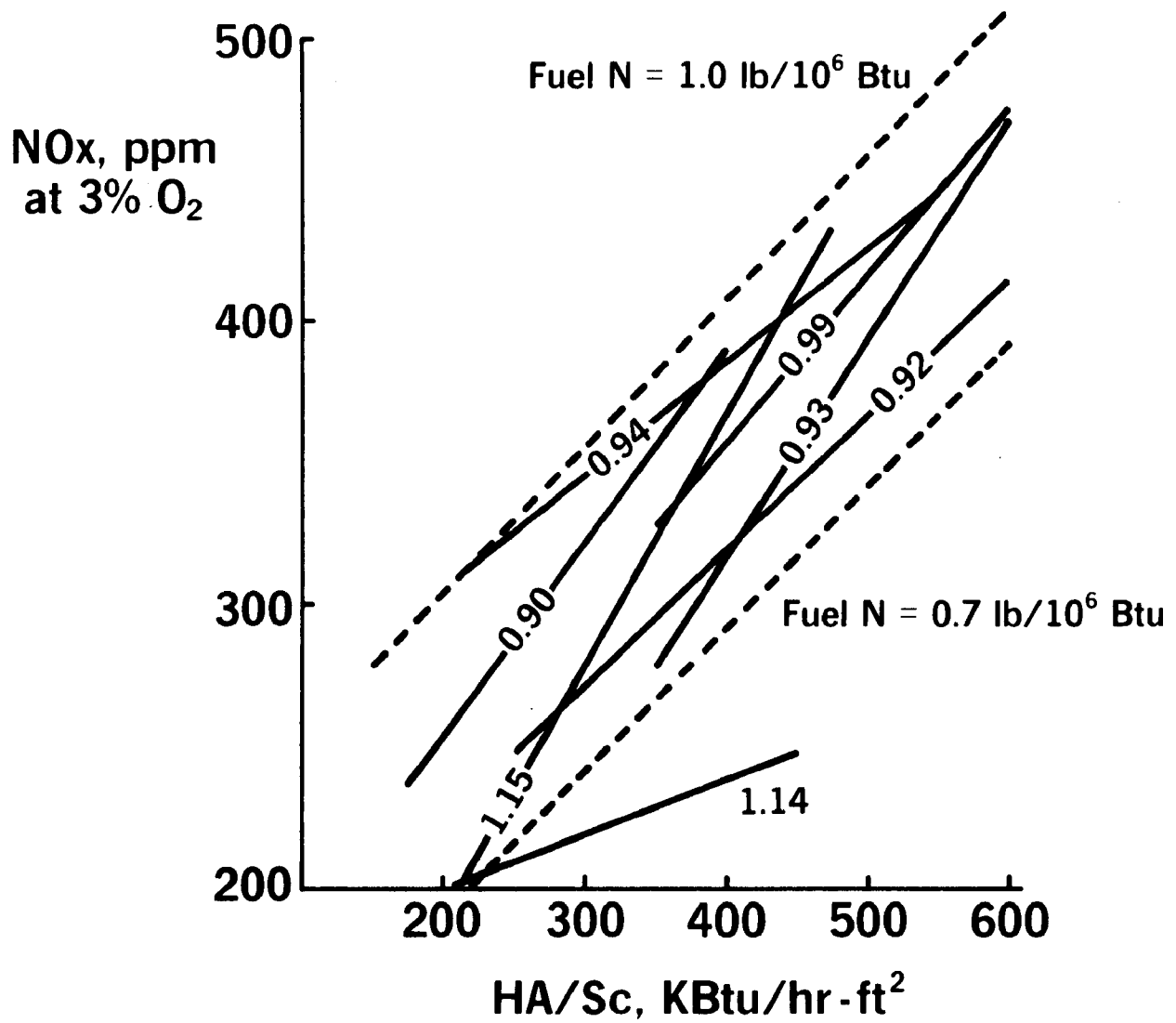and Dual Register Burners with subbituminous coal

Figure 4

Percent

**Relative
NOx scale**
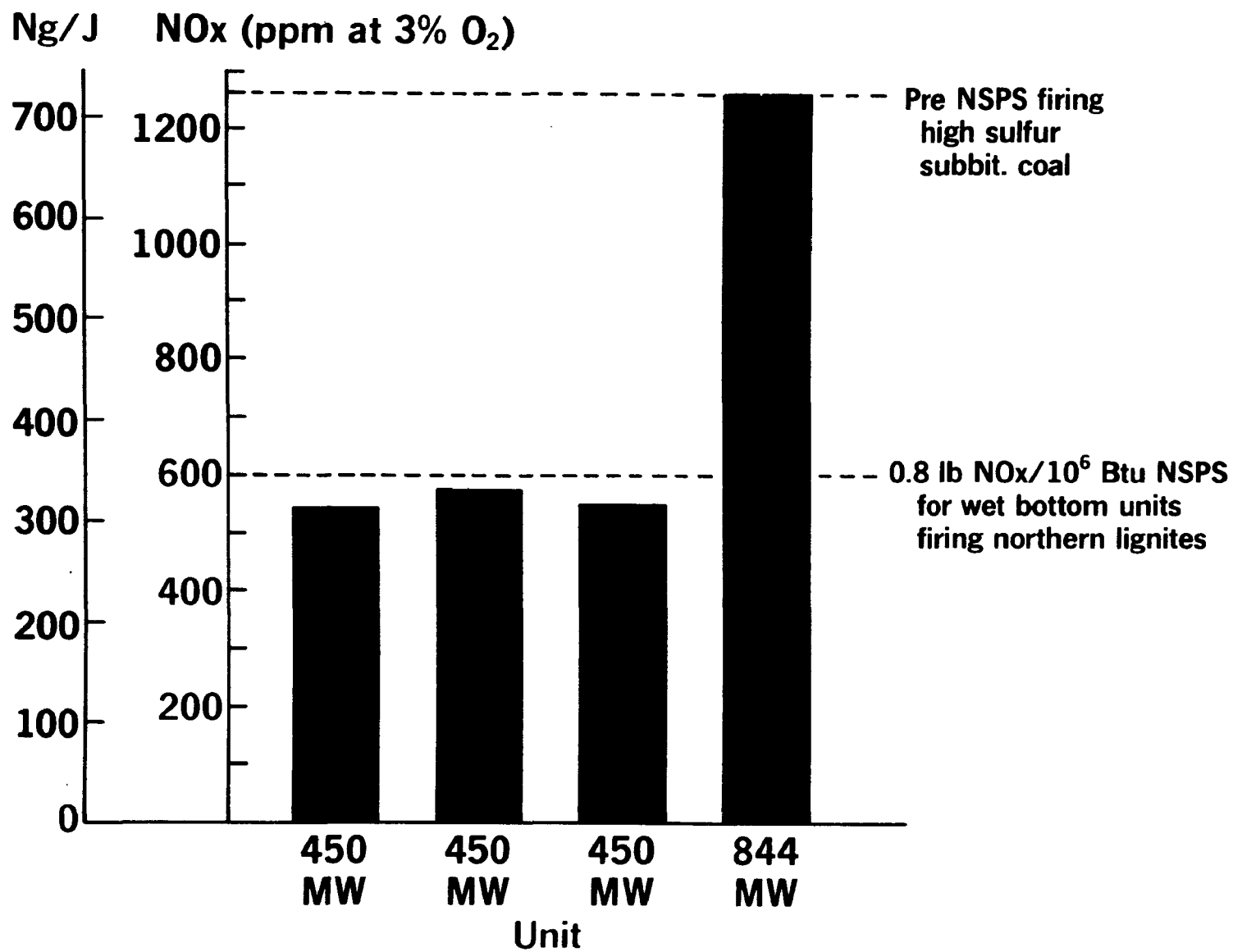
B&W low NO_x (coal) development

Figure 5
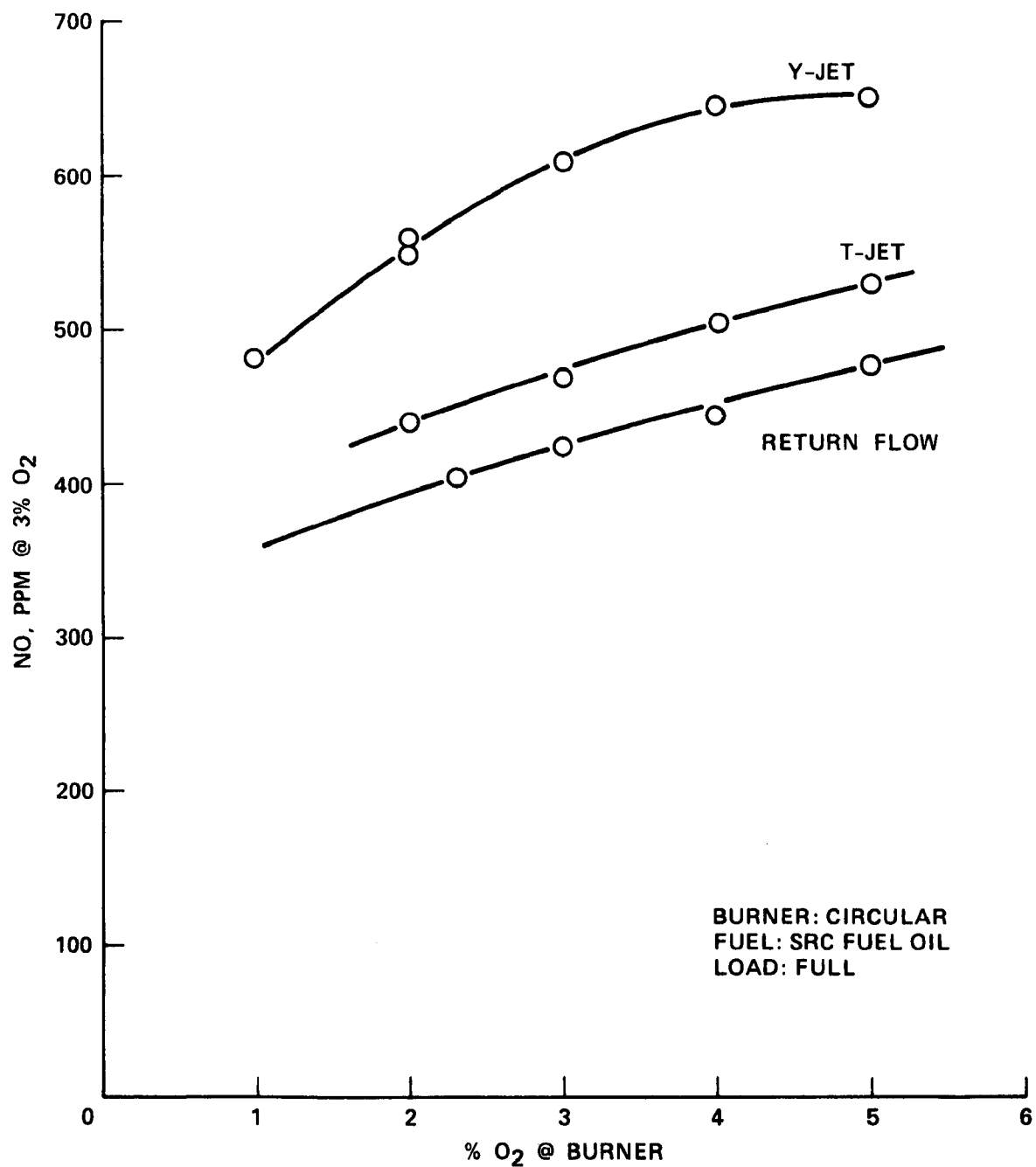
Low NOx combustion system concept

Figure 6

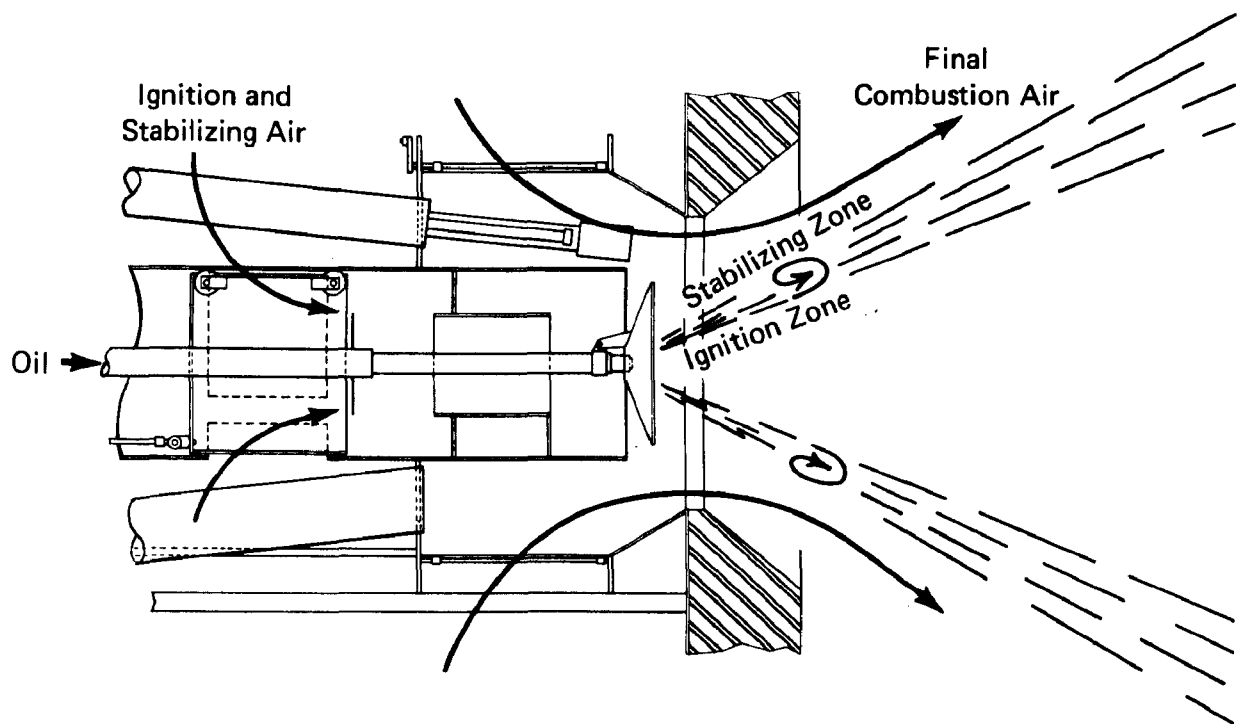Fuel N_2 correlation with NO_x
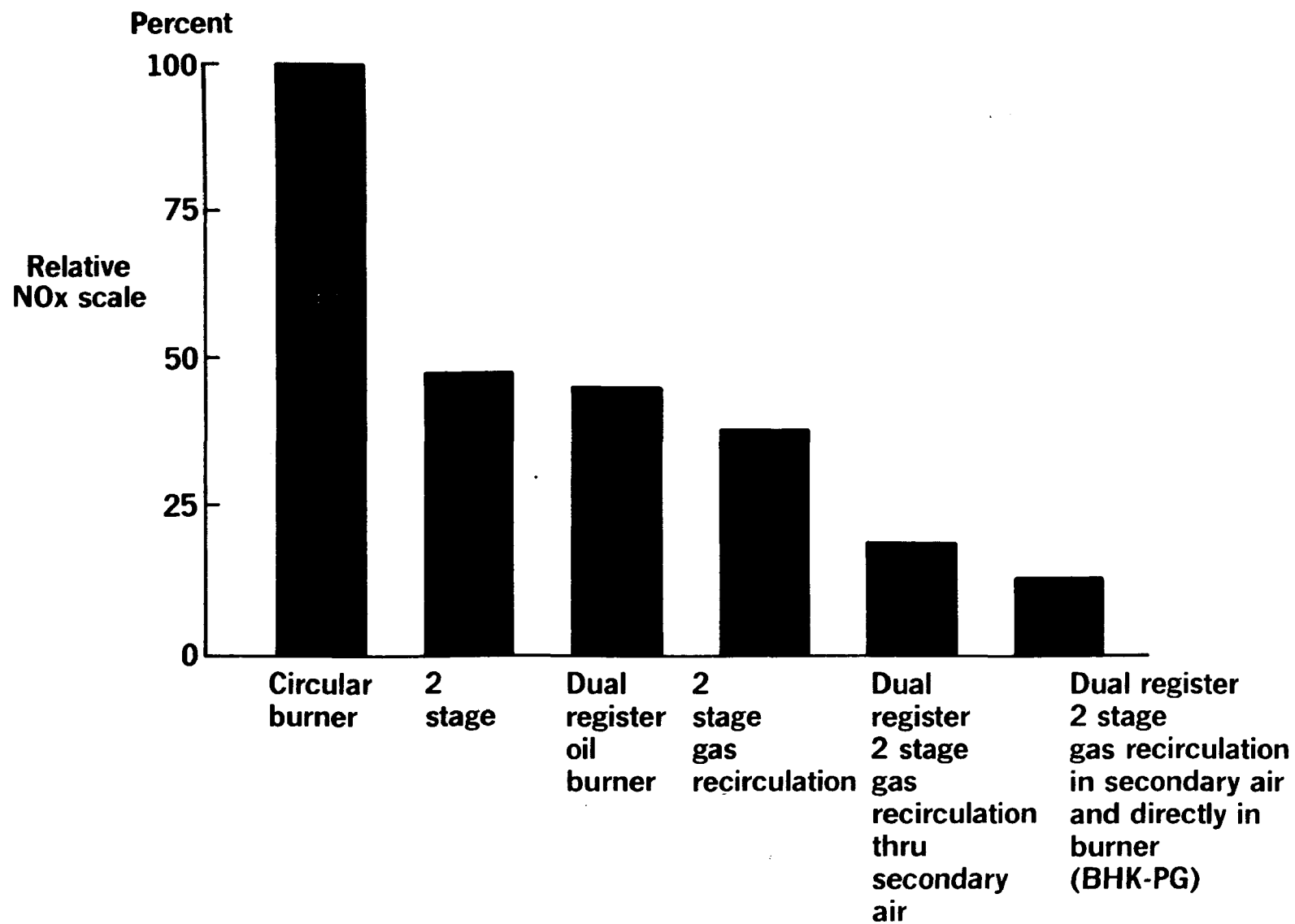
Figure 7

Cyclone furnace NO$_x$ levels

Figure 8

Influence of fuel atomizer design on NOx emissions

Figure 9

Dual register oil burner

Figure 10

Percent

Relative
NOx scale

B&W low NOx (oil) development

Figure 11

CURRENT DEVELOPMENTS IN LOW NO_x FIRING SYSTEMS

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ABSTRACT

Low NOx firing systems for natural gas and oil were developed for horizontal and tangential firing. The oil and natural gas "PM" firing system uses fuel rich and fuel lean regions in combination with flue gas recirculation to achieve low NOx emissions, the former region being produced by a diffusion flame, while the latter is produced by a premixed flame. The pulverized coal "SGR" and "LNCFS" tangential firing systems achieve low NOx emissions by delaying mixing of the main combustion air with the fuel.

INTRODUCTION

The reduction of NOx emissions from steam generators has become a paramount issue in most industrialized nations, with the strictest governmental regulations being in Japan and the USA (Table I). The local emission requirements in both countries are often more stringent than the national codes and vary considerably, depending in part on industrialization density and climatic conditions.

Although tangential firing has the lowest proven NOx emissions, Combustion Engineering, Inc. (C-E) and Mitsubishi Heavy Industries, Ltd. (MHI) have been deeply involved in NOx control studies for over a decade. Since the first oil embargo in 1973, C-E efforts have been directed primarily at controlling NOx formation in coal combustion and eventually led to the development of the "Low NOx Concentric Firing" (LNCF) concept. This system has been successfully demonstrated in both the laboratory (1) and the field (2) and is scheduled for rigorous testing in a large utility boiler, under contract with EPA (3). The results of these studies will be released following completion of additional testing in the utility units in mid-1981.

MHI first developed NOx control technology for oil and gas firing and the principles of this technology were proven with an impressive array of both new and retrofit applications. The continued price spiraling of fuel oil has altered the fuel market structure in Japan and the shift to coal as a fuel for steam generation has been increasing in recent years. Fortunately, the NOx control technology developed by MHI for gas and oil was found to be applicable to coal and the first commercial applications of these techniques are being evaluated currently.

C-E has obtained a license to apply the MHI NOx control techniques on steam generating equipment in the USA and Canada. The license covers two basic methods of reducing NOx emissions: control of NOx formation during combustion and removal of NOx from the flue gas following the completion of combustion. The latter system is described in a companion paper, "The Development of a Catalytic Reduction System for Coal-Fired Steam Generators" (4).

96

This paper will discuss the MHI method of controlling NOx generation during combustion and will describe the "PM" burner as originally developed for oil and gas, the "SGR" burner for coal, and finally, the PM burner for coal.

OIL AND GAS FIRING PM BURNER

PRINCIPLE OF OIL AND GAS FIRING PM BURNER

Recognizing that the "diffusion flame combustion system," employed in almost all existing oil-fired boilers, has a limitation on NOx production performance, MHI produced the PM burner, based on the "premix flame combustion theory" generally used in designing rockets. The marked reduction of NOx emission demonstrated by this burner has been recognized by both industry and academia and the operational results on actual boilers has been excellent.[*]

Here is the principle upon which this PM burner was developed. Generally speaking, there are two types of flames, diffusion flame and premixed flame (Fig. 1). The former is the flame that is produced when the injected fuel diffuses and burns while mixing with surrounding air. With this type of flame, NOx production decreases as air supply decreases and increases with increasing air. A premixed flame is one produced when the fuel is evenly mixed with air prior to ignition. With this type of flame, NOx production decreases with excessive air supply as well as with inadequate air supply. Combining the characteristics of premixing with "off-set" combustion, MHI developed the "off-set premixed flame theory." The PM burner is the product of a study based on this theory.

The concept of the PM burner is shown in Fig. 2. Combustion occurs in two different zones of the fuel-air mixture: in the fuel-rich mixture (NOx value at C_1) and in the fuel-lean mixture (NOx value at C_2) with the same total excess air ratio "X" as that for conventional burners. Thus, the average NOx value, point C (the mean value of C_1 and C_2) is markedly lower than that obtainable with conventional firing techniques. This is

[*]The 1977 prize of the Japan Society of Mechanical Engineers for excellent technical achievements was awarded to MHI because of this burner.

the case with gaseous fuels, i.e., they are burned under premixed conditions in both fuel-rich and fuel-lean mixtures, so the overall NOx value falls at point C.

With liquified fuels, however, burning occurs under diffused flame conditions in the fuel-rich mixture in order to maintain a stable flame. Thus, the overall NOx value is shown as Point C', the mean value of C_1' and C_2. The characteristically stable ignition associated with this PM burner provides the additional benefit of more flexible operation than conventional burners over a wide range of burner loads.

OIL-FIRED PM BURNER FOR TANGENTIAL FIRING

The corner assembly of a tangential firing system consists of a number of fuel nozzles stacked one upon another, the number depending on the total heat input to the unit. A typical fuel cell for the PM burner is shown in Fig. 3.

A specially designed atomizer produces two oil spray patterns; an inner conical spray for fuel-rich combustion and an outer "umbrella" partial spray for fuel-lean combustion. In order to control the oxygen atmosphere in the fuel-rich combustion zone, separate gas recirculation (SGR) is injected through nozzles on either side of the oil compartment. The outer (fuel-lean) oil is introduced through widely spaced atomizer ports, which permit passage of the SGR.

Thus, the inner spray ignites at the diffuser and burning occurs simultaneously with the mixing of fuel and air. The process is one of diffused combustion and corresponds to point C', in Fig. 2. Ignition of the outer spray is delayed and takes place after mixing with air from the auxiliary compartment. The process is one of premix combustion and corresponds to point C_2 in Fig. 2. The average NOx value is then at point C'.

Figure 4 shows the effects of NOx production of fuel nitrogen content, overfire air (OFA), flue gas premixed with total combustion air (GM), flue gas injection through SGR compartments (SGR), and total excess air. The effect of SGR on NOx production with various fuel oils is shown in Fig. 5.

Figure 6 illustrates a typical structure of the oil fired ROPM burner assembly for horizontal-fired applications. The oil fired ROPM burner is composed of a fuel-rich oil spray, an air-rich oil spray, and intervening SGR.

Only one oil gun is provided at the center of the inside air passage. As was the case with the PM burner, the fuel oil is sprayed from the tip of the oil gun at two different spray angles forming two concentric hollow cones, providing an inner fuel-rich combustion zone and an outer fuel-lean zone. The NOx level vs. fuel N and NOx vs. SGR ratio of the oil fired ROPM burner are shown in Figs. 7 and 8.

GAS FIRED PM BURNER

Figure 9 illustrates a typical gas-fired cell of the PM burner assembly installed in a tangentially fired windbox. The cell consists of one fuel-rich nozzle and two air-rich nozzles.

The SGR nozzles are not installed since both the fuel-rich and fuel-lean nozzles produce premixed and almost straight flames and there is very little interference between these flames. If the boiler employs gas recirculation for furnace outlet gas temperature (FOT) control, the GR can be admitted between fuel cells, rather than through the furnace bottom, for more effective NOx control. The NOx level vs. GM ratio of the gas fired PM burner is shown in Fig. 10.

GAS FIRED ROPM BURNER

Figure 11 illustrates a typical structure of the gas fired ROPM burner assembly for horizontal firing, consisting of one fuel-rich gas burner and one fuel-lean burner. The air passage is radially divided into two sections; the fuel gas and air supplied through the central or internal passage produces the fuel-rich flame and the fuel gas and air supplied through the outside circular passage produces the fuel-lean flame.

An oil gun is shown in the center of the burner, but this is of a conventional design and is used only for auxiliary purposes, not for low NOx firing of oil. The NOx level vs. GM ratio of the gas fired ROPM burner is shown in Fig. 12.

COMMERCIAL APPLICATION OF OIL & GAS BURNERS

Recognizing the benefits and practical features of the PM burner, Tokyo Electric Power Company, Inc. (TEPCO) adapted the PM burner to its Anegasaki No. 5 unit (tangential gas-fired 600-MW unit) in 1977. The operation was excellent and the unit achieves very low NOx levels over the entire operating range of the boiler.

Table II is a list of operating converted boilers and several new contracts for both gas and oil fired PM burners.

As of this writing, a total of 25 boilers representing all kinds of firing—gas and oil, tangential and horizontal—have been put into commercial operation with PM burners. Selected data on four of these boilers is shown in Table III. The following facts were obtained from these installations:

(1) The theory of "Off-set Premix" has been proven in commercial installations and the operation of PM burners lends itself to industry practices.

(2) Low NOx emission levels are obtainable over a wide range of boiler loads.

(3) Combustion is extremely stable and the flames are easily detectable over the entire range of boiler loads.

Figure 13 shows the lowest NOx emission levels obtained in four actual boilers (same plants as for Table II). The chart compares PM burner performance with conventional burners.

COAL FIRED SGR BURNER FOR TANGENTIAL APPLICATIONS

STRUCTURES AND FUNCTION

Figure 14 shows a conventional coal tilting tangential firing cell, which consists of a coal compartment and two auxiliary air compartments. Coal and primary air are introduced through the center of the coal nozzle and some secondary air (termed "fuel air") passes through the annulus around the coal nozzle. The remainder of the secondary air (termed "auxiliary air") is introduced through separate compartments above and below the coal. Although the coal and air are admitted in

100

parallel streams, secondary air is continually introduced into the coal stream, both before and after ignition, and there is no clearly defined primary combustion zone.

The conventional burner has been redesigned to create separate primary and secondary combustion zones and has been named the "SGR burner" (Fig. 15).

The SGR burner has three features distinguishing it from the conventional burner:

1) Gas recirculation is introduced through SGR compartments above and below the coal nozzle.

2) The auxiliary air compartments are farther from the coal compartment.

3) The coal nozzle has a divergent tip, which acts as a flame holder for maintaining ignition close to the nozzle.

The first two features maintain a reducing atmosphere at the nozzle during primary combustion by minimizing the infusion of secondary air into the coal stream. The third feature assures that devolatization and improved combustion of the coal occurs within this fuel-rich primary combustion zone.

TEST RESULTS WITH SGR BURNER

MHI has two coal-fired test furnaces at its Nagasaki research laboratory. The smaller furnace is water cooled, of circular wall, steel construction with refractory lining and rated at 0.5 TPH. The larger furnace is similar in construction and rated at 4 TPH.

Two SGR test burners were constructed and tested; the first with a capacity of 525 kg/h was tested in the small furnace and the other, rated at 3000 kg/h, was tested in the larger furnace. Both were of a design similar to that shown in Fig. 15.

The test results are shown in Figs. 16 through 21. Analysis of coals indicated in these figures is shown in Table IV.

(1) Effect of excess air on NOx is shown in Figs. 16 and 17. As with conventional burners, decreasing excess air is an effective method of reducing NOx.

(2) Effect of OFA on NOx is shown in Figs. 18 and 19. Again, its effect is characteristic of most other burner designs.

101

(3) Combined effect of OFA and SGR on NOx is shown in Figs. 20 and 21. The concept of the SGR ports was to impede the ingress of secondary auxiliary air into the primary combustion zone in which devolatilization and combustion occurs. These tests indicate that the effectiveness of SGR varies from coal to coal. In those cases where it is ineffective, minimum SGR flow is introduced for cooling these ports without introducing air, which would increase NOx.

CONFIRMATION OF BURNER SCALE-UP PERFORMANCE

MHI has had considerable experience relating test furnace performance to actual field performance with converted burners. This experience indicates that if the following relationship is maintained between the burner firing rate (Q) and the burner height (H), the NOx emissions from the burners will be the same:

$$H=AQ^N \text{ where A is a constant}$$

Figure 22 shows the results of such an investigation and compares the NOx production of a small burner in this test facility with a full sized burner in the Takasago No. 1 unit, firing the same coal. The burner design for both coals was conventional tangential type.

COMMERCIAL APPLICATION OF COAL-FIRED SGR BURNER

The first commercial application of the SGR burner is Matsushima 1 and 2 of Electric Power Development Co. (EPDC). These are duplicate 500-MW boilers and the first large coal-fired units ordered after a decade of oil and gas utilization.

Since Matsushima 1 has just started its trial operation, we do not yet have data on the performance of its SGR burners. We plan to have this information within a few months.

Figure 23 shows the relationship between burner capacity (Q) and burner height (H) for the same NOx production. This is based on the formula discussed previously and shows control data points taken from the test furnaces and the Takasago unit. From this relationship, it is expected that the 1830 mm burner height for Matsushima will achieve the same NOx emissions as demonstrated for that coal in both small and large test furnaces.

An analysis of the coals tested in the two test furnaces thus far are shown in Table IV.

During the study of the SGR coal burner, which is the first design series in the low NOx coal burner program, MHI collected data pertaining to the relation between the primary air/coal ratio and NOx formation for the purpose of determining possible further improvements in low NOx burners.

Data from the test furnaces is plotted in Fig. 24 and one can see that when the primary air/coal ratio is in the range from 1-3, the NOx value decreases as this ratio is reduced with every kind of coal tested, although the slopes of the curves vary.

On the other hand, C-E had acquired data on the relationship between the primary air/coal ratio and NOx formation at ratios ranging from 3 to 8, which is higher than the usual ratios. Some of this data is shown in Fig. 25, including that of a Japanese coal and an Australian coal which had been sent to C-E for testing.

Figure 25 presents a quite different trend from that of Fig. 24, in that the NOx value decreases as the primary air increases when the primary air/coal ratio ranges between 2 and 7 or 8. The test results in these two cases are apparently contradictory, but may be explained as follows.

By means of the explanation of the principle of the PM burner, the principle of the SGR burner will become clear as well.

PRINCIPLE OF NOx REDUCTION

Generally, the pulverized coal combustion zone is theoretically divided into two sub-zones as shown in Fig. 26; one is the primary combustion zone where pulverized coal carried by primary air burns while mixing with that primary air, and the other is the secondary combustion zone where the remainder of the coal burns while mixing diffusing secondary air injected from the auxiliary air compartments. However, with conventional burners the secondary air starts to mix with the primary air/coal stream as soon as they are injected into the durnace and distinct primary and secondary combustion zones do not exist.

103

Thus, volatile matter burns with high excess air instead of burning only with the primary air in the primary combustion zone.

Because of this, the combustion process and NOx reducing theory described here can not be applied to conventional burners. In other words, MHI's Low NOx burners are so designed that they can establish distinctly separate primary and secondary combustion zones.

The quantity of coal that burns in the primary combustion zone is proportional to the ratio of primary air to coal and the quantity of coal that burns in the secondary combustion zone is the remainder of the coal. Thus, the amount of NOx generated from the combustion of pulverized coal can be expressed as a sum of that generated in the primary and that in the secondary combustion zones, as shown in Fig. 27.

(1) The formation of NOx in the primary combustion zone ({NOx}p) in Fig. 27.

The primary air/coal ratio of 3-4 approximately corresponds to the air quantity theoretically required for combustion of volatile matter in coal. In the region where this ratio is within the range of 3-4, primary air is almost all consumed by the combustion of volatile matter. At lower ratios, oxygen availability is decreased, the combustion of volatile matter is retarded, and the conversion of N in volatile matter to NOx is reduced. Moreover, as a result of incomplete combustion, the quantity of unburned gas from the volatile matter entering the secondary combustion zone is increase.

A primary air/coal ratio of 7-8 corresponds to the air quantity theoretically required for complete combustion of the coal. Therefore, in the region where the primary air/coal ratio is between 3-4 and 7-8, O_2 is insufficient for the complete combustion of fixed carbon but the conversion of N in volatile matter to NOx becomes more active as the ratio increases. However, the reducing action on NOx formation of substances such as HC, NH_3, HCN etc., produced from the fixed carbon, also becomes more active, with the net result that the NOx valued at the outlet of the primary combustion zone eventually drops as the primary air/coal ratio increases.

Primary air/coal rations greater than 7-8 result in excess air combustion, negating the NOx reducing action and resulting in a steep rise of NOx value.

Thus, the NOx formed in the primary combustion zone has the characteristics as expressed by the solid lines in the chart of $(NOx)_p$ in Fig. 27.

(2) The formation of NOx in the secondary combustion zone ({NOx}s in Fig. 27):

In the region where the primary air/coal ratio is less than 3-4, a large quantity of unburned gas from the primary combustion zone burns with the char as the secondary air diffuses and mixes with them in the secondary combustion zone. The quantity of unburned gas increases as the primary air/coal ratio is throttled further, and causes relative retardation of diffusion and mixing of secondary air and a consequent drop of the conversion rate of N in unburned gas and char to NOx. Thus, the formation of NOx varies little with the change of the primary air/coal ratio, as shown by the heavy solid line in the chart.

In the region where the primary air/coal ratio is between 3-4 and 7-8, the percent of coal that burns in the primary combustion zone increases as the primary air/coal ratio increases. Consequently, the percent of the coal that burns in the secondary combustion zone decreases and the formation of NOx in this zone decreases.

The sum of (NOx)p from the primary combustion zone and (NOx)s from the secondary combustion zone is the total of the NOx produced from the combustion of pulverized coal. As shown in the bottom chart in Fig. 27, NOx increases in the region where the primary air/coal ratio is between 0 and 3-4 and decreases in the region where that ratio is between 3-4 and 7-8 and increases again when that ratio exceeds 7-8.

PRINCIPLE OF THE COAL FIRED PM BURNER

It is a tested conclusion that with coal fired burners, the NOx value is high in the region where the primary air/coal ratio is 3-4 and falls as the ratio deviates in either direction, increasing or decreasing. This is a similar trend in NOx formation to that which occurs with the premixed oil and gas fired burners when the air ratio

is approximately 1 and falls as the ratio deviates from this point in either direction.

In a direct-fired system, the pulverizer is directly coupled with the firing system. The primary air/coal ratio is dictated by pulverized drying and conveying requirements, and generally falls in the range 1.5-2.0. Pulverizers provided with spare capacity, can increase this ratio to 3.0 or thereabout. This is undesirable in a normal firing system since NOx increases as this ratio increases, as shown in Fig. 27. Fortunately the relation between the NOx value and the primary air/ coal ratio in combustion of coal is similar to that between the NOx value and the air ratio in premixed combustion of oil and gas. This suggests the possibility of using the principle of fuel-rich and fuel-lean with coal, as well, and this forms the basic principle of the PM burner.

Referring again to the bottom chart in Fig. 27, the circled points illustrate the low NOx burner. The coal-air mixutre from the pulverizer can be divided into two streams; one with a ratio of C_1 (fuel-rich) and the other C_2 (fuel-lean). If these two streams are permitted to fire independently, the NOx emission level for the whole burner assembly will be the level corresponding to the point C_0 which is considerably lower than the point C'_0 which represents the NOx emission level obtainable if the entire coal/air stream burned as a single flame in separate primary and secondary combustion zones, as with the SGR burner. The structure of the coal fired PM burner is shown in Fig. 28. The concentrating effect of coal to the outside radius of the delivery pipe is used to make the separation between concentrated and dilute coal streams. Figure 29 shows comparison of NOx emission of conventional burner, SGR burner and PM burner.

CONCLUSION

The PM burner for oil and gas, based on "Offset Premix Flame Theory," successfully achieves dramatically lower NOx emission levels than is possible with conventional burners. The most prominent feature of the oil and gas PM burner is that it can greatly reduce NOx emission while maintaining stable combustion. Moreover, it can reduce

particulate matter emission as well and requires no additional effort in operation and maintenance of the equipment. Neither catalyst nor ammonia injection is needed. Thus, the advantages of the PM burner may be summarized by stating that it can effect a marked reduction in NOx emission economically, not only in new boiler applications but in most retrofit applications, as well.

A number of oil and gas PM burners have already been successfully applied to various types of boilers such as supercritical pressure, forced and natural circulation, pressurized, and balanced draft, indoor and outdoor types. The fact that all these burners have been operated successfully and to the customer's satisfaction is proof that this burner design is applicable to any type of utility boiler.

In the case of coal-firing, the SGR burner provides an effective means of reducing NOx, but field confirmation of its performance must await testing to the Matsushima until later this year.

We believe that the more recently tested coal-fired PM burner will replace the SGR burner on future new boiler applications since its potential for NOx reduction is much superior. The current status of the low NOx burners, then, is shown in Fig. 30.

REFERENCES

1. EPA Contract No. 68-02-1885

2. C-E Studies at Richmond Power & Light Company, Whitewater Unit No. 2

3. EPA Contract No. 68-02-3655.

4. Sengoku, T., Todo, Y., Yokoyama, N., and Howell, B. M., "The Development of A Catalytic NOx Reduction System for Coal-Fired Steam Generators,"Presented at the EPRI-EPA Joint Symposium on Stationary Combustion NOx Control, Denver, Colorado, October 6-9, 1980; Published as Combustion Engineering publication TIS-6710, Windsor, CT: Combustion Engineering, Inc., 1980
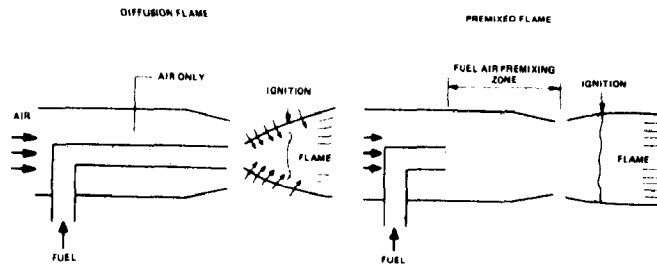
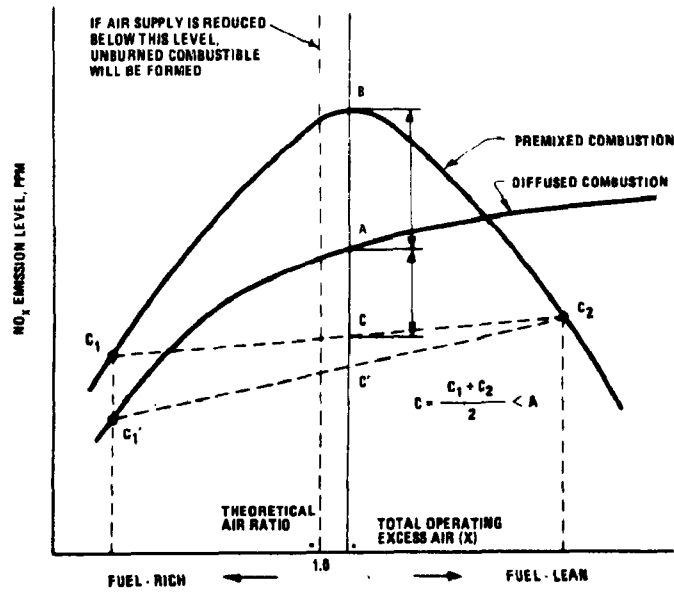Fig. 1: Diffusion flame and premixed flame
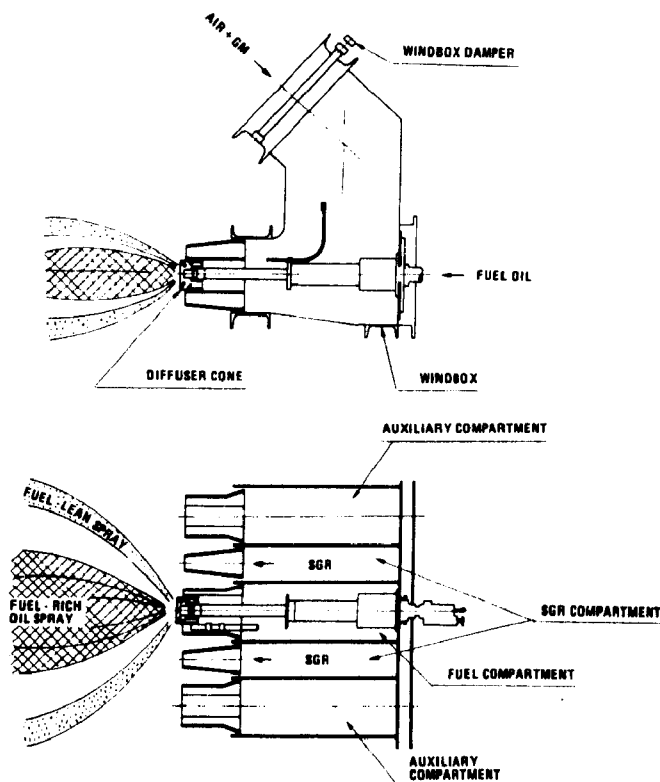

Fig. 2: Concept of the PM burner

Fig. 3: PM burner cell for firing oil in tangential firing system

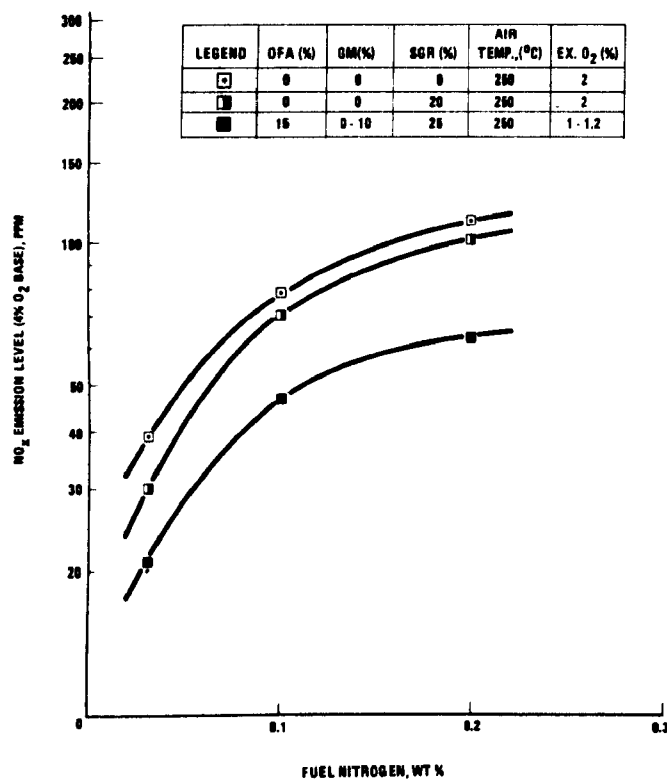| LEGEND	OFA (%)	GM(%)	SGR (%)	AIR TEMP.,(°C)	EX. O_2 (%)
▣	0	0	0	250	2
▥	0	0	20	250	2
■	15	0 - 10	25	250	1 - 1.2

Fig. 4: Oil fired PM burner for tangential firing—fuel N vs. NOx emission

LEGEND	FUEL	OFA (%)	GM (%)	AIR TEMP. (°C)	$E_x O_2$ (%)
◇	HEAVY OIL (N = 0.1%)	0	0	250	2.0
□	CRUDE OIL (N = 0.03%)	0	0	250	2.0
○	HEAVY OIL (N = 0.03%)	0	0	250	2.1

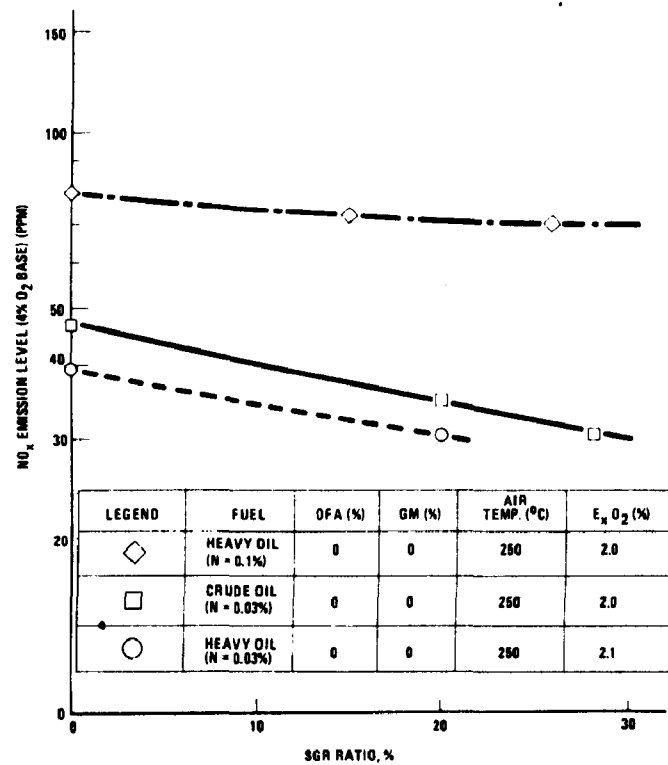Fig. 5: Oil fired PM burner for tangential firing—SGR ratio vs. NOx emission (test furnace)
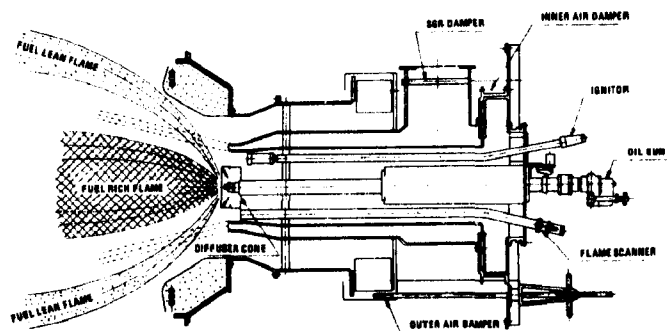

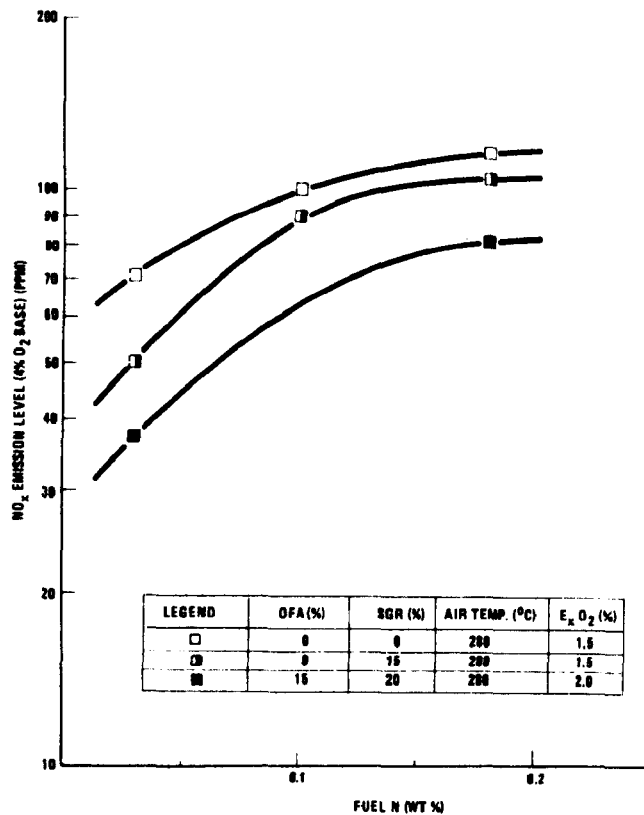Fig. 6: Structure of oil fired ROPM burner for horizontal firing

111

Fig. 7: Oil fired ROPM burner for horizontal firing—fuel N vs. NOx emission (test furnace)
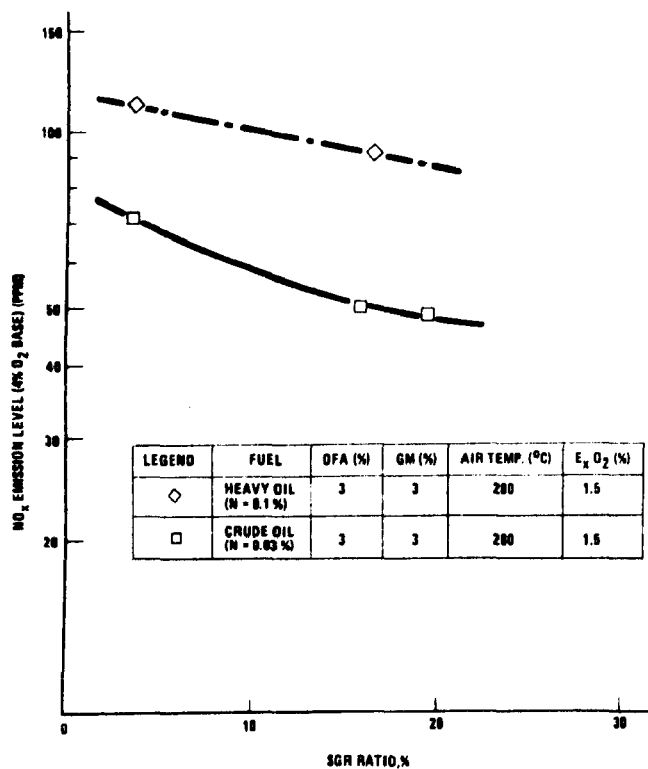

Fig. 8: Oil fired ROPM burner for horizontal firing—SGR ratio vs. NOx emission (test furnace)

112
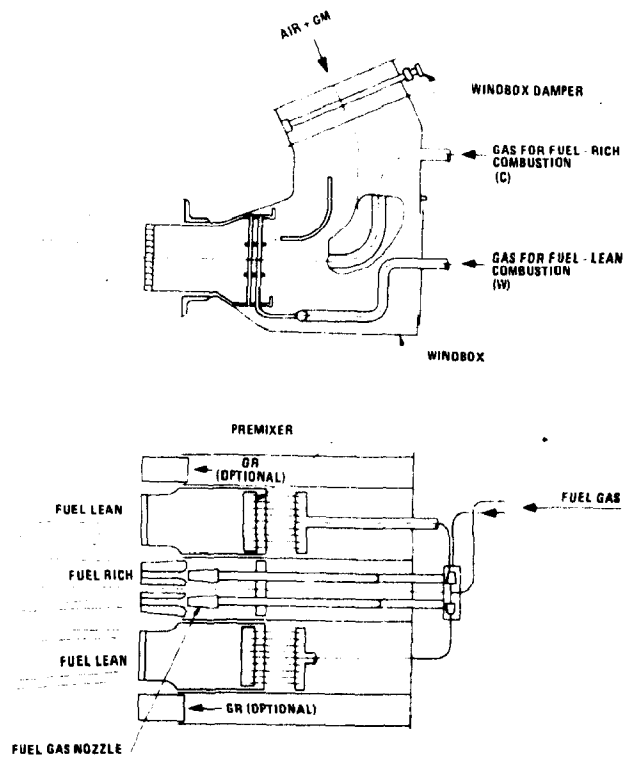
Fig. 9: PM burner cell for firing gas in tangential firing system
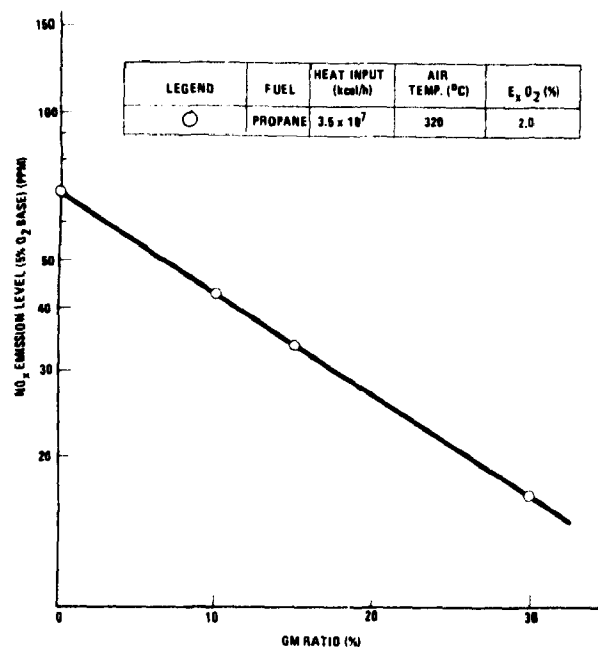
Fig. 10: Gas fired PM burner for tangential firing—GM ratio vs. NOx emission
          (test furnace)

113
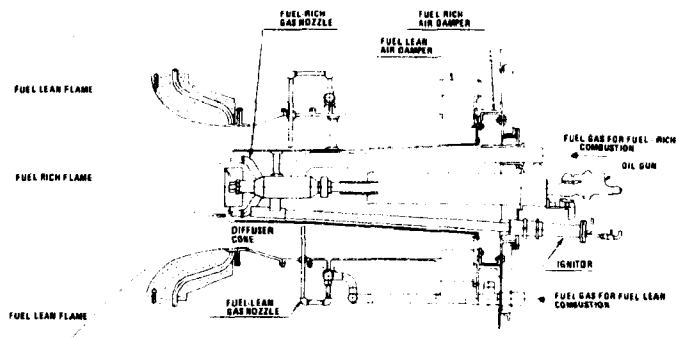
Fig. 11: Structure of gas fired ROPM burner for horizontal firing
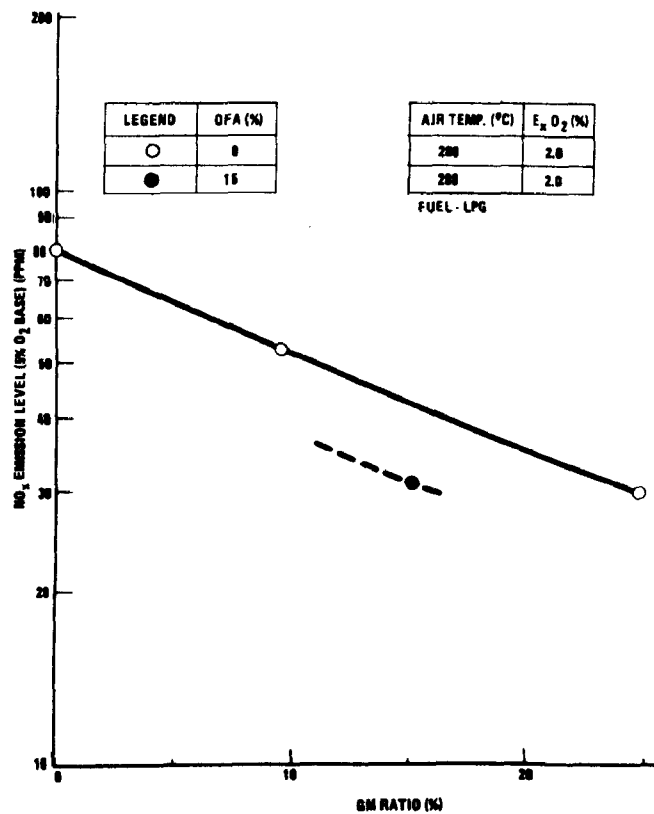
Fig. 12: Gas fired ROPM burner for horizontal firing—GM ratio vs. NOx emission

114
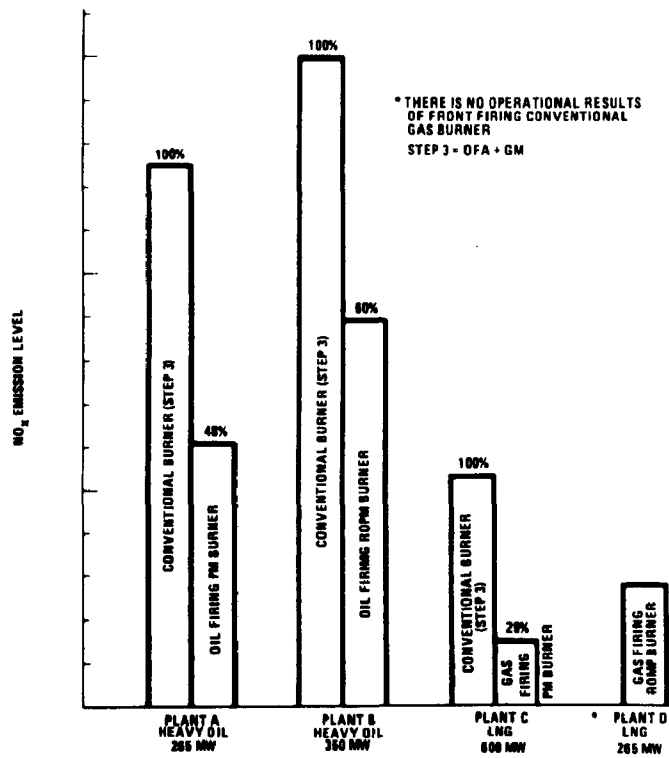
Fig. 13: Operational results of PM burner in actual boiler (comparison of minimum NOx before and after modification)
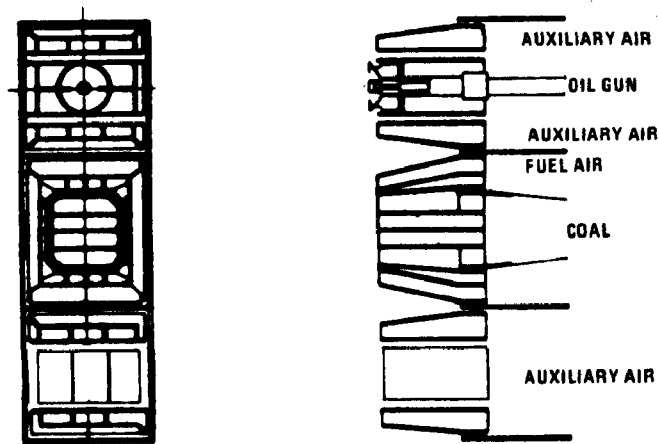
Fig. 14: Configuration of conventional coal tangential firing nozzle

115
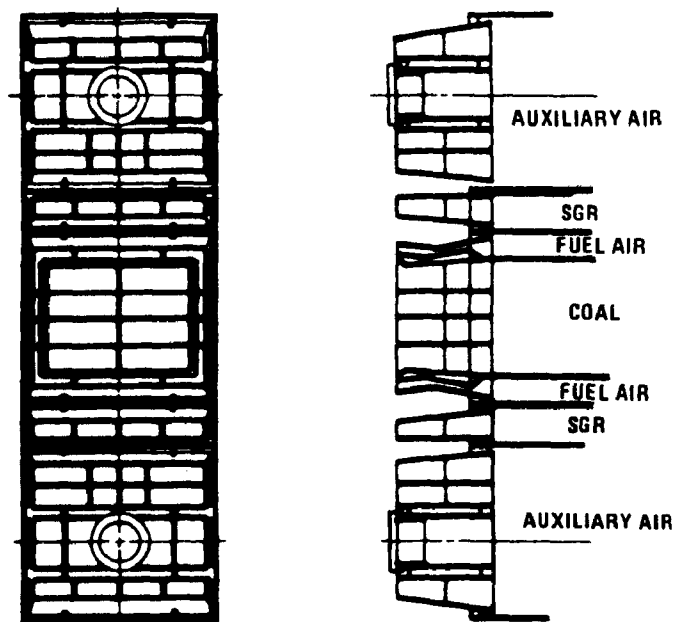
Fig. 15: Configuration of SGR burner for coal tangential firing nozzle
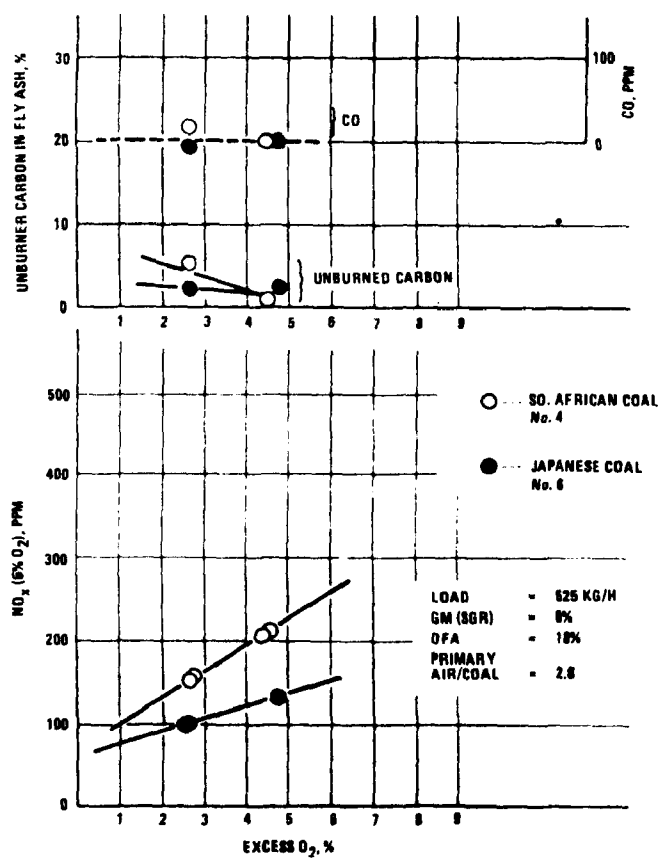
Fig. 16: NOx with excess O_2 SGR test burner
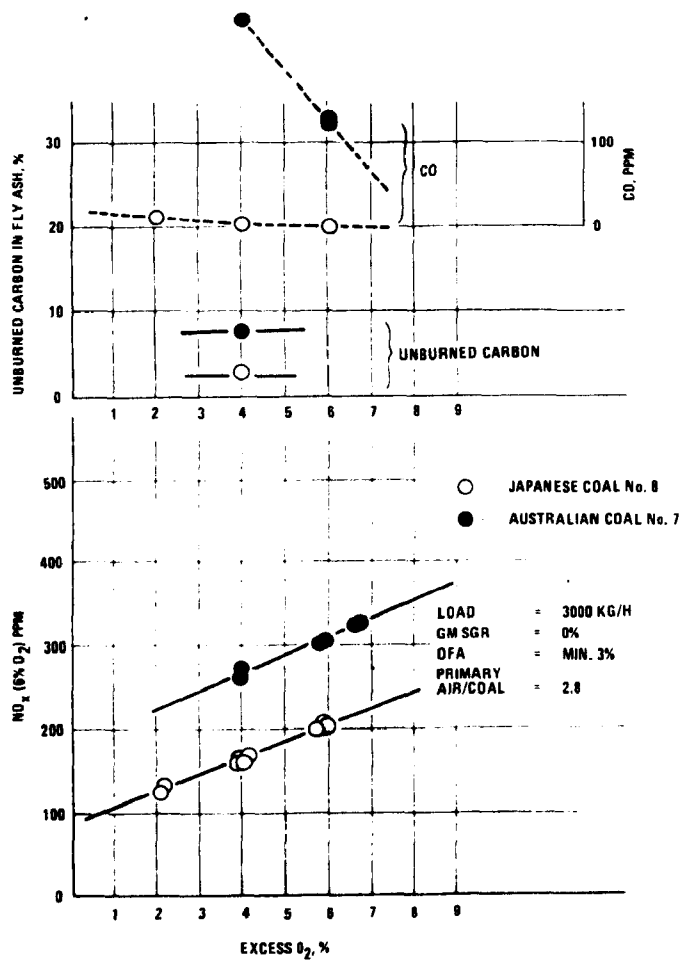
Fig. 17: NOx reduction with excess 0^2—SGR: 3000 kg/h capacity test burner.
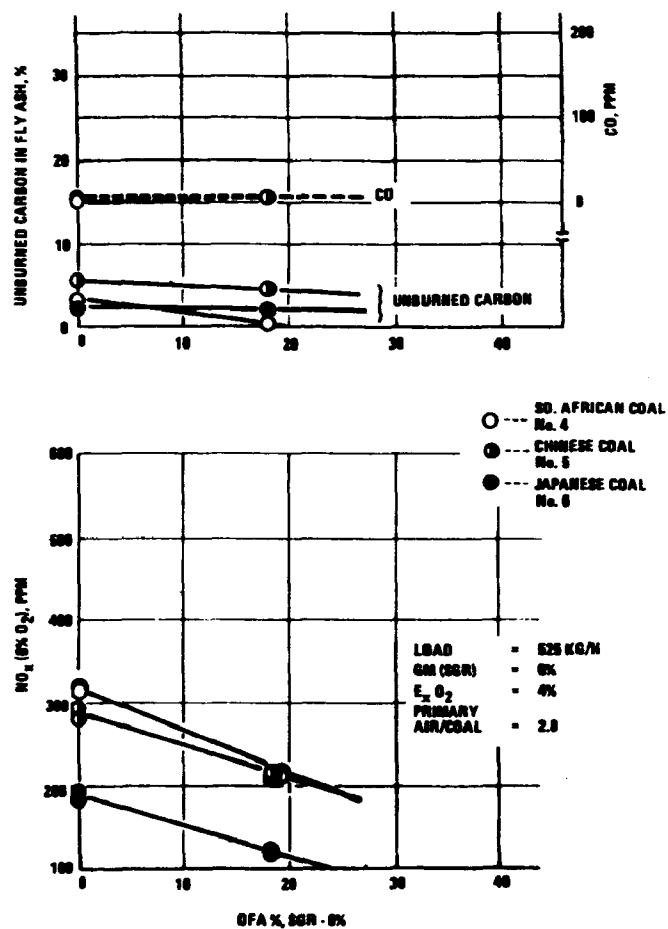
Fig. 18: NOx reduction with OFA—SGR
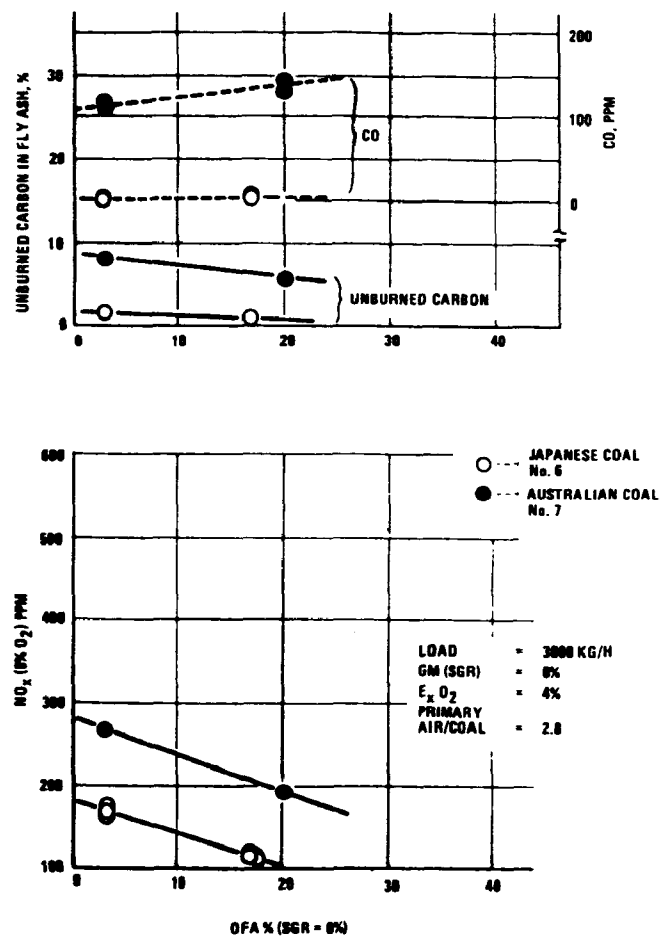
Fig. 19: NOx reduction with OFA—SGR
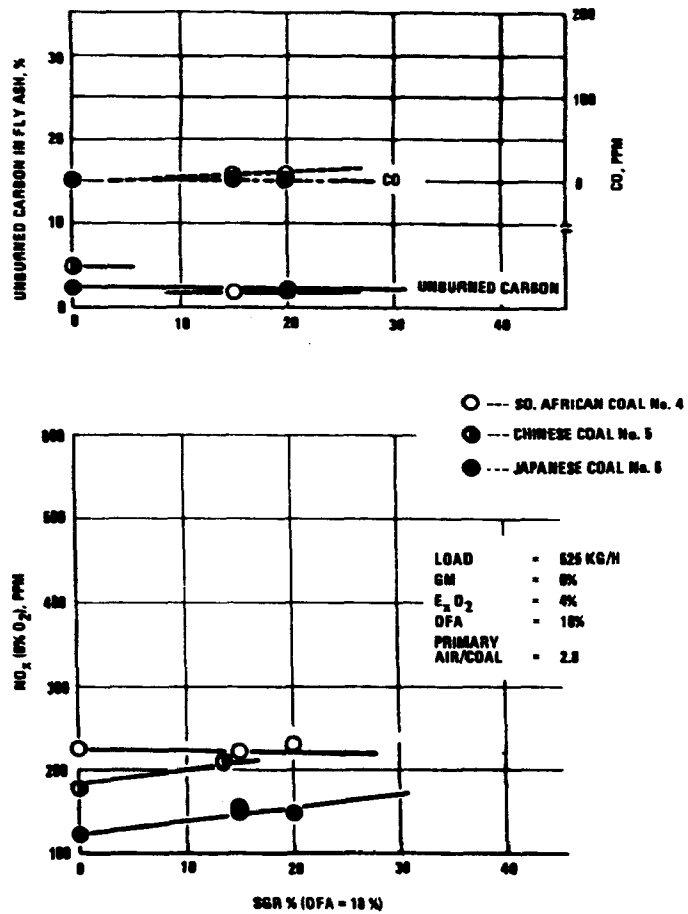
Fig. 20: NOx reduction with SGR of OFA=18%—SGR
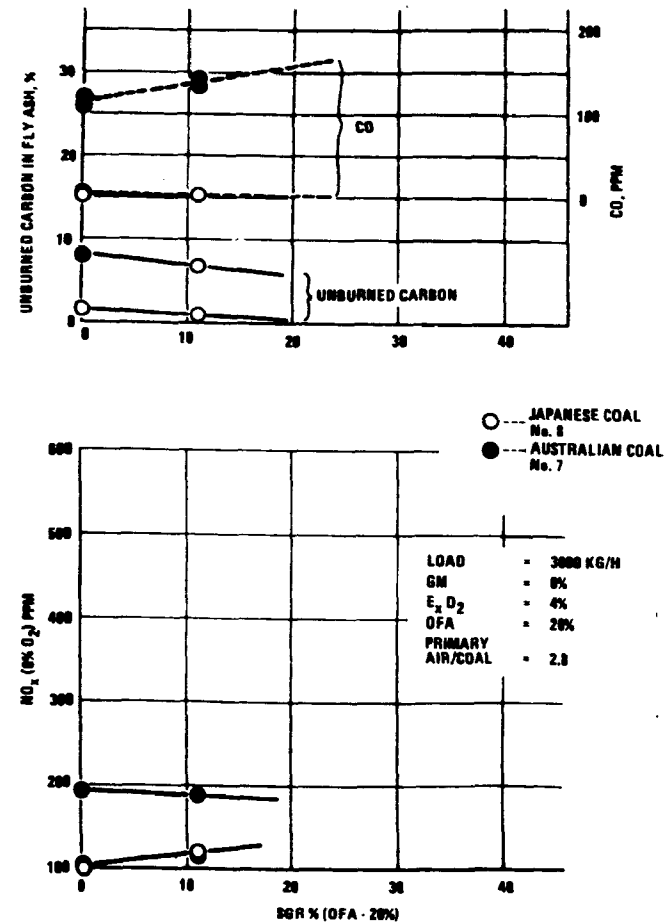
Fig. 21: NOx reduction with SGR at OFA=20%—SGR

120
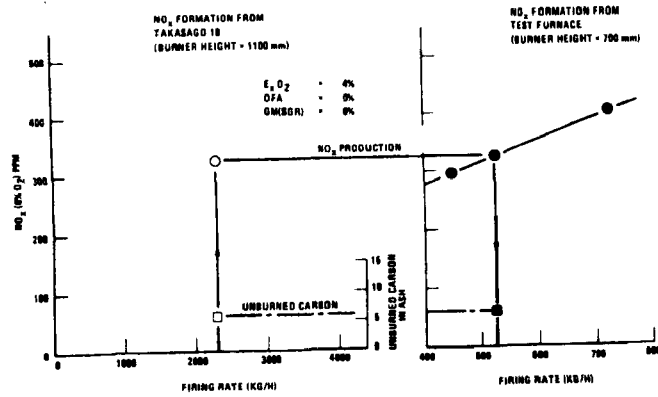
Fig. 22: Relationship between burner size and burner capacity for the same NOx formation (conventional and tangential burner
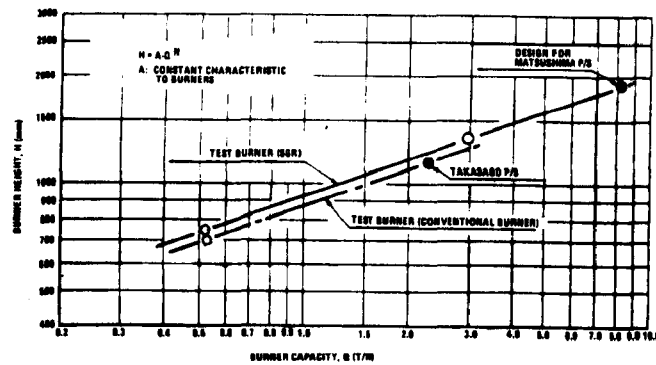
Fig. 23: Relation between burner size and burner capacity for the same NOx formation (conventional burner)
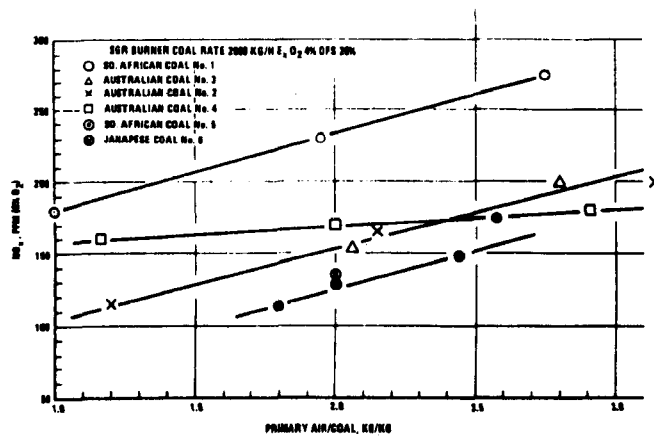
Fig. 24: NOx primary air-coal (fuel rich side)

121
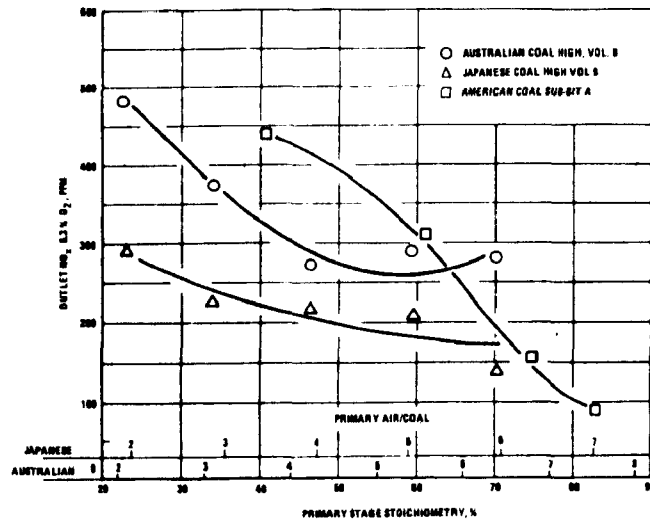
Fig. 25: Effect of primary stage stoichiometry on NOx (fuel lean side C-E)
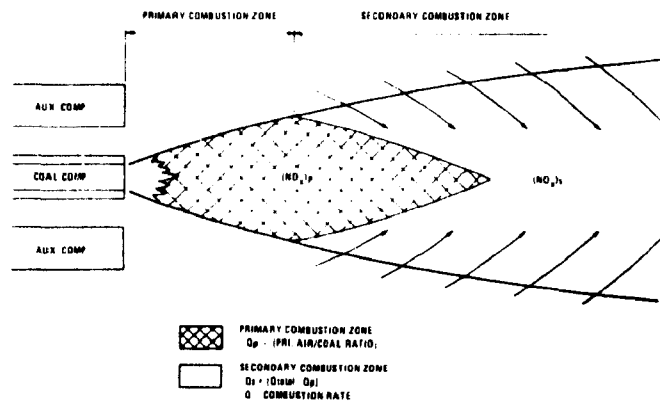
Fig. 26: Combustion model of pulverized coal firing
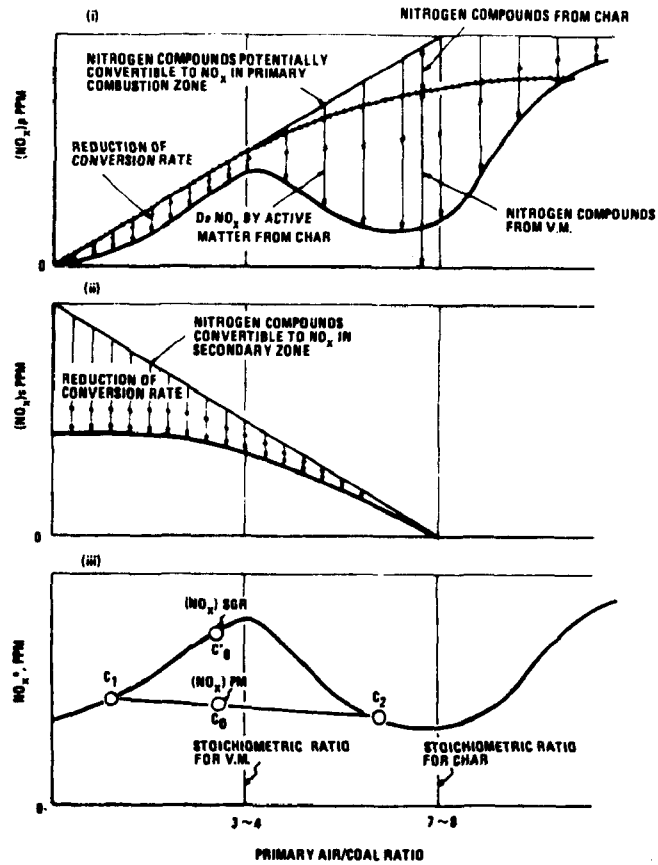
Fig. 27: NOx formation characteristics with primary air/coal ratio and conceptional figure of PM coal burner

123

OIL

AUX 2

SGR

FUEL
RICH

SGR

FUEL
LEAN

AUX 1

OIL
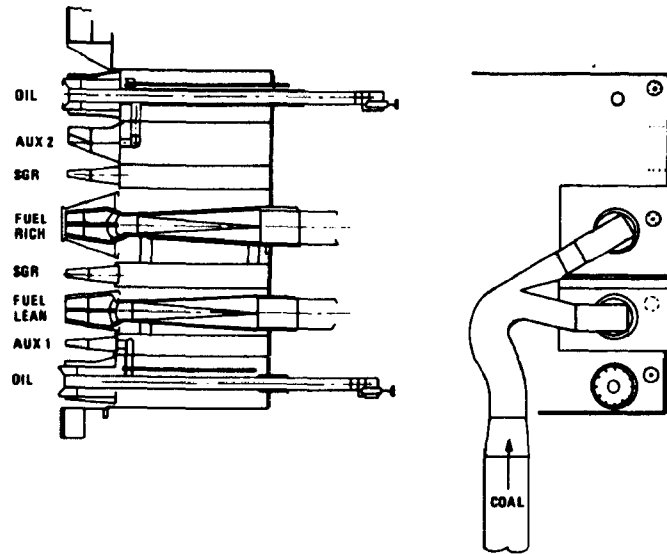
COAL

Fig. 28:   Structure of coal-fired PM cell in tangential firing system

CONVENTIONAL FLAME

PRIMARY AIR/COAL

(NO_x) CONVENTIONAL

LOW NO_x PM FLAME

(NO_x) SGR

NO_x, PM

C_1

(NO_x) PM

C_2

0

3~4

7~8

PRIMARY AIR/COAL RATIO
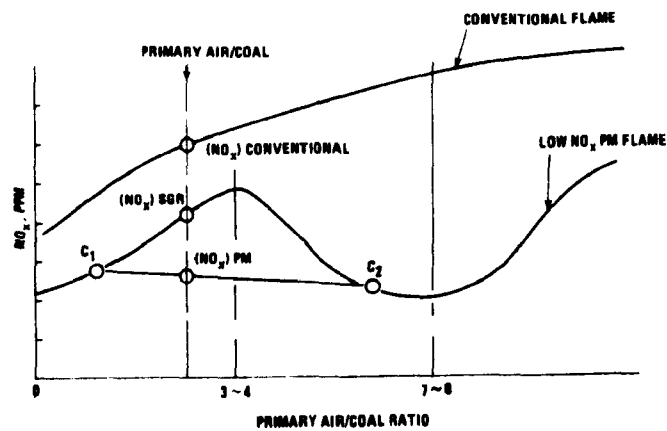
Fig. 29:   Comparative NOx formation characteristics of coal-fired PM and
           conventional flames

FUEL	FIRING SYSTEM	NO_x TARGET VALUE		FIRST APPLIED UNIT

COAL — TANGENTIAL

SGR BURNER SYSTEM
NO_x 150 PPM

COAL FIRING PM BURNER SYSTEM
NO_x 100 PPM

FUTURE PROJECTS

COMBINED CIRCULATION - 500MW
OCT., 1980

OIL

TANGENTIAL

OIL FIRING PM BURNER SYSTEM
NO_x 70 PPM

CONTROLLED CIRCULATION - 265 MW
JULY, 1977

HORIZONTAL

OIL FIRING ROPM BURNER SYSTEM
NO_x 80 PPM

CONTROLLED CIRCULATION - 350 MW
MAR., 1979

GAS

TANGENTIAL

GAS FIRING PM BURNER SYSTEM
NO_x 20 PPM

COMBINED CIRCULATION - 600 MW
APR., 1977

HORIZONTAL

GAS FIRING ROPM BURNER SYSTEM
NO_x 30 PPM

CONTROLLED CIRCULATION - 265 MW
FEB., 1978

NOTE: (1) ☐ ALREADY IN COMMERCIAL OPERATION

☐ NOW UNDER CONSTRUCTION OF MANUFACTURING

(2) KIND OF FUEL   COAL: AVERAGE JAPANESE BITUMINOUS COAL
                      OIL: HEAVY OIL (N 0.1%)
                      GAS: NATURAL GAS

(3) NO_x PPM BASIS: 4% O_2 FOR OIL, 5% O_2 FOR GAS, 6% O_2 FOR COAL (DRY VOL)

Fig. 30: Development of PM burner system by MHI

TABLE I

COMPARISON OF NATIONAL REGULATIONS ON NO_X EMISSION RATES IN JAPAN AND UNITED STATES

Fuel	Gas Quantity Rate Emitted		Allowable NO_X Emission Rates for New Units			
			Japan (1977)		USA (1979)	
	① 10^3 Nm³/h	② 10^3 SCF/h	③ ppm at 3% O_2	lb/10^6 Btu	ppm at 3% O_2	lb/10^6 Btu
Gas	≥ 500	≥ 18,662	68	0.08	161	0.2
	40-500	1493-18,662	113	0.14		
	10- 40	373- 1493	146	0.18		
	≤ 10	≤ 373	169	0.21		
Oil	≥ 500	≥ 18,662	138	0.18	230	0.3
	10-500	373-18,662	159	0.21		
	≤ 10	≤ 373	191	0.25		
Coal	No stipulation		480	0.67	④360/⑤432	④0.5/⑤0.6

Notes:

① Normal cubic meters per hour (0°C and 760 mm Hg).

② Standard cubic feet per hour (60°F and 14.7 psia).

③ Values are corrected to 3% O_2 base for convenience in comparing with USA standards. Japanese values based on 4% O_2 for oil, 5% O_2 for gas, and 6% O_2 for coal.

④ Sub-bituminous coal and solids derived from coal.

⑤ Most other coals.

TABLE II
LIST OF UTILITY BOILERS EQUIPPED WITH MHI PM BURNER SYSTEM

		Unit name	Unit cap. (MW)	Boiler type	Firing	Draft	Fuel/Atomization	Start of operation
Gas firing PM burner	New Unit	Anegasaki #5, Tokyo Electric	600	SC	T	P	LNG, LPG/-	APR., '77
		Tobata Kyodo #4, Tobata Joint Elec.	375	CC	T	B	LNG, BFG/-	FEB., '78
		Shin-Kokura #3, Kyushu Electric	600	SC	T	P	LNG/-	SEP., '78
		Shin-Kokura #4, Kyushu Electric	600	SC	T	P	LNG/-	JUN., '79
		Sodegaura #4, Tokyo Electric	1000	SC	T	P	LNG/-	JUN., '79
	Modified unit	Goi #3, Tokyo Electric	265	CC	H	P	LNG, Oil/Steam	MAR., '78
		Goi #1 Tokyo Electric	265	CC	H	P	LNG, Oil/Steam	FEG., '79
		Goi #5, Tokyo Electric	350	C	H	P	LNG, Oil/Steam	APR., '79
		Minami-Yokohama #3, Tokyo Electric	450	CC	T	P	LNG/-	JULY, '79
		Minami-Yokohama #2, Tokyo Electric	350	CC	T	P	LNG/-	NOV., '79
		Minami-Yokohama #1, Tokyo Electric	350	CC	T	P	LNG/-	MAR., '80
Oil Firing PM burner	New unit	Iwakuni #3, Chugoku Electric	600	SC	T	P	LPG, Oil/Steam	JULY., '81
		Plant "S"	350	SC	T	P	Oil/Steam	SEP., '82
		Plant "J"	600	SC	T	B	Coal, Oil/Steam	NOV., '82
	Modified unit	Yokosuka #1, Tokyo Electric	265	CC	T	B	Oil/Mech.	JULY, '77
		Kashima #1, Tokyo Electric	600	SC	T	P	Oil/Mech.	MAY, '78
		Ooi #1, Tokyo Electric	350	CC	T	P	Oil/Mech.	JULY, '78
		Chiba #1, Tokyo Electric	125	NC	T	B	Oil/Steam	MAY, '78
		Plant "H"	350	CC	T	P	Oil/Mech.	NOV., '78
		Yokosuka #2, Tokyo Electric	265	CC	T	B	Oil/Steam	DEC., '78
		Yokosuka #4, Tokyo Electric	350	CC	H	P	Oil/Steam	MAR., '79
		Kashima #3, Tokyo Electric	600	SC	T	P	Oil/Mech.	MAR., '79
		Yokosuka #5, Tokyo Electric	350	CC	H	P	Oil/Steam	JUN., '79
		Chiba #2, Tokyo Electric	125	N/C	T	B	Oil/Steam	JUN., '79
		Yokosuka #3, Tokyo Electric	350	CC	H	P	Oil/Steam	DEC., '79
		Takasago #2, Kansai Electric	450	SC	T	P	Oil/Mech.	JAN., '80
		Takasago #1, Kansai Electric	450	SC	T	P	Oil/Mech.	APR., '80
		Sanpo #1, Kansai Electric	156	CC	T	B	Oil/Mech.	JUN., '80

Note: Boiler type: NC—Natural circulation, CC—Controlled circulation, SC—Combined circulation
Firing: T—Tangential, H—Horizontal   Draft: P—Pressurized, B—Balanced

127

TABLE III
PRINCIPAL DATA OF BOILERS EQUIPPED WITH VARIOUS TYPE OF PM BURNERS

Item \ Unit	A	B	C	D
Burner type	Oil-PM	Oil-ROPM	Gas-PM	Gas-ROPM
Unit output (MW)	265	350	600	265
Fuel	Heavy oil	Heavy & crude oil	LNG	LNG & Naphtha
Firing system	Tangential firing	Horizontal firing	Tangential firing	Horizontal firing
Draft system	Balanced draft	Pressurized draft	Pressurized draft	Pressurized draft
Type of boiler	Controlled circulation, twin furnace	Controlled circulation, divided furnace	Supercritical combined circulation, divided furnace	Controlled circulation, divided furnace
No. of burners	3 elevations×8 corners =24	3 elevations×6 rows =18	5 elevations×8 corners =40	3 elevations×6 rows =18
Capacity of one burner (kcal/h)	32.86×10^6	52.02×10^6	38.93×10^6	40.02×10^6
Type of fuel atomization	Mechanical atomization —return system	Steam atomization	—	Steam atomization

128

TABLE IV
ANALYSIS OF COALS TESTED

NO.	COAL	PROXIMATE ANALYSIS				ULTIMATE ANALYSIS			HHV S.M.F. kcal/kg
		V.M. %	F.C. %	ASH %	F.C./V.M.	N DRY/DAF %	O DRY %	O/N	
1	SOUTH AFRICAN	25.3	55.0	17.0	2.17	1.6 (1.93)	10.8	6.75	6420
2	CHINESE	28.1	57.8	10.7	2.06	0.8 (0.9)	11.7	14.63	7020
3	JAPANESE	33.8	37.0	26.8	1.09	0.9 (1.23)	7.9	8.78	5850
4	SOUTH AFRICAN	31.3	51.6	13.2	1.65	1.7 (1.96)	13.3	7.82	6540
5	CHINESE	29.8	48.8	18.4	1.64	1.03 (1.26)	12.0	11.65	6330
6	JAPANESE	43.9	37.7	12.7	0.88	1.1 (1.26)	14.5	13.18	6370
7	AUSTRALIAN	30.7	54.2	11.9	1.77	1.6 (1.82)	9.1	5.69	6890
8	JAPANESE	46.4	37.3	10.7	0.80	1.1 (1.23)	14.1	12.82	6510

AN EVALUATION OF NO_x EMISSIONS
FROM COAL-FIRED STEAM GENERATORS

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130

ABSTRACT

The design evolution of the Riley coal-fired TURBO Furnace and Directional Flame Burner is reviewed. Burner aerodynamics are characterized and the effectiveness of burner adjustments and staged combustion in reducing NO_x emissions in this unique firing system are discussed. Field test emissions data are presented and analyzed with respect to burner operating variables. A decrease in NO_x emissions is observed as mixing of fuel and air in the near burner zone is delayed. Further development of directional flame and controlled mixing burners for coal-firing applications is also discussed.

INTRODUCTION

In a continuing effort to characterize the production of NO_x in coal-fired Riley TURBO Furnaces, the Riley Stoker Corporation is obtaining field data on operating units as part of the company's long-term NO_x Program. Since our report at the Second EPRI NO_x Control Technology Seminar, the additional field data collected has been incorporated into the data base from which a regression analysis is performed to aid in the prediction of NO_x emissions from the TURBO Furnace. This model for predicting NO_x was discussed in some detail in previous conferences[1,2] and is only briefly mentioned here.

The additional data collected in the past 2 years includes information on dry bottom TURBO Furnaces with overfired air. A great effort has been placed on trying to quantify the effects of variation and adjustments to the specific types of burner hardware unique to this firing system. This includes components such as velocity control dampers, adjustable secondary air vanes, and coal stream spreaders. Although the Riley TURBO Furnace and its firing system have been detailed in the open literature, a summary review is made here to reacquaint the reader.

The focal point of much of the latest effort has been to characterize the burner aerodynamics which have the greatest effect on controlling the evolution of fuel-bound nitrogen into NO. The aerodynamics of concern are in the near burner zone, described in our previous paper as the primary zone of the overall furnace model. Although the thermal fixation of nitrogen in air contributes significantly to the NO emission, the conversion of fuel-bound nitrogen is the prime contributor to the overall emission of NO in the range of values evaluated here.

TURBO FURNACE DESIGN

Furnace Design Features

The unique configuration of the Riley TURBO Furnace was first used in
the late 1940's. At that time, the difficulty concerned the combustion of a
petroleum byproduct known as fluidized coke. While this fuel had a high
calorific value, it was slow in burning and needed a longer furnace
residence time. Bending the front and rear walls inward, but not to the
extent of a roof- or arch-fired furnace, provided a cost-effective means of
furnishing a longer path for the combustion process compared to a straight
wall unit front-, rear- or opposed-fired. As illustrated in Figure 1, the
fuel and air admitted through the burners on both walls was inclined to the
center of the furnace. Combustion took place as the mixture curled down and
then up through the lower furnace.

The venturi shape formed by this tubing arrangement and the diffused
flame pattern provided by the Directional Flame Burner produced an even heat
distribution across the unit while the walls of the lower and upper furnace
remained comparatively free of ash or slag buildup.

Second generation Riley TURBO Furnaces were built primarily for
natural gas and residual oil firing as was dictated by the energy climate at
that time. The furnace had a flat floor formed by the water wall tubes.
With the ability of the burner to vary the direction of the air with respect
to the fuel flow, it brought the performance of these widely varying fuels
more in line with each other by bringing the furnace exit gas temperature on
each fuel closer together than it would be on a straight wall unit. Coal
was also burned in these flat bottom or slag tap type furnaces, but this was
usually limited to comparatively high slagging characteristic coals. A
typical coal-fired wet bottom TURBO Furnace of this type is shown in
Figure 2. For other types of coal, Riley still used straight wall-fired
units at that time.

During the mid- to late-1960's, many boilers were being built to fire
oil and gas. About this same time, Riley began to intensify its research in
the area of NO_x emissions. This work occurred into the early 1970's and
has been well documented.[3,4,5,6] The work consistently showed that the

baseline emission of NO_x was always lower in the TURBO Furnace than the straight wall-fired units. To meet the modern needs of the industry and the switch of the energy mix back to a coal base, the third generation Riley TURBO Furnace was developed. This modern concept includes a dry hopper bottom with a water-impounded ash receiver below the hopper throat. The critical furnace design dimensions are shown in Figure 3.

A list of some of the Dry Bottom Riley TURBO Furnaces supplied for coal firing is shown in Table I. These units were designed to fire a wide range of coal types ranging from eastern bituminous to western subbituminous. The typical analysis for a few of these coals in shown in Table II. Figures 4 through 9 illustrate the variation of the sectional side elevations for some of the units in Table I. As can be seen in these figures, there are significant differences in each unit design and its equipment for this one type of boiler. These differences are the results of many factors. Some of the more important factors are the coal characteristics such as higher heating value, slagging tendency, grindability, and customer preferences.

Burner Design Features

The Directional Flame Burner (Figure 10) is used exclusively in the Riley TURBO Furnace. This is a unique diffusion-type burner. These are slow mix, nonswirl burners. The secondary air and primary air coal jets are essentially parallel. Adjustments can be made to the directional secondary air vanes to deflect the secondary air into or away from the primary stream. A velocity control damper is provided to allow for varying the secondary air velocity. An adjunct overfire air or staged combustion port is dampered to adjust burner zone stoichiometry. With the combination of these three airflow control systems in the burner, the degree of mixing in the primary flame zone can be controlled over a wide range. A major effort is being made to characterize the effect of these three design features on NO_x production in coal-fired TURBO Furnaces.

Although not adjustable on commercial burners, some modification has been made for test purposes to utilize an adjustable coal spreader. This allows variations of the axial relationship between the primary and

secondary stream while also significantly changing the interaction point of the flames from the front and rear wall burners.

All of these burner adjustment features not only impact NO_x evolution, but can have an important major effect on overall furnace performance. Care must be taken when making burner adjustments that this performance is not adversely compromised. This would include situations such as high CO, excessive carbon loss in the ash, reduced unit efficiency, poor or loss of superheater or reheater temperature control, extreme reducing atmospheres that could cause corrosion or excessive fouling, or a host of other difficulties.

With this in mind, our long-term NO_x control program includes a potential problem analysis in our decision process to ensure that a viable NO_x control scheme is formulated that will incorporate safe and reliable boiler operation with the most efficient utilization of present fuel resources.

FIELD TEST RESULTS

Burner Aerodynamics

As discussed earlier, one of the methods of controlling the fuel and air mixing history in the Directional Flame Burner is through adjustment of the secondary air vanes located above and below the coal nozzle (as shown in Figure 10). These directional air vanes can be tilted up or down in a number of different positions to change the rate of fuel/air mixing. A description of these various positions is given in Figure 11.

Burner exit geometrics for four selected vane positions are illustrated in Figure 12 for the fuel nozzle slot. These sketches help to provide a conceptual understanding of the influence of burner vane position on near field fuel/air mixing.

The burner input to the furnace, as shown in Figure 12, can be divided into three streams: the coal plus primary air stream, and secondary air streams above and below the burner nozzle. The slowest mixing occurs for air vane setting characterized as Number 2. Secondary air above the burner nozzle at this setting is introduced essentially parallel with the primary coal air stream while the air entering below the nozzle is directed away

135

from the primary stream. The degree of mixing between these primary and secondary streams increases progressively for burner vane positions numbered 2, 9, 10, and 7, respectively. Burner vane setting Number 7 produces the earliest intersection of the upper secondary air stream with the primary coal-air stream. In all of the cases shown in Figure 12, the coal spreader is tilted up with respect to the burner centerline. The same order of burner air vane ranking, however, would also exist for a coal spreader designed with a 0° upward tilt.

The results of tests on three dry bottom TURBO Furnaces to determine the effect of burner vane position on NO_x is shown in Figure 13. The results for each unit represent operation at maximum continuous rating and are evaluated for similar firing conditions with the only change being the adjustment of the burner directional air vane position. One of the units is designed without overfire air and is operated on subbituminous coal. The other two units are designed for different levels of staged combustion and each fires bituminous coal.

The mixing concepts described earlier can be used to provide some insight on the trend in the variation of NO_x emissions with burner air vane setting. NO_x levels are observed to increase with the degree of mixing. Highest emission levels occur at air vane position Number 7, while lowest emission levels occur at position Number 2.

The effect of a limited range of coal spreader angles on NO_x emissions is shown in Figure 14. NO_x emissions appear to be the most sensitive to the degree of coal spreader tilt at the higher NO_x producing (i.e., earliest mixing) air vane settings.

Staged Combustion

Field data analyzed to date shows that staging the combustion process by the use of overfire air always has the effect of decreasing NO_x. The percentage reduction can vary a great deal, from as low as 8 percent to as high as 24 percent. All reductions were evaluated under similar firing conditions with the only mechanical change being the shift of overfire air dampers from shut to full open. The large variations in the NO_x percentage reductions are the result of numerous design and operating factors.

136

The effectiveness of overfire air as a NO_x control technique is dependent, to a degree, on what other control methods are applied. If the NO_x emissions, for example, have already been reduced by some other means with the burner aerodynamics, such as directional vane or coal spreader setting, the effects of overfire air are not as great. This is basically verifying what has been known for some time. NO_x controls are not additive and this is even more prevalent when the baseline NO_x levels are already low.

FUTURE WORK

The current effort of collecting and analyzing field data on emissions and furnace performance will continue into the forseeable future. Many of the units listed in Table I not already online, will be coming online in the next 12 months. The information collected on these new TURBO Furnaces will be included into the data base for this type of boiler. This will aid in refining the regression analysis used to predict emissions and furnace performance. Test series on specific units will be designed to give further quantifications to the effects of the design and adjustment of the various burner hardware.

In the laboratory, the field program will be supplemented by numerous development projects. These will include cold flow model studies into the aerodynamic characteristics of the burners, further development of a lower furnace model, and firing tests in a research furnace. The present Riley research furnace, capable of firing 300 MMBtu/hr on gas or oil, is in the process of being retrofitted to fire solid fuels to a nominal rate of 100 MMBtu/hr. This conversion includes equipment for sizing, storing, and metering the fuel, as well as an air preheater for proper combustion, and a tail-end cleanup system to ensure local emission regulations are adhered to.

Development will be for the directional flame and circular controlled mixing types of burners. Circular burners are being developed in a full range of sizes for application in both utility and industrial units, primarily for retrofit and upgrading purposes.

SUMMARY

The dry bottom Riley TURBO Furnace offers a unique furnace and burner combination that allows flexibility in limiting NO_x release while

maintaining safe and efficient operation consistent with economic use of our indigenous natural resources. The field data has shown that adjustments to the various burner hardware, such as overfire air ports and directional air vanes, can significantly reduce the NO_x emissions. The improved combustion techniques being developed will assist in further reducing pollutant emissions to meet the new environmental regulation that will be more stringent in the future for the full range of boiler sizes in the utility and industrial market.

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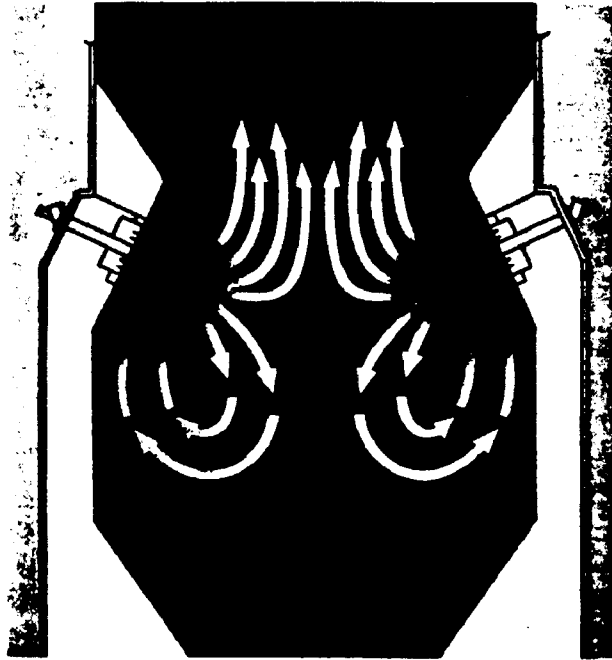
Figure 1. Configuration and flow patterns of the TURBO Furnace.
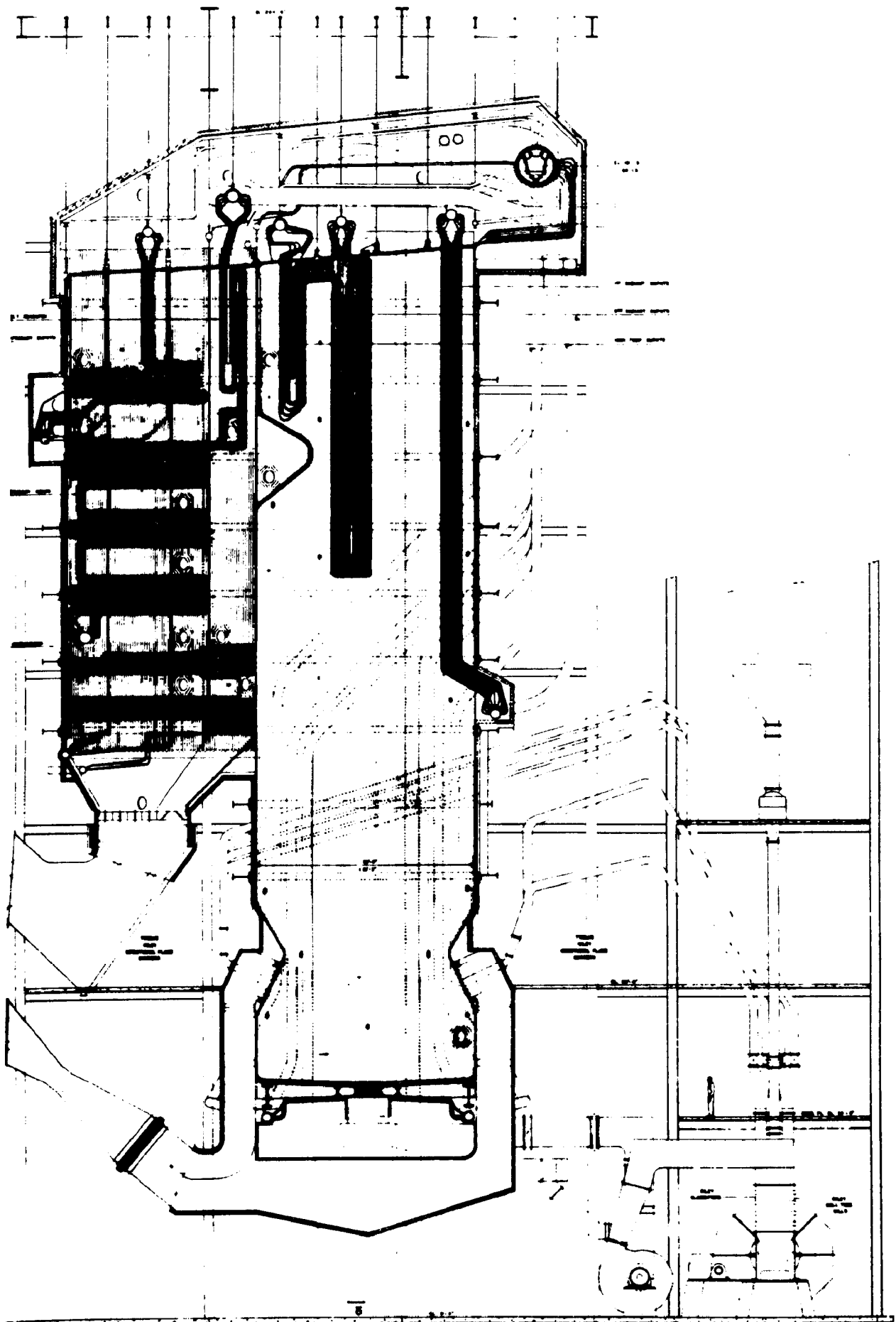
Figure 2.   Typical coal-fired wet bottom TURBO Furnace.

SIDE VIEW

PLAN VIEW
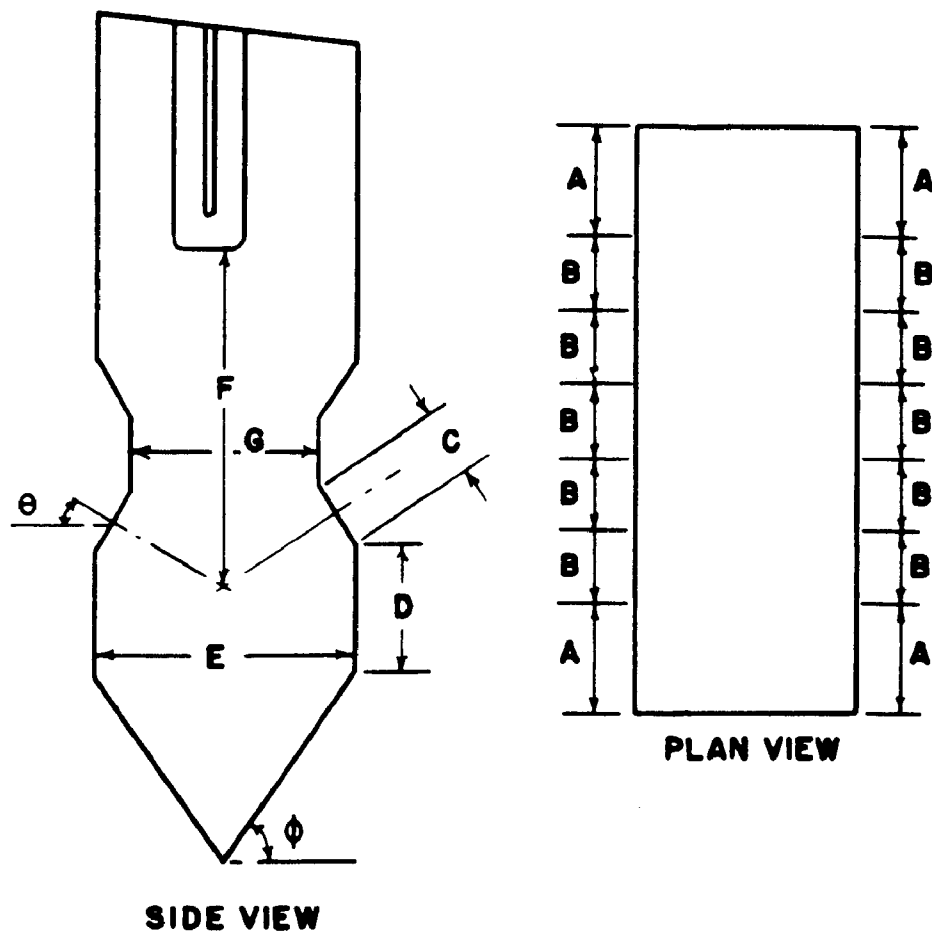
Figure 3. Dry bottom TURBO Furnace critical design parameters.

142
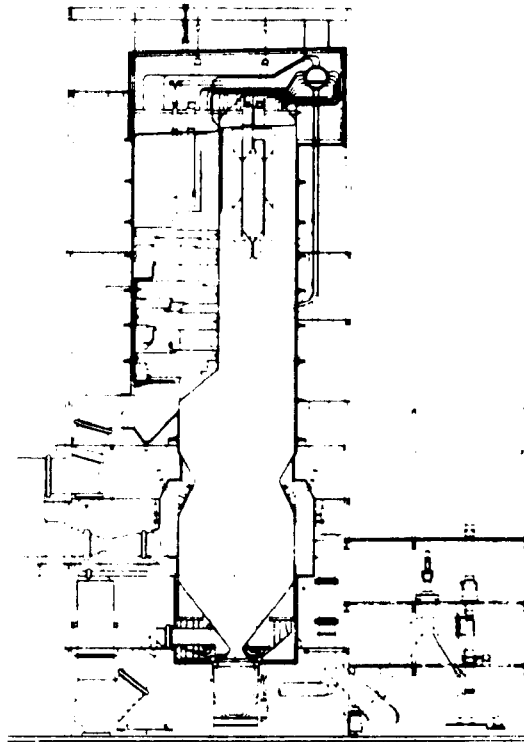
Figure 4. Southwest Power Station City Utilities of Springfield
Springfield, Missouri.
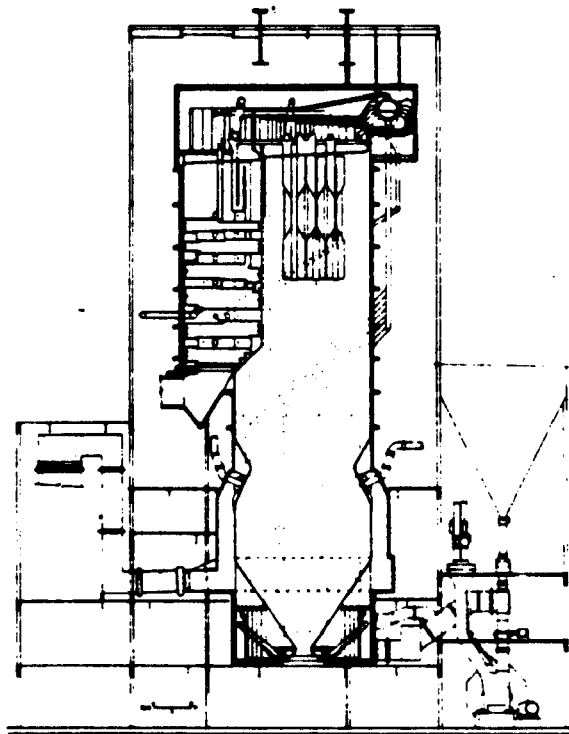
Figure 5. Interstate Power Company Lansing Power Station Lansing, Iowa.
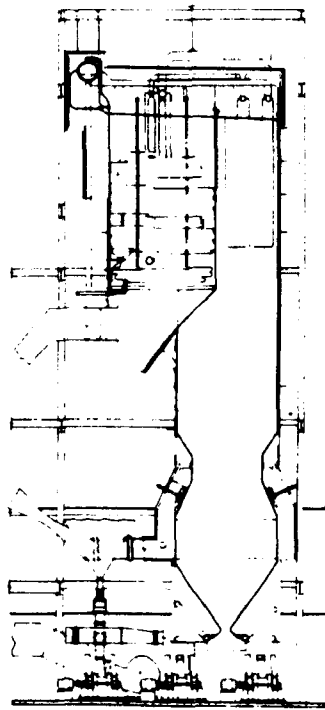
Figure 6. Santee Cooper South Carolina Public Service Authority, Georgetown Steam Electric Station, Unit No. 2, Georgetown, South Carolina.
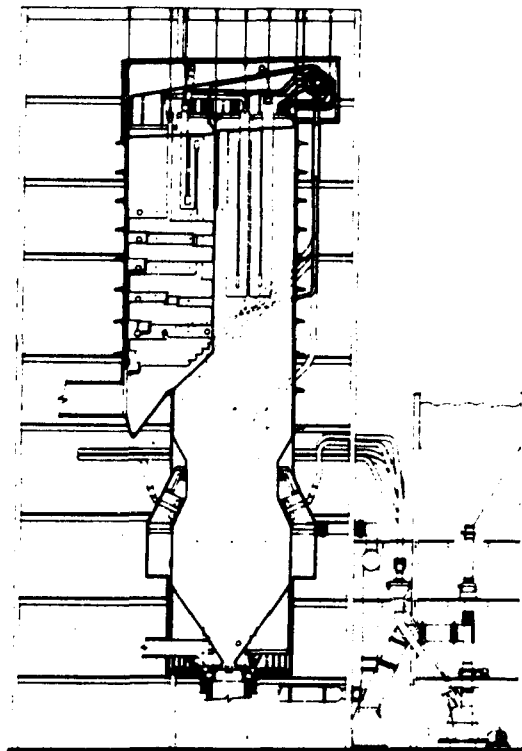
Figure 7. South Mississippi Electric Power Association, Purvis Plant, Units No. 1 and 2 Hattiesburg, Mississippi.
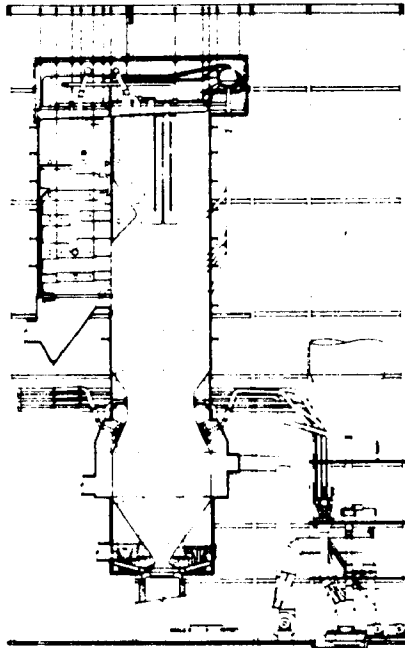
Figure 8. Alabama Electric Cooperative, Inc. Tombigbee Plant, Units No. 2 and 3, (near) Jackson, Alabama.
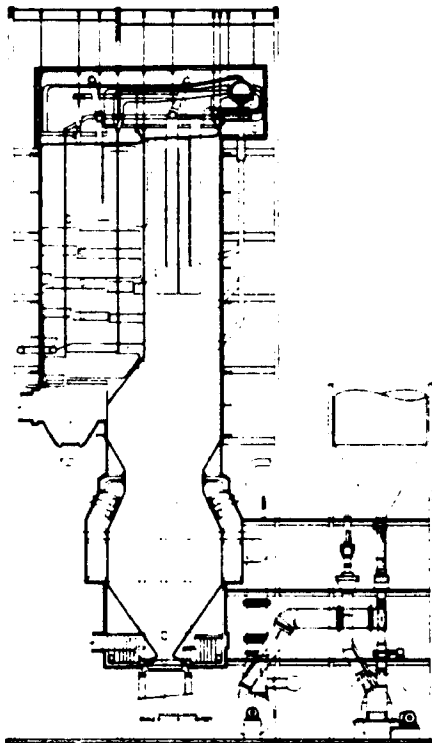
Figure 9. Arizona Electric Power Cooperative, Inc. Apache Station, Units No. 2 and 3, (near) Cochise, Arizona
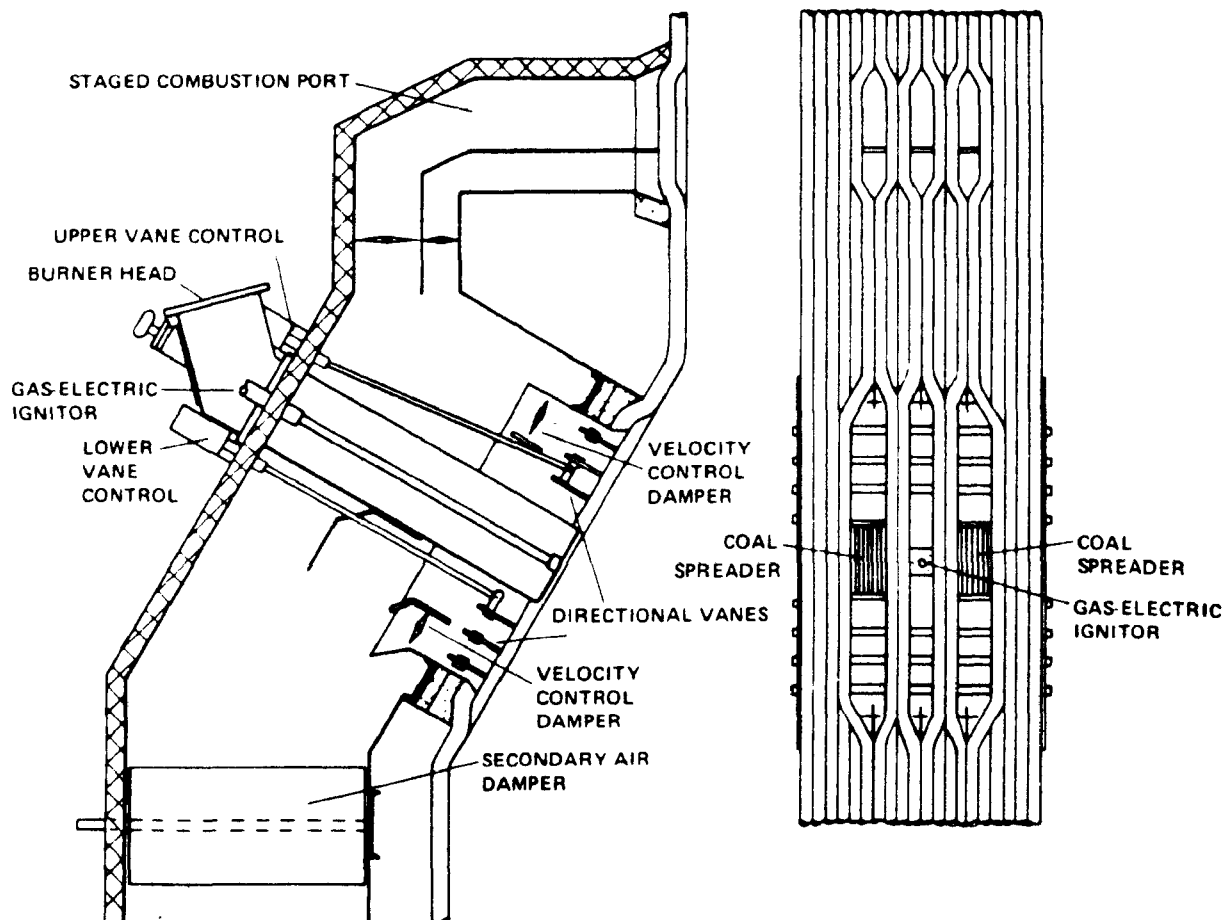
Figure 10. Riley Directional Flame Burner with staged combustion ports for coal firing.
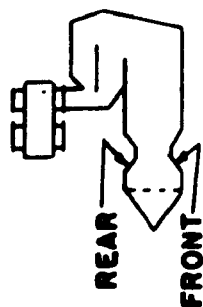
NUMBER OF VANE SETTING	REAR		FRONT
1	(UPPER VANES) (LOWER VANES)		
2			
3			
4	(ALTERNATING BURNERS)		
5			
6			
7			
8			
9			
10			

Figure 11. Burner air vane settings.
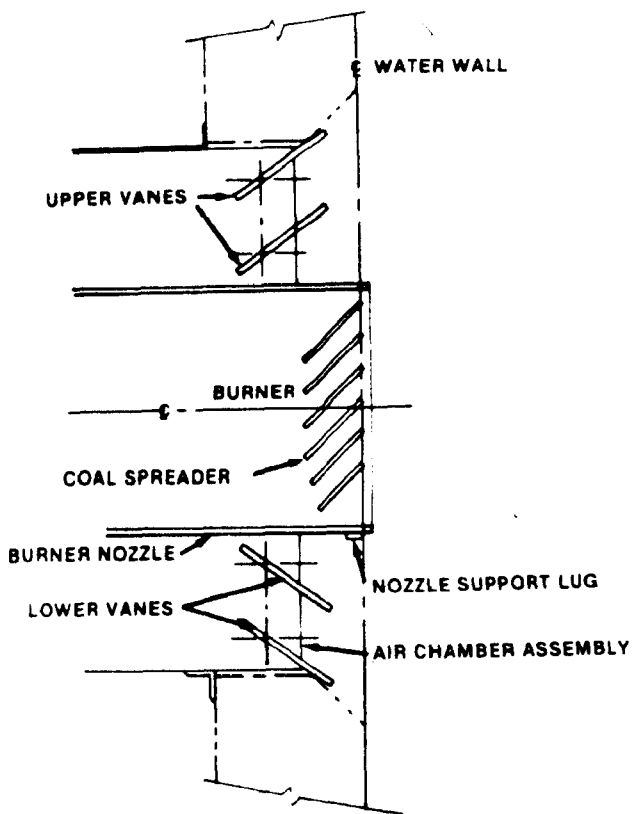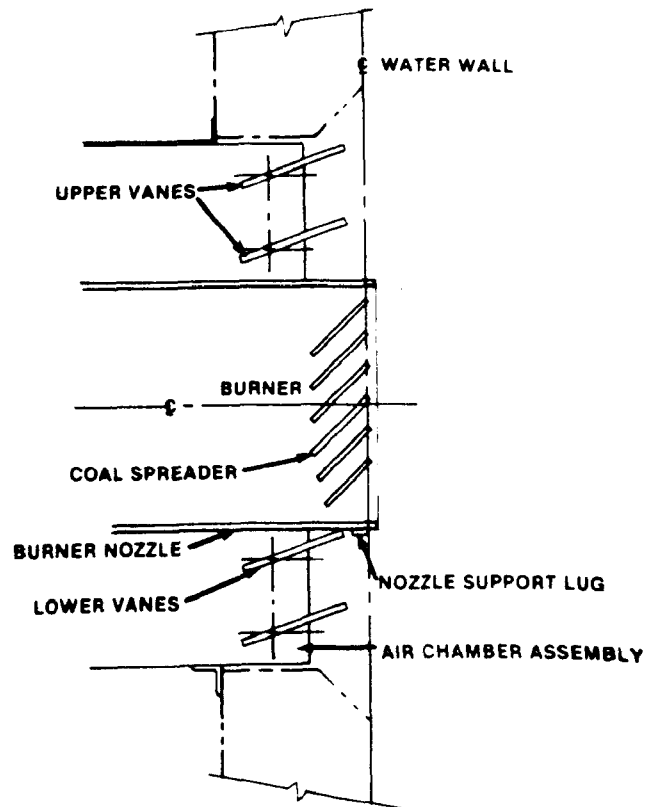
147
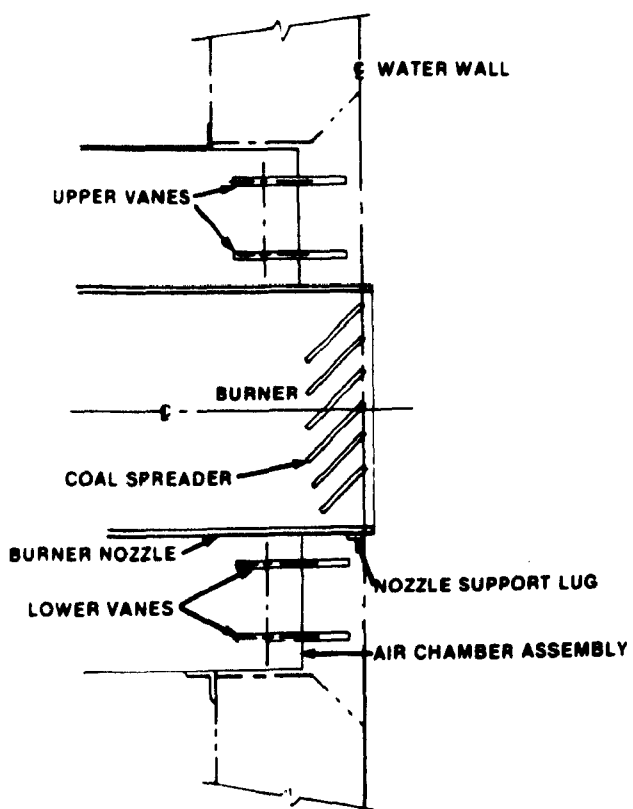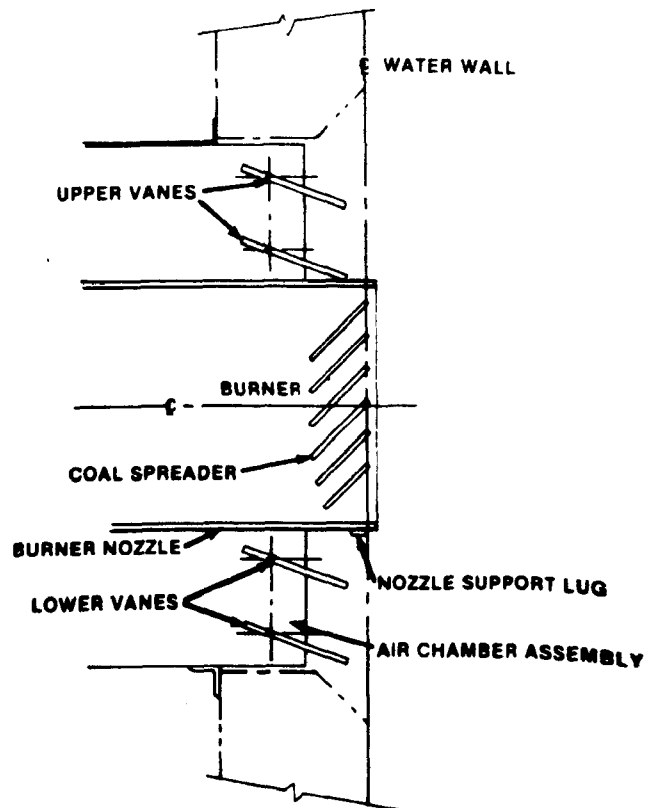
Figure 12. Directional flame burner exit geometries.

148
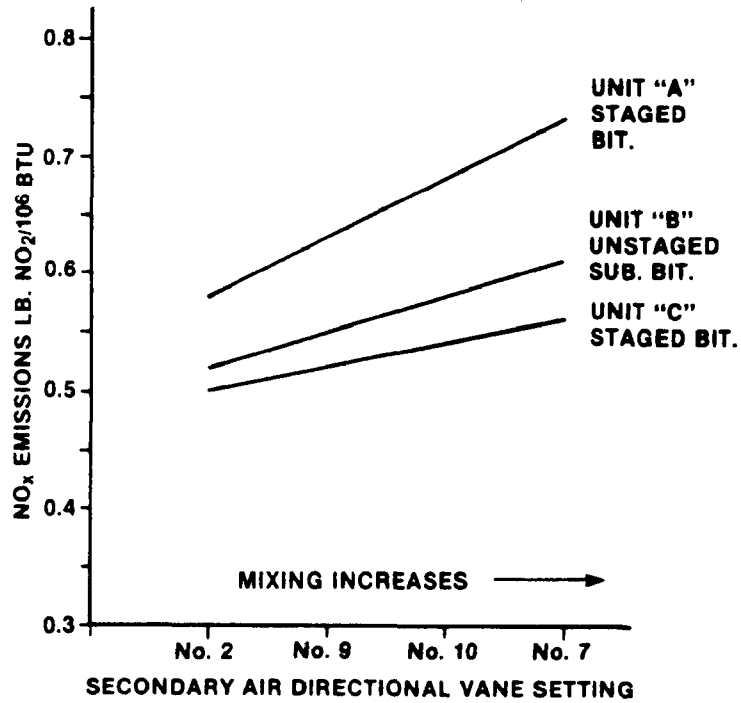
Figure 13. Effect of burner air vane position on NO_x emission.
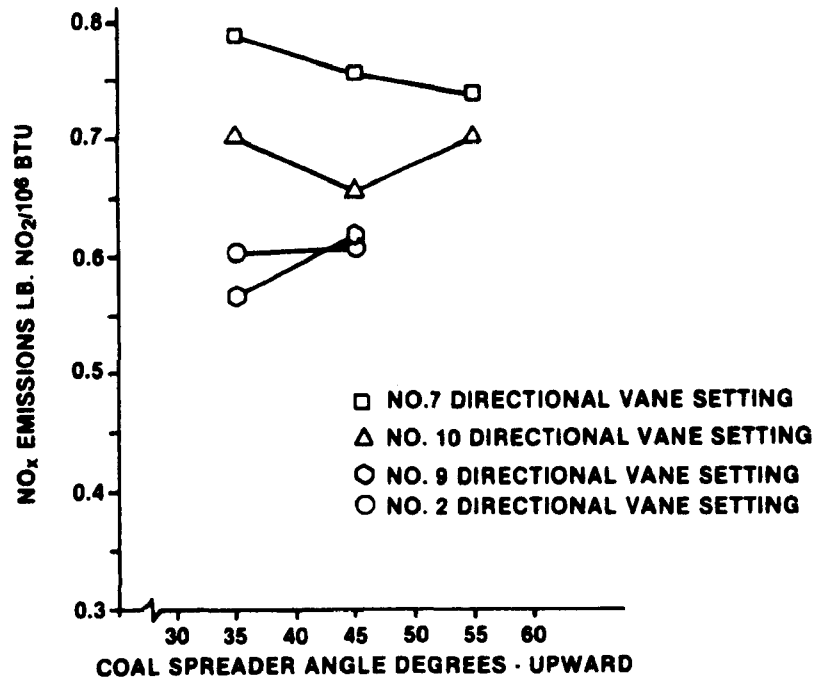
Figure 14. Effect of coal spreader angle on NO_x emission.

149

TABLE I. RILEY DRY BOTTOM TURBO FURNACE UNITS

Customer	Scheduled Startup Year
Union Carbide	1963
City of Springfield	1976
Emery Industries	1976
Interstate Power Company	1977
Cleveland Cliffs Iron Company	1978
South Mississippi Electric Power Association (two units)	1978
Santee Cooper Public Service Authority	1977
Delmarva Power and Light Company	1980
Dairyland Power Cooperative	1979
Salt River Project	1978
Arizona Electric Power Cooperative, Inc.	1978
City of Kansas City	1980
Alabama Electric Cooperative, Inc.	1978
Wisconsin Electric Power Company	1980
Wisconsin Electric Power Company	1982
Arizona Electric Cooperative, Inc.	1978
Alabama Electric Cooperative, Inc.	1979
Salt River Project	1978
Salt River Project	1984
Cleveland Cliffs Iron Company	1979
Cajun Electric Power Cooperative, Inc.	1979
Cajun Electric Power Cooperative, Inc.	1980
Hoosier Energy Division	1981
Hoosier Energy Division	1982
Santee Cooper Public Service Authority	1980
Santee Cooper Public Service Authority	1981
Central Illinois Light Company	1983

TABLE II. COAL ANALYSIS

Properties	Coal Rank		
	Bituminous	Bituminous	Subbituminous
% C	66.32	66.80	47.81
% H	4.62	4.67	3.43
% N	1.41	1.40	1.05
% O	7.07	4.01	11.13
% S	2.07	3.54	0.42
% Ash	12.71	12.88	6.16
% Moisture	5.8	6.7	30.0
HHV Btu/lb	11,832	12,064	8,253
Ash fusion temperature (I.D.-Oxy)	2,550	2,180	2,120
Slagging index	Low	High/severe	High/severe

NO$_x$ EMISSIONS CHARACTERISTICS OF ARCH-FIRED FURNACES

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ABSTRACT

Field tests have been conducted on three subbituminous pulverized-coal arch-fired utility boiler configurations. The objective of these tests was to determine as-found NO_x emission levels and the influence of combustion modifications on these emissions. These configurations are unique in that the coal is introduced downward from the arch into the furnace with the bulk of the combustion air added through the front wall perpendicular to the flame jet. Staged combustion conditions are thereby generated which have been shown to be conducive to low NO_x emissions.

Corrected NO levels ranged from 200 ppm to 350 ppm. The lowest emissions were emitted from the largest (275 MW) boiler. Variations in excess air, air flow injection distribution between burner and front wall and burner stoichiometry were shown to reduce NO emissions by 5 to 35 percent. A discussion of these results is presented.

INTRODUCTION

Promulgation of New Source Performance Standards (NSPS) by the U.S. Environmental Protection Agency (EPA) for coal-fired utility boilers has created significant interest in developing suitable low-NO_x combustion systems. Several programs under boiler manufacturer, EPA and EPRI sponsorship (1-5) have been underway directed at developing new burner/boiler design concepts. All of these designs in one manner or another use a staged combustion process which has been shown to be the most practical means of achieving reduced NO_x emissions.

An alternative to these new burner/boiler configurations is the arch-fired furnace. Boilers of this design are characterized by (A) burners situated in the furnace arch, oriented vertically and firing down into the furnace and (B) a significant portion (up to 80 percent) of the combustion air supplied through the furnace frontwall along the flame front perpendicular to the flame jet. A long U-shaped flame is thereby generated with inherent staged combustion conditions. This method of firing has acquired several descriptions including "arch-fired," "vertically-fired," "down-fired," "U-flame," and "down-shot." The terms "arch-fired" and "vertically-fired" have been used interchangeably during this study. The arch-fired design should not be confused with other firing configurations which, although fired from the top of the furnace downward, introduce all combustion air at the burner. These boilers, therefore, do not have the inherent staged combustion conditions of the arch-fired design and consequently do not have corresponding low NO_x emission characteristics.

Arch-fired boilers have been used in utility applications for over sixty years. Boilers of this general configuration were the first to successfully

use pulverized coal combustion. Development of subsequent designs contributed significantly to modern design concepts (7). Modern use of arch-firing in the United States has been limited to three subbituminous coal-fired boiler configurations used by the Wisconsin Electric Power Company (WEPCo) and several applications to anthracite coal-fired boilers (8).

This paper presents a discussion of arch-firing as a low-NO_x design approach for subbituminous coal combustion in utility boilers. The boilers considered in this study are the three WEPCo configurations. Descriptions of these boiler designs are presented together with results of field tests conducted to characterize NO emissions. Comparisons are made between the emission characteristics of the arch-fired boilers. A discussion is presented identifying in a speculative manner the significant combustion parameters conducive to low-NO_x.

This study was conducted as part of an EPRI sponsored program to investigate the use of arch-firing as an alternative utility boiler design. The results of this study are documented in an EPRI report, "NO Emissions from Pulverized Coal Vertically-Fired Boilers" (9). An economic evaluation of the use of arch-firing has been conducted by Foster Wheeler Energy Corporation (10).

BOILER DESCRIPTIONS

The three boiler configurations are unique having been custom designed by engineers at WEPCo. The smallest boilers, with a capacity of 80 MW, are located at the Port Washington Generating Station. The two other designs are at the Oak Creek Generating Station. The 125-MW boilers are located in the North Plant while the 275-MW boilers are in the South Plant. Nine boilers were included in the test program: four of the 80-MW class (Boilers 2, 3, 4, and 5), three of the 125-MW class (Boilers 1, 2, and 4), and two of the 275-MW size (Boilers 5 and 6).

A summary of the design parameters for the three boiler configurations is presented in Table I. This information is provided as reference for interested utility and manufacturing engineers. A brief description of the furnace

155

design factors follows. More comprehensive descriptions of these boilers can be found in References 8 and 9.

The general arrangement of the three boiler types are illustrated in Figure 1. The boilers share several common design features as well as having individual characteristics. In all three, the burners are located in the furnace arch, are oriented vertically and fire down into the furnace. The pulverized coal for these boilers is prepared and temporarily stored above the burners in bins. Feeders control the flow of pulverized coal into the primary air stream that transports the coal through the burner and into the furnace. Ignition occurs approximately three to five feet from the burner outlet, producing a flame jet that penetrates to the bottom of the furnace. Combustion air is added around the burner (termed secondary air) and from the front wall perpendicular to the flame jet. Front wall air is introduced into the furnace through slits between the front wall watertubes.

The final common design feature of these units is the incorporation of radiant superheat and reheat heat transfer in the furnace. These elements were included in the original design to improve low-load steam temperatures and overall operating efficiency. In essence, however, this design results in heat transfer characteristics in the furnace that differ from those of conventional waterwall furnaces. Close control of the combustion conditions in the furnace is also required in order to maintain proper steam conditions. Excessive steam tube temperatures are controlled primarily by overall boiler excess air. In all three designs, the furnace front wall and division walls under the arch (where present) consist of watertubes. The furnace side and back walls consist of steam tubes.

The primary differences between the WEPCo boilers (other than capacity) involve (a) the burner design and combustion air distribution, generating differing near burner combustion conditions, (b) the arrangement of the burners and (c) the presence of division walls.

The design of the burners used on the 80 MW and 125 MW boilers is simple, consisting of tapered pipes with a four pronged helix inside near the burner tip. The helix is used to impart swirl to the pulverized coal/primary air stream. The burners used on the 275 MW boilers, on the other hand, are much

more complex. A diagram of the burners used on the 275 MW boilers is presented in Figure 2. The pulverized coal is transported from the feeder to the burner by scavenging air. The primary air is spiraled around the coal stream generating a hollow cylinder of pulverized coal injected into the furnace. The balance of the combustion air is supplied both at the burner and from the furnace front wall. The additional air supplied at the burner passes through the two concentric cones shown in Figure 2. The inner cone converges to generate high velocity air that assists the flame jet in penetrating to the bottom of the furnace. The outer cone diverges to produce low velocity combustion air in the immediate vicinity of the burner tip. Both cones have non-adjustable vanes to impart swirl to the incoming air. Modifications have been made to block approximately 50 percent of the outer cone inlet area. There is no available hardware to control secondary air flow to individual burners in a cell.

The arch-fired designs also differ in the number and arrangement of the burners and the presence of division walls. These factors are illustrated in Figure 3. The 80 MW boilers are fired through 20 burners arranged in a single line evenly spaced across the length of the arch. There are no division walls used on this design. The 125 MW are fired through 16 burners also arranged in a single line but separated into four groups of four. The presence of water-tube division walls underneath the arch between these burner groups form four furnace "cells." The sixteen burners on the 275 MW design have also been separated into four groups of four. The arrangement of these burners, as shown in Figure 3, is significantly different. The burners in each group are configured in a "trapezoidal" pattern forming two rows of burners across the arch. The outer row of burners (farthest from the furnace front wall) are therefore somewhat shielded from the front wall air by the inner row of burners. The division walls on the 275 MW boilers extend across the furnace and up into the initial convective passes. The furnace is thereby effectively separated into four sub-furnaces operating somewhat independently.

NO EMISSIONS MEASUREMENT RESULTS

Presented in this section are the results of the NO emission testing
conducted on the three arch-fired boiler designs. The test program on each
boiler consisted of two parts: (1) a baseline characterization to determine
as-found emission levels and the influence on NO levels of excess air, and
(2) combustion modification tests directed at determining the effect of
alterations in the inherent staged combustion conditions on NO emissions. The
available flexibility of combustion air distribution along the flame jet and
burner stoichiometry through burners-out-of-service operation were used as the
two methods of implementing staged combustion. The following discussions
follow this format, describing first the results of the baseline tests and
then the combustion modification tests.

All tests conducted during this program used the coal customarily fired
in these boilers. The primary coal sources for these boilers are located in
Southern Illinois/Western Kentucky. The 125 MW boilers also periodically fire
western coal from Wyoming. A summary of analyses for as-fired pulverized coal
samples collected during the program are presented in Table II.

BASELINE NO EMISSION CHARACTERIZATION

The full load NO emissions for the three boiler types are presented in
Figure 4. With the exception of one of the 80 MW boilers, the emissions data
form three groups corresponding to the three boiler types. Note that the NO
levels decrease with increasing boiler capacity. For all three designs, the
NO levels increased with increased excess air.

The spread in the emission levels for three of the four 80 MW boilers
(Port Washington Boilers 2, 4 and 5) was introduced by variations in the

158

excess air level. NO emissions are shown to increase by approximately 30 ppm for each one percent increase in flue gas O_2. The NO levels for the remaining unit (Boiler 3), however, were significantly lower, by 80 ppm at comparable O_2 levels. This difference between the emission levels from this boiler and the other three 80 MW units was partially attributed to the quantity of primary air flow. While the data presented in Figure 3 for Boilers 2, 4, and 5 represented operation at primary air pressures of 15 to 16 inches of water, the NO emissions data for Boiler 3 were obtained while operating at 13 inches of water. To further investigate this, NO emissions were measured over a range of primary air pressure on Boilers 2 and 3. While these data indicated a strong dependence of NO on primary air pressure (10 to 15 ppm per one inch H_2O increase in primary air pressure in this range), the NO emissions from Boiler 3 at comparable primary air pressures were still 50 ppm below those of the remaining three boilers. This difference has not been completely resolved.

Also presented in Figure 4 are the emission levels for the three 125 MW boilers tested (Oak Creek Boilers 1, 2 and 4). Boilers 1 and 4 operated at nearly full capacity, while Boiler 2 had a maximum load of 92 MW due to convective superheat tube metal temperature limitations. Emissions for Boilers 1 and 4 are shown to be comparable. Operation of Boiler 2 at the lower load required higher excess air and consequently produced higher NO levels. The limited data presented in Figure 4 indicate a sensitivity of approximately 20 ppm NO decrease with each 1 percent decrease in O_2. This was confirmed by the more extensive test series conducted at lower loads.

The composite NO emission data for loads in excess of 225 MW for both 275 MW boilers are also included in Figure 4. As shown, corrected NO emissions were between 190 and 205 ppm, with the highest emissions corresponding to the peak load of 265 MW. Failure to achieve full load (275 MW) and limitations in excess air flexibility were due to excessive steam tube element temperatures. Increased flexibility in excess air was available at 200 MW operation. Results of tests conducted at this reduced load are shown in Figure 5. Furnace exhaust O_2 ranged from 6 to 10 percent, with corresponding NO levels increasing from 175 to 250 ppm, an increase of 20 ppm NO per

159

1 percent O_2. These data suggest the possibility of additional NO reductions of 30 to 50 ppm with reductions in excess air to levels corresponding to 4 percent O_2--levels that had been achieved previously on individual 80 MW and 125 MW boilers. Operation at this excess air level was not possible on the 275 MW boilers due to excessive tube metal temperatures.

As mentioned previously, the 275 MW boilers are divided into four cells by division walls, effectively producing four independent sub-furnaces. Some variation was noted between the NO emission levels of the four furnace cells comprising each of these boilers. NO emissions differed by as much as 25 ppm at comparable excess air levels. The reasons for this could include manageable differences (heat input, combustion air distribution, coal feed distribution) and several other nonmanageable conditions (furnace slagging and subtle differences in burner hardware). The causes of the differences between the cells were investigated but never fully identified.

COMBUSTION MODIFICATION TESTS

The initial combustion modification tests conducted on the arch-fired boilers were directed at investigating the impact on NO emissions of changes in the front wall air addition patterns along the flame front. These tests were made possible by the compartmentalized front wall windboxes, especially on the 80 MW and 125 MW boiler configurations which are equipped with three levels of secondary air injection along the flame path. Distribution of combustion air between the secondary to front wall air on the 275 MW boilers was less straightforward due to the more complex burner design.

A second series of combustion modification tests were conducted on each boiler type involving burners-out-of-service operation to increase the fuel richness in the initial flame region. On the 80 MW and 275 MW boilers, lack of suitable hardware precluded the removal of individual burners from service. Instead, coal flow through individual feeders was stopped resulting in the associated pair of burners being removed from service. Shutoff dampers were available on the 125 MW boilers allowing individual burners to be removed from service.

160

NO emissions on the 80 MW boilers were shown to be significantly influenced by the distribution of front wall air addition. The measured distribution of air flow from primary (P), secondary (S) and the three front wall levels (F1, F2, F3) and resulting furnace NO emissions are presented in Figure 6. As shown in Figure 6, decreasing the proportion of combustion air flow through the lowest air levels (farthest from the burner) by adjusting sidewall air position increased NO emissions. NO emissions at base condition (all sidewall dampers wide open) increased from 275 ppm to 325 ppm with the lower dampers half closed and to 340 ppm with the lower dampers closed. As noted in Figure 6, the proportion of air flow to the upper two levels increased as did the proportion of secondary air introduced around the burner, thus maintaining constant total air flow. Primary air flow remained constant.

Similarly, NO emissions decreased as the front wall air was biased to the lower levels. Operation with the top level of dampers closed on Boiler 3 reduced NO by approximately 15 ppm from the full open position. Repeating these tests on Boiler 2 decreased NO levels by 45 ppm (8% reduction) by stopping the air flow to the top level.

Operation with two of the ten feeders out of service (4 of the 20 burners) on Boiler 2 reduced NO by approximately 50 ppm. Operation at this condition with all dampers full open and 4 percent O_2 at 55 MW achieved NO emissions of 200 ppm, the lowest levels reached during testing on the 80 MW class boilers.

Typical results of the front wall air distribution tests conducted on the 125 MW boilers is shown in Figure 7. NO emissions were shown to be relatively insensitive to front wall air distribution. Measured air distribution patterns are presented in Figure 7. If anything, NO emissions increased slightly as air was biased to the lower levels, that is, closing the top level dampers. It should be noted that numerous combinations of full and partially closed dampers were tried on all three 125 MW class boilers with results consistent with those presented in Figure 7.

A series of tests were conducted on Boiler 4 (125 MW), with two and four burners out of service, to investigate the impact on NO emissions of gross flame stoichiometry in the near burner region. Results from these tests

161

indicated a relatively small impact on NO emission levels. NO emissions decreased by up to 30 ppm depending on the pattern of burners out of service.

Combustion modification tests conducted on the 275 MW boilers were limited to (A) changes in the combustion air distribution between the secondary and front wall air and (B) biasing the coal feed between the inboard and outboard burner pairs. Operation with a feeder out of service was not attempted as this would have resulted in severe disruptions in tube element temperatures. Similarly, operation with individual burners out of service could not be applied since there were no coal shutoff dampers to individual burners. Other procedures that could potentially have been employed to alter the combustion process, such as (A) varying the secondary air flow between the four burners in a cell or (B) changing the primary or secondary air swirl, were also not possible due to hardware limitations.

The combustion modification tests discussed in this section were conducted on cells 2 and 3 only. Tests showed that these interior cells (controlling the radiant superheat areas of the furnace) had somewhat more flexibility and were amenable to the modifications imposed without causing severe boiler upset. While the results are limited to one cell, the trends in the emissions are taken to be characteristic of the entire boiler.

The results of the series of tests of redistributing the secondary and tertiary air flows are presented in Figure 8. These data represent operation at a reduced load of 200 MW with consistent cell exhaust O_2 concentrations of 6 percent. Biasing air flow to the front wall decreased NO emissions by 10 to 25 ppm. Similar adjustments to the combustion air distribution in Cell 3 resulted in a somewhat larger NO reduction. The differences in NO reductions between the cells were investigated but not resolved.

A brief series of tests were conducted on cell 2 to determine the effects of varied coal feed distribution on NO emissions. From a base condition, feeder speeds were varied to provide a biasing of the coal first to the outboard feeder (delivering coal to the outer burner pair) and then to the inboard feeder (delivering coal to the burner pair next to the front wall). Biasing the coal away from the front wall decreased NO by ~10 ppm, while biasing towards the front wall increased NO by a similiar amount.

162

FLY ASH CARBON CONTENT MEASUREMENTS

Fly ash samples were extracted from the flue gases upstream of the air preheater and analyzed for carbon content using ASTM procedures (11). Excessive fly ash carbon content is, of course, an indication of incomplete combustion and could be a factor limiting the application of staged combustion.

The results of the data on fly ash carbon concentration obtained during the test program are presented in Figure 9 as a function of furnace exhaust NO. Although a significant degree of scatter is present, it is evident that carbon content generally increased as the NO decreases. This was especially true for the 275 MW class boilers. It has been speculated that the high carbon content from these boilers is due to the multiple burner rows with the outboard flame jet somewhat screened from the front wall air addition. Additional investigation into causes of the trend shown in Figure 9 will be necessary in order to propose solutions and the impact on NO emissions. It should be noted that the data presented in Figure 9 represent as-fired conditions with no attempts to optimize the potential tradeoffs of NO and high carbon content.

DISCUSSION

It is interesting to note from the results presented in the previous section that the NO_x emission levels from the three arch-fired boiler designs decreased as the size and complexity of the combustion process increased. The lowest emissions were measured on the 275 MW design that had the largest proportion of combustion air introduced at the burner and therefore would have been expected to have less inherent staged conditions and correspondingly higher NO_x levels. Two explanations have been proposed to account for this: (A) the heat absorbing characteristics of the furnaces and (B) fundamental differences in the combustion processes between the boiler types. The purpose of this section is to discuss in a speculative manner the results of this test program in terms of these hypotheses.

FURNACE HEAT ABSORPTION

It has been demonstrated that reduced flame temperatures result in lower NO_x emissions (12). Large furnace volumes and/or furnace division walls providing increased heat absorbing surfaces could be expected to result in lower NO_x emissions. As discussed previously, there are significant differences between the furnaces configurations of the arch-fired furnaces, especially with regard to the division walls on the 275 MW design. This has been proposed as a possible explanation of the reduced NO_x emission from these boilers.

To test this hypothesis, estimates have been made of the volumes and available heat absorbing surfaces for three regions in each arch-fired design corresponding to: (A) the entire furnace, (B) the lower furnace below the plane of the arch and (C) the region directly below the arch.

164

A summary of the estimated volumes and surface areas of these regions is included in Table III together with heat absorption on a per unit volume and area basis. As shown in Table III by the consistent heat absorption, the three arch-fired boiler designs show a nearly proportional increase in volume and area as the size of the boiler increases. It would appear from these data that the hypothesis of the lower NO emissions on the 275 MW boilers due to size and heat absorption does not appear to be valid.

This analysis, however, does not take into account the location of the heat absorbing surfaces with respect to burner arrangement, flame jet mixing patterns and the medium (water or steam) transported through the furnace and division wall tubes. Each of these factors could significantly influence heat removal patterns in the flames and resulting NO_x formation.

DIFFERENCES IN THE COMBUSTION PROCESSES

The influence of differences in the inherent staged combustion processes on outlet NO_x emissions is much more complex. While the application of staged combustion has repeatedly been demonstrated as a practical means of achieving low NO_x emissions, the level of understanding of the fundamental nature of this process is generally low (12). Staged combustion has been conceptualized as reducing NO_x emissions by reducing the formation rate of both thermal and fuel NO_x. In addition, the destruction of NO to other products has been observed in the intermediate regions of one staged combustion process (13). It may be that competing or counterbalancing reactions occur within the flame structure that significantly affect final NO levels.

The complexity of understanding the NO_x formation/reduction processes in the arch-fired furnace design are compounded by the aerodynamic mixing patterns characteristic of these configurations. The inherent staged combustion process can be conceptualized as taking place in four steps: (A) the near burner region, (B) the intermediate stage, (C) lower furnace combustion and (D) burnout. These zones are identified in Figure 10 for the arch-fired design.

As discussed previously, significant differences exist between the burner designs of the 80 MW and 125 MW boilers, and that of the 275 MW configuration

that are reflected in the near burner mixing patterns identified as region A in Figure 10. The simpler burner arrangement produces a coal/air jet entering a region of relatively quiescent furnace gases. This situation is conducive to forming a well mixed jet in which the coal rich internal core is broken down relatively rapidly. The more complex burner on the 275 MW design produces a jet with a fuel rich central core surrounded by a concentric ring of air moving at comparable velocities. The resulting low levels of shear between these two streams could result in the fuel rich central core maintaining its integrity (and its fuel rich conditions) until well into the furnace. The longer residence times at fuel rich conditions could result in a decreased proportion of fuel nitrogen conversion to NO_x as opposed to the 80 MW and 125 MW designs.

Conceptually, the intermediate region (region B in Figure 10) would correspond to the region of entrainment of the front wall combustion air into the flame jet. Calculations have shown, however, that buoyancy forces in this region are important and tend to drive the relatively cold front wall air down the wall delaying mixing with the flame jet until into the lower furnace regions. This flow pattern shown in Figure 10 is also enhanced by front wall flow deflectors on the 125 and 275 MW arrangements. It can be speculated that oxygen deficient flame conditions exist within this intermediate region containing intermediate combustion products (H, CO, NH_3, HCN) that have been shown to reduce NO_x to N_2. This would be especially true of the outer row of burners in the 275 MW design that are partially shielded from penetration of the front wall air by the inner burner row. The inherent staged combustion process of the arch fired design, especially the 275 MW furnaces, may be extremely conducive to NO_x reduction.

The lower furnace region identified as region C in Figure 10 is also of interest. Results of earlier tests conducted on arch-fired designs demonstrated the lower regions to have the highest furnace temperatures (14). In this region mixing between the frontwall air and flame jet are still incomplete so that furnace geometry could play a significant role in NO_x formation by controlling local flame stoichiometry. It has been conceptualized that the application of arch-firing to boilers in the 600 MW

166

class will require an opposed fired design. The opposed flame interaction in this region could significantly alter NO_x formation and/or reduction patterns. Also, the possibility of NO_x formation from nitrogen contained in the char in the upper furnace burnout zone (region D) cannot be discounted. Again, the level of understanding of these processes is not complete enough to formulate any definitive answers.

CONCLUSIONS

- Arch-fired utility boilers with front wall air addition that have been in service for up to 40 years have demonstrated NO_x emission levels comparable to specially designed low NO_x combustion systems.

- It has been speculated that these low emission levels are attributable to combustion conditions similar to that found in the more sophisticated new designs.

- Assessment of the arch-fired configurations as a viable alternative to the modern low NO_x combustion systems will require economic and reliability comparisons which are now in progress.

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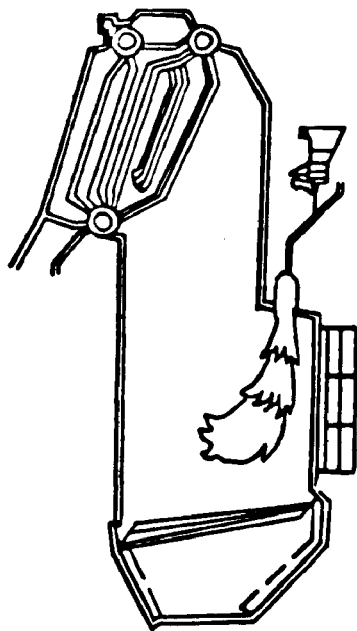
Port Washington
(80 MW)
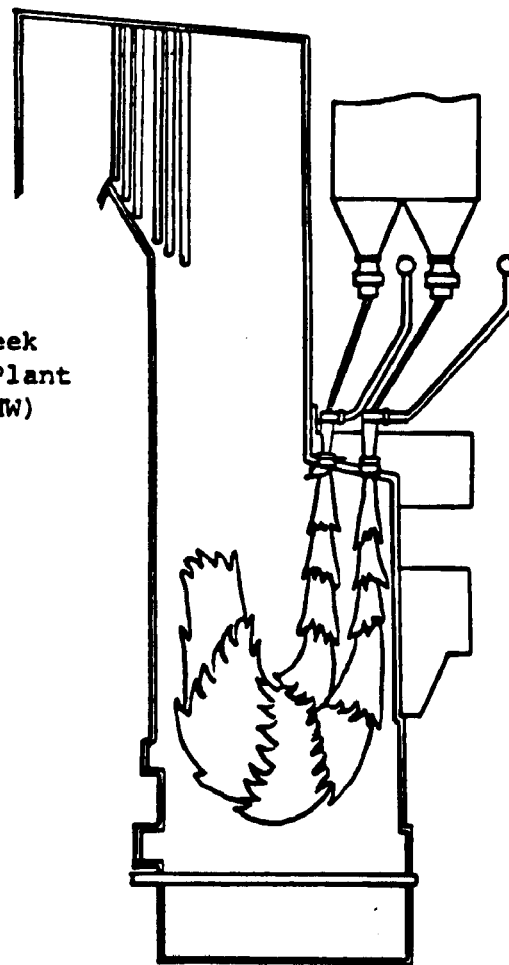
Oak Creek
South Plant
(275 MW)
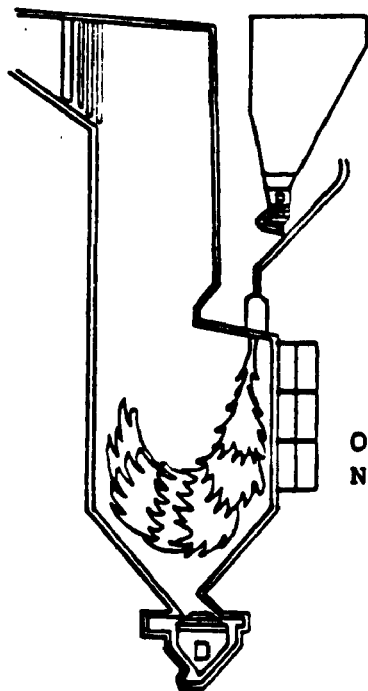
Oak Creek
North Plant
(125 MW)

Figure 1. WEPCo arch-fired boilers

170
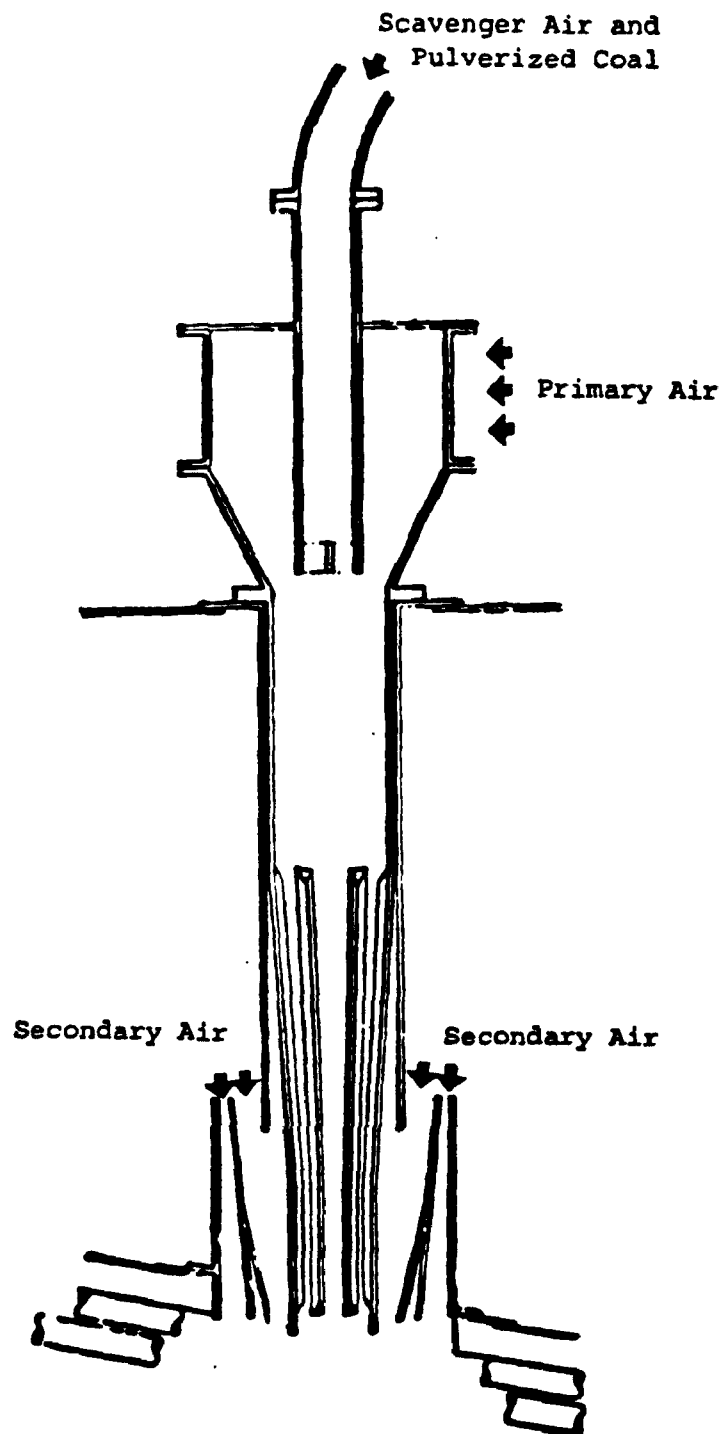
Figure 2.   Oak Creek South Plant 275 MW Burner Configuration

Front Wall

O O O O O O O O O O O O O O O O O O O O O

Arch
80 MW

Front Wall

O O O O | O O O O | O O O O | O O O O

Arch
125 MW

Front Wall

O   O | O   O | O   O | O   O

O O | O O | O O | O O
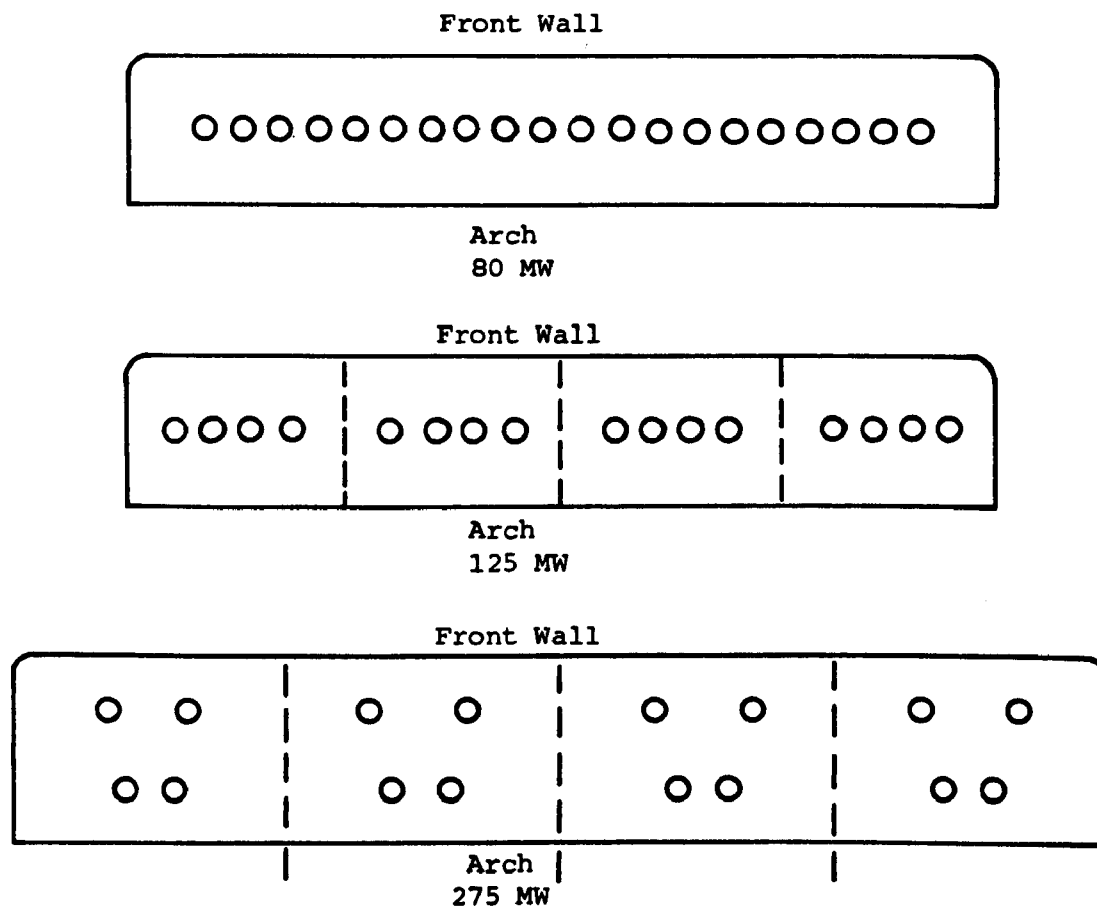
Arch |
275 MW

Figure 3.   Arch arrangement of WEPCo furnaces - not to scale
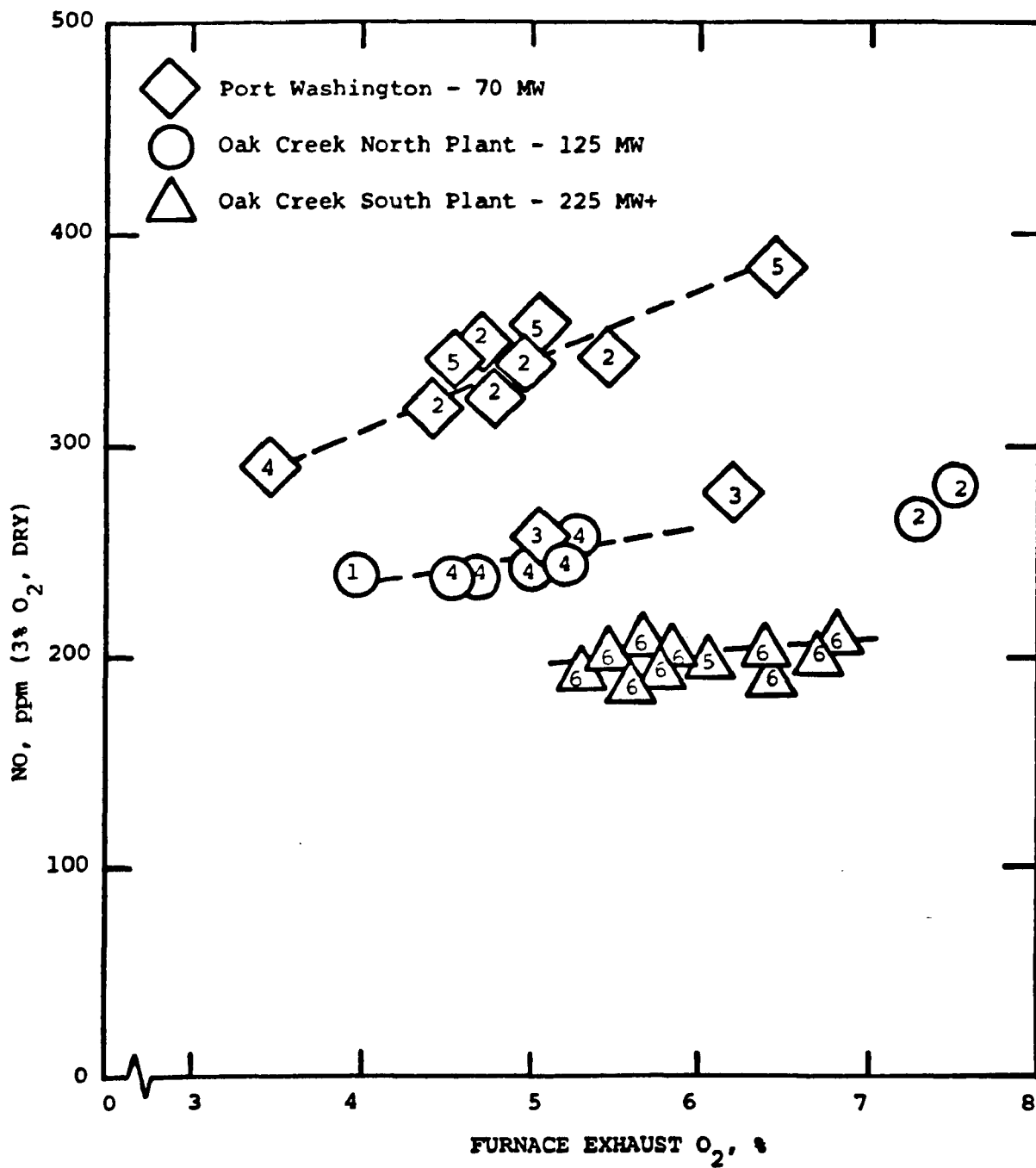
Figure 4. Full load baseline NO emissions, WEPCo arch-fired boilers. The numbers in the symbols denote the boiler numbers for each station.

173
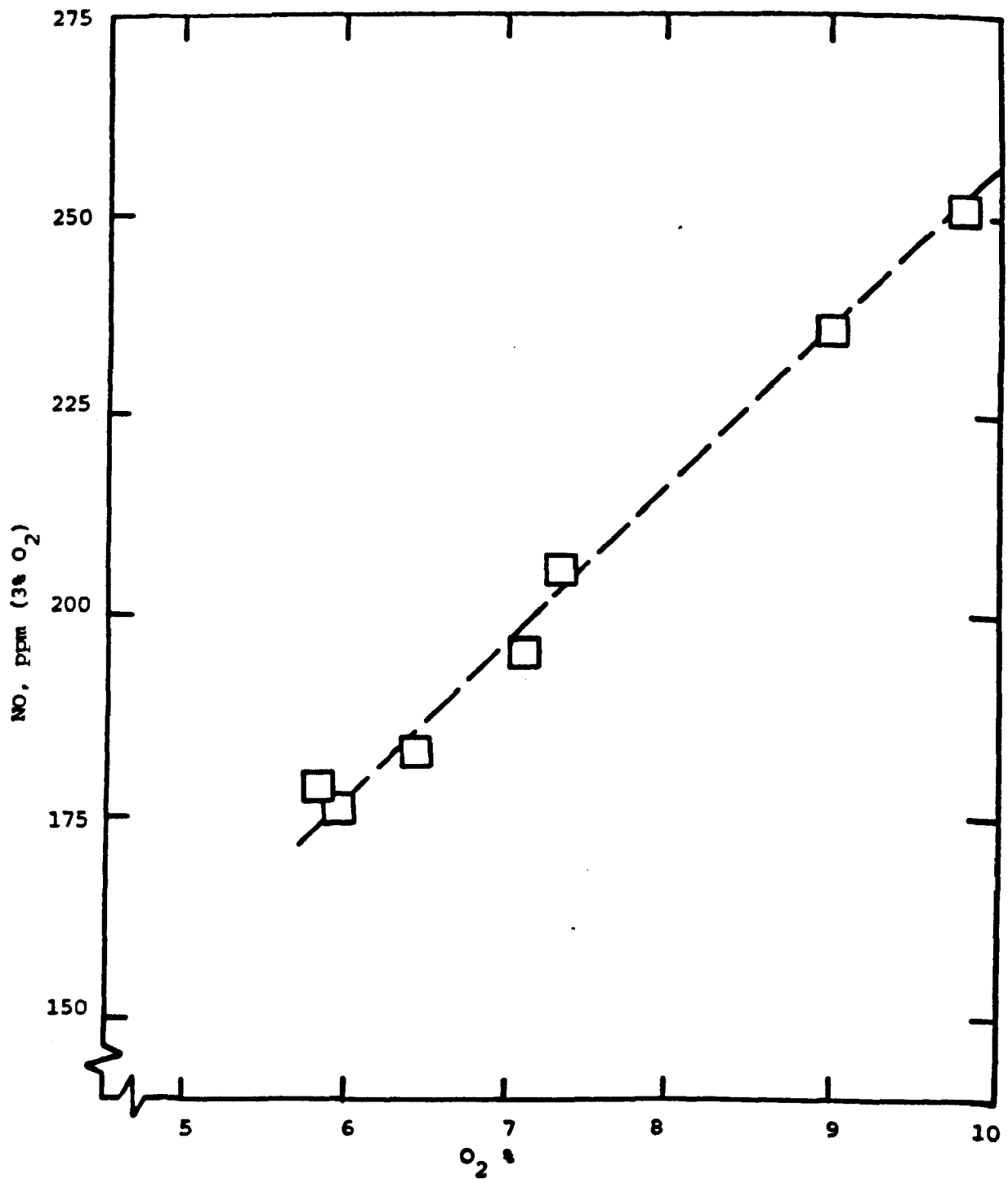
Figure 5. Composite NO Emissions as a Function of Excess Air, Oak Creek Boiler 6, 200 Mw
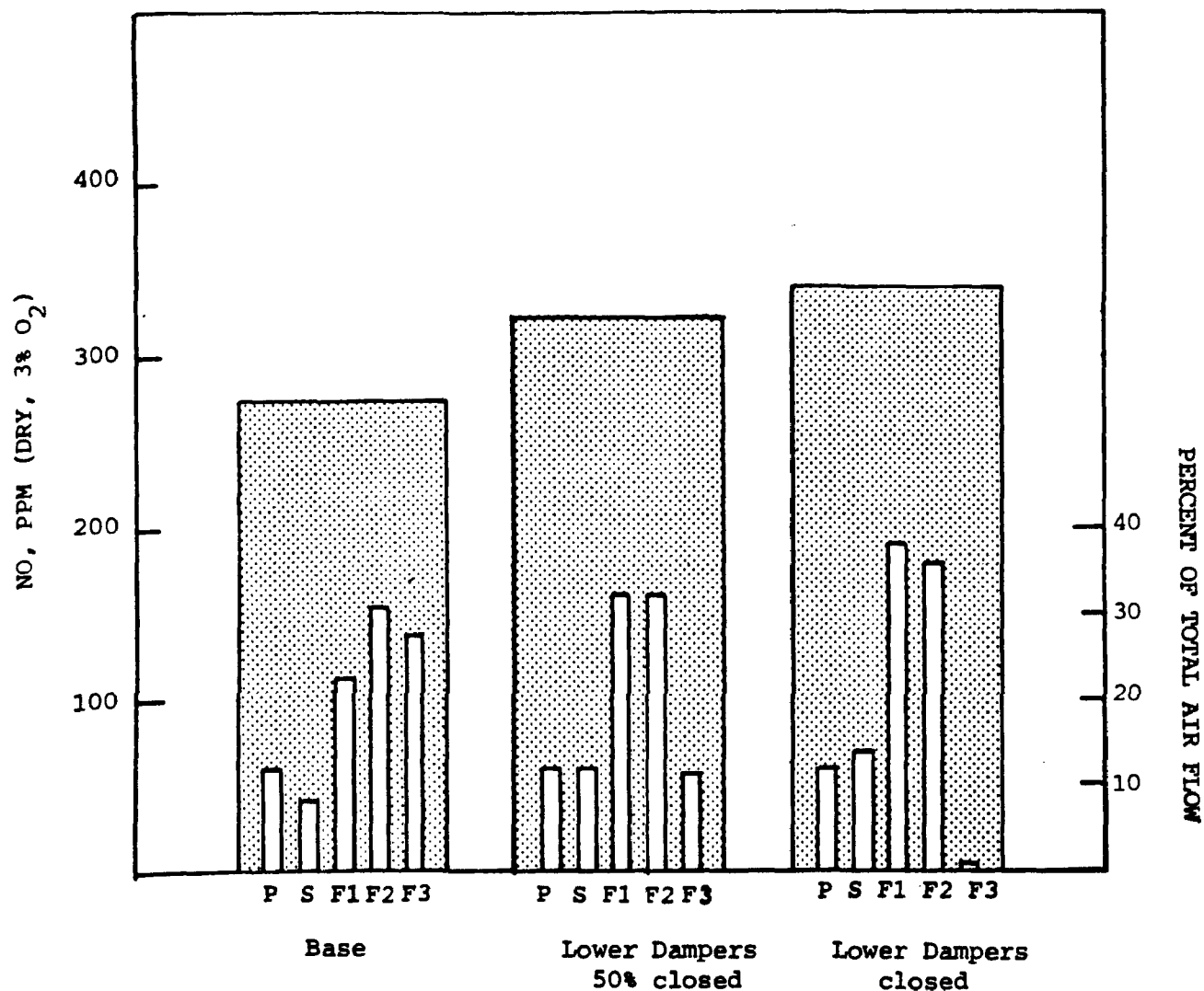
Figure 6. Impact of front wall air distribution on NO emissions, Port Washington Boiler 3 (80 MW), 55 MW, 6.5% O_2 (P-Primary Air Flow, S-Secondary Air Flow, F1-Front Wall Upper Level Air Flow, F2-Front Wall Mid Level Air Flow, F3-Front Wall Lower Level Air Flow)
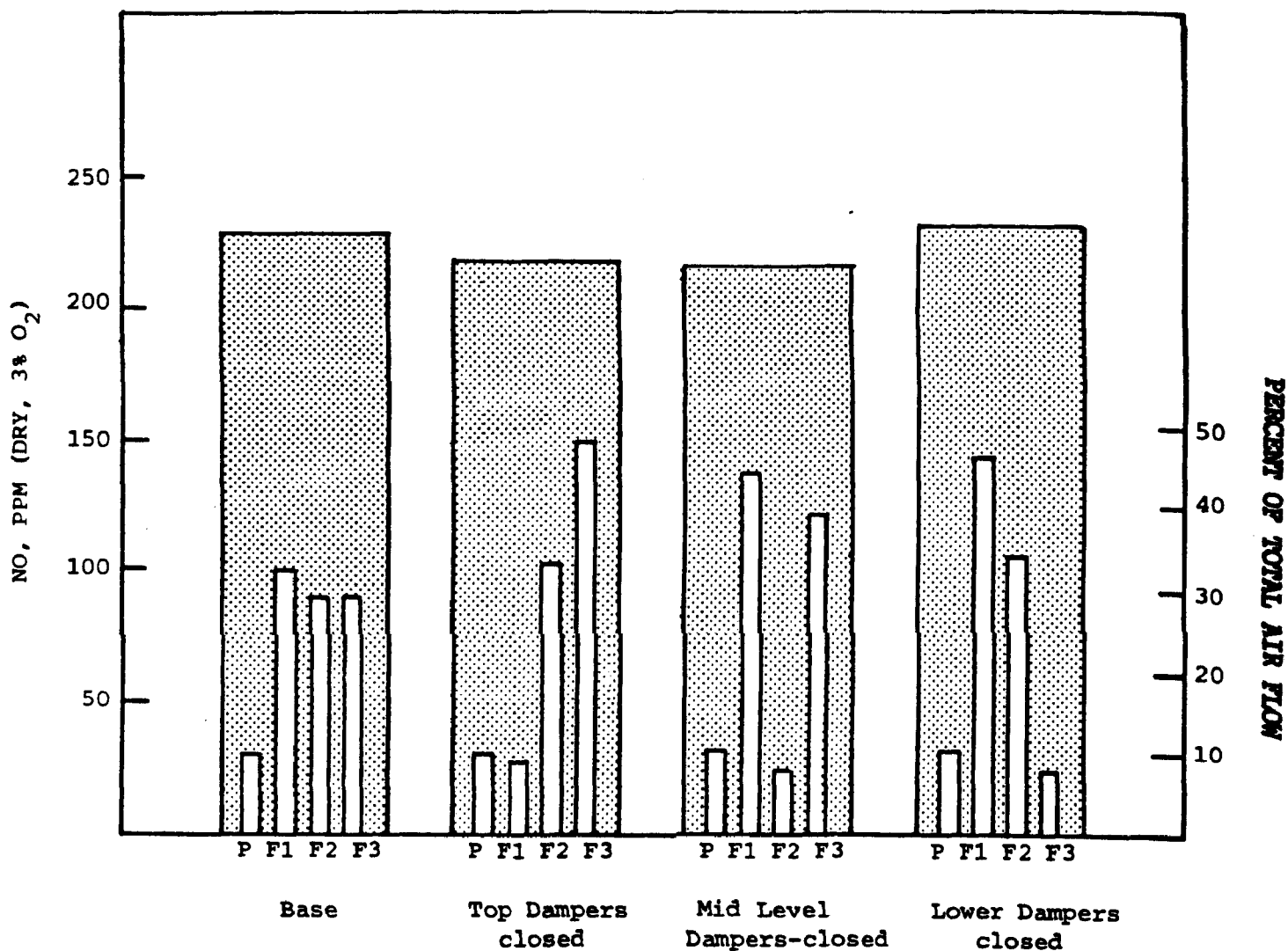
Figure 7.   Impact of front wall air distribution on NO emissions
             Oak Creek Boiler (125 MW), 107 MW, 4.0% O_2
             (P-Primary Air Flow, F1-Front Wall Uppper Level Air Flow,
             F2-Front Wall Mid Level Air Flow, F3-Front Wall Lower
             Level Air Flow)
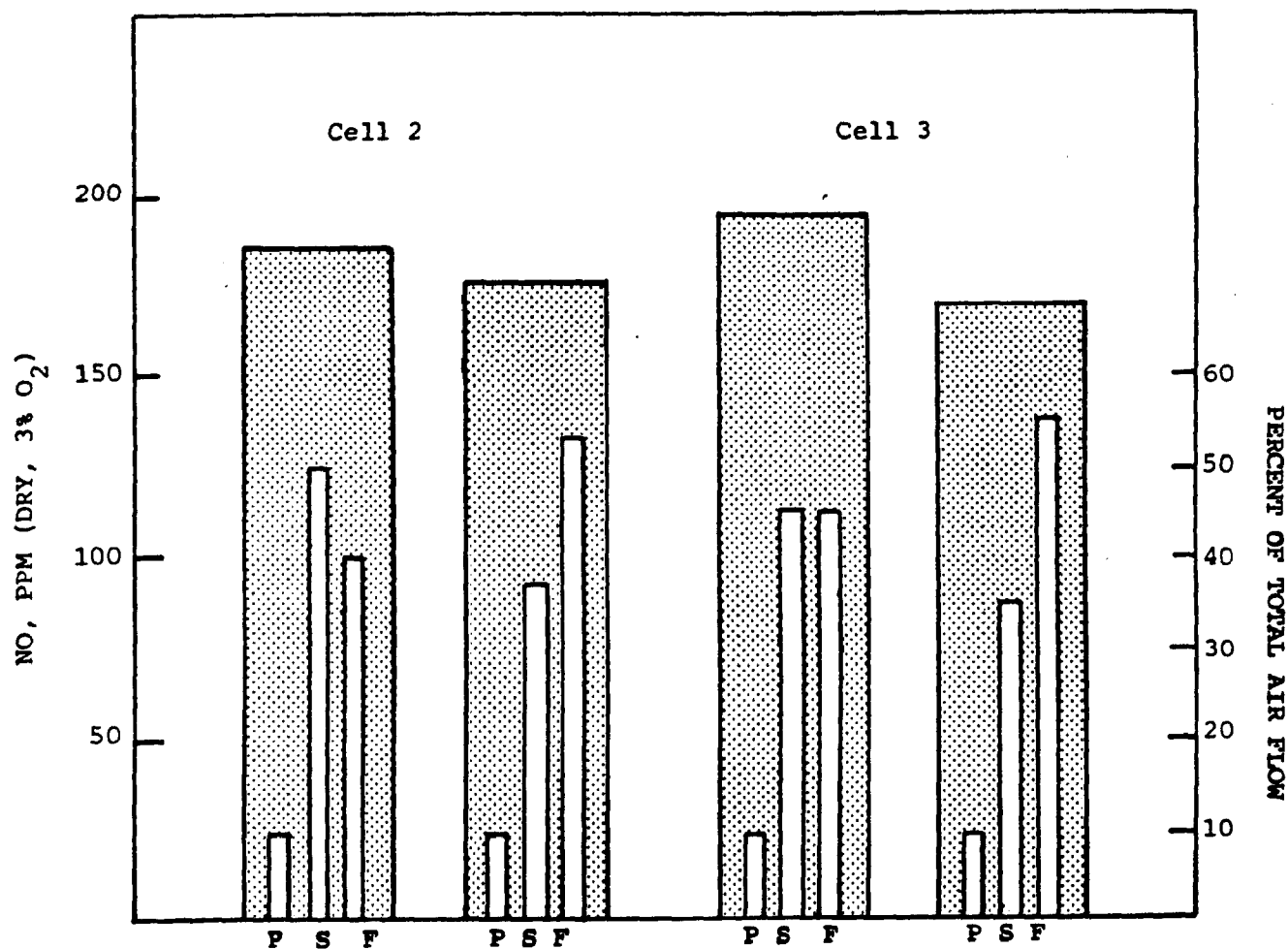
Figure 8.   Impact of combustion air distribution on NO emissions
             Oak Creek Boiler 6 (275 MW), 200 MW, 7% O_2
             (P-Primary Air Flow, S-Secondary Air Flow, F-Front
             Wall Air Flow)
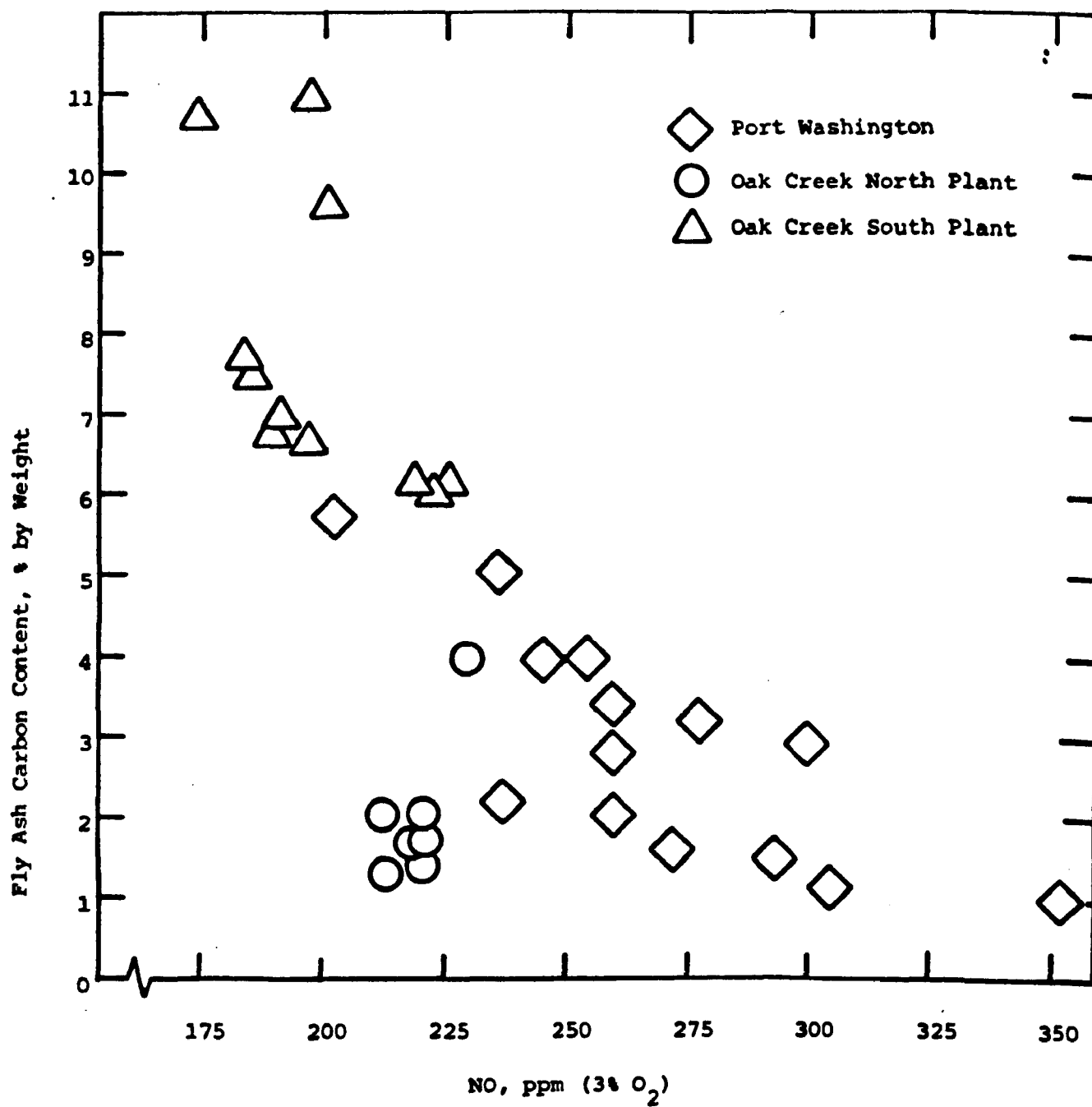
Figure 9. Fly Ash Carbon Content as a Function on NO Emissions, WEPCo Arch-Fired Boilers.
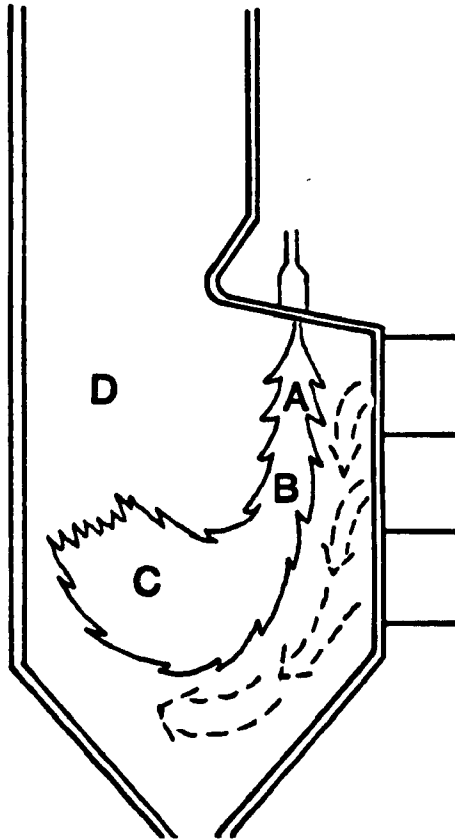
Figure 10.   Schematic of Inherent Staged
              Combustion Process

A   Near Burner Region

B   Intermediate Stage

C   Lower Furnace Region

D   Burnout Zone

179

TABLE I. ARCH-FIRED BOILER OPERATING PARAMETERS
(AT PEAK LOAD DURING TEST CONDITIONS)

	Port Washington	Oak Creek North Plant	Oak Creek South Plant
Load, MW	70.0	125.0	265.0
Steam flow 10^3 lb/hr	520.0	888.0	1780.0
Heat input 10^6 Btu/hr	694.0	1185.0	2293.0
Coal flow 10^3 lb/hr	57.8	98.8	191.0
Total air flow 10^6 ft^3/hr	19.9	32.6	72.0
Primary air flow 10^6 ft^3/hr	1.9	4.4	7.2
Secondary air flow 10^6 ft^3/hr	16.3	28.2	28.2
Tertiary air flow 10^6 ft^3/hr	1.7	--	36.6
Furnace volume 10^3 ft^3	74.0	111.0	171.6
Tube surface area 10^3 ft^2	10.8	17.2	38.3
Number of burners	20	16	16
Burner diameter, in.	6.0	4.5	6.0

TABLE II. AS-FIRED COAL ANALYSES
(Percent by Weight)

	Port Washington Midwestern	Oak Creek North and South Plants	
		Midwestern	Western
Proximate (Wet)			
Moisture	1.40	1.82	2.81
Ash	15.38	14.29	20.70
Volatile	32.37	35.04	37.29
Fixed Carbon	50.85	48.85	39.20
Btu/lb	11,985	11,925	10,318
Ultimate (Dry)			
Carbon	67.99	68.73	60.55
Hydrogen	4.34	4.69	4.55
Nitrogen	1.30	1.46	1.27
Chlorine	0.20	0.30	0.06
Sulfur	3.01	1.72	1.04
Ash	15.60	14.55	21.30
Oxygen	7.56	8.55	11.23

TABLE III. ARCH-FIRED HEAT RELEASE DATA

	80 MW	125 MW	275 MW
Total heat input, Q 10^9 Btu/hr	0.69	1.19	2.29
Total furnace volume, V_F 10^3 ft^3	74.0	111.0	171.6
Q/V_F	9.3	10.7	13.3
Total furnace area, A_F 10^3 ft^2	10.8	17.2	38.3
Q/A_F	63.9	69.2	59.8
Lower Furnace Volume, V_{LF} 10^3 ft^3	36.0	58.5	97.3
Q/V_{LF}	19.2	20.3	23.5
Lower furnace Area, A_{LF} 10^3 ft^2	6.1	10.5	19.5
Q/A_{LF}	113.1	113.3	117.4
Below Arch Volume, V_{BA} 10^3 ft^3	12.5	25.0	46.6
Q/V_{BA}	55.2	47.6	49.1
Below Arch Area, A_{BA} 10^3 ft^2	2.8	6.5	10.0
Q/A_{BA}	246.4	183.1	229.0

RELATIONSHIP BETWEEN NO_x AND
FINE PARTICLE EMISSIONS

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183

ABSTRACT

Data from EPRI-sponsored field test programs at pulverized coal-fired
utility power plants indicate that boiler combustion conditions producing low
NO_x emissions also tend to suppress the generation of fine, submicron
particulate matter. Specifically, the mass of fine particles measured at the
outlet of boilers in the 0.1-micrometer diameter region are reduced by up to
one or more orders of magnitude when low NO_x emissions are observed. These
observations are consistent with the present theories of volatilization/
condensation processes believed to be responsible for particle generation in
the fine particle size region.

The significance of this discovery is that particulate collectors
(electrostatic precipitators and fabric filter baghouses) generally exhibit a
minima in collection efficiency at this particle size region. Furthermore,
these particles: (1) can contribute to visibility problems due to particle
growth within the plume, and (2) have been implicated as bad actors from a
health effects standpoint due to their possible enrichment in trace elements
and unfavorable transport properties. It now appears that these deficiencies
inherent to particulate control devices may, in part, be overcome by the
application of NO_x combustion control.

ACKNOWLEDGEMENTS

RELATIONSHIP BETWEEN NO_x AND FINE PARTICLE EMISSIONS

INTRODUCTION

Over the past several years EPRI has supported a number of field test programs at pulverized coal-fired utility boilers to evaluate state-of-the-art particulate control devices, namely electrostatic precipitators and fabric filter baghouses. A major objective of this continuing effort is to provide the utility industry with basic information on particulate collection performance with emphasis on particle size dependent collection efficiency, trace element emissions and stack opacity. Operational and economic data are also obtained to provide the necessary information for a complete assessment of control technology options.

The field test approach used in these evaluations involves monitoring of the boiler and combustion processes (i.e., the source of particulate matter) during the particulate control device testing. As a consequence of this total systems approach to field testing, and the emphasis on fine particle collection efficiency measurements, a conspicuous dependence emerged between NO_x emissions and the generation of fine submicrometer size particles in the boiler. Specifically, it appears that suppressed fine particle generation is associated with lower NO_x emissions. This observed dependence between NO_x and fine particles is the subject of this paper. Before presenting these results and their ramifications, fundamental characteristics of particulate matter emissions from coal fired boilers are first briefly discussed.

CHARACTERISTICS OF PARTICULATE MATTER EMISSIONS

The distribution of particulate matter (fly ash) mass over the particle size range at the outlet of a 520 MW opposed wall fired boiler[1] is shown in Figure 1. These data are especially significant since they represent the first time that a bimodal particle size distribution was measured in the field. The bimodal distribution consists of (1) a fine particle mode (aerosol

spike) at approximately 0.1 micrometer diameter and (2) a large particle mode which actually reaches a peak and then tails off to the larger particle sizes. It should be emphasized that these data (and data contained in subsequent figures) are based on measurements taken before the particulate control device and therefore represent boiler outlet conditions. The fine particle mode was measured with an extractive Thermo-Systems electrical aerosol size (mobility) analyzer. The large particle mode was measured in situ with a conventional cascade impactor. Prior to discovery of the aerosol spike, it was very common practice to artificially extend size distribution curves to zero at the low end of the cascade impactor data.

The format of Figure 1 is well known to those involved in the particle measurement sciences but may be a little confusing to those not familiar with reduced particle size distribution data. For purposes of interpretation this differential mass plot can be viewed as a mass histogram where the area under the curve is equal to total mass. Thus, the contribution of particulate mass within a specific size range to the total mass can be easily visualized by comparing the area under the curve in the region of interest to the total area. Clearly, the aerosol spike represents a very small fraction of the total mass of particulate matter leaving the boiler. In this case, the mass of the spike is roughly one percent of the total mass, or 99 percent of the total number of particles. This may seem insignificant until one realizes that conventional particulate control devices (electrostatic precipitators and baghouses) typically exhibit reduced collection efficiency in this particle size range. At this particular boiler, which was equipped with a large electrostatic precipitator, the particles in this size range represented about 20% of the stack emissions on a mass basis.

It was apparent from these early tests that the fine particulate matter can represent a significant fraction of total stack emissions. The importance of this from an environmental standpoint stems from the fact that these small particles (1) can grow once in the atmosphere due to agglomeration and contribute to plume opacity and ambient visibility impairment; (2) serve as condensation sites and catalyze atmospheric chemical reactions and (3) are highly respirable. Furthermore, there has been much concern that these particles might be enriched in trace elements.

In retrospect, the discovery of the aerosol spike should not have been totally unexpected. Flagan at Cal Tech[2] independently predicted the presence of the aerosol spike at about the same time that the above measurements were made, based on a theoretical model of particle formation during coal combustion. Figure 2 is a comparison of the previous data to theoretical predictions based on Flagan's model of particle formation involving (1) high temperature volatilization of ash components followed by (2) condensation and coagulation of the volatile material as the gases cool toward the boiler exit. Note that for comparison purposes between theory and field measurements, the results are presented on a particle number basis in contrast to a mass basis used in the previous figure.

Since the data in Figure 1 were obtained, a number of boilers have been tested and they all to some degree exhibit an aerosol spike and a bimodal particle size distribution. This leads to a conclusion that the aerosol spike is a generic feature of fly ash generated in combustion processes occurring in conventional pulverized coal boilers.

Figure 3 summarizes particle size distribution data from six utility boilers of varying designs burning different coals. An obvious feature of these data is that the large particle mode seems to be highly variable from unit to unit. Careful examination of these data suggest that the large particle mode may in fact be a superposition of one or more discrete particle modes. The shape and variability of the large particle mode is more than just a simple effect of variations in total coal ash content and is an area of research beyond the scope of this paper. For simplicity, the large particle mode as discussed here is considered as a single particle mode.

The fine particle distribution is also highly variable which is more obvious in a blow up of the fine particle region as shown in Figure 4. The important aspects to note are (1) the aerosol spike is very monodisperse (narrow) which is consistent with the homogeneous gas phase condensation formation theory and (2) the spike appears to occur at essentially the same particle diameter in all units.

Table 1 is a summary of the submicron mass data shown in the previous figures. Note that the ash content as evidenced by total mass emissions varies nearly an order of magnitude from unit to unit. The percentage of total mass represented by the fine particle spike is also variable. However,

there is no simple correlation apparent between ash content and mass of aerosol spike.

CORRELATION BETWEEN NO_x AND FINE PARTICLES

It was implied earlier that there was an observed connection between NO_x emissions and the quantity of fine aerosol generated in the boiler. Figure 5 is a summary of the aerosol spike mass data generated to date, plotted vs. NO_x. There is considerable scatter in the correlation which can be attributed at least in part to a very poor quantitative understanding of fine particle generation mechanisms. However, it is quite apparent that as NO_x increases the relative mass of the aerosol spike also increases. Although a correlation between NO_x and fine particulate matter was not originally sought or expected, as more and more field data were collected it became apparent that a correlation may exist. Theories of particle formation are still evolving and an explanation can only be speculative. From a very simplistic standpoint one might hypothesize that the temperature time history during combustion processes may be a critical factor common to both formation of submicrometer aerosol and NO_x. One might argue that the hotter temperature which may enhance NO_x formation (especially in the predominately pre-NSPS boilers represented here) may also volatilize more coal ash constituents leading to the relationship observed. Nevertheless, based on information to date it appears that attempts to reduce NO_x via combustion control may have a beneficial side effect, i.e., reduce fine particle generation and emissions. The possibility of continued beneficial effects at NO_x emission levels below the range of NO_x data presented here remains to be verified.

To illustrate the very rudimentary state of understanding of fine particle generation and its connection with NO_x, Figure 6 indicates the day to day variability of the aerosol spike emissions observed at one plant. In this particular case the quantity of submicron aerosol varied significantly under repeated boiler conditions. NO_x and boiler load remained constant during the tests.

SUMMARY

Figure 7 reemphasizes the significance of the aerosol spike as it relates to particulate emission control. Here the particle collection performance of a very high efficiency baghouse and a large electrostatic precipitator are compared.[3] Note that in the region of the aerosol spike there is a minimum in collection efficiency for both control devices. Obviously then the presence of fine particles can have a pronounced impact on control device performance and selection. It appears that this deficiency inherent to particulate control may in part be overcome by application of NO_x combustion control.

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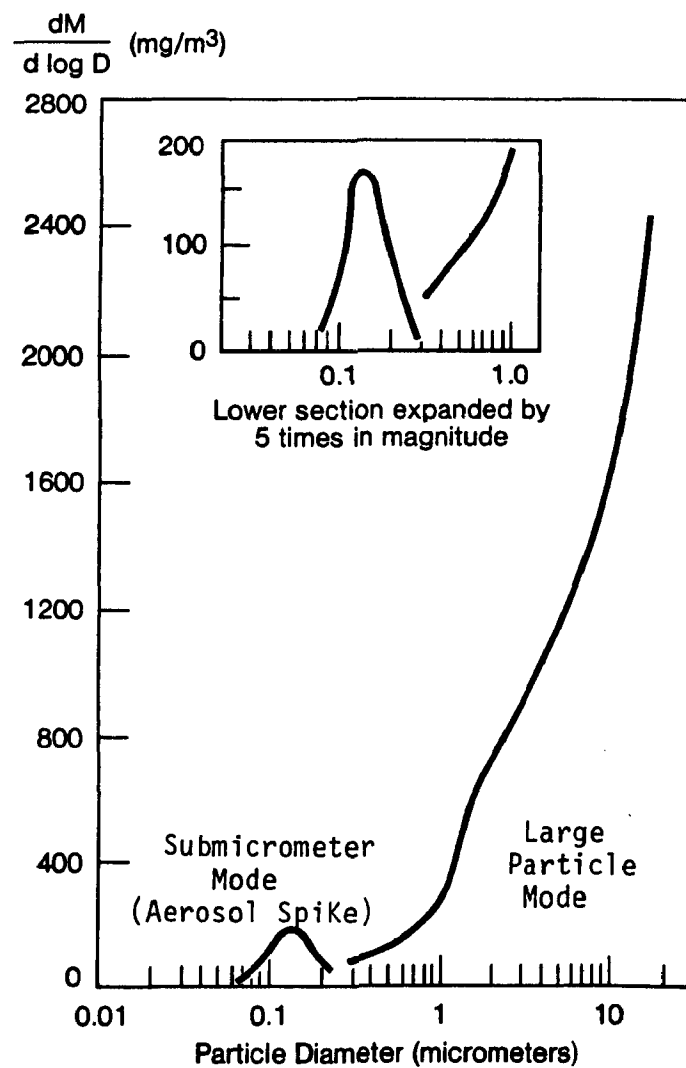
Figure 1. Differential mass particle size distribution at
boiler outlet illustrating bimodal nature of
particulate matter (520 Mw coal fired boiler)

$$\frac{dN}{d\log D} \text{ (number/m}^3\text{)}$$

Theoretical
(Flagan and Friedlander, 1976)

520 MW opposed
wall fired

Particle Diameter (micrometers)
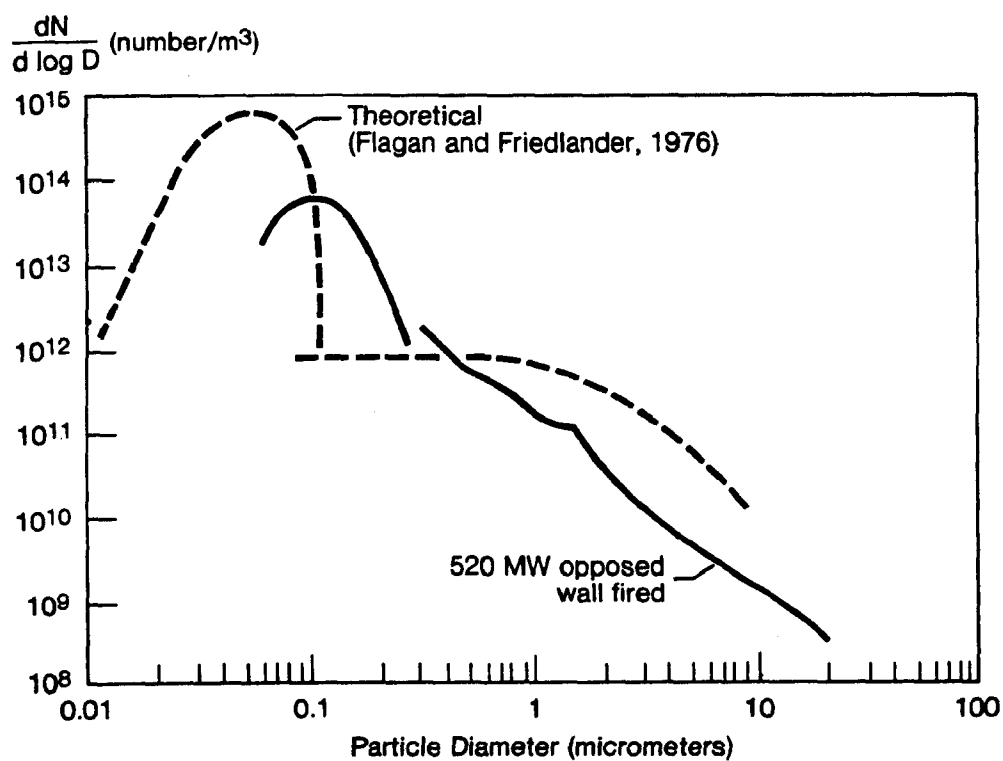
Figure 2. Comparison of measured differential number size
distribution with theoretical prediction

193
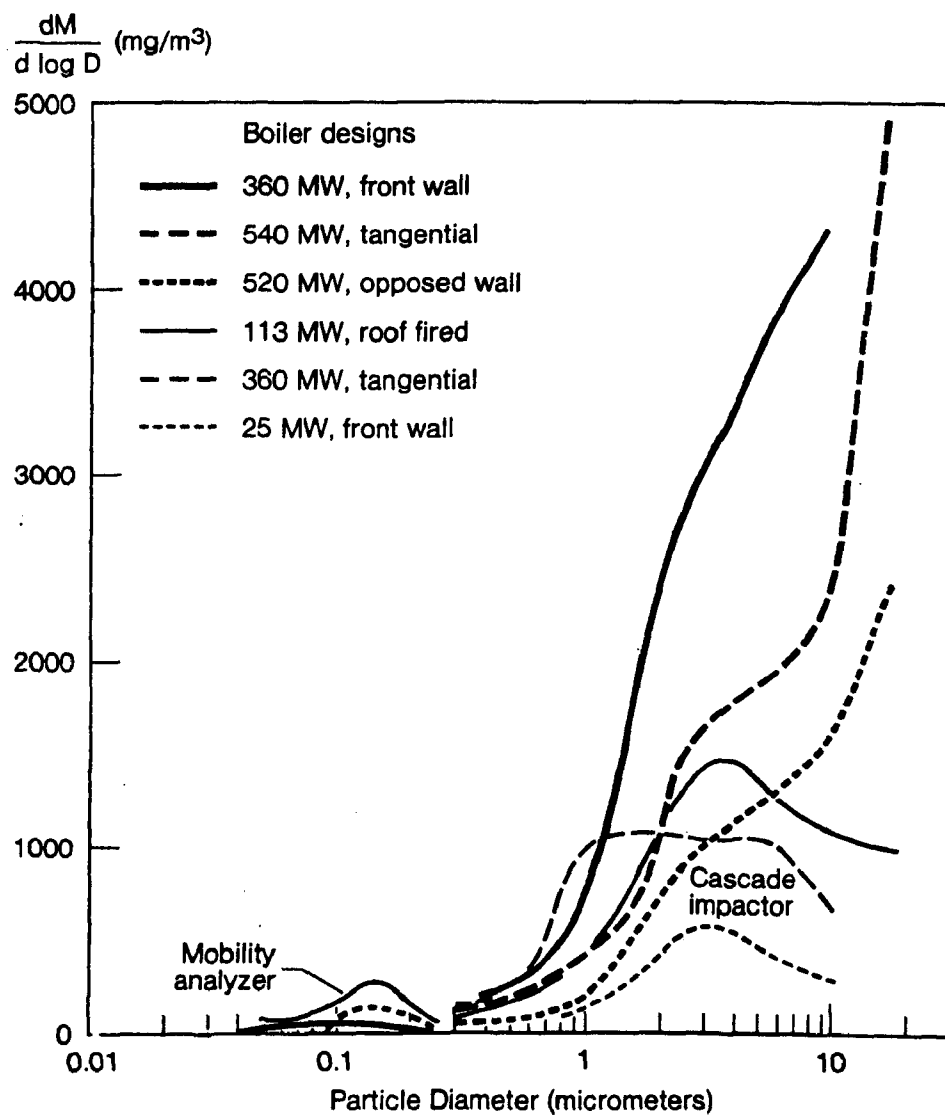
Figure 3. Differential mass particle size distribution
for six coal fired uitlity boilers

194
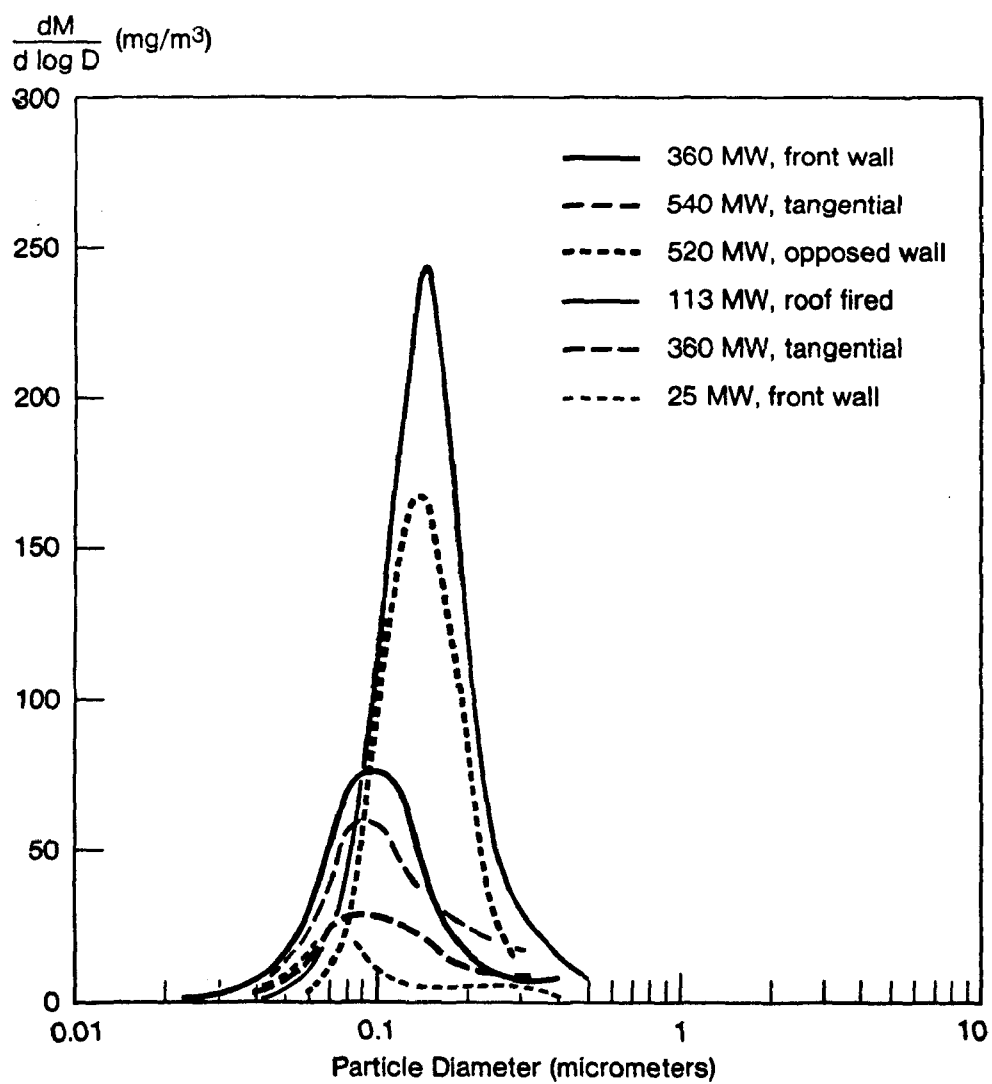
Figure 4. Aerosol Spike Differential Mass Particle Size
           Distributions for Six Utility Boilers

195
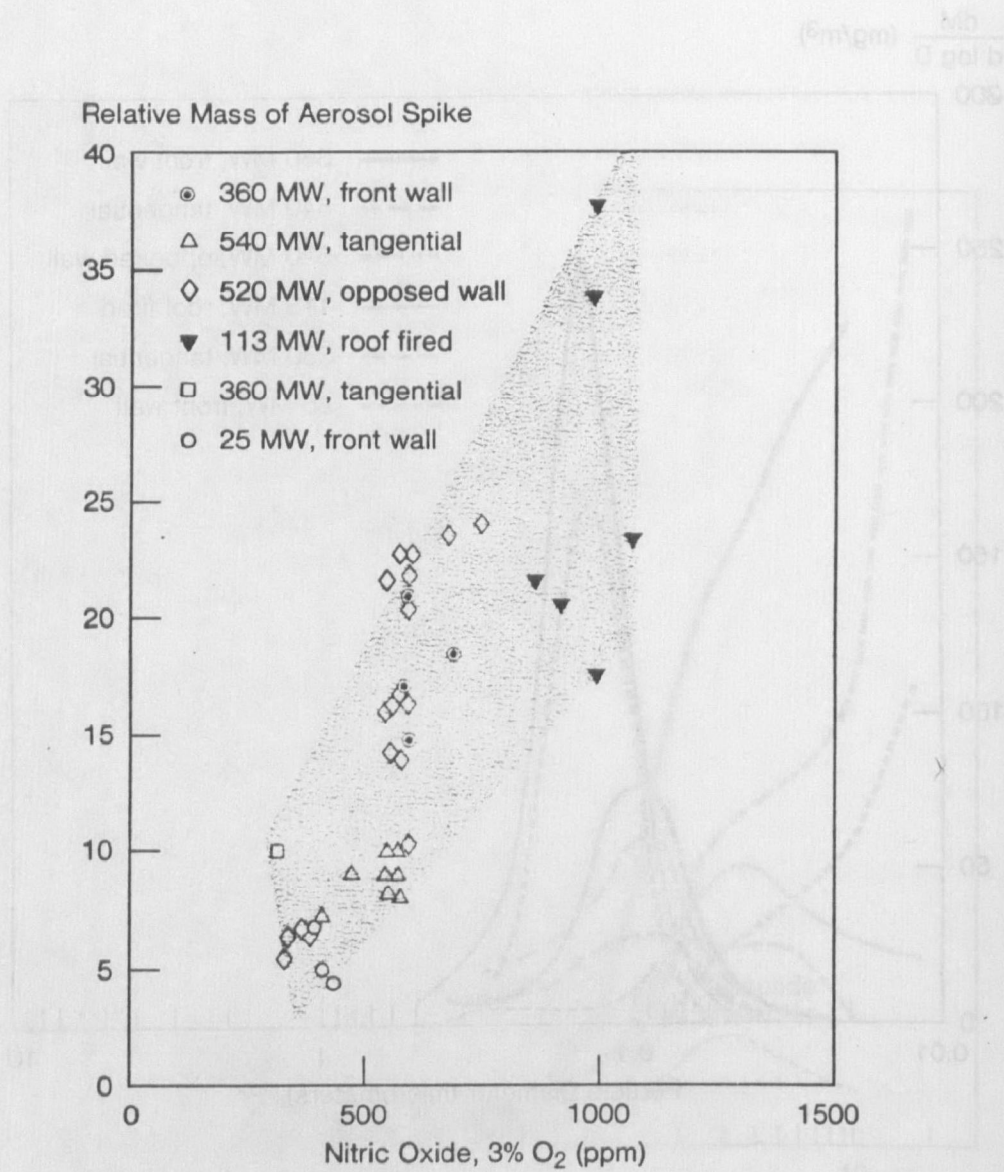
Figure 5. Relationship Between NOx Emissions & Aerosol Spike

196
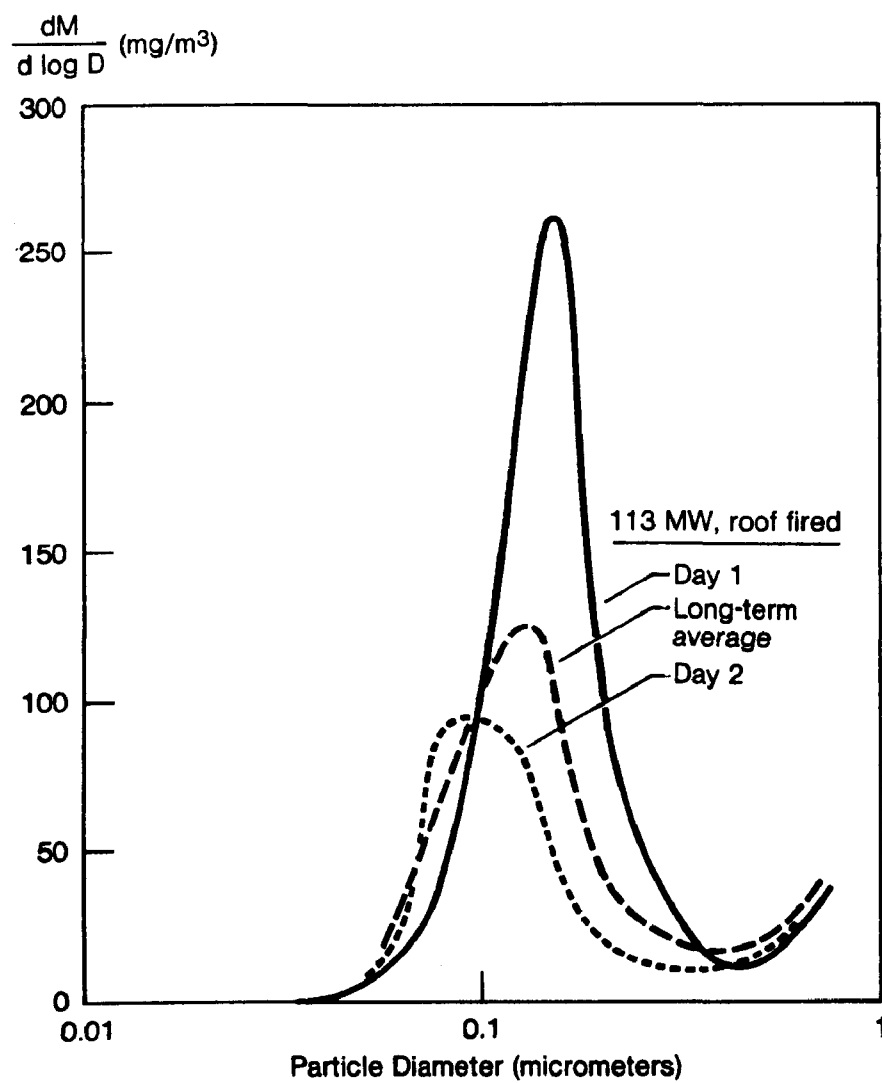
Figure 6. Variations in Aerosol Spike at Constant Boiler Load
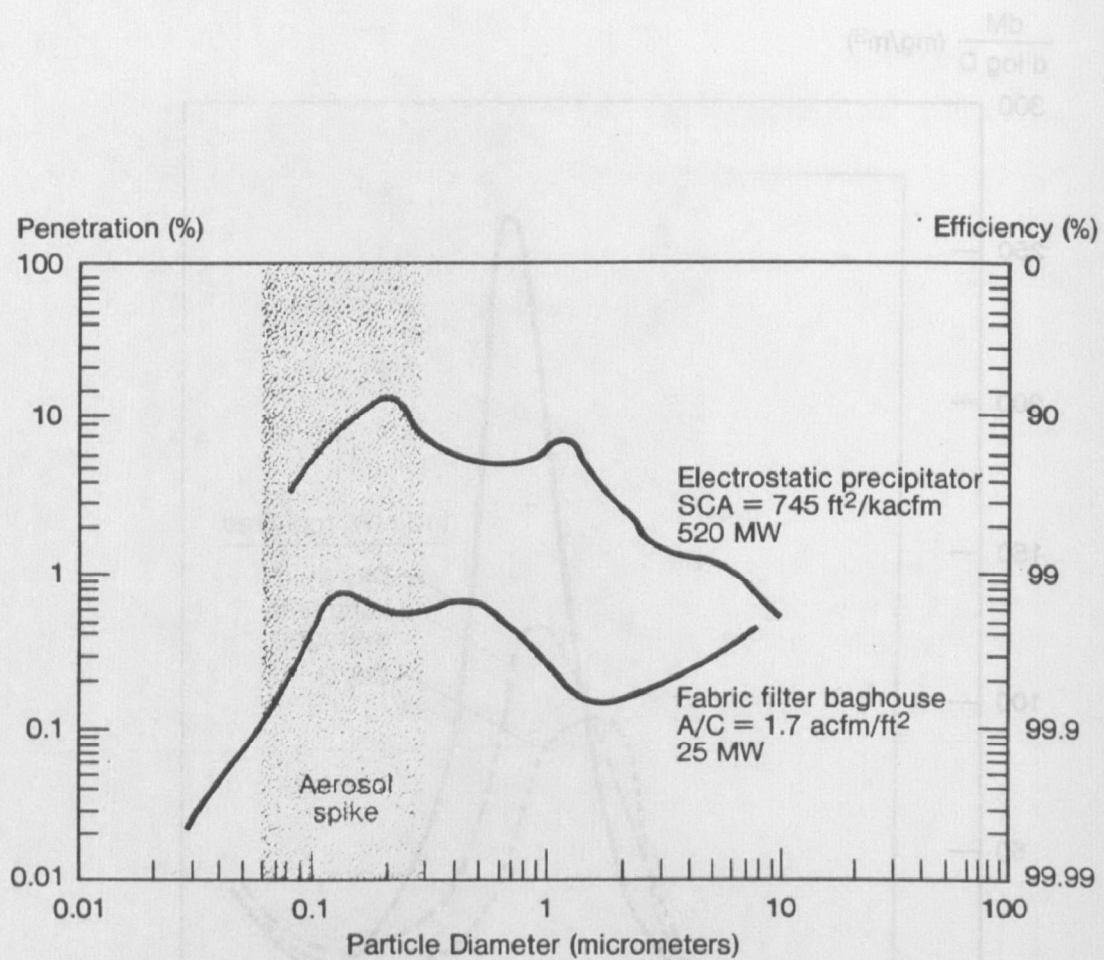
Figure 7. Size Dependent Collection Efficiency of Particulate
Controls Illustrating Minimum Performance in Region
of Aerosol Spike

TABLE I

TOTAL & FINE PARTICULATE EMISSION SUMMARY FOR SIX UTILITY BOILERS

Boiler Description	Total Mass grams/m^3 (grains/ft^3)	Mass <2μm (percent)	Mass of Aerosol Spike (percent)
360 MW, front wall fired Western, low sulfur, subbituminous	10.5 (4.6)	7	0.3
540 MW, tangential fired Eastern, high sulfur, bituminous	9.5 (4.2)	4	0.2
520 MW, opposed wall fired Western, low sulfur, subbituminous	6.4 (2.8)	4	1.3
113 MW, roof fired Western, low sulfur, subbituminous	3.4 (1.5)	8	2.2
360 MW, tangential fired Western, low sulfur, subbituminous	2.3 (1.0)	20	0.9
25 MW, front wall fired Western, low sulfur, subbituminous	1.7 (0.75)	8	0.5

COMMERCIAL EVALUATION OF A LOW NO_x COMBUSTION
SYSTEM AS APPLIED TO COAL-FIRED UTILITY BOILERS

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ABSTRACT

Development testing of an advanced, two-stage combustion system, capable of limiting NO_x emissions from pulverized coal-fired boilers to less than 0.2 LB_m $NO_2/10^6$ Btu has been completed. Test programs have been conducted on both a 1.2 MW_T and 10.2 MW_T system. These tests have confirmed that NO_x emissions can be correlated to a dimensionless parameter proportional to the second stage flame temperature. In addition, scaleup criteria were formulated which allowed the design of commercial scale low NO_x combustion systems.

Subsequently, a detailed engineering evaluation was performed on two candidate applications of this technology. The objectives of that study were: 1) to refine scaleup correlations and design procedures; 2) to conceptually design a steam generator incorporating the two stage combustion concept; 3) to economically evaluate that design as compared to a conventional, post-NSPS steam generator design; and 4) to identify areas of commercial concern with the new designs and to recommend further research to address these concerns.

This paper summarizes the significant results and conclusions from the test programs and the engineering study. The favored Venturi furnace system is expected to limit NO_x emissions from coal-fired boilers to less than 0.2 LB $NO_2/10^6$ Btu, while increasing the capital cost of the boilers by significantly less than the projected costs of tailend NO_x removal systems to meet future strict NO_x emission standards.

INTRODUCTION

In 1976, The Babcock & Wilcox Company (B&W) entered into a contract
with the Electric Power Research Institute (EPRI) to investigate practical
methods for minimizing the emission of nitrogen oxides (NO_x) from coal-fired
utility boilers. The goal of this research was to achieve 100 ppm of NO_x
using only combustion modifications. It was achieved, as reported in the
previous EPRI NO_x Control Seminar [1], by utilizing an advanced staged com-
bustion technique called the primary combustion furnace.

The primary combustion furnace was conceptualized to limit NO_x emissions
through effective control of temperature and oxidant availability. Unlike
conventional staged combustion, where separation of stages may be ambiguous,
the B&W process consists of two individual, physically separated combustion
chambers. The first stage is operated with substantially less than the
amount of air necessary to complete combustion. Under these conditions, the
fuel-bound nitrogen compounds tend to react to form molecular nitrogen within
the fuel-rich regions of the flame. After giving up some of their heat to
combustor surroundings, the products of partial combustion then pass into
the second-stage furnace where additional air is added to complete combustion.
NO_x formation in the second stage can be further suppressed (or first-stage
NO_x can be reduced) by limiting the second-stage, flame-zone temperature.

Initial testing of this concept took place on a 4-million Btu/hr
(1.2 MW_T) device. These tests, aimed toward understanding of the parameters
which affect NO_x formation and reduction, revealed that NO_x could be limited
to 100 - 150 ppm by operating with a first stage stoichiometry of 60% - 80%,
as long as the second-stage, flame-zone temperature (measured) was less than
about 1800°F. A plot of NO_x emissions, as a function of a characteristic,
measured flame temperature for these small-scale tests is reviewed in
Figure 1.

Subsequently, prototype-scale testing was completed on a 35-million Btu/hr (10.2 MW_T) scale. The purpose of this portion of the test program was twofold:

- To confirm that the effects of the various operating parameters on NO_x, noted during model furnace testing, would occur in a similar manner on the prototype system.

- To develop a scale-up strategy, based on the results of model and prototype testing, to be used to predict NO_x emissions from a commercial system.

This information was then factored into a detailed engineering design study performed by B&W's Fossil Power Generation Division. This study included the following tasks:

- Refinement of scale-up correlations and design procedures.

- Design of a 650-MW_e steam generator to accommodate the advanced staged combustion concept.

- Economic evaluation of the new design as compared to a conventional 650-MW_e, coal-fired boiler built to meet the original EPA New Source Performance Standard of 0.7 lb $NO_x/10^6$ Btu.

• Identification of potential commercial concerns or unknowns included in the new design, as well as a recommendation of research to address those concerns.

This paper is an update of the work accomplished since the last EPRI NO$_x$ Seminar in 1978. Results from the prototype test program are presented and compared to previous model-scale data. Pertinent highlights of the boiler design study and commercial evaluation will also be discussed.

PROTOTYPE-SCALE TEST FACILITY

The prototype-scale test program was conducted in a four-drum Stirling boiler rated at 40,000 lb/hr of steam. This boiler is located at B&W's Alliance (Ohio) Research Center.

To transform this boiler into the Low-NO$_x$ Combustion System (LNCS) shown in Figure 2, a separate first-stage furnace was mounted on the burner wall. This furnace consisted of a rectangular tunnel with a five-foot-square cross section by about 13 feet long. It differed from the 1.2 MW$_T$ device in that it was inclined at a 30° angle to minimize the accumulation of solids on the furnace floor. The transition between the first and second stage consisted of a converging section having a 55° included angle and terminating at a rectangular opening 19-1/2 inches wide by five feet high. This furnace was designed to accommodate the same residence time as the 1.2 MW$_T$ device when firing at 10 MW$_T$ (35 million Btu/hr).

Cooling of the first-stage furnace was achieved by circulation of pressurized water through the membrane-wall tubes. Total first-stage heat absorption could be determined from the measured temperature gain of the subcooled water, while chordal thermocouples were used to measure local

heat flux at 24 locations in the first stage.

Second-stage air was injected through pivoting, rectangular-slot nozzles located on either side of the first-stage furnace exit. These slots were sized to duplicate the second-stage air velocities from the 1.2 MW_T system.

As in the small-scale test facility, an ample number of sample probe access ports were located in both stages of combustion. These ports are diagrammed in Figure 3. As shown, NO_x, O_2, CO and CO_2 concentrations in the stack flue gas were routinely measured and continuously recorded. Particulate samples were also extracted from the stack for determination of combustion completeness. Temperature profiles in the second-stage ignition zone were taken for the majority of the test runs, while less routine measurements included HCN, NH_3, NO_x, O_2, CO, CO_2, inflame solids and temperature profiles in the first-stage furnace. It is impossible to report all these results in the space allotted. (A full report is forthcoming from EPRI [2].) However, the following sections describe the results having the most impact on the design of a commercial unit.

COMPARISON OF MODEL AND PROTOTYPE RESULTS

Effects of input variables were investigated during both the model-scale and prototype-scale tests. In this section, parametric influence of pertinent variables on NO_x emissions, as well as a comparison between test results from the two combustion systems, are presented.

Effect of First-Stage Air/Fuel Stoichiometry on NO_x

The prototype tests verified that an optimum overall air/fuel stoichiometry of 60% - 75% exists at which NO_x emissions could be minimized. The effect of stoichiometry on NO_x is shown in Figures 4 and 5, first, for the prototype system with and without flue gas recirculation to cool the second-stage flame, and second, for comparison of the model and prototype furnaces. At very low stoichiometries, first stage NO_x formation was low, but stack NO_x increased because the large amounts of cyano species (>500 ppm) produced in the first stage were converted to NO_x through oxidation reactions in the second stage. This conversion was enhanced by high, second-stage flame temperatures, since less heat was released and removed from the first stage.

At high stoichiometries, NO_x formation in the first stage was not as effectively suppressed. Even though reduction of NO_x still took place across the second-stage flame front as a result of higher first stage heat removal and lower, second-stage temperatures, NO_x emissions remained high because first-stage NO_x formation was high under local oxidizing conditions. The reduction of NO_x noted across the second-stage flame front can be seen by comparing the first stage exit NO_x line to the stack NO_x curves in Figure 4.

It can be seen from Figure 5 that NO_x emissions from the two furnaces were very similar at any given first-stage stoichiometry. The prototype furnace generally produced slightly higher NO_x at a particular stoichiometry due to decreased heat removal surface in the larger furnace.

Effect of Gas Phase Stoichiometry on NO_x

Although it was convenient to correlate NO_x emissions with overall air/fuel stoichiometry, this parameter can be misleading when applied to coal combustion because a significant fraction of the coal may remain in the solid phase. This would be especially true in combustion systems characterized by low temperatures or short residence times in the flame zone.

The first stage of the B&W low NO_x combustion system was fired with a low-turbulence burner under low-temperature conditions (2000-2500°F). Stratification of the mixture inside the first-stage combustor can be seen from Figure 6 in which contours of constant gas-phase stoichiometry are plotted for a test run at an overall stoichiometry of 70%. The gas-phase stoichiometries were calculated from the measured gas composition at each sampling plane located 3.3 feet (1 meter) and 6.7 feet (2 meters) from the burner outlet.

This figure shows that local gas-phase stoichiometries very seldom approached the overall value. In fact, much of the flame periphery remained under oxidizing conditions.

Since NO_x formation occurs primarily in the gas phase [3, 4], it would seem that to limit first stage NO_x, one should minimize the gas-phase stoichiometry. This can be seen from the contours of constant fuel nitrogen conversion plotted on Figure 7. Since low conversion closely corresponded to low, gas-phase stoichiometries (as illustrated by the contour having a gas-phase stoichiometry of unity superimposed on the plots), an attempt was made to increase the uniformity of the mixture by using an impeller to

disperse the coal into the air stream. The resultant gas-phase stoichiometry contours are shown on Figure 8. It can be seen that the local gas-phase stoichiometires were much more uniform, but that little improvement was made in achieving more reducing conditions. As a result, first-stage NO_x changed very little. The largest effect of the change, however, was a 4% decrease in combustion efficiency due to severe flame impingement on the first-stage furnace side walls.

Effect of Second Stage Temperature on NO_x

Early in the model-scale test program, it became obvious that second-stage, flame-zone temperature had an overriding effect on NO_x emissions from this combustion system. With constant conditions in the first stage, the second-stage NO_x could be increased or decreased, depending on the second-stage, flame-front temperature. Additionally, the first-stage NO_x concentration could be increased by nearly a factor of three without significantly changing stack NO_x concentrations. This startling result has been reported elsewhere [1, 5] and need not be explained in detail here.

Unfortunately, the early correlation between NO_x and second-stage flame temperature involved a single characteristic measured temperature. Since such a temperature could not be easily estimated during the design of large units, another more meaningful correlation was necessary.

As a first attempt, NO_x emissions were correlated with a calculated, theoretical, second-stage temperature, which was defined as the temperature of the second-stage mixture if combustion were completed under adiabatic second-stage conditions. This correlation is shown on Figure 9. It can be seen from this figure that a consistent relationship existed between NO_x and

theoretical second-stage temperature. But, by segregating the data, distinctive curves could now be drawn for each furnace load. It is believed that the load effect, which was not noted in the correlation with measured temperatures, was probably caused by the fact that second-stage heat losses (clearly a function of load) were not accounted for in the theoretical calculation. The successful design correlation which normalized the load effect is described below.

DEVELOPMENT OF AN NO_x CORRELATION PARAMETER (NCP)

An expression incorporating the parameters influencing second-stage temperature, while normalizing the load effects, is given below:

$$\frac{Q (1 - \beta)}{Q_N (1 + f)}$$

In this parameter, Q and Q_N are the load and the nominal load of the furnace; β is the amount of first-stage heat removed, expressed as a fraction of the fuel-energy input; and f is the amount of recirculated flue gas expressed as a fraction of the total coal and combustion air-flow rates. Nominal load was chosen as that load which would maintain mean-gas-residence time similarity between model and prototype furnaces.

A closer look would reveal that this parameter is actually the combination of the following two terms:

$$\frac{Q (1 - \beta)}{Q (1 + f)} \times \frac{Q}{Q_N}$$

The first term is representative of the theoretical second-stage temperature

209

while the second term is a modifier showing the effect of load changes.

A linear correlation of NO_x emissions with NCP, established from a least-squares fit of all data, is shown in Figure 10. Data plotted include both model and prototype-scale Pittsburgh No. 8 bituminous coal test results. These data cover a first-stage stoichiometry range from 50% - 75%, and FGR from 0% - 30%. Load variation covered a range of roughly 2 to 1. It's apparent the correlation is excellent.

Figure 11 is a plot of the Montana subbituminous coal data as a function of NCP. Superimposed on this graph is the linear correlation developed from the Pittsburgh No. 8 bituminous coal data. It can be seen that the Montana subbituminous coal data are generally higher than the correlation line by roughly 25 ppm, and that the scatter of data is slightly greater. However, since the deviation is not severe, a separate correlation line for Montana subbituminous coal has not been considered necessary at this point.

It should be noted that the correlations shown in Figure 10 and Figure 11 are valid only within a restricted range. In other words, the correlation was developed for the optimized conditions only. All of the data plotted are results from tests with optimum-slot, air-nozzle direction (15°) and excess air level (about 3% excess O_2). Also, since the correlation is empirical in nature, extrapolation outside a certain range of applicability would not be appropriate. The recommended ranges of applicability for a set of input variables are listed in Table 1.

210

It is also evident as shown by the data plotted in Figure 10 and Figure 11 that low NO_x emissions can be consistently obtained with the LNCS. As long as the operation was optimized with respect to slot angle, excess air and reasonable load, NO_x emissions were well controlled at 100 - 200 ppm.

ESTIMATION OF FIRST-STAGE HEAT REMOVAL

Determination of the NCP is straightforward. All terms in its make-up, except the first-stage heat removal term, are basic input information. However, to complete the determination of the NCP, a method had to be devised to predict heat loss in the waterwall, coal-fired, fuel-rich, first-stage furnace. To achieve this end, a simple algebraic predictive equation was developed by combining the energy-balance equation and the radiation-balance equation for the first-stage furnace. This equation can be expressed as:

$$\frac{b\phi + c - \beta}{(1 + a\phi)\,\beta^{1/4}} = d\,\frac{HA/SC}{\bar{\varepsilon}}$$

In this equation, β is the amount of heat loss to the water-cooled furnace wall expressed as a fraction of the fuel-energy input; ϕ is the first-stage stoichiometry; a, b, c and d are coefficients determined by coal composition, heating value and combustion air preheat; HA/SC is the furnace heat release rate (the ratio between furnace-energy input and furnace surface area); $\bar{\varepsilon}$ is the system mean, gray-body emissivity. Derivation and discussion of this model equation has been detailed elsewhere[6].

The accuracy of this predictive equation was evaluated by comparing the predicted values with the experimental data. During the model and prototype-scale testing of the LNCS, measurements of first-stage heat removal were taken for two coals (Pittsburgh No. 8 bituminous and Montana subbituminous) fired in two different size furnaces at air/fuel stoichiometry ranging from 50% - 90%, and load changes from 50% to 120% of nominal load. The performance of the predictive equation was found satisfactory for all cases. Examples of the measured and predicted heat transfer for the bituminous coal are shown in Figure 12.

As the size of the first-stage combustor increases toward commercial scale, the furnace heat liberation rate increases. Therefore, at a constant first-stage residence time, first-stage heat removal would be expected to decrease as larger units are designed. This would increase the NCP and the predicted NO_x emission. Fortunately, the predicted increase in NO_x emission as a function of furnace capacity is not expected to be sizeable, as shown on Figure 13.

It can be seen that, under optimized conditions, scaling from 35 million Btu/hr to 1 billion Btu/hr should only increase NO_x emissions from 140 ppm to 160 ppm. Alternatively, NO_x emissions can be trimmed by providing more heat removal surface area in the first stage. For the prediction of first-stage heat absorption in very large furances, conventional predictive procedures were shown to be valid.

SCALE-UP PROCEDURE

The procedure for scale-up design of a low NO_x combustion system can be outlined as follows:

1. Calculate nominal load using furnace dimensions (or vice versa).

2. Calculate first-stage heat removal using appropriate methods.

3. Calculate the NCP using the input information on load, coal type, amount of FGR, etc.

4. Estimate stack NO_x concentration by using the correlation with the NCP shown in Figure 8.

5. If the calculated NCP is less than 0.4 (lower limit of confidence) take the NO_x value at 0.4. Do not extrapolate.

6. If the calculated NCP is greater than 0.8 (upper limit of confidence), the designer has failed to take full advantage of the LNCS. Redesign is recommended.

DESIGN CRITERIA FOR COMMERCIAL APPLICATION

The laboratory data collected on both low-NO_x combustion systems identified several design criteria essential for minimizing the emission of nitrogen oxides. The most significant is the second-stage flame temperature. A target adiabatic temperature of 2600°F (1700°K) was selected for the commercial design to limit NO_x emissions to 0.2 lb/10^6 Btu. The heat transfer correlation described earlier could then be used to determine the size of the primary furnace necessary to achieve that second-stage adiabatic temperature.

In order to ensure that the degree of second-stage mixing is similar to that of the laboratory devices, the commercial system will be geometrically similar in second-stage injection design. Primary furnace exit velocity, staged air injection velocity, and the direction of both flows will be duplicated in the commercial design. The design of the injection ports will be such that velocity and direction can be controlled independently to accommodate changes in load and second-stage combustion conditions.

The primary furnace will be fired with burners that are geometric duplicates of the laboratory versions. The heat input per burner will be on the order of 150 - 300 x 10^6 Btu/hr (44 - 88 MW_T). The small-scale operation of the LNCS indicated that moderate changes in burner design had little effect on NO_x emissions. Therefore, the primary objective for the commercial design will be for efficient, stable operation over a range of loads and furnace conditions. The B&W dual-register burner has proven to be an effective tool for limiting initial NO_x formation in the primary furnace. Slightly more than 20% of the total heat input to the commercial system will be absorbed

214

by the primary furnace walls. Both the residence time and heat absorption were calculated at the optimum first-stage stoichiometric ratio of 0.7 to minimize NO_x emissions.

COMMERCIAL DESIGN

The boiler design task of the LNCS commercial application study resulted in two different boiler designs. One design, the primary combustion furnace (PCF), utilizes the multiple, primary furnace concept, while the Venturi design has only a single primary furnace. A brief description of each design, as compared with a conventional boiler design, will highlight the differences.

Conventional Design

The boiler chosen as a basis for comparing the LNCS designs to conventional designs is shown in Figure 14. It is a 650-MW_e, balanced-draft, Babcock & Wilcox, Carolina-type radiant boiler of post-1971 design. It is arranged with a water-cooled, dry-bottom furnace, along with conventional superheater, reheater, economizer and air-heater components. The boiler was designed to produce less than 0.7 lb/10^6 Btu of NO_x (500 ppm) when firing a midwestern bituminous fuel with 49 dual-register burners in a compartmented windbox.

PCF Design

The first LNCS boiler design evaluated during this study is shown in Figure 15. It is a balanced-draft, Babcock & Wilcox, tower-type radiant

boiler also rated at 650 MW$_e$. The tower design proved to be more economical for this particular application because extra space was required around the boiler to accommodate the primary furnaces. This design eliminates any interference by removing the large downflow section of the convection pass found on the more conventional Carolina design. It is designed to be fired with 28 primary combustion furnaces (PCF) and utilize conventional dry-bottom furnace, superheater, reheater, economizer and air-heater components, while producing less than 0.2 lb/10^6 Btu NO$_x$ (150 ppm).

An iterative, heat-rate analysis showed that the heat transferred from the primary combustion furnace containments should be utilized in the boiler itself rather than in the pre-boiler cycle. Circulation and manufacturing considerations prompted the decision to make the PCF containments an integral part of the furnace wall circuitry. However, to maintain adequate flow through that circuit, five circulation pumps were added. In addition, a flue-gas recirculation system was added for NO$_x$ and steam temperature control.

Venturi Design

The design complexities associated with the PCF design prompted the development of an alternative LNCS boiler design. The arrangement shown in Figure 16 eliminates the primary combustion furnace containments by operating the entire lower portion of the boiler furnace at an air/fuel stoichiometric ratio less than 1. The remainder of the combustion air is injected at the constriction of the furnace formed by two wall arches. This arrangement has been designated the "Venturi" furnace design.

The primary furnace (below the arches) is fired with 28, high-input, dual-register burners. There are no circulation pumps necessary and the remainder of the boiler is almost identical to the base unit. By maintaining proper first-stage heat removal, this design is also expected to meet the 0.2 lb $NO_x/10^6$ Btu emission goal.

ECONOMIC ANALYSIS

Assuming the data collected from the laboratory testing can be extrapolated to the necessary scale, both LNCS steam generator designs should be functionally satisfactory. However, an economic analysis indicated that the Venturi design is much more cost effective. Table 2 is a summary of the cost study.

The LNCS designs both have reduced gas temperatures exiting the furnace. This requires additional convective heat transfer surface to be installed to maintain design (1005°F) steam temperatures. This surface accounts for the largest portion of the pressure-part cost increase. Additional structural steel is also necessary to support the additional furnace and convective surface and the weight added by the two furnace-wall arches in the Venturi design. The PCF design, in addition to the items mentioned above, has cost increases associated with the attachment of primary combustion furnace containments and the need to use circulation pumps.

COMMERCIAL CONCERNS

In spite of the careful consideration given each of the system designs, B&W is concerned that several phenomena, unique to staged combustion, could

cause operating difficulties in the future. The primary concerns at this time are first-stage furnace waterwall corrosion and carbon utilization. After completing the engineering study of the commercial LNCS systems, many early concerns such as prohibitive cost, complicated control systems and operating procedures, manufacturing and construction problems, development of flame safety equipment and others proved to be unjustified.

The first concern arises from operating <u>experience</u> which has shown increased tube metal corrosion in areas suspected of exposure to reducing atmospheres. The nature of operation of the LNCS System will expose large areas of furnace-wall tubes to reducing atmospheres.

The second concern, carbon utilization, is an area of concern due to <u>inexperience</u> with staged combustion in utility boilers firing pulverized coal. The second stage mixing of combustion air with combustion products and unburned fuel from the primary furnace, and its effect on carbon burnout, have not been quantified. The relatively low temperatures in the second-stage combustion zone could also reduce combustion efficiency.

CONCLUSIONS

As a result of a detailed engineering analysis of advanced staged combustion techniques as applied to a new, pulverized coal-fired boiler, it has been concluded that the EPRI/B&W Low NO_x Combustion System <u>could</u> be a viable commercial alternative to tail-end NO_x removal to meet future strict EPA NO_x emission standards (circa 0.2 lb $NO_2/10^6$ Btu). Due to its relative simplicity and lower capital cost, the Venturi furnace described previously most favorably embraces the concept. The PCF design, however, is

still considered a retrofit possibility, especially for cyclone units oil-fired boilers that a utility wishes to convert to coal.

Before offering this system as a commercial product, B&W will complete several additional research programs to address the remaining concerns mentioned above. The results of these programs will help refine the LNCS design and enable a more precise, second-generation estimate of material and operating costs to be made.

FUTURE WORK

The commercial concerns noted previously could best be alleviated by converting an existing utility boiler into a low-NO_x Venturi furnace based on the design and scale-up criteria developed during the system analysis study. If this were done, it would only take a few years to measure corrosion rates under actual operating conditions to determine whether a potential problem really exists. It would take a few weeks (using variable-angle, second-stage injection ports) to determine whether trade-offs exist between low NO_x emissions and acceptable carbon conversion. Most importantly, such a test would provide day-to-day operating experience to finalize control schemes and to assess reliability of system components.

Unfortunately, it is unlikely that such a test could occur in the near future. Based on preliminary discussions with a number of utilities, the following factors substantiate this opinion:

- Retrofit of a Venturi furnace would be extremely expensive due to pressure-part changes required in the lower furnace walls. Substantial funding from an outside agency (EPRI, EPA, DOE) would be required for a project of this magnitude.

- A long outage in excess of 8 weeks would probably be required to modify the unit. Most utility companies do not have enough reserve capacity to afford such an extended outage.

- Because fewer new boilers are being built, most utilities are stressing maximum availability of their existing units, even old and inefficient units. Any test program which could disrupt the production of electricity is not likely to be approved.

- At this time, many utilities are concerned that very strict NO_x emission standards will prevent widespread committment to coal because they perceive problems involving costs and plant reliability. Until strict emission standards are promulgated (requiring extensive combustion modifications or expensive tail-end NO_x removal, they will probably remain unwilling to test major modifications to reduce NO_x.

In the meantime, B&W has undertaken the following programs to provide data which will enable the risk associated with each concern to be quantified.

Furnace Tube Wall Corrosion (Background)

Fireside corrosion of waterwall tubes in coal-fired utility boilers began to be a problem in the late 1930s. The trend at that time of high furnace heat release rates, coupled with increasing steam pressure requirements, resulted in higher furnace-wall temperatures and led to increased deposits of slag on furnace waterwalls. Presence of aggressive iron and alkali sulfates in the slag layer coincided with severe loss of metal. It was further noted at this time, that low, excess-air operation greatly aggravated this corrosion problem, presumably by fluxing the slag layer and providing even more aggressive reduced sulfur compounds (H_2S, S, FeS_2) in the vicinity of the waterwall. Flame impingement often accompanied corrosion in these units, and relatively high concentrations of CO (0.5 - 6.0%) were measured in the vicinity of the wall, indicating the presence of reducing conditions.

Staged combustion of coal also results in local, gas-phase reducing conditions, as well as longer flames. During the testing of the primary combustion furnace under this EPRI contract, for instance, CO concentrations in a similar range (0.1 - 9.0%) were measured in both the model and prototype first-stage furnaces.

Mechanisms for corrosion in a reducing atmosphere are still not totally understood. Hydrogen sulfide (H_2S) gas, which is present in quantities up to 0.5% in the low NO_x system can be potentially harmful. Sulfidation attack by H_2S on metals in hydrogen-rich atmospheres has been observed in steam reformers associated with many refinery operations. The questionable effect of large quantities of hydrogen, however, makes it difficult to transfer the refinery experience to utility boiler operation.

Another possible mechanism for corrosion involves deposition of pyrite (FeS_2) on the metal surface, followed by reaction of the pyrite with the protective metal oxide layer. Removal of the oxide layer by alternating exposure to both oxidizing and reducing gases could lead to rapid metal loss. Deposition of other ash constituents (like alkali sulfides and sulfates) can also cause corrosion by diffusion of tube-metal iron into a slag layer under the deposit or by dissolving the iron oxide layer into complex iron alkali tri-sulfates.

Tube-thickness measurements made during the prototype PCF test program indicated that corrosion could be occurring on the floor of the first-stage furnace. After about 300 hours of operation, the only points where measurable metal loss took place were located on the furnace floor tubes where dry and partially fused ash accumulated. It was also observed that flame impingement occurred on the furnace floor, creating a local reducing atmosphere (see Figure 6). Gas samples taken in a plane located 6.7 feet downstream of the burner showed that the roof and sidewalls were exposed to local oxidizing conditions ranging in stoichiometry from 100% - 140%. The floor, however, maintained a gas phase stoichiometry of 85% - 95%.

Test Programs

It can be seen from the above discussion that, if waterwall corrosion takes place in a low-NO_x combustion system, it could occur as a result of one or several imperfectly understood mechanisms. In the commercialization of the low NO_x concept, it is of first importance to select potential materials for adequate (>10 years) metal life. In order to achieve this goal, two fundamental corrosion studies are planned:

1. A screening test of candidate tube metals exposed to a gas-phase atmosphere typical of that measured in previous low-NO_x combustion tests.

2. A parametric variation of furnace conditions aimed at determining the effects of various sulfur forms on corrosion rates of carbon steel. Variables could include temperature, sulfur concentration, alkali availability, oxidizing/reducing cycle, and gas phase stoichiometry. Potential methods to control corrosion, such as air curtains or flue gas inerting, could also be investigated.

In the metal screening tests, the following materials have been selected for testing:

1. Carbon steel (SA210)
2. Croloy 2-1/4
3. Type 304 and 304L Stainless Steels
4. Types 309 and/or 310 Stainless Steel
5. Incoloy 800
6. Inconel 671
7. Aluminized carbon steel via diffusion coating, dipped coating, and flame spraying
8. Chromized and Aluminized Croloy 2-1/4 and Carbon steel.

Two autoclave systems have been designed and installed at B&W's Alliance Research Center to carry out corrosion tests of these materials.

Three samples of each material will be exposed to the gas mixture (typical of the concentrations measured at 70% stoichiometry near the exit of the first-stage furnace) for three time periods. Corrosion rates for two of the three samples removed after each time period will be determined by loss-of-weight measurement. The third sample of each material will be examined by electron microscope to determine composition and structure of the scale for comparison with unexposed archive samples.

The objective of these tests is to compare the resistance of each material to sulfidation attack under conditions of constant temperature and gas composition. The data should also provide some qualitative information concerning the effects of time, temperature and localized sulfur activity on corrosion rates. Based on this information, initial Venturi furnace designs will consider the cost/benefit dichotomy of corrosion resistant materials in zones (such as the lower arch) where highly reducing conditions are likely near the wall.

In the event that gas-phase sulfidation by H_2S or S_2 is not the dominant mechanism of corrosion, B&W is planning a subsequent corrosion study beginning in calendar year 1981. Additional tests beyond the screening tests will be required at conditions more closely simulating the low-NO_x furnace conditions, including the effects of ash deposits. In this study, further information will be developed concerning corrosion rates for only those materials that are deemed acceptable from the material screening study. Although detailed plans have not as yet been made, the following outline contains our current thoughts:

- Three sets of samples should be provided for each material: bare metal samples, samples coated with a uniform layer of FeS_2 (iron pyrite) and samples coated with a layer of sintered flyash from a high-sodium western coal.

- Samples should be exposed at constant temperature to a typical fuel-rich gas for 500, 1000, and 2000 hours.

- Samples should be exposed to various temperatures ranging from 500°F to 900°F.

- Samples should be exposed to periodic addition of O_2 to the gas composition.

In addition to the measurement of corrosion rates, analysis may include detection of SO_3 in the reactor exit gases, and sulfur forms existing in the corrosion products. In particular, evidence of pyrosulfate or alkali tri-sulfate will be sought. Sulfide penetration into the metal substrate will also be measured since its presence could indicate future catastrophic failure of materials that initially show low corrosion rates.

CARBON UTILIZATION (Background)

The concern that carbon burnout may be unacceptable in a full-scale Venturi furnace operating in the low NO_x mode stems from the following considerations:

225

- During prototype testing of the Pittsburgh seam #8 bituminous coal, large agglomerates of sticky particles which formed in the first-stage furnace were not completely combusted in the second state. The sub-bituminous coal, however, which did not agglomerate, achieved 99+% burnout under all conditions. Carbon burnout for each of these fuels is illustrated in Figure 17.

- Carbon burnout depends on the amount of time that the particle is exposed to high temperatures in the presence of oxygen. The local oxygen concentrations, in turn, depend on the penetration and entrainment of the second-stage air jets into the first-stage exit gases. In the prototype tests, the air had to penetrate across a jet approximately 20 inches wide, but in the commercial Venturi furnace, the fuel-rich jet is 21 feet wide.

Work done on the model and prototype low-NO_x systems at B&W showed that there was a slight trade-off between increased second-stage mixing (i.e., higher air jet velocity or higher jet penetration angle) to achieve better burnout, and decreased mixing to minimize second-stage NO_x. It is possible that the same conditions considered optimum during the test programs would need to be refined in the field. Therefore, B&W is studying the mixing process in a full-scale Venturi furnace by utilizing advanced flow modeling techniques in order to show that complete combustion is possible under low NO_x conditions. Armed with the information from this study, B&W will then optimize the second-stage mixing during the eventual field testing of the Venturi furnace concept.

PRELIMINARY FIELD TESTING

The third major concern with commercializing the Venturi furnace concept is that the use of flue-gas recirculation fans, along with operation in an unfamiliar staging mode, may decrease the availability of early commercial units. As stated previously, extensive field testing of a demonstration unit is the only way to assess the impact of this concern. Before the demonstration unit will be accepted by a customer, however, it may be advantageous to point to preliminary field tests where boilers were subjected to "deep staging", i.e., burner air/fuel stoichiometries on the order of 0.6 - 0.8. Such tests could be conducted on an existing boiler equipped with overfire air ports. B&W has begun discussions with an electric utility that has expressed interest in participating in such a test program.

SUMMARY

In the above sections, B&W has defined interim research aimed at further defining the practical limit of NO_x control using advanced staged combustion techniques. These programs result from a detailed engineering study of the Venturi furnace, based on model and prototype test results. This low-NO_x system, as designed, seems to be a viable alternative to either tail-end NO_x reduction or the EPA burner concept, both of which will be commercially demonstrated in the near future. With the potential decrease in NO_x emission standards just around the corner, it would seem prudent for the utility industry to carry this research to its final demonstration before the alternative technolo are forced upon them.

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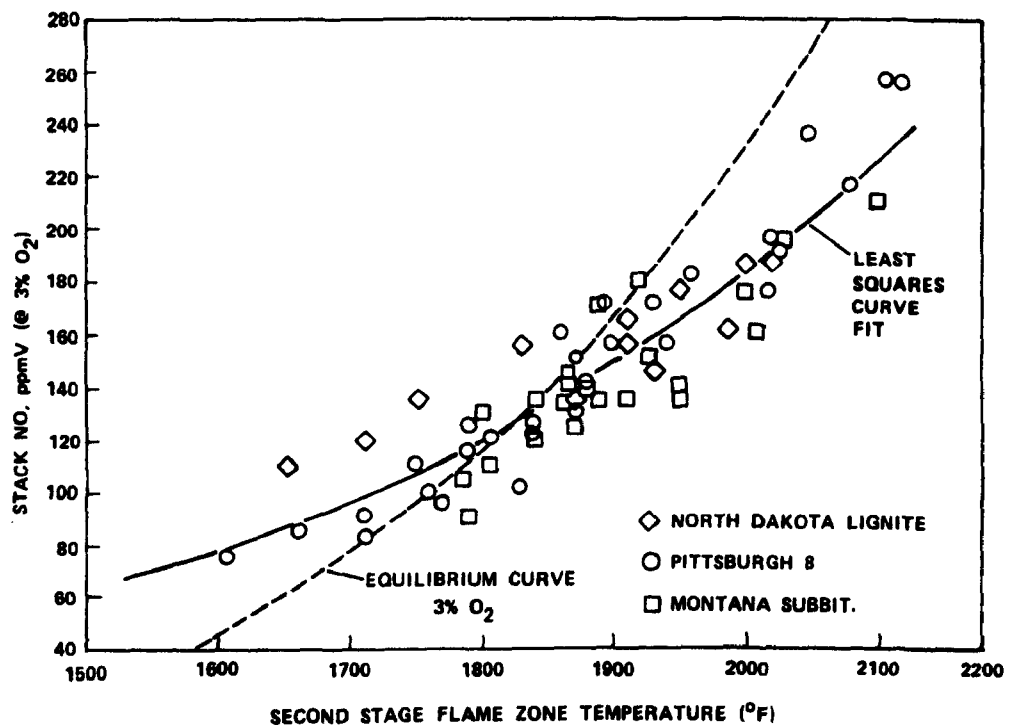
Fig. 1 NO$_x$ emissions as a function of a measured second stage flame temperature
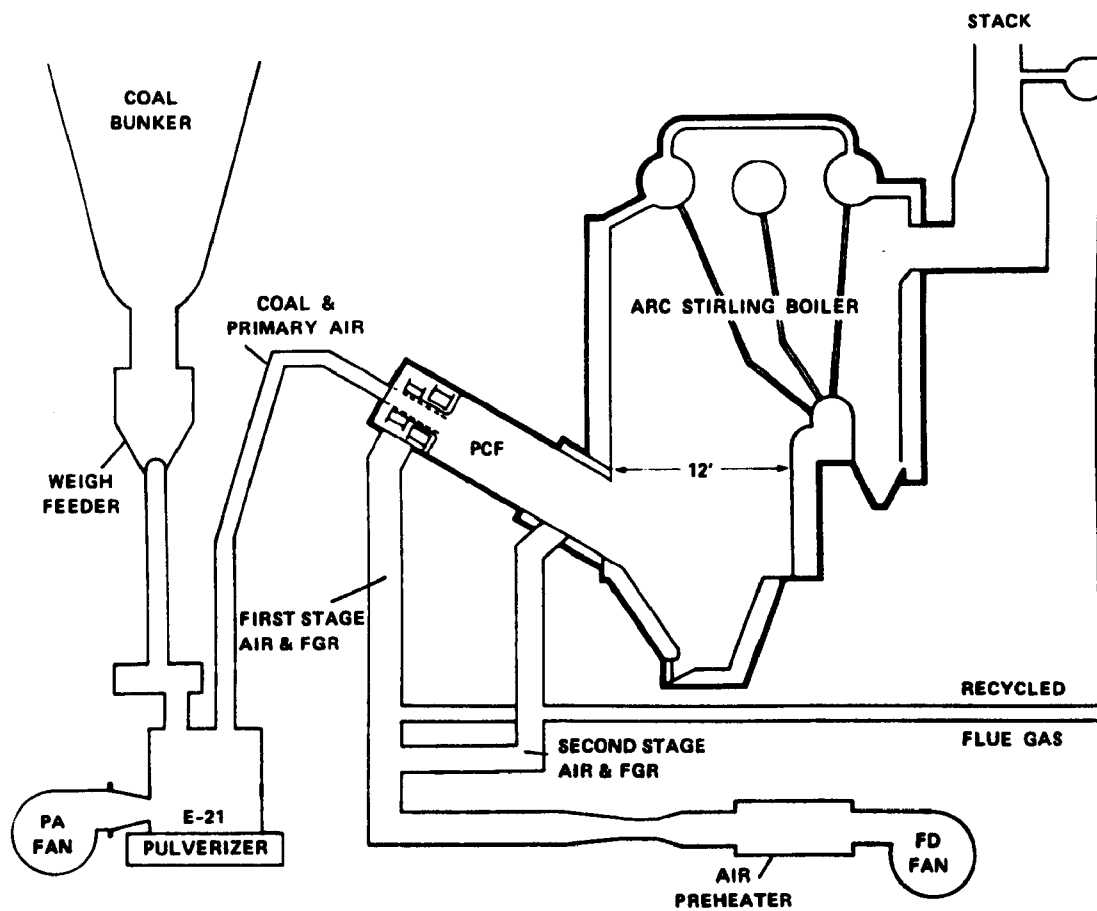
Fig. 2 Prototype scale test facility

231
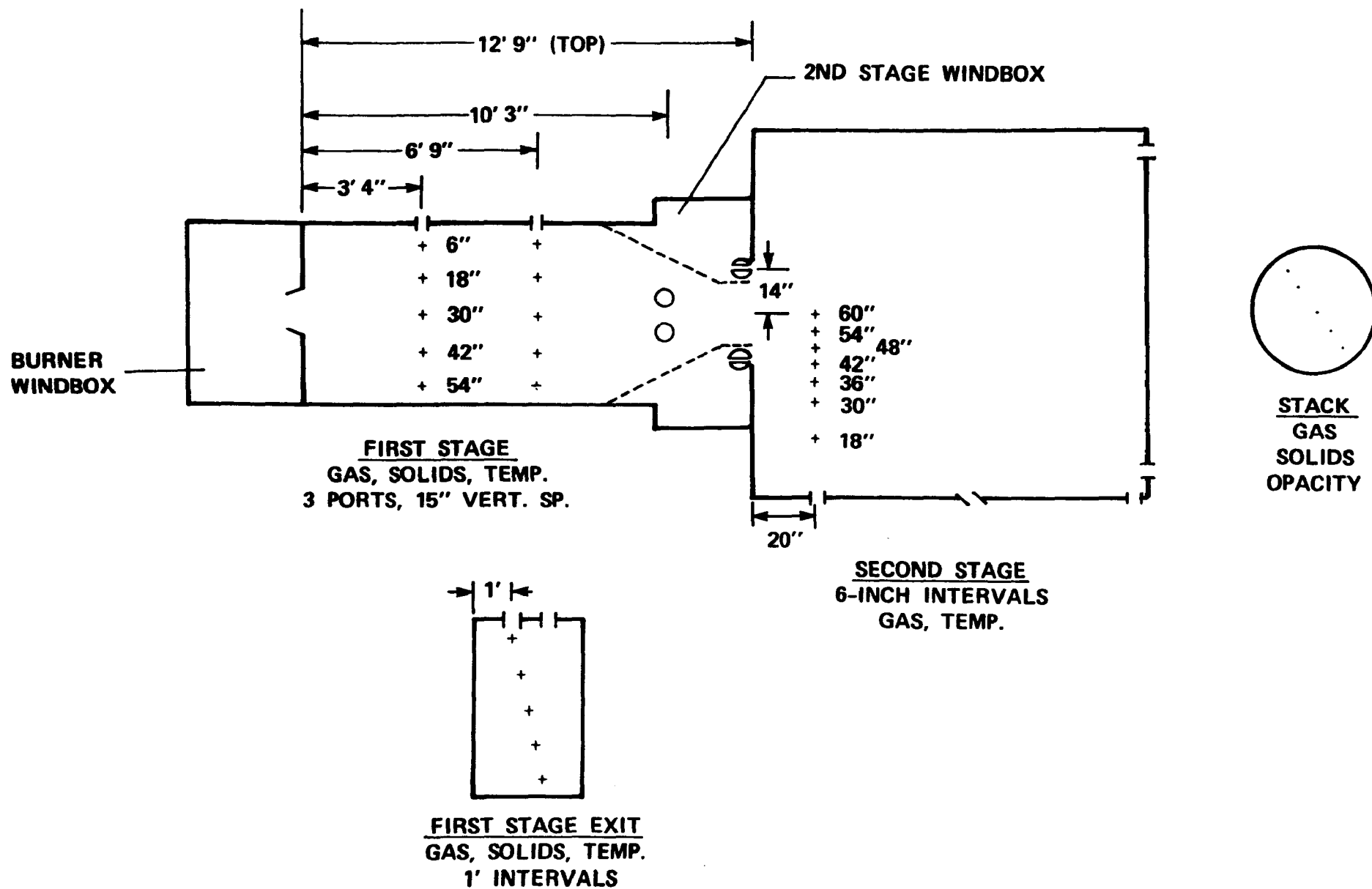
FIGURE 3 SAMPLE PORT LOCATIONS (PROTOTYPE TEST FACILITY)

PROTOTYPE DATA
PITT. NO. 8 BITUMINOUS COAL
LOAD = 37 x 10^6 BTU/HR
3% EXCESS O_2
○ STACK NO_X, 15% FGR TO 2ND STAGE
■ STACK NO_X, NO FGR
● FIRST STAGE EXIT NO_X
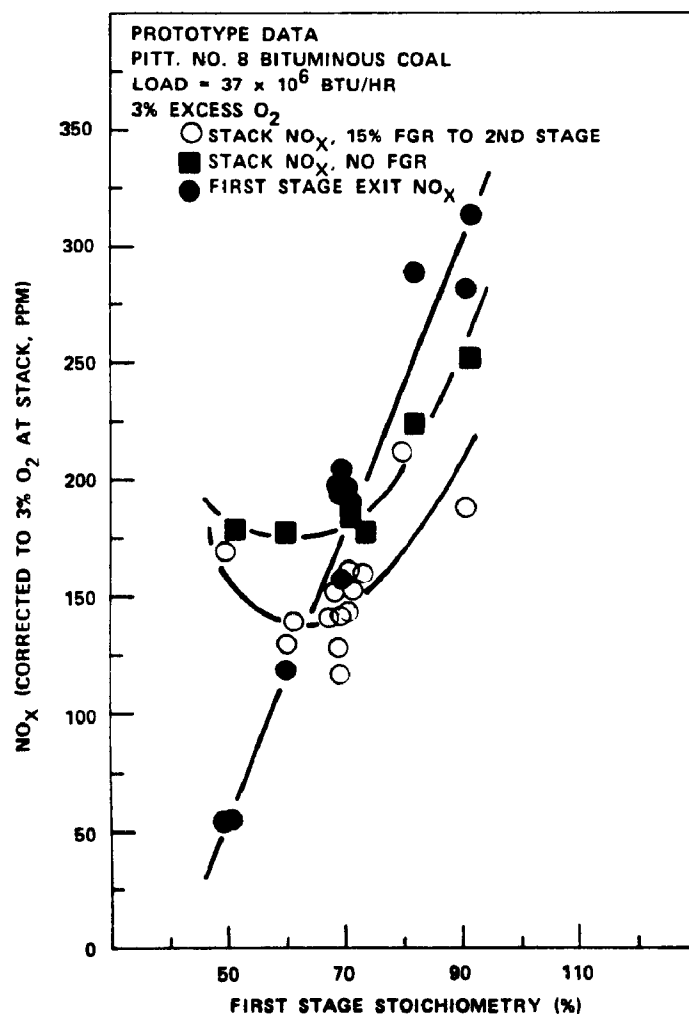
Fig. 4 Effect of first stage stoichiometry on NO_X — prototype system

233
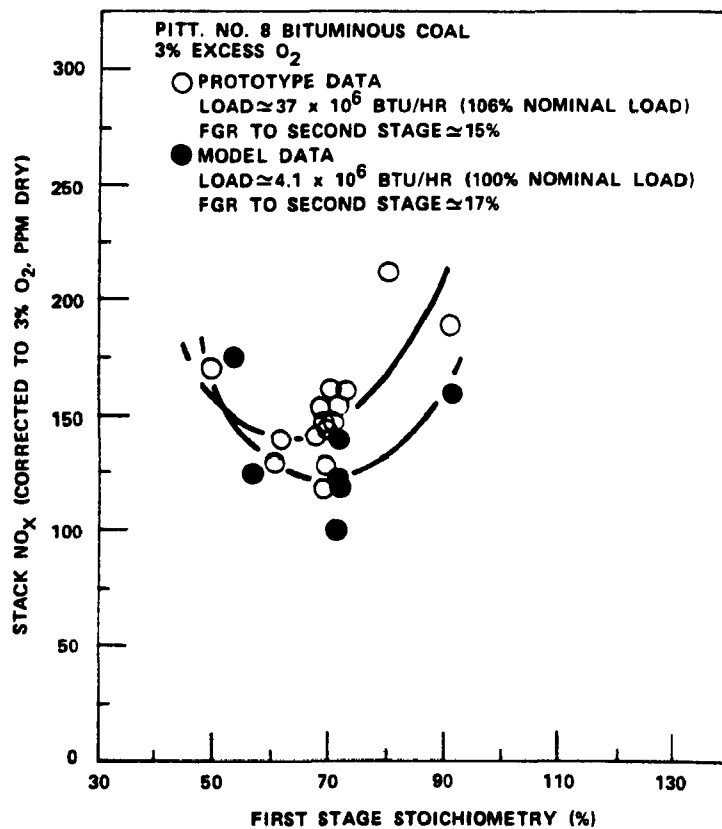
Fig. 5 Effect of first stage stoichiometry on NO_x — comparison of model and prototype data

234

TOP

WEST

EAST

BOTTOM

PLANE 1, 4 FEET FROM BURNER

TOP

WEST

EAST

BOTTOM
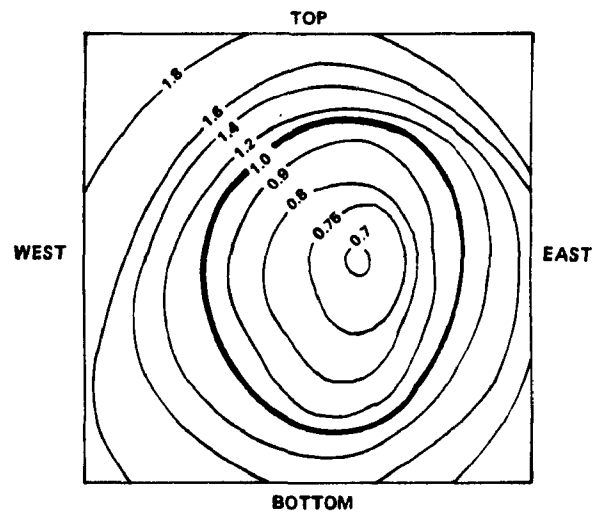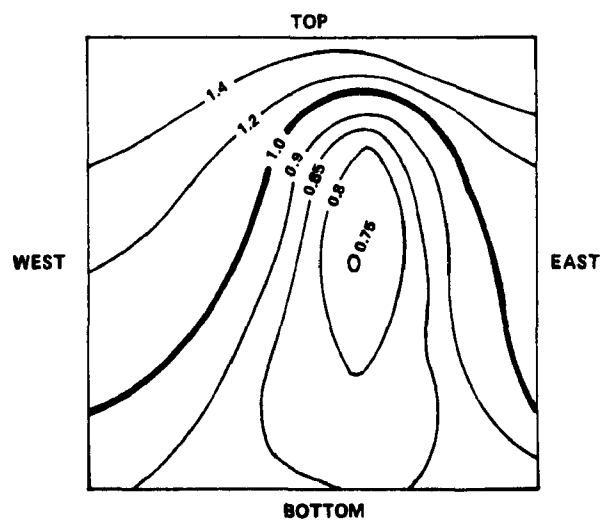
PLANE 2, 8 FEET FROM BURNER

Fig. 6 First stage flow patterns — prototype combustor

235

TOP

WEST

EAST

BOTTOM

PLANE 1, 4 FEET FROM BURNER

TOP

WEST

EAST

BOTTOM

PLANE 2, 8 FEET FROM BURNER
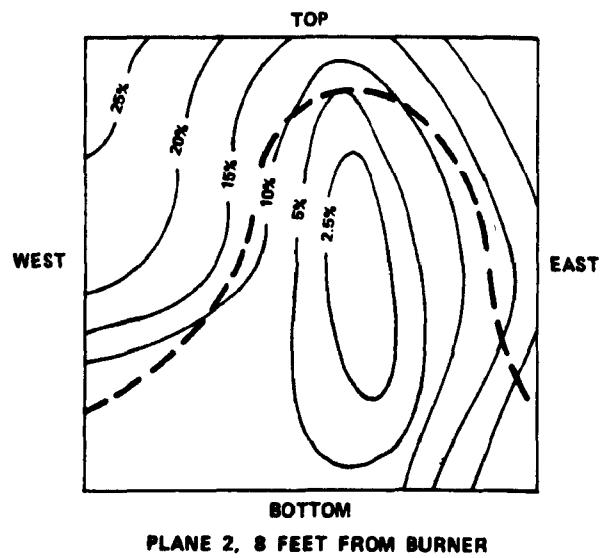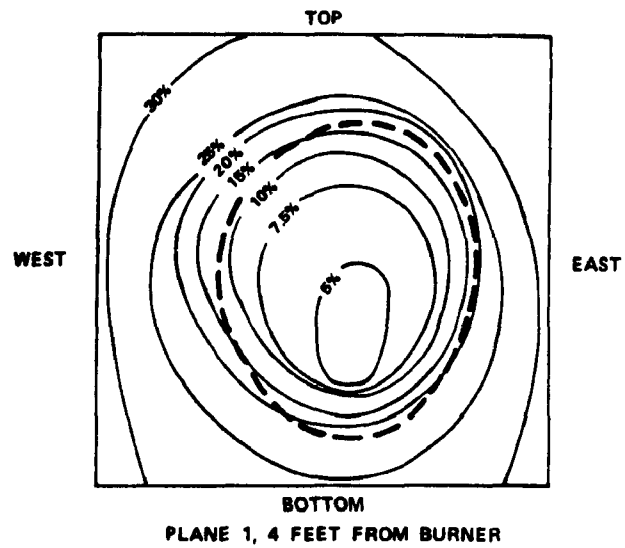
Fig. 7 First stage fuel N conversion — prototype combustor

236

TOP

WEST   EAST

1.5
1.2
1.0
0.9
0.8
0.75

BOTTOM
PLANE 1, 4 FEET FROM BURNER

TOP

WEST   EAST

1.2
1.0
0.9
0.8
0.75

BOTTOM
PLANE 2, 8 FEET FROM BURNER
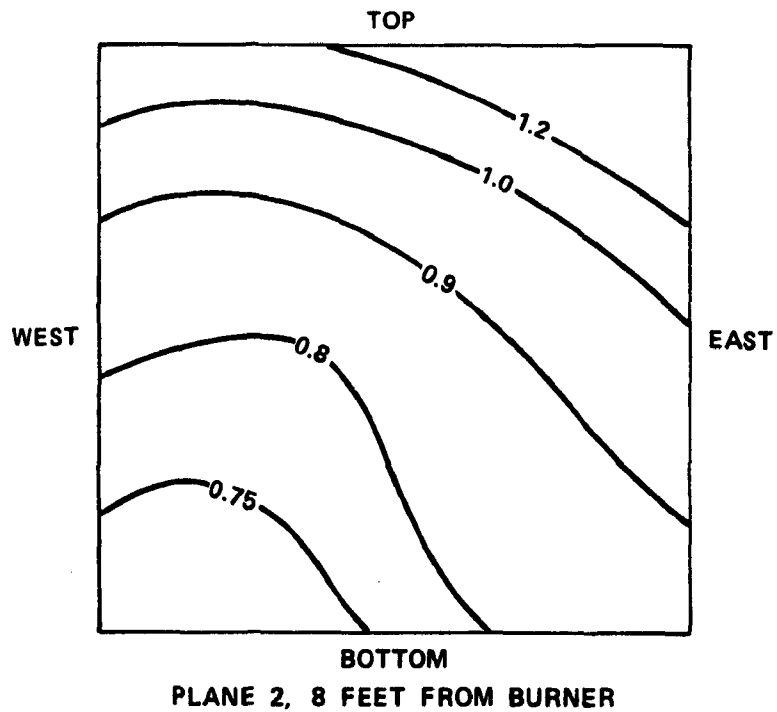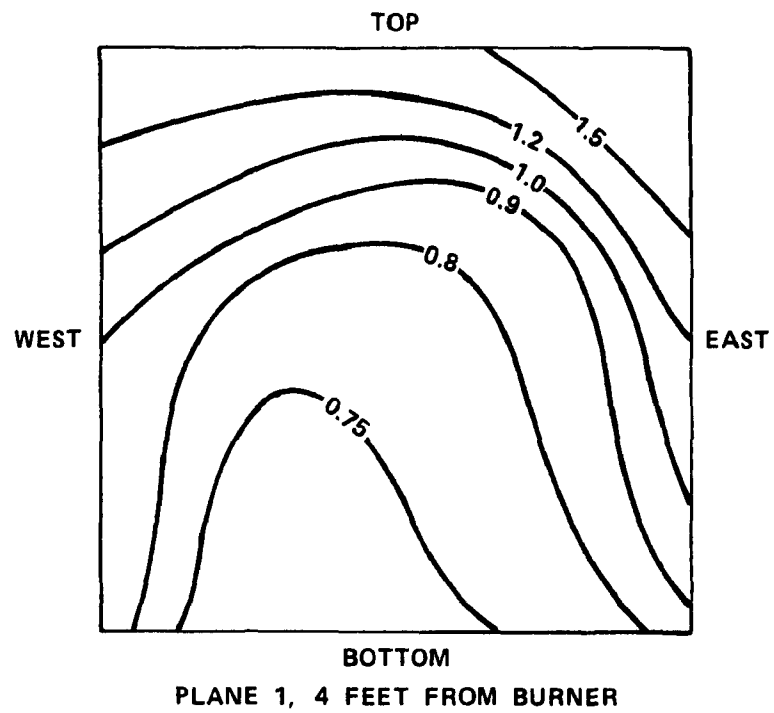
FIGURE 8   GAS-PHASE STOICHIOMETRY PROFILES (RADIAL-VANE IMPELLER)
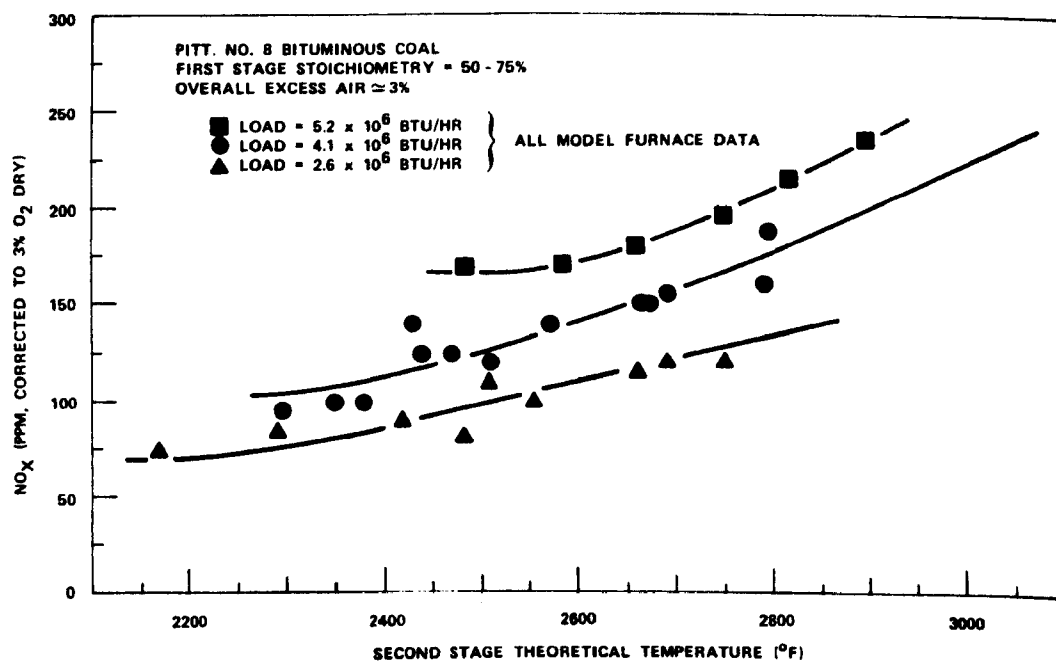
Fig. 9 NO$_x$ emissions correlated against a calculated second stage temperature
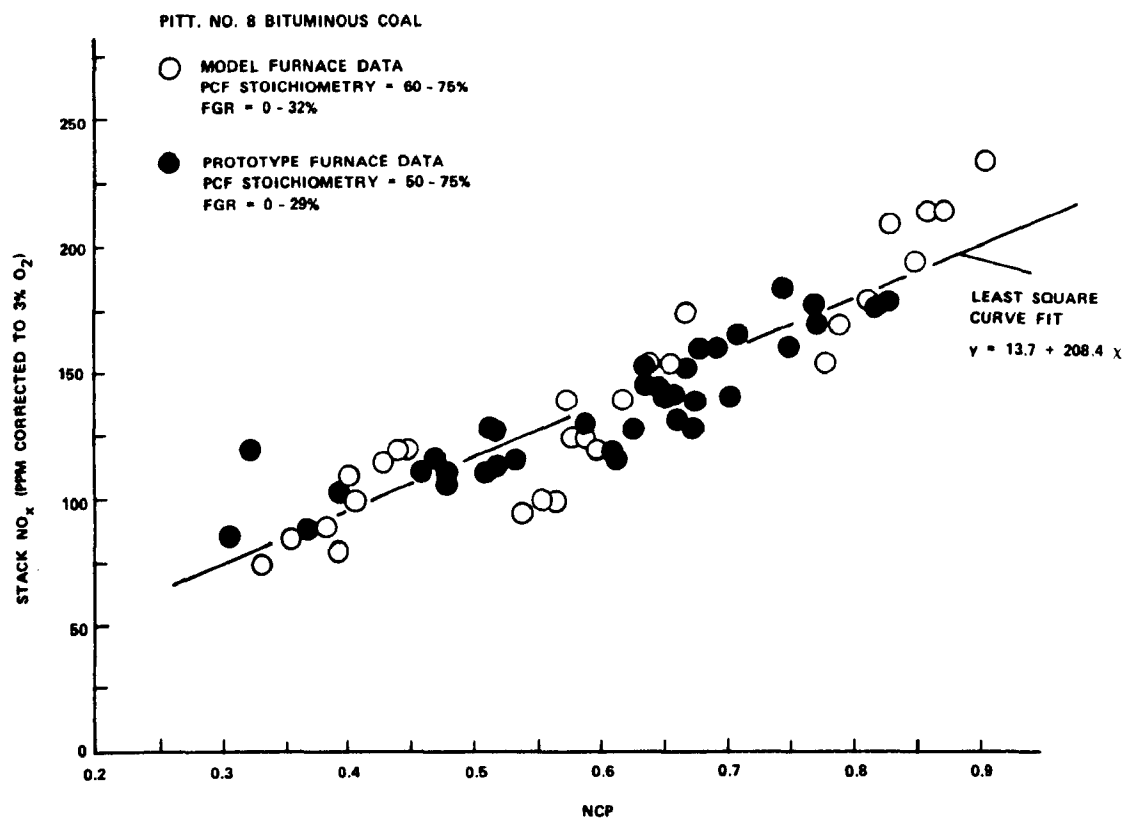
Fig. 10 NO$_x$ correlation for Pittsburgh seam #8 bituminous coal
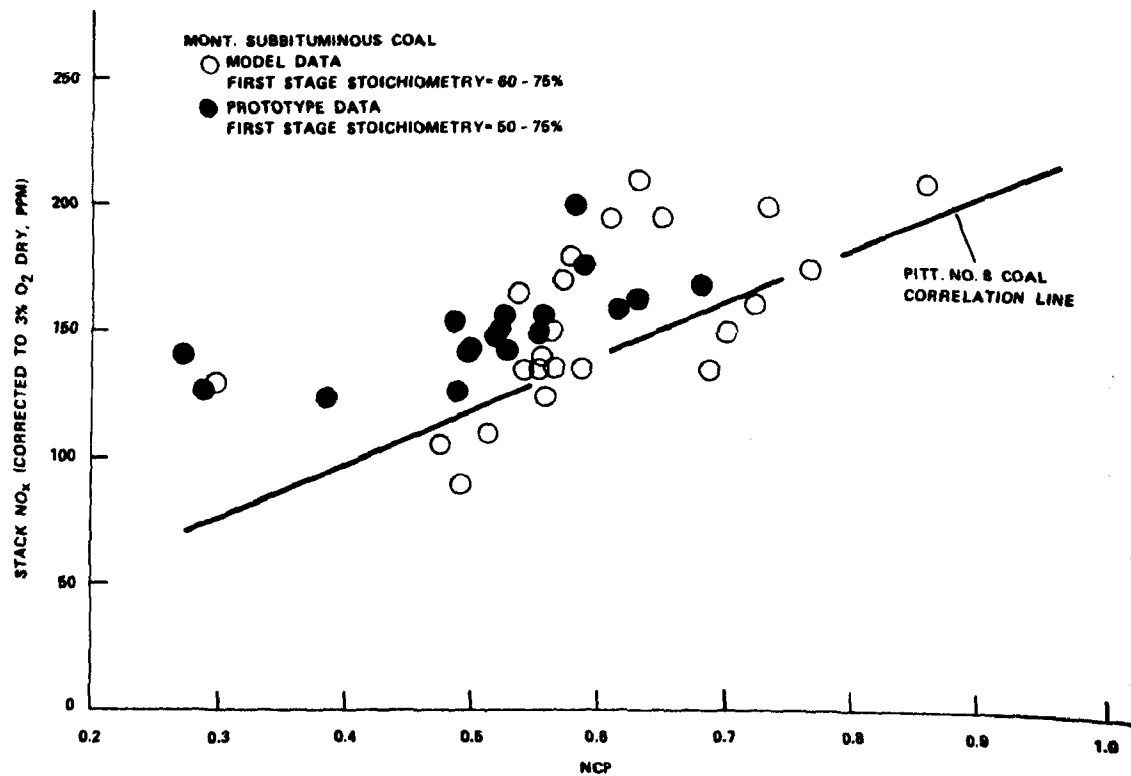
Fig. 11 NO$_x$ correlation for Montana (Decker Seam) subbituminous coal

240
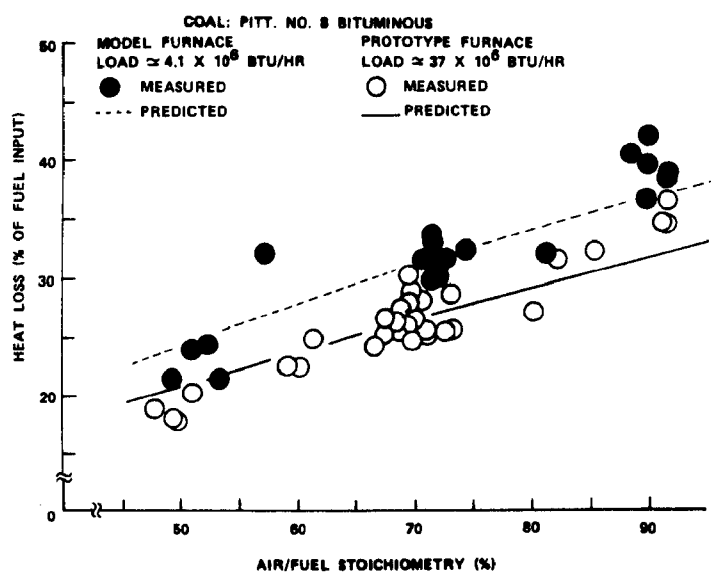
FIGURE 12 Comparison of actual and predicted heat removal

241
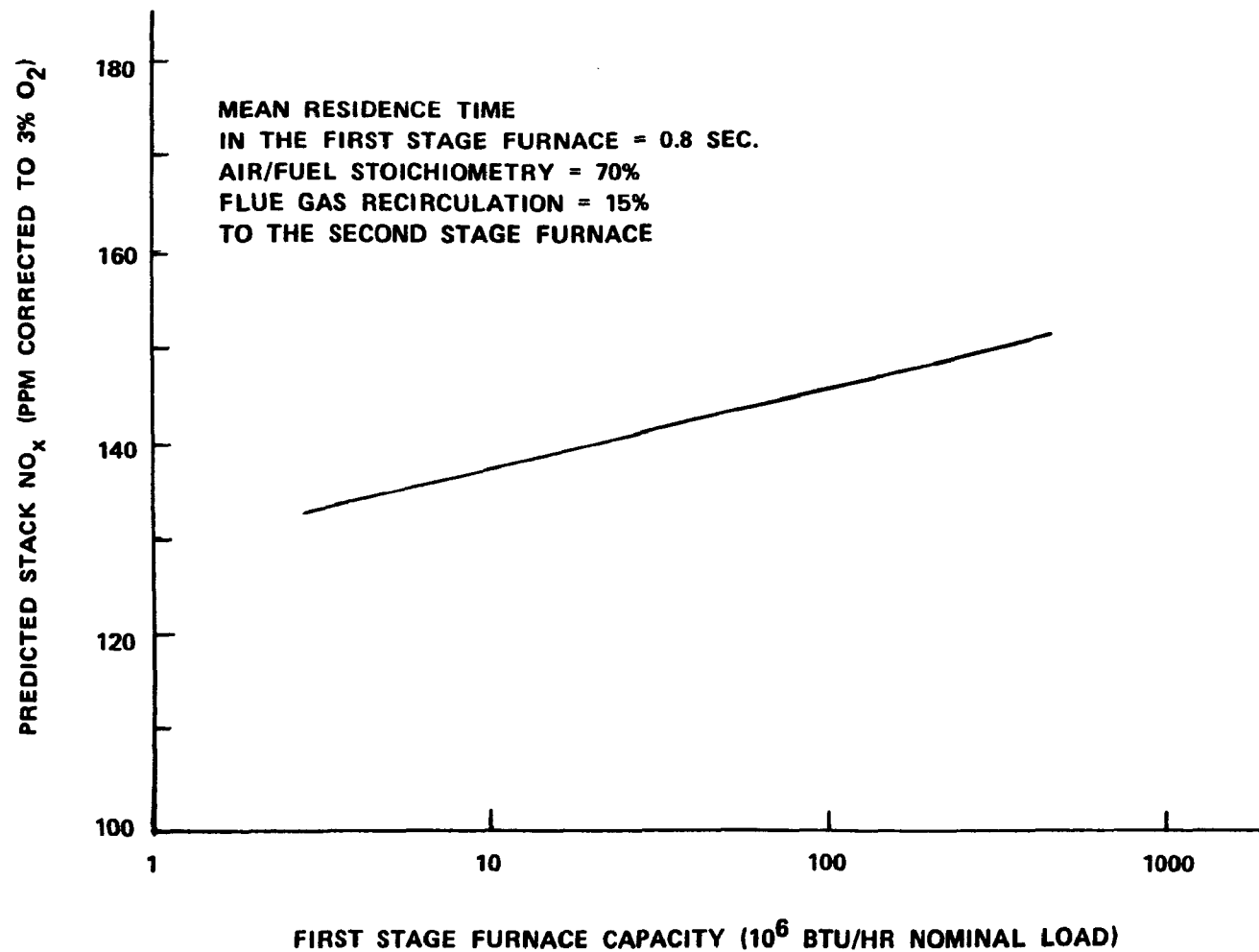
FIGURE 13   PREDICTED NO$_X$ EMISSIONS (FULL SCALE PCF)

FIGURE 14   CONVENTIONAL FURNACE DESIGN

243

FIGURE 15   PRIMARY COMBUSTION FURNACE DESIGN
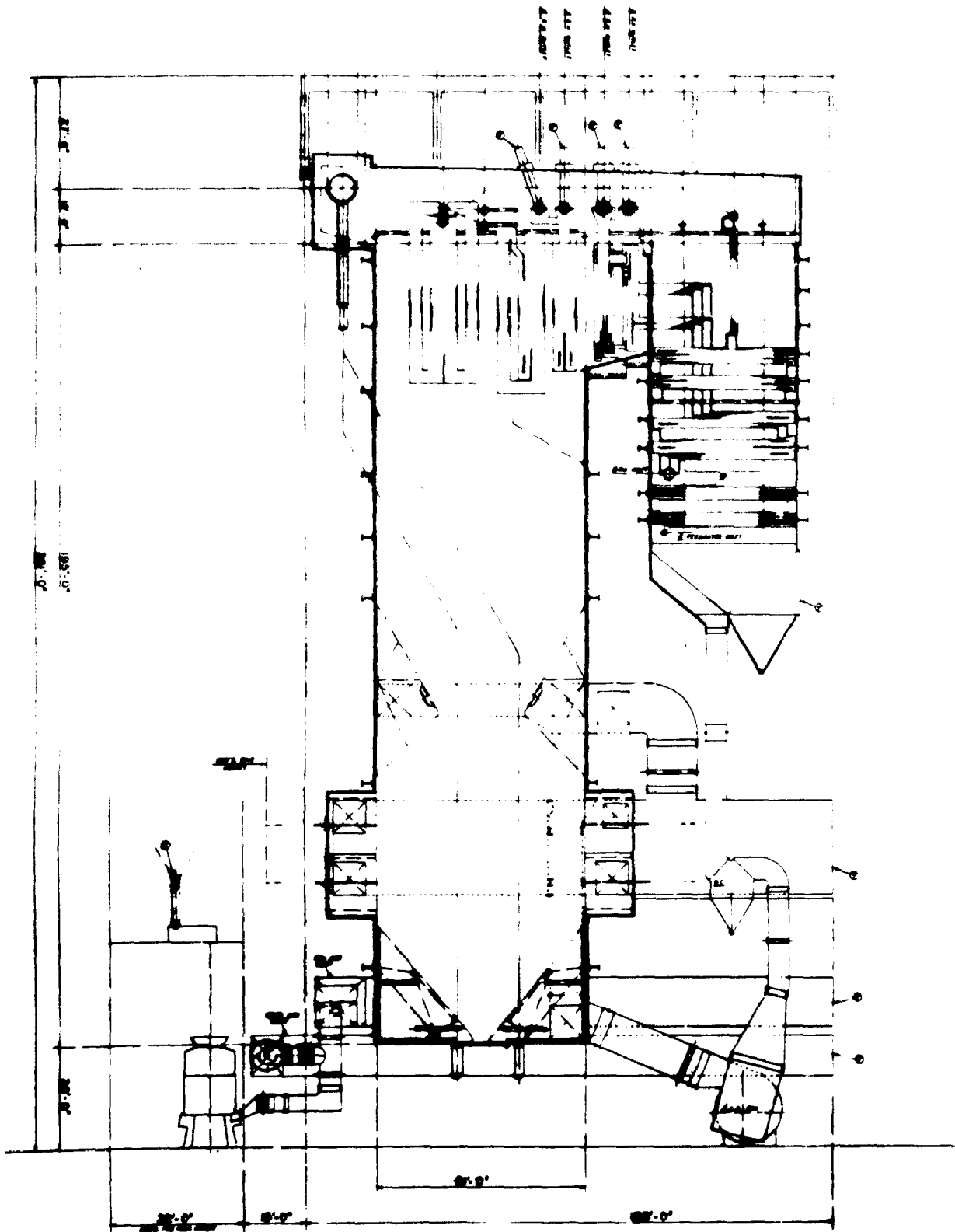
FIGURE 16 VENTURI FURNACE DESIGN

245
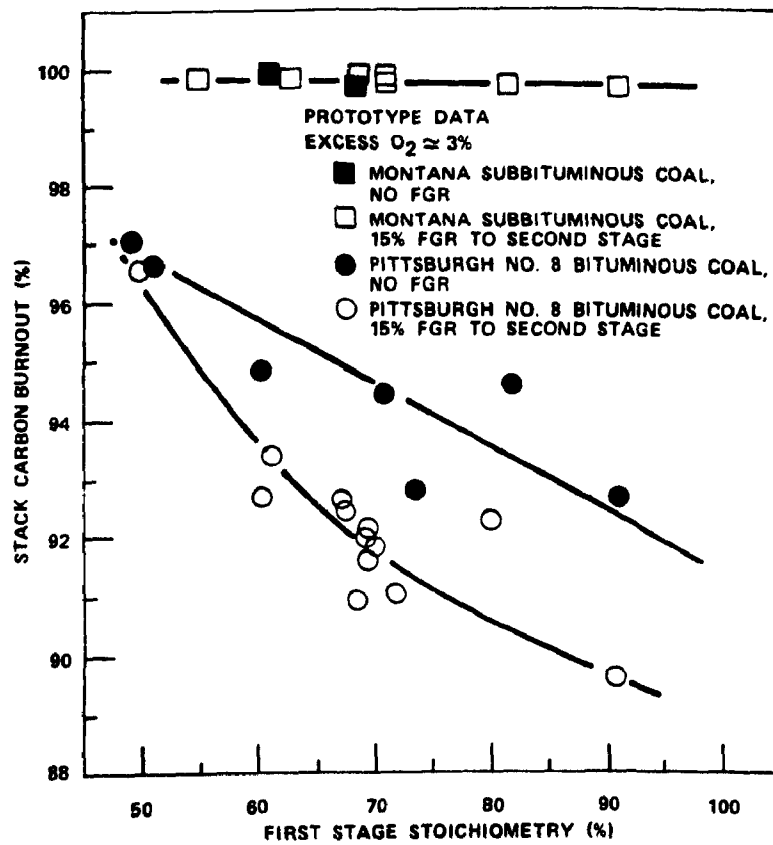
Fig. 17 Carbon conversion efficiency — prototype furnace

TABLE 1

Input Variable	Range of Applicability
First stage stoichiometry	60-75%
FGR	0-20%
Slot Angle	0-30%
Overall Excess O_2	2.5-3.5%
NCP	0.4-0.8

TABLE 2. COST-COMPARISON SUMMARY

Boiler Components	COST INCREASE (% OF CONVENTIONAL BOILER COST)	
	Venturi Design	PCF Design
Pressure parts	5.5	8.0
Flues and Ducts	0.75	1.3
Structural Steel	2.25	6.6
Primary Furnaces	N/A	8.4
Circulation Pumps	N/A	4.7
	———	———
	———	———
	8.5%	29%

NOTE:

Percentages are based on a typical cost of $65/KW for the conventional boiler design, which can vary depending on scope, fuel, turbine heat balances, etc.

THE DEVELOPMENT OF DISTRIBUTED
MIXING PULVERIZED COAL BURNERS

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ABSTRACT

This paper summarizes work sponsored by the EPA to establish generalized design criteria for low emission pulverized coal burners. Data for single and multiple configurations in research furnaces at 50 and 100×10^6 Btu/hr are presented with the current design of distributed mixing burners. NO_x emissions down to 100 ppm (0% O_2, dry) have been obtained for bituminous coals under acceptable burnout conditions by sub-stoichiometric burner staging. These data show that the optimum burner zone stoichiometry is approximately 70 percent of theoretical air for all burners tested to date.

Section 1

INTRODUCTION

Increased utilization of coal is a major factor in the U.S. efforts to reduce imports of petroleum-based fuels. Although in the future gasification and liquifaction will provide alternate coal-derived fuels, direct coal combustion offers the only opportunity to make an immediate impact on fuel usage patterns. This paper addresses one problem associated with direct coal combustion - the production of air pollutants in general and nitrogen oxides in particular. The Federal New Source Performance Standards for boilers have recently been revised, and for nitrogen oxides (NO_x) these are dependent upon fuel type (1, 2):

- Anthracite, bituminous and lignite - 0.6 lb NO_x/Million Btu;
- Sub-bituminous - 0.5 lb NO_x/million Btu;
- Coal-derived fuels - 0.5 lb NO_x/million Btu.

These limits are achievable by current commercial practice, however their adoption will not prevent a significant increase in emissions of nitrogen oxides if the amount of coal burned by stationary sources increases. Consequently, there is considerable incentive to provide technology to reduce NO_x emissions well below those specified by the New Source Performance Standards.

Modification of the combustion process to minimize thermal and fuel NO is the most cost-effective method of NO_x control and is normally achieved by staging the heat release process in such a way as to provide an initial fuel-rich zone before all the fuel and air is mixed to allow burnout. Staged heat release can be accomplished by physical staging i.e., dividing the combustion air into two streams and injecting one of these streams into the combustion chamber some distance away from the burner supplying the fuel and part of the combustion air. An alternate method of heat release staging involves use of the burner to provide an initial fuel-rich zone. The EPA Distributed Mixing Burner (DMB) is one example

of the latter NO_x control technique. The DMB uses combined fuel injection and air delivery characteristics to provide a flame envelope which can be accomodated by existing boiler designs.

The major objective of EPA contract No.68-02-2667 is to provide information which will aid the field demonstrations of the DMB and also allow the design to be generalized to various firing configurations and the complete range of U.S. coals. This paper concentrates upon pilot scale studies concerned with burner development.

Section 2
FACILITIES

The pilot scale test facilities used in these studies have been described in detail elsewhere (3) and consist of two combustors:

- Small Watertube Simulator (SWS) with a firing range of 8-12 x 10^6 Btu/hr.

- Large Watertube Simulator (LWS) with a firing range of 50-125 x 10^6 Btu/hr.

Table 1 summarizes the dimensions and operating data for both combustors which are kept cool during the experiments by spraying water on the outside surfaces. Sample ports are located at the exit of both furances for collection of gaseous and particulate samples. Continuous monitoring instruments are used during the experiments for O_2, CO, CO_2 and NO effluent stack measurements. Both furnaces are equipped with pulverizers that produce size distributions similar to field systems. All input parameters (air temperature, flow rates, coal feed rate, etc.) are monitored during the experiments.

Table 2 lists the properties of the test fuels. The baseline fuel is a high volatile, Utah bituminous coal and to date two different shipments of this coal have been test fired (Utah I and II). Other fuels tested are listed in Table 2.

A sketch of the basic distributed mixing burner used in these studies is shown in Figure 1. It consists of a central coal pipe surrounded by annular channels for combustion air. The coal injector has a radial mixing device near the exit plane and the secondary channel includes variable annular swirl vanes. For burners consisting of two secondary channels, the amount of swirl in each channel could be controlled independently. The fuel and air flow at the burner throat is overall reducing and tertiary air to provide burnout is supplied thro outboard air ports located as shown in Figure 1. The optimized dimensions and settings for the DMB are listed in Table 3 for different scales.

253

Section 3

SINGLE BURNER EXPERIMENTS

The effective stoichiometry immediately downstream of the burner throat
.s one of the most important parameters associated with low NO_x burner design.
)ata are shown in Figure 2 for a 50×10^6 Btu/hr burner in the LWS. NO_x emissions
lecrease steeply as the stoichiometry of the burner zone is decreased over the
:ange shown. CO concentrations remain unchanged until the burner zone stoichio-
netry reaches about 60-70 percent of the theoretical air required for stoichio-
netric combustion (SR_B). At this point CO levels rise abruptly and overall
burnout decreases. This limit is associated with a failure to mix the reactants
adequately before their temperature has been reduced below some critical level.

Figure 3 shows the effect of excess air on NO emissions at fixed SR_B for
two different burners in the LWS. (For these experiments, the level of excess
air was varied by changing the air flow through the tertiary ducts). It is
apparent from these data that NO concentrations are relatively insensitive to
the overall excess air level. Provided that the conditions of the burner zone
are chosen to minimize NO emissions, other parameters relating to the outboard
air (i.e., velocity, position of tertiary ducts, amount of air, etc.) have a
much more significant impact on CO levels and overall burnout than the NO_x
emissions. This observation is consistent with data obtained using a scaled-
down version of this burner in a multiple burner configuration (see Figure 4).

Other work on Distributed Mixing Burners (DMBs) to optimize the various
operating parameters has been reported elsewhere (3, 4). The parameters include:

- The amount of swirl of primary and secondary streams;
- The spatial location of outboard air ducts;
- The location of the coal injector;
- The effect of coal type fuel.

254

As a result of these experiments, the design criteria for additional experimental and prototype burners have been established. These are listed in Table 4. These criteria were incorporated into burners to be tested in a multiple burner configuration in the LWS. These data will be described in the next section.

Section 4

MULTIPLE BURNER EXPERIMENTS

One important aspect of burner performance is the effect of burner interactions which occur in a multiple burner array. These interactions involve:

- Shielding of flames in the center of the array from the cold walls by other flames;
- Variations in the mass and temperature of the gases entrained by the flame jet;
- Variations in mixing patterns caused by the confinement of one flame by another.

In addition, only the smallest industrial boilers are fired by four burners or less. Consequently, multiple burner experiments were conducted in the LWS to study the performance of the distributed mixing burner in a multiple burner array. A single-secondary DMB with a nominal heat input of 12.5×10^6 Btu/hr was chosen for these experiments and the design criteria used were those listed in Table 4. Four burners were installed in a 2 x 2 array on a single wall of the LWS with a total heat input of 50×10^6 Btu/hr. Tertiary ports were placed so as to service each burner in a manner similar to the single burner operation. A schematic of the configuration is illustrated in Figure 4. The fuel used for most of the tests was the baseline Utah bituminous coal (Utah 1).

The overall characteristics of the heat release pattern in the 2 x 2 burner array were different from those observed when testing single burners in the LWS. The individual flames ignited within the refractory divergent and extended into the furnace as discrete flames for 2-3 feet. At the intersection of the individual flames and the tertiary air jets, the four flames joined to form a single large diffuse flame that extended into the furnace 10-12 feet. If a slight perturbation affected one of the burners, this was not reflected in the larger flame pattern. A large perturbation, however, such as a flameout in one of the

burners, would significantly alter the flame shape and burnout characteristics (CO levels and opacity of effluent gases). It was possible to test the multiple burners over a larger operating map than was possible for single burners probably because interactive effects improve burner stability.

NO and CO emissions are shown in Figure 5 over the range of excess air levels studied. NO levels lower than 125 ppm (0% O_2, dry)0.14 lbs $NO_2/10^6$ Btu were obtained before the CO levels began to be affected. In addition to the decrease in O_2 availability in the burner throat, changing the SR_B also changes the velocity in the secondary and tertiary air channels and thus might alter the overall mixing pattern. These NO levels are similar to those obtained with single burners (see Figure 3) at the same heat input. Burnout characteristics were generally better with the multiple burner configuration than with single burners.

The variation of NO and CO with load is shown in Figure 6. It was not possible to turn the burners down lower than 50×10^6 Btu/hr due to the capacity of the coal mill. Therefore, the burners were overfired up to 147 percent of the nominal design value (50×10^6 Btu/hr). The increased heat release resulted in higher NO concentrations and slightly lower CO levels. The stability and other operating characteristics were not noticeably affected. Single data points at loads of $80-90 \times 10^6$ Btu/hr were tested and it was possible to maintain low NO_x levels (<0.2 lb $NO_2/10^6$ Btu) by staging the burners to low SR_B (0.5-0.6). Burn-out and CO characteristics were the same as, or better than, those obtained operating at the 50×10^6 Btu/hr heat input design point. Thus, the DMB design can compensate for conditions which would result in higher NO emissions by staging the burner to lower SR_B values.

Effect of Tertiary Parameters - Two parameters associated with the injection of tertiary air through the outboard air injectors were investigated: air velocity and removal of some tertiary ports from operation. The effect of outboard air velocity is shown in Figure 7. The nominal velocity is approximately 75 feet per second and the high velocity condition (twice normal), was achieved by reducing the flow area at the duct exit. The NO_x emissions were essentially

the same at both conditions and CO concentrations were also very similar. However, overall flame stability was reduced by increasing the outboard velocity. Small perturbations in the input conditions (air flow rates to the burner, coal feed rate, etc.) usually resulted in pulsed flickering of the flame, increased CO emission and on occasions, flameouts.

It was also possible to direct the flow of air to selected rows and/or columns of tertiary air system in the burner array (see Figure 4). This usually resulted in decreased flame stability and increased CO emissions. These changes did not have a significant impact on NO_x emissions. A summary of these data is tabulated in Table 5. The performance of the multiple burner system was most effected when the middle row or column was removed from operation. The results obtained with four burners are consistent with data obtained in the single burner experiments where NO_x emissions were more sensitive to burner zone parameters than to outboard air variables.

Fuel Effects - Three different bituminous coals were tested in the multiple burner configuration. The fuels are listed in Table 2 and the results for the fuels tested are shown in Figure 8. There were no observable differences in the general burner performance with each fuel. The NO_x emissions were nearly identical over the range of conditions tested. This is in agreement with other work in the SWS with these fuels. More work is required on fuels exhibiting a wider range of fuel properties (nitrogen, ash, heat content, water content, etc.) to formulate specific conclusions as design criteria relating to different fuels.

Section 5

SUMMARY

The pilot-scale testing of low NO_x burners has lead to formulation of specific design criteria for prototype distributed mixing burners. It is evident from these tests that burner and operational parameters affecting the burner zone can have a significant impact upon NO_x emissions. The most predominant variable identified thus far is the stoichiometry of the burner zone. Approximately 60-70 percent of the theoretical stoichiometric air for a given fuel is the optimum operating point. This same trend was observed for both single and multiple burner configurations in the LWS research furnace. It is also evident from the tests that factors affecting the outboard air have little impact on NO_x emissions over the range studied. These parameters do, however, have an impact upon fuel burnout, flame stability, and the stable range of burner operation. Results from single and multiple burner configuratic are very similar. For the bituminous coals studied, the NO_x emissions appear to be relatively independent of fuel properties. This was demonstrated in both single and multiple burner configurations.

Section 6

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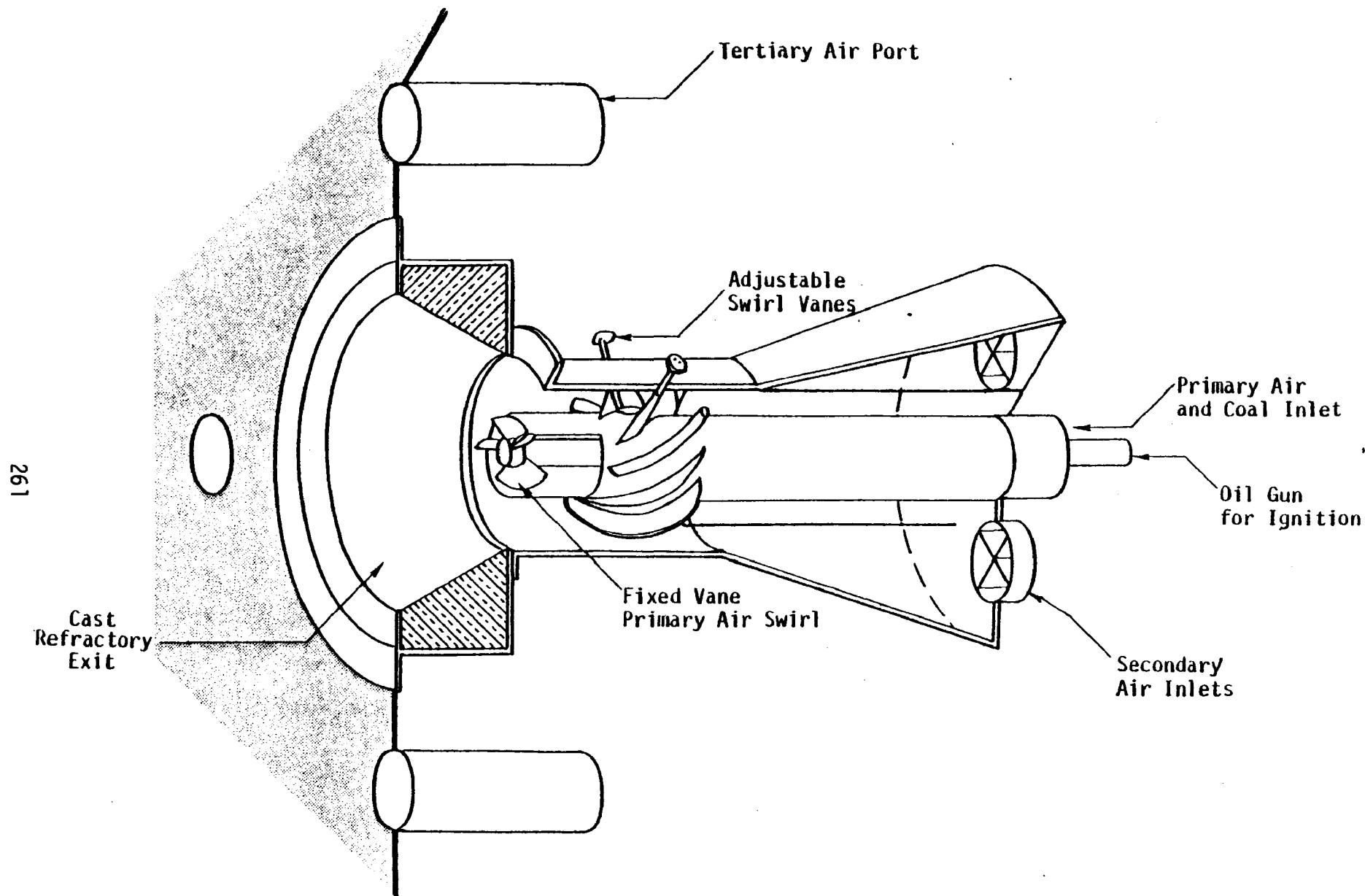
Figure 1. Single Secondary Burner (SSB) Used in Pilot-Scale Experiments.
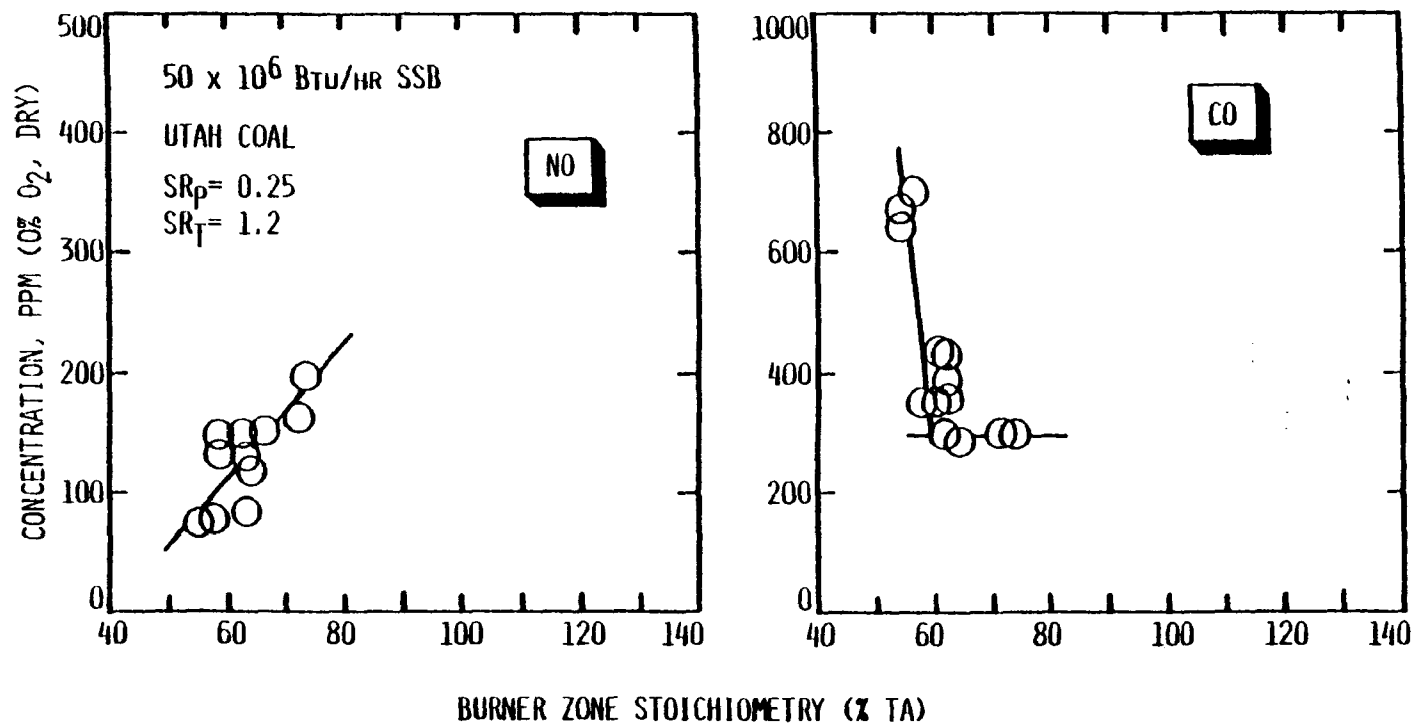
Figure 2. NO/CO Emissions from A Single-Secondary Burner in the LWS.
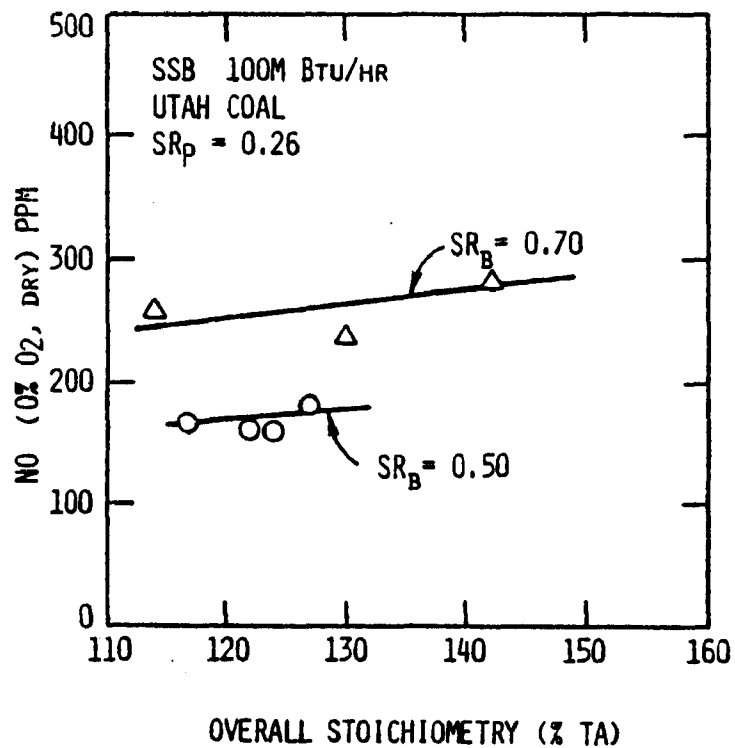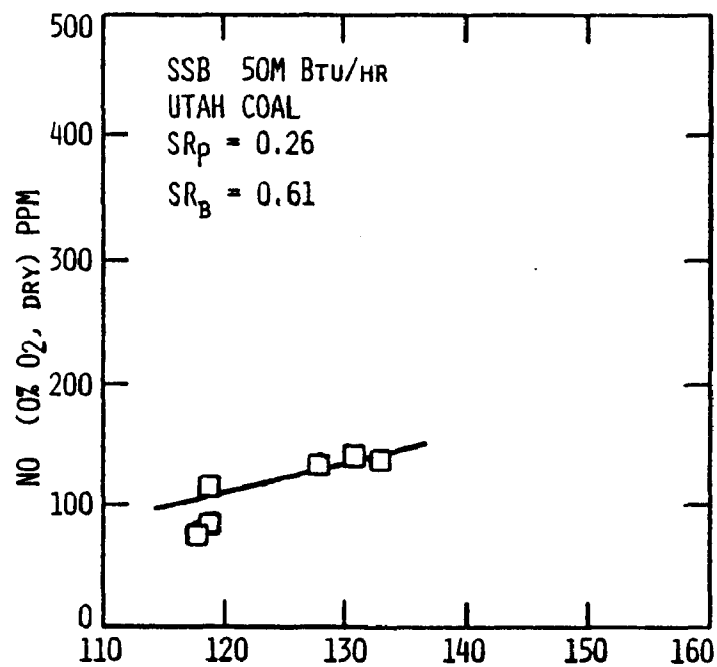
Figure 3. NO_x Emissions for Single Burners in the LWS.

263
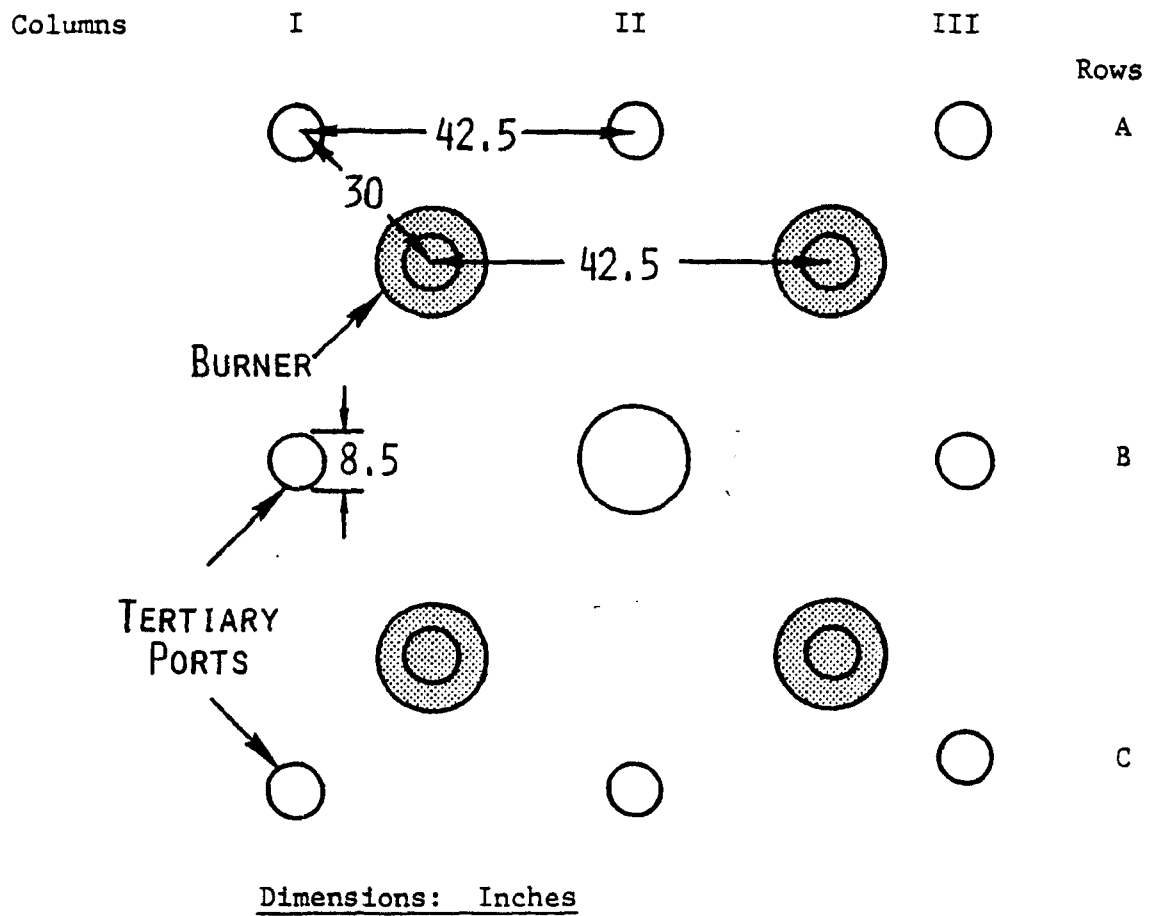
Figure 4. Schematic of Four Burner Array in the LWS.
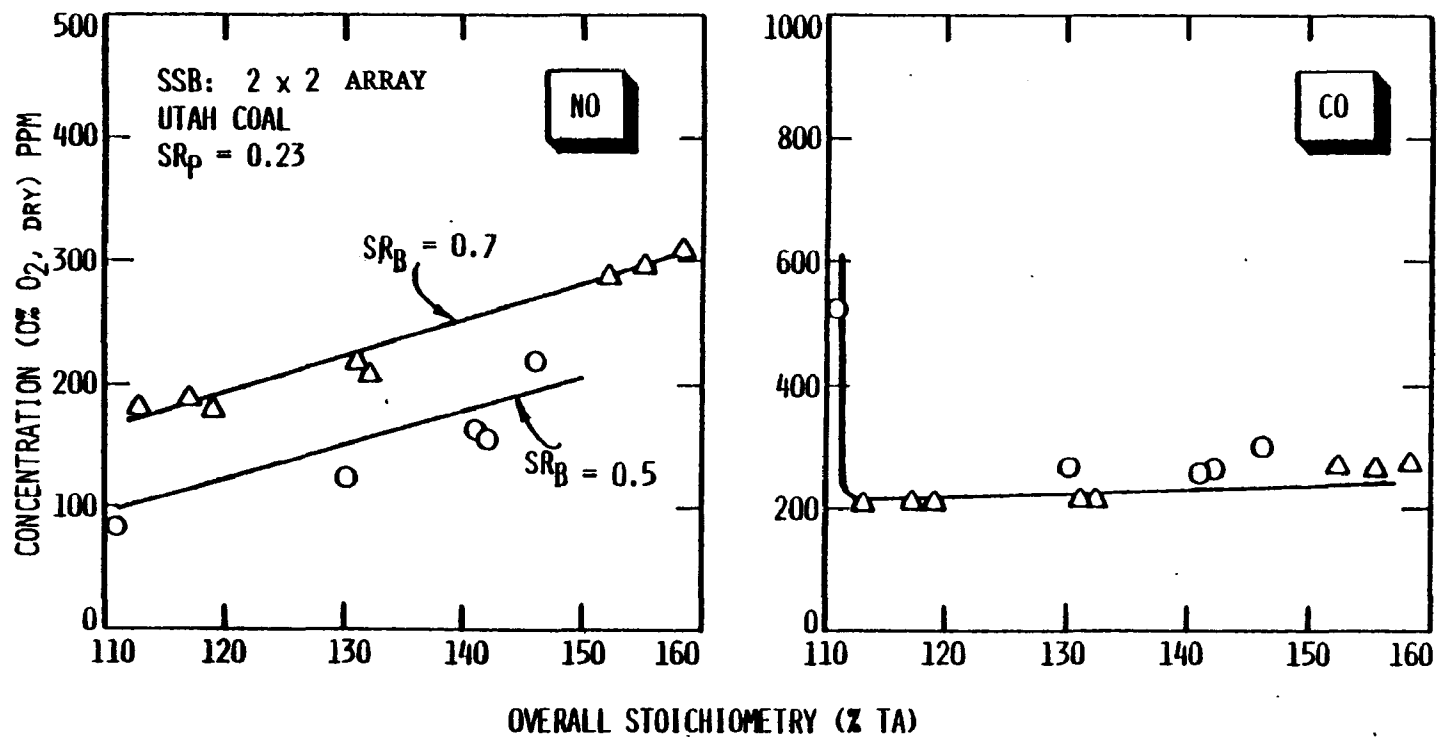
Figure 5. Emissions Profile of Multiple Burner Array in LWS.
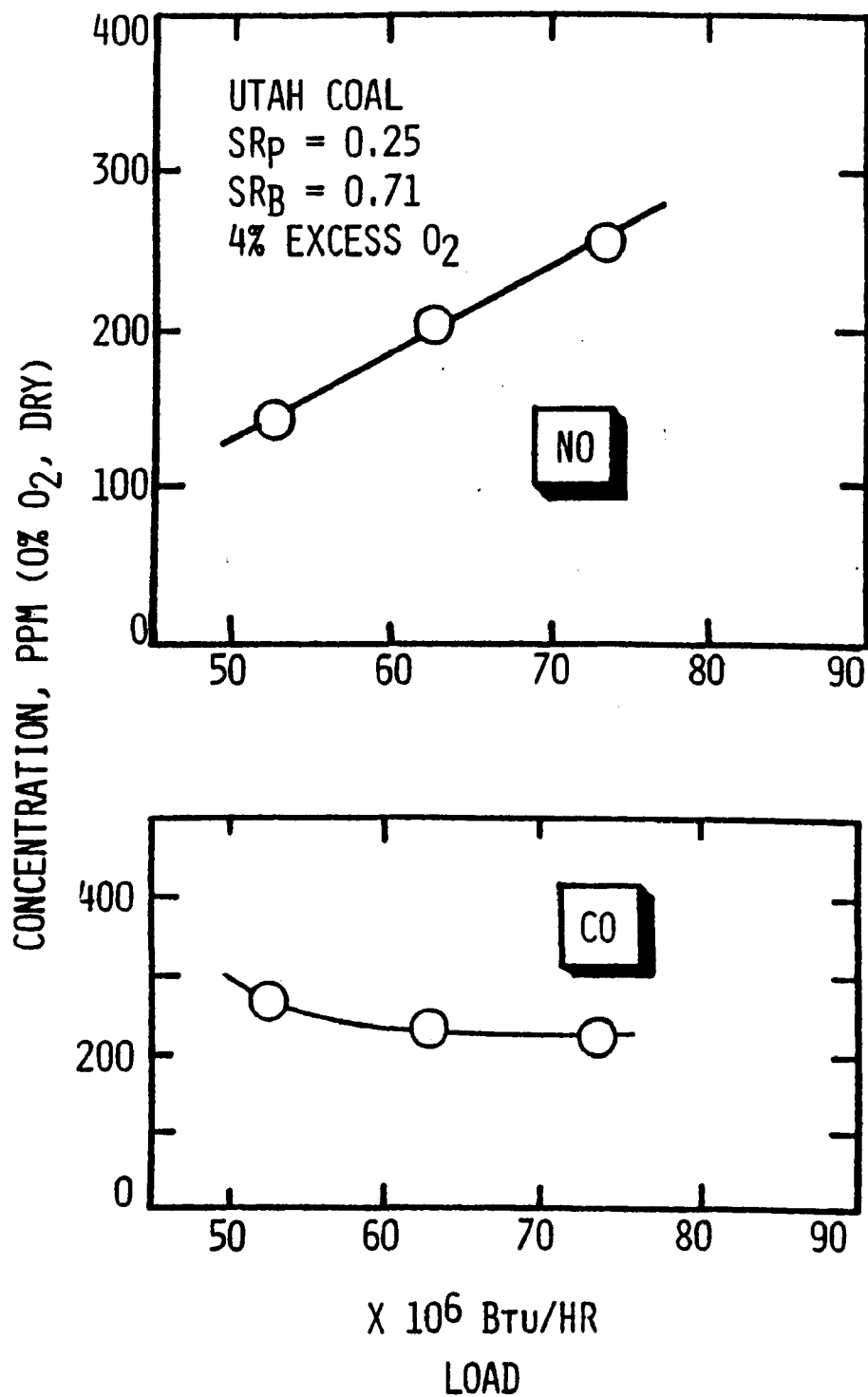
Figure 6. Emissions at Various Loads in
Multiple Burner Array in LWS.

266
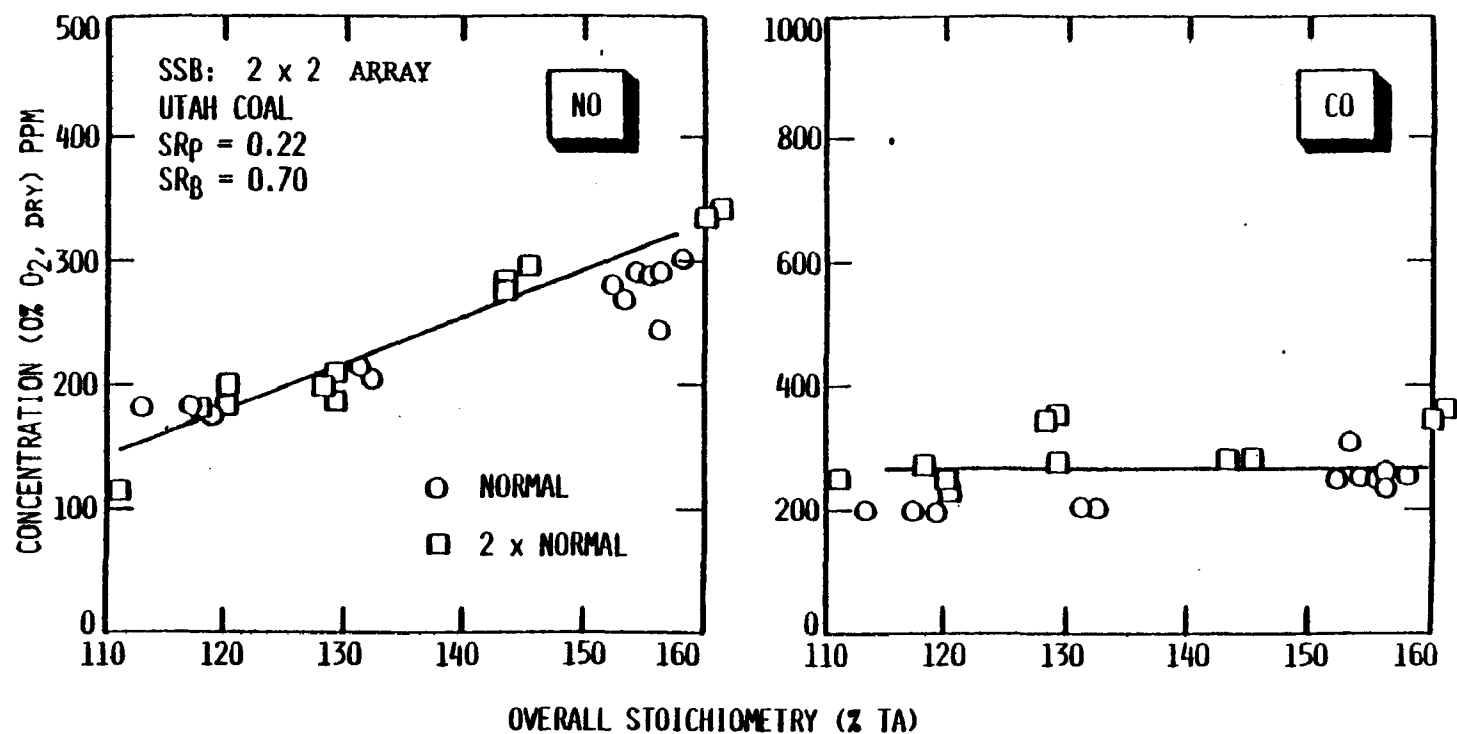
Figure 7.   Effect of Outboard Air Velocity upon NO/CO Emissions from
Multiple Burner Tests in LWS.

267
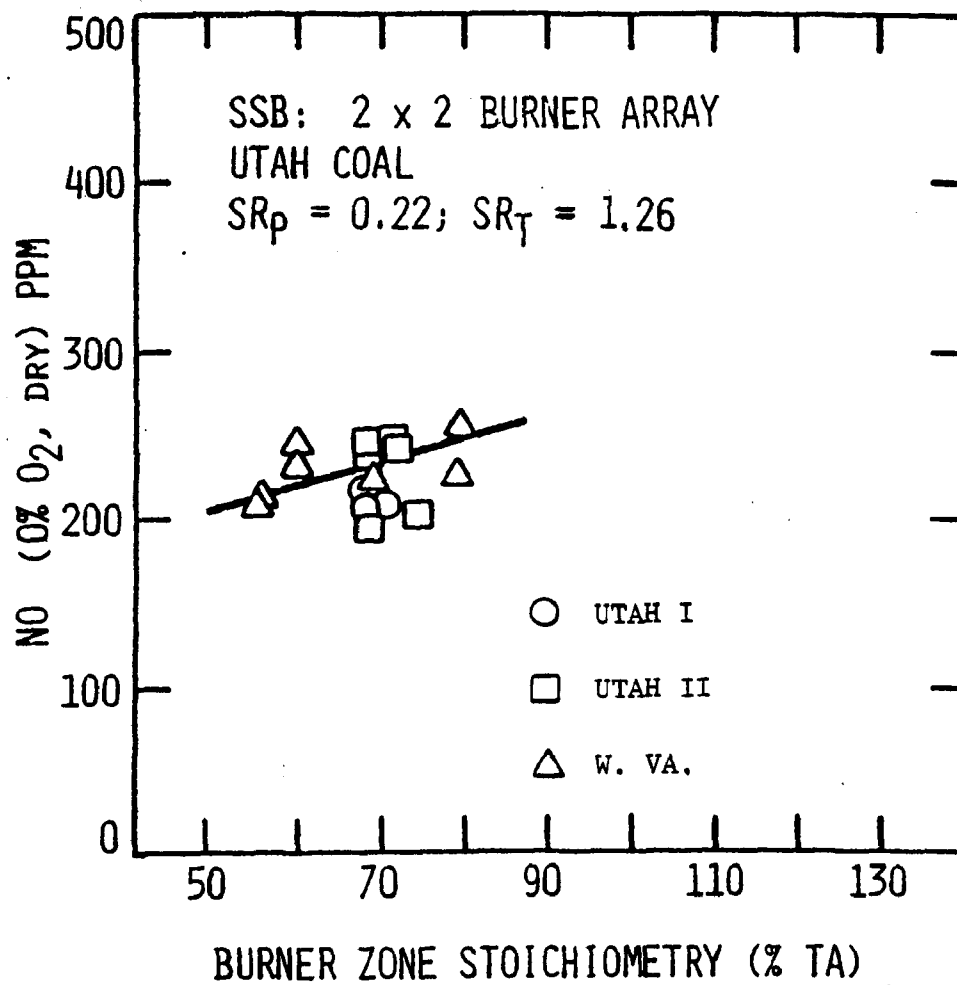
Figure 8. NO$_x$ Emissions from Bituminous Coals in
Multiple Burner Tests in the LWS.

Table I. Dimensions of Research Furnaces

	Small Watertubes Simulator (SWS)	Large Watertube Simulator (LWS)
Designed Firing Rate (Btu/hr)	12×10^6	50 to 125×10^6
Geometry	Horizontal Trapezoidal Tunnel	Vertical Rectangular with Tapered Bottom
Dimensions	5'6" H x 4'0" W x 10'0" L	59' H x 16' W x 28' D
Firing Depth (ft)	10	18
Surface Area (ft^2)	225	5050
Furnace Volume (ft^3)	207	20950
Firing Arrangement	Wall	Wall/Corner
Burner Arrangement	Single	Single/Multiple
Wall Cooling	Water-wall	Water-wall
Air Preheat (secondary)	70-500°F	70-700°F
Pulverizer (both on-line)	Hammer Mill	Bowl (C-E Raymond)
Primary Air	Unvitiated, Ambient Temperature	Vitiated, 150-170°F

Table II. Analysis of Fuels Used in Pilot Experiments

PROXIMATE, % AS RECEIVED	UTAH I	UTAH II	W. KENTUCKY	W. VIRGINIA
Moisture	6.39	7.41	5.46	1.29
Volatile Matter	38.89	38.84	36.63	31.01
Ash	7.40	8.83	8.33	13.76
Fixed Carbon	47.32	44.92	49.58	53.94
Heating Value (Btu/lb)	12,340	11,877	12,392	12,500
ULTIMATE, (% DRY)				
Carbon	73.17	72.24	73.42	72.37
Hydrogen	5.55	5.76	5.12	4.88
Nitrogen	1.42	1.54	1.59	1.34
Sulfur	0.68	0.76	3.46	1.77
Ash	7.91	9.54	8.82	13.76
Oxygen (by difference)	11.37	10.16	7.59	5.88

Table 3.   Design Information for Single Secondary Burners

Design Variable	Burner Capacity (10^6 Btu/hr)			
	10	12.5	50	100
Fuel Injector				
Diameter (in.)	5	5.5	10.5	15.75
Area (in.^{2})	19.63	24	86	195
Swirl Angle (degrees)	Variable	45	45	45
Setback (in.)	0	0	0	0
Secondary Air Channel				
Outer Diameter (in.)	9.5	10.5	20	28
Annulus Thickness (in.)	4.5	2.5	4.75	6.1
Area (in.^{2})	51.25	63	228	421
Swirl Vanes (degrees)	Variable	60	60	60
Setback (in.)	0	0	0	0
Tertiary Ducts				
Distance from Burner ₵ (in.)	—	22	44	62
Spacing Around Burner (degrees)	22.5	90	90	90
Number of Ports	16	4	4	4
Injection Angle (degrees)	0	0	0	0
Axial Position (in.)	0	0	0	0
Diameter (in.)	4.5	6	12	16
Total Area (in.^{2})	254.5	113	452	804
Throat and Exit				
Throat Diameter (in.)	—	10.5	20	28
Throat Area (in.^{2})	—	87	314	616
Half Angle of Exit (degrees)	—	25	25	25
Length of Exit (in.)	—	9 (18.5)*	18.5	27

Table 4. Prototype Distributed Mixing Burner Design Parameters

Parameter	Nominal Design Point	Testing Range
Fuel System		
Primary Temperature ($^{\circ}$F)	S. D.	130-180
Primary Stoichiometry (% T.A.)	S. D.	17-30
Primary Velocity (ft/sec)	75	50-90
Primary Swirl	45° Vanes	Variable
Air System		
Secondary		
Temperature ($^{\circ}$F)	S. D.	400-650
Burner Zone Stoichiometry (% T.A.)	50-70	40-120
Inner Swirl	Variable	Variable
Outer Swirl	Variable	Variable
Axial Velocity (ft/sec)	60	50-90
Inner/Total Area	0.33	Variable
Inner/Total Flow Rate	0.33	Variable
Tertiary		
Temperature ($^{\circ}$F)	S. D.	400-650
Swirl	None	—
Axial Velocity (ft/sec)	50	40-60
Angle (degrees)	0	—
Number	4	—
Location (radius/throat diameter)	2.2	
Divergence (degrees)	0	—
Exit		
Half Angle (degrees)	25	Variable
Length/Diameter	1.0	
Setback - Inner Secondary (inches)	0	Variable
Setback - Outer Secondary (inches)	0	Variable
Operational Variables		
Capacity (10^6 Btu/hr)	S. D.	—
Turndown (% capacity)	S. D.	$\approx$50
Overall Stoichiometry (% T.A.)	S. D.	100-150

Table 5. Summary of Effects of Tertiary Air
Upon Multiple Burner Operation

CONDITION	ROW OR COLUMN* OUT OF SERVICE	RESULTS [+] COMPARED TO BASELINE OPERATION	
		NO	CO
I	Col. I or III	18% Low	42% High
II	Row C	25% Low	68% High
III	Row B	18% Low	32% High
IV	Column II	No Change	45% High
V	Row B and Column II	No Change	45% High
VI**	All in Service; Velocity 2 x Normal Operation	No Change	No Change

* Refer to Figure 4 for designation.

+ Burner zone and overall stoichiometry were kept constant when rows or columns were taken out of service.

** Stable range of operation not as great as normal baseline.

273

JAPANESE TECHNICAL DEVELOPMENT
FOR COMBUSTION NO$_x$ CONTROL

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ABSTRACT

Electric Power Development Co., Ltd. has been executing a research and development program on combustion NO_x control for coal-fired boilers in cooperation with Japanese boiler manufacturers. Target NO_x emission levels of 100 ppm or below (O_2 = 6%, N = 1.8%) have been defined and to date have not been achieved.

However, results obtained from this program have been applied in a stepwise manner to existing or new coal-fired power plants. NO_x emission levels for existing plants have been reduced to 160 - 300 ppm (O_2 = 6%, N = 1.2%) in comparison to uncontrolled levels of 400 - 500 ppm. Regarding new coal-fired boilers, EPDC is constructing two 250-MW boilers with target emission levels of 250 ppm (0 = 6%, N = 1.7%) at the Matsushima Thermal Power Station. In addition, plans are to construct a 700 MW boiler at Takehara (No. 3 unit) with target emission levels of 200 ppm. Presently, EPDC believes that NO_x emission levels will be 150 ppm (O_2 = 6%, N = 1.8% design base) for the No. 3 unit boiler.

This report describes ongoing R&D programs, and the results of combustion modification efforts (such as the technology development of low NO_x burners, two-stage combustion, gas mixing, etc.), and low NO_x countermeasures for new boilers.

ACKNOWLEDGEMENTS

Section 1

INTRODUCTION

As coal use is expanded, environmental issues become more important. In general, most of the environmental risks associated with coal combustion are amenable to control.

These environmental impacts differ because of regional characteristics such as meteorology, population density and resource distribution. Thus, it is not surprising that nations and regions take different approaches to environmental control measures.

Japanese government environmental standards are the most stringent in the world. Local governments may impose standards on pollutant sources which are more stringent than required by national law. Almost all local governments have independently enacted pollution control ordinances. Thus, power utilities in Japan must take countermeasures to meet the stringent standards and pollution control ordinances of local governments.

NO_x emission levels of coal-fired boilers are remarkably high in comparison to the other fossil fuel-fired boilers. Development of NO_x control technologies for coal to meet emission levels achievable for LNG or oil combustion is very difficult.

Electric Power Development Co., Ltd. (EPDC) has been developing NO_x control and removal technologies in cooperation with Japanese boiler manufacturers. Two methods to reduce NO_x emissions from boilers have been pursued. The first is postcombustion NO_x removal, such as Selective Catalyst Reduction (SCR) and Selective Non-Catalytic Reduction (SNR). The second method focuses on combustion NO_x control such as low NO_x burners and combustion modification.

EPDC and Japanese manufacturers have been has been conducting R&D programs on both methods. This paper describes the results of the combustion NO_x control program, while the results of using postcombustion methods are reported in another paper at this Symposium and for convenience summarized in

Appendix A.   277

Section 2

NO$_x$ CONTROL REGULATIONS IN JAPAN

STATUS OF AMBIENT NO$_x$ LEVELS

In August 1967, the Basic Law for Environmental Pollution Control was enacted for the purposes of protection of national health and the preservation of the of living environment.

The Japanese government selected the environmental quality standards in May of 1973 and revised them in July of 1978. These environmental quality standards are shown in Table I. The revised standards are slightly less stringent than the initial standards.

After the revised standards were enacted, regional noncompliance areas (over 0.06 ppm) consisted of 4.6% of all general environmental-atmosphere stations (892 sites) and 36% automobile influenced stations (182 sites). The current compliance status with the NO$_x$ environmental quality standard is shown in Figure 1. Figure 2 shows that the emissions NO$_x$ density increased from 1971 to 1973, but has remained approximately constant since then.

NO$_x$ EMISSION REGULATIONS

NO$_x$ emission regulations for stationary sources were established in August 1973, and revised four times prior to the present environmental quality standard. Table II shows the progressive changes in the NO$_x$ emission standards to the current levels of 400 ppm (at 6% O$_2$) for coal-fired boilers and 150 ppm for oil-fired boilers (at 4% O$_2$).

POLLUTION CONTROL ORDINANCES OF LOCAL GOVERNMENTS

Pollution control ordinances imposed by local governments are generally more stringent than the national standards. Examples of local ordinances imposed on existing coal-fired plants are shown in Table III. Local ordinances applicable to new coal-fired plants are shown in Table IV.

Matsushima City is located in Nagasaki Prefecture of western Japan. Here NO_x emission controls are less stringent than elsewhere since the area is not heavily industrialized. Thus, the Matsushima thermal power station does not employ SCR technology.

However, at Takehara thermal power plant where the No. 3 unit is currently under construction, another power company is planning to construct a large thermal power plant nearby. In this instance, the local government has requested the power companies not to increase total NO_x emissions beyond present levels. Thus emissions from Takehara Unit No. 3 and the new power station must comply with the stringent controls shown in Tables IV and V. This situation has required EPDC to install both SCR equipment and combustion NO_x control technology on Takehara Unit No. 3.

TOTAL MASS NO_x CONTROL

Six industrial areas in Japan (e.g., Tokyo and Yokohama) do not now meet the established NO_x ambient air quality standard of 0.04 ppm. Local governments in these areas are considering stringent NO_x controls to achieve this standard.

In August 1977, the city of Yokohama (the leading local government for pollution control), proposed an NO_x Guidance Plan that would reduce NO_x emission levels 36% by 1981 from major industries. Since EPDC's Isogo thermal power station is located in Yokohama, a 36% NO_x reduction may be required. The NO_x Guidance Plan stipulated that the time limit to retrofit combustion controls extended until April 30, 1979. If SCR was used, this time limit extended to March 31, 1981.

EPDC has elected to apply combustion modification because the Isogo Power Station is too narrow to install the SCR equipment. The combustion modifications chosen are described in this paper.

Section 3

OBJECTIVES OF COMBUSTION CONTROL DEVELOPMENT
FOR COAL-FIRED BOILERS

EPDC has two objectives in NO_x combustion control develoment. The first objective is to develop a technology that will meet existing NO_x control regulations. The second is to reduce cost of control compared to SCR.

NO_x emission levels from the combustion of oil or LNG are low in comparison to coal-fired boilers. If advanced combustion control technologies were applied to oil or LNG boilers, NO_x emissions would be less than 100 ppm for oil and 50 ppm for LNG.

Reductions to these levels may not justify the installation of SCR equipment for oil and LNG boilers in most areas of Japan. To date, however, the Shinkokura power plant and other oil-fired plants in Japan have installed SCR equipment.

For coal, advanced NO_x control technology would enable stack gas NO_x levels to be reduced to only 200 ppm (O_2 = 6%) because of the inherent high nitrogen content of the fuel (Table VI). In Japan, environmental preservation takes precedence over other factors such as the economy and the desire to reduce oil and gas consumption. Thus, local governments and the public have demanded lower NO_x levels in order to approve new facilities. These actions have forced NO_x emission levels for coal-fired boilers to comparable levels for oil-fired units. In most cases, this requires the application of SCR equipment. However, EPDC is also developing combustion NO_x control technology to obtain the most economical and lowest emission coal-fired power plant through a combination of combustion and SCR control technology.

EPDC'S TARGET OF COMBUSTION NO_x CONTROL TECHNOLOGY

EPDC's target emission level obtainable with combustion NO_x control technology is 100 ppm (and below) at 6% O_2 and 1.8% fuel nitrogen content. Figure 3 shows three cases of a model low pollution coal-fired thermal power plant.

Case 1 is Takehara No. 3 unit, which is under construction. Takehara No. 3 will have SCR equipment and be capable of NO_x emission levels of 60 ppm and below.

Case 3 employs a Dry FGD system, which does not have SCR equipment, but the NO_x emission level is aimed at 60 ppm and below. This is due to capture of NO_x within the FGD system to the degree that an inlet NO_x concentration of 100 ppm will be reduced to 60 ppm at the FGD exit. Case 3 has been determined to be the most economical, reliable, and least polluting coal-fired plant in EPDC's analyses.

Section 4

EPDC COMBUSTION NO$_x$ CONTROL DEVELOPMENT PROGRAMS

Since 1977, EPDC has been conducting R&D programs for low NO$_x$ emission coal-fired boilers in joint research with Japanese boiler manufacturers, such as Mitsubishi Heavy Industries (NHI), Babcock Hitachi K.K. (BHK), Ishikawajima Harim Heavy Industries (IHI) and Kawasaki Heavy Industries (KHI).

This R&D, using test furnaces owned by boiler manufacturers is testing various types of imported coals (from Australia and China among others) planned for use in new coal-fired power stations. The range of nitrogen content for coal stocks from these countries is shown in Table VI.

An outline of EPDC's R&D program for combustion NO$_x$ control technology is shown in Table VII.

Testing is being performed as follows:

- Survey tests to achieve lower NO$_x$ emissions by optimizing conditions of two stage combustion, gas mixing, etc., and

- Confirmation that CO, unburned hydrocarbons, unburned carbon and the other pollutants do not increase.

Recently, our joint researchers built a multi-burner test furnace. We anticipate obtaining good data concerning the interacting effects between burners.

Section 5

R&D RESULTS OF TEST FURNACES

NO_x REDUCTION LEVEL

One sample of test results is shown in Figure 4. Test conditions are for 1.7% and 0.9% nitrogen content in coal and for (1) a conventional burner, (2) a new low NO_x burner without Two Stage Combustion (TSC) or Gas Recirculation (GR), (3) a new low NO_x burner with TSC but without GR and (4) a new low NO_x burner with both TSC and GR.

Under the best conditions, NO_x emission levels are between 160 ppm and 210 ppm, (unburned carbon content below 5%) for 1.7% N, and between 90 ppm and 150 ppm for 0.9% N.

An outline of the results for the test furnaces is as follows:

- The new burner improves NO_x levels by roughly 40 ppm to 60 ppm.

- TSC improves NO_x level 60 ppm to 100 ppm.

- TSC combined with GR improves NO_x levels by 80 ppm to 100 ppm.

- Higher fuel nitrogen content increases NO_x emissions.

- Total NO_x reduction is 270 ppm to 280 ppm from the levels emitted by a conventional burner.

EPDC and its joint researchers will investigate more effective combustic conditions and further advanced low NO_x burners to achieve the target 100 ppm NO_x emission level.

283

P.O.M. MEASUREMENT RESULTS

Table VIII shows P.O.M. measurement results at one particular test furnace.

This measurement was performed using the EPA No. 5 modified sampling method developed by Battelle and a liquid chromatography analyzer.

These measurements indicate the following:

(1) Total emissions of P.O.M. with two stage combustion (reported in the United States as an increase of 35%) increased 32%.

(2) The increase of P.O.M. emission owing to combustion modification is 20 to 60%.

(3) Absolute P.O.M. values increase at partial load.

(4) Measured P.O.M. emissions were much less than the values reported in the U.S.A. It is not clear whether the observed difference is due to the measuring method (GC-MS method in the U.S.) or the type of coal. This difference shall be studied in the future.

Another observation is that as NO_x emissions decrease with combustion modification, P.O.M. emissions increase. Therefore, some adjustment is needed to alleviate this problem.

This correlation is shown in Figure 5, and according to the data taken by Hitachi, P.O.M. emissions are around 10 $\mu g/Nm^3$ when NO_x emissions are lowered to 100 ppm. This is about five times that of normal combustion.

Section 6

COMBUSTION MODIFICATION EXPERIENCE
AT ISOGO THERMAL POWER STATION

The Isogo power station is located in city of Yokohama about 30 km south
of Tokyo in an area known as the Keihin Industrial Area. The City of Yokohama
is very anxious to reduce pollution, and thus the pollution prevention
agreement between Yokohama city and EPDC is uniquely severe.

In 1977, Yokohama city proposed a guiding principle for restricting NO_x
emissions, resulting in a NO_x emissions reduction of about 36%. Accordingly,
the proposed NO_x emission level from a coal-fired plant in Yokohama is
159 ppm.

HISTORY

Isogo No. 1 and No. 2 boilers (capacity of 265 MW each), manufactured by
Ishikawajima-Harima Heavy Industries Co., Ltd. (IHI), were completed in 1967
and 1969, respectively. A summary description and general boiler arrangement
are shown in Table IX. The original burner arrangement is shown in Figure 6.

In advance of the first restrictive regulations on NO_x emissions from
stationary sources in 1973, Isogo Units 1 and 2 were equipped with two stage
combustion with an over air port system (OAP) for NO_x control.

As a second step and in accordance with successive, more stringent regu-
lations, IHI-FW dual flow pulverized coal burners (DF-CN burners, Figure 7)
and a boundary air system (Figure 8) were applied to the No. 1 boiler in 1976
and to the No. 2 boiler in 1977.

As a third step, burners out of service (BOOS) and steam injection from
oil guns were tested on the No. 2 boiler in 1978.

A fourth step to decrease NO_x emissions was based on the test results of
the third step and the results on IHI's test facility (capacity of 2 ton/h
pulverized coal firing). It was decided that the installation of eight

285

additional OAPs close to both side walls and a division wall (Figure 9) and installation of the steam injection nozzles on each oil burner gun would be carried out for No. 2 boiler. The target completion date was Spring 1979, aiming at NO_x reductions less than 160 ppm (at 6% O_2) under routine operation conditions. The same modifications were performed successfully on the No. 1 boiler in 1980. A summary of these countermeasures and the results are shown in Table X.

PRIMARY COMBUSTION CONTROL TEST

Figure 10 shows the relationship between TSC air ratio and NO_x level, and the predicted OAP damper open ratio for NO_x emissions less than 159 ppm. At 100% damper open ratio, TSC air is about 15% of total air volume.

Adapting these primary test results and results of IHI's test furnace to the Isogo power station, we predicted the NO_x level to be 150 ppm and below under the condition of 30% TSC air volume to total air volume.

RESULTS OF NO_x REDUCTION AFTER IMPROVEMENT OF COMBUSTION MODIFICATION

After installing OAP as illustrated in Figure 9, we had 190 ppm of NO_x as the upper level in normal operation and 150 ppm as the minimum level. At that time, boilers operating under routine conditions performed almost satisfactorily without slagging and fouling trouble.

However, when an NO_x emission level of 150 ppm is reached, superheater tube metal temperature increases beyond the recommended operating limit, and to protect the tubes, we have to restrict the two stage air volume (OAP air volume).

Figure 11 shows actual data for NO_x and indicates for increasing or decreasing load, NO_x levels seldom exceed 200 ppm. The predicted NO_x reduction was almost obtained. However, the increase in superheater tube temperature exceeded our expectations. Therefore, the achieved NO_x levels are normally less than 190 ppm.

UNBURNED MATERIAL

Other potentially serious problems accompanied NO_x reduction. These included an increase in CO, unburned solids in the fly ash, and increased

286

emissions of other hazardous organic materials such as P.O.M.   In fact, these problems were recognized during the early stages of the field test runs.

To reduce the unburned material mentioned above, we have tried to improve the mixing conditions between the secondary staged air and the combustibles produced in the primary zone through the installation of additional OAPs.

By applying side OAPs, the remarkable NO_x reduction could be achieved while keeping unburned material at a constant level.

FUEL ANALYSIS

The fuel coal burned at Isogo Power Station is a blended variety, containing Taiheiyo coal as the main constituent.   The typical analysis is shown in Table XI.

IMPROVEMENT OF SH TUBE TEMPERATURE AND SPRAY QUANTITY

To prevent the SH tubes from increasing in temperature, we modified the superheater layout, the final configuration of which is shown in Figure 12. In addition, the spray attemperation quantity was increased from 66 to 100 ton/hr.   Currently, the spray quantity being employed is the same as that used before modifications for NO_x reduction.   Unfortunately, the trend of high superheater temperatures is not remarkably improved.

Section 7

COMMERCIALIZED LOW NO$_x$ BURNER
FOR NEW COAL-FIRED POWER PLANTS

EPDC is constructing new coal-fired power plants such as the Matsushima power station and Takehara Unit No. 1. Each plant has incorporated NO$_x$ combustion control technology developed with the aid of results from test furnaces.

MATSUSHIMA POWER STATION

Matsushima power station No. 1 unit is now performing trial operations until January 1981, and shortly thereafter, it will start commercial operation.

A description of the Matsushima power station is following:

- Output   500 MW x 2 unit

- Fuel   Coal (imported)

- Boiler Manufacturer   MHI

- Type of Boiler   Supercritical pressure reheat type U.P. boiler

- NO$_x$ (guaranteed)   285 pm (O_2 = 6%) (N^2 = 1.7%)

- NO$_x$ (target)   same as guaranteed

- Burner type   SGR burner (illustrated in Figure 13)

NO$_x$ emission levels from the Matsushima power station are about 200 ppm (O_2 = 6%, N = 1.7%), measured after trial operation without burner adjustment or optimization.

COMPARISON OF NO$_x$ EMISSIONS BETWEEN LABORATORY TEST RESULTS AND FIELD DATA

Figure 14 shows test furnace results and field data, the latter from EPDC's Takasago and Sunagawa of Hokkaido Electric Power Co.

We find good correlation between actual field data and test data using domestic coal, and therefore anticipate reducing NO$_x$ emission levels to approximately 250 ppm (O$_2$ = 6%, N = 1.7%) as suggested by Figure 14.

TAKEHARA POWER STATION NO. 3

Construction has recently initiated on Takehara Unit No. 3 and commercial operation is scheduled for March 1983. An outline of Takehara No. 3 is as follows.

●	Output	700 MW x 1 unit
●	Fuel	Coal (imported coal)
●	Boiler Manufacturer	BHK
●	SCR Manufacturer	BHK
●	Type of Boiler	B & W Supercritical pressure reheat type UP boiler
●	NO$_x$ (guaranteed at boiler)	250 ppm (O$_2$ = 6%, N = 1.8%)
●	NO$_x$ (target at boiler)	200 ppm (O$_2$ = 6%, N = 1.8%)
●	NO$_x$ (guaranteed at stack)	60 ppm and below (O$_2$ = 6%, N = 1.8%)
●	Burner type	PG dual burner

The PG dual burner is shown in Figure 15.

COMPARISON OF NO$_x$ EMISSION BETWEEN LABORATORY TEST RESULTS VS. FIELD DATA

Figure 16 shows the correlation between actual field data and test furnace data with heat release rate at the burner zone. This relation will be confirmed when Takehara No. 3 boiler is operating. EPDC anticipates achieving the target NO$_x$ level.

REFERENCES

1. Y. Nakabayashi, Status of R&D on NO_x removal in Japan and results of EPDC's R&D for $DeNO_x$ Process. Second EPRI NO_x Control Technology Seminar, Denver Colorado, Nov. 1980.

2. Environmental White Paper, 1980, Japanese Environmental Protection Agencies.

Appendix A

Summary of Emission Control
Research and Development in Japan

for Coal-Fired Boilers

	Test Subjects	Location	Companies and Joint Researchers	Capacity	Fiscal 1975	1976	1977	1978	1979	1980	1981	Remarks
1. Desulfurization technology	(1) Soot separating desulfurization system (dust collecting)											
	a) Hitachi	Takehara Thermal Power Station	Hitachi	Approx. 2,000Nm^3/h								
	b) Mitsubishi	" "	Mitsubishi	"								
	c) IHI	Isogo Thermal Power Station	I H I	"								
	(2) Dry flue gas desulfurization system	Takehara Thermal Power Station	S H I / I H I	10,000Nm^3/h								
2. Denitration technology	(Low Nox burner development test)											
	(1) Low NOx burner test	Takehara Thermal Power Station	Hitachi	Actual boiler			Test plant					Put into practical use (Dec. '75)
		Isogo Thermal Power Station	I H I	Actual boiler								Number of machines equipped(#1 Mar. '76) (#2 May '77)
	(2) Ultra-low Nox boiler test	Babcock Hitachi Kure Works	Hitachi									
		MHI Nagasaki Laboratory	Mitsubishi	Test furnace								
		IHI Aioi Works	I H I									

SUMMARY OF EMISSION CONTROL

RESEARCH PROJECTS FOR COAL FIRED BOILERS

Test Subjects	Location	Companies and Joint Researchers	Capacity	Fiscal 1975	1976	1977	1978	1979	1980	1981	Remarks
(3) 2-stage combustion device	Isogo, Takehara, Takasago	IHI, Hitachi, Mitsubishi	Actual boiler								Production type Isogo #1 Jul. '73 #2 Jun. '72 Takasago #1 Jul. '74 #2 Jun. '75 Takehara #1 Nov. '71
(Research and development of denitration technology) (1) SCR test a) Hitachi Shipbuilding & Engineering Co. (HZ)	Isogo Thermal Power Station	Hitachi Shipbuilding & Engineering Co.	Max. 250Nm³/h and others								
b) I H I	"	I H I	Max. 1,000Nm³/h and others								
c) Mitsubishi Heavy Industries (MHI)	Takasago Thermal Power Station	M H I	Max. 600Nm³/h and others								
d) Hitachi	Takehara Thermal Power Station	Hitachi	Max. 2,300Nm³ and others								
e) Kawasaki Heavy Industries (KHI)	"	K H I	Max. 4,000Nm³/h and others								
(2) SNR test a) Coal ash effect confirmation test	Central Institut of Electric Power Industries (CRIEPI)	CRIEPI	Test furnace								
	Takasago Thermal Power Station	M H I	20Nℓ/min								
b) Boiler temperature measurement	Isogo Thermal Power Station	I H I	Actual boiler								

SUMMARY OF EMISSION CONTROL RESEARCH PROJECTS FOR COAL FIRED BOILERS
(Continued)

Test Subjects	Location	Joint Researchers	Capacity	1975	1976	1977	1978	1979	1980	1981	Remarks
				4 7 10 1	4 7 10 1	4 7 10 1	4 7 10 1	4 7 10 1	4 7 10 1	4 7 10 1	
(2) Denitration											
a) Air preheater test	Takasago Thermal Power Station	Gadelius	10,000Nm3/h								
			5,000Nm3/h								
	Takehara Thermal Power Station	HZ	2,000Nm3/h								
	Isogo Thermal Power Station	I H I									
FGD Equipment for practical use											
(1) Isogo Thermal Power Station											
(#1)		I H I	265MWx2Units								#1 Unit (scheduled) to start up in MAR/76.
(#2)											#2 Unit (scheduled) to start up in MAY/76.
(2) Takasago Thermal Power Station											
(#1)		Mitsui Miike	250MWx2Units								#1 Unit (scheduled) to start up in FEB/75.
(#2)											#2 Unit (scheduled) to start up in MAR/76.
(3) Takehara Thermal Power Station											
(#1)		Hitachi	250MWx1Unit								Scheduled to start up in Feb./77
(4) Matsushima Thermal Power Station											
(#1)		I H I	500MWx1Unit								#1 Unit (scheduled) to start up in Dec./81. (3/4 Capacity)
(#2)		Hitachi	500MWx1Unit								#2 Unit (scheduled) to start up in Jul./81.

SUMMARY OF EMISSION CONTROL RESEARCH PROJECTS FOR COAL FIRED BOILERS

(Continued)

Test Subjects	Location	Companies and Joint Researchers	Capacity	Fiscal 1975–1981	Remarks
3. Dust Collecting Technology (1) H. ESP	Isogo Thermal Power Station	S H I	10,000Nm³/h		
	Takasago Thermal Power Station	Gadelius	5,000Nm³/h		
	Takehara Thermal Power Station	Hitachi	2,300Nm³/h		
	Isogo Thermal Power Station	I H I	2,000Nm³/h		
	Takasago Thermal Power Station	M H I	900Nm³/h		
(2) Ditto. but test plant	Matsushima Thermal Power Station	S H I	500MWx1Unit		#1 Unit (scheduled) to start up in DEC/80.
		M H I	500MWx1Unit		#2 Unit (scheduled) to start up in JUL/81.
(3) Bag filter	Not decided yet.	Not decided yet.	Not decided yet.		
4. Waste Water Treatment Technology (1) Reverse osmosis process denitrification test	Isogo Thermal Power Station	S H I	Max.7m³/day		
(2) Biological treatment denitrification test	Manufacturer's laboratory	Mitsui Miike Ebara, HZ	Laboratory scale		
5. Attachment techniques (1) Desulfurization a) GGH test	Takasago Thermal Power Station	Gadelius	10,000Nm³/h		
b) De SOx fan test	Takehara Thermal Power Station	Hitachi M H I	10,000Nm³/h		
c) Corrosion-resisting material test	"	Fuji Resin	Test Piece		

SUMMARY OF EMISSION CONTROL RESEARCH PROJECTS FOR COAL FIRED BOILERS

	Test subjects	Location	Companies Joint Researchers	Capacity	Fiscal 1975			1976			1977			1978			1979			1980			1981			Remarks
					4	7	10	1	4	7	10	1	4	7	10	1	4	7	10	1	4	7	10	1	4	7	10	1	
Denitration Technology Demostration Test		Takehara Thermal Power Station		800,000Nm^3/h																									Entrusted by Government

SUMMARY OF EMISSION CONTROL RESEARCH PROJECTS FOR COAL FIRED BOILERS

(Concluded)

FIGURE I

STATUS OF COMPLIANCE WITH ENVIRONMENTAL QUALITY STANDARDS
RELATING TO AIR POLLUTION

1. Sulfur dioxide

☐ Effective no. of
monitoring stations

▨ No. of stations in
compliance with environ-
mental quality standards

2. Nitrogen dioxide (1977 status of compliance with new standard)

■ No. of stations in excess of 0.06 ppm
▨ No. of stations in zone from 0.04
to 0.06 ppm (inclusive)
☐ No. of stations below 0.04 ppm

Stations monitoring
ordinary ambient
air quality (892)

Stations monitoring
automobile emissions
gas (182)

Notes: 1. Classified according to the annual 98 percentile value of
daily average NO₂ concentration, with a Saltzman coef-
ficient of 0.84.

2. Monitoring stations for automobile emissions situated
over roadways have been excluded.

297

FIGURE 2

CHANGES IN THE ANNUAL DENSITY OF MAJOR AIR POLLUTANTS
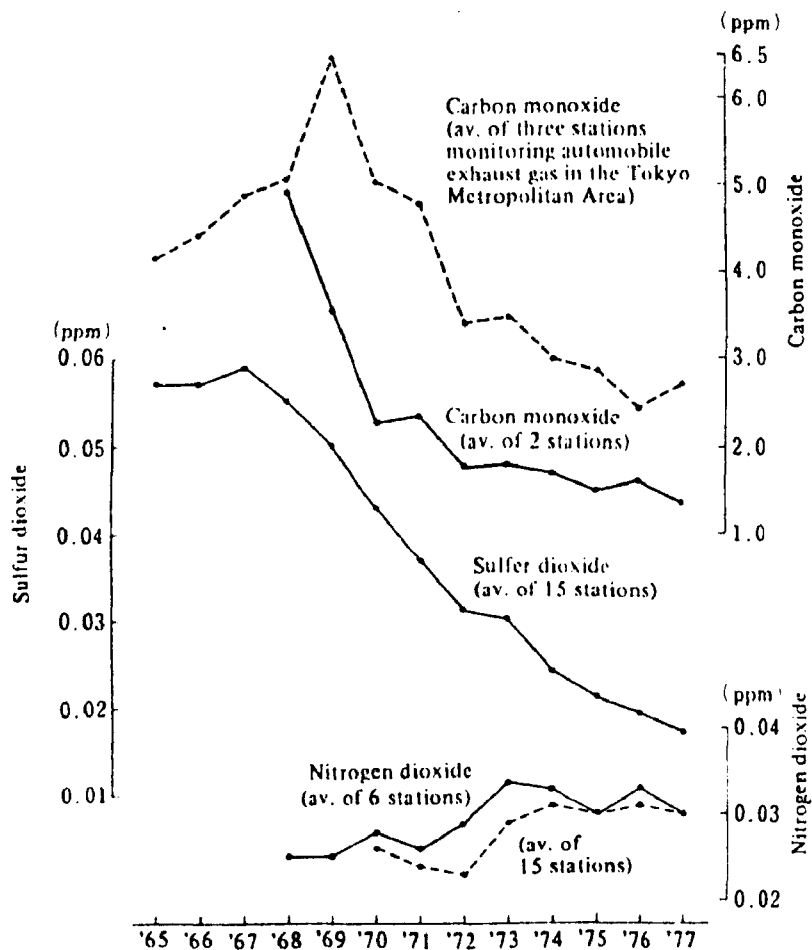
Notes: 1. Carbon monoxide measurements by automobile exhaust gas monitoring stations are given in terms of calendar years.

2. Saltzman coefficient of 0.72 is used for nitrogen oxides.

Figure 3

Model Anti-pollution Coal-fired Thermal Power Plant

Case	System	Power Plant Flow	Con-centration	Remarks
1	Low Dust Denitration System	NH$_3$ — Boiler → H.ESP → SCR → A/H → ○ → GGH → Water → Wet FGD → WWT	-	H.ESP: Hot-side Electrostatic Precipitator SCR: Selective Catalyst Reduction Equipment
2	High Dust Denitration System	Boiler → SCR → A/H → ○ → GGH → Water → Wet FGD → WWT NH$_3$ Ash Treatment	-	A/H: Air Preheater GGH: Gas-Gas Heat Exchanger FGD: Flue Gas Desulfurization
3	Dry FGD System	Boiler → A/H → BH/New EP → ○ → NH$_3$ → Dry FGD → BH → ○	-	W.WT: Waste Water Treatment Equipment BH: Bag House O: Fan

FIGURE 4

One Sample of Test Results
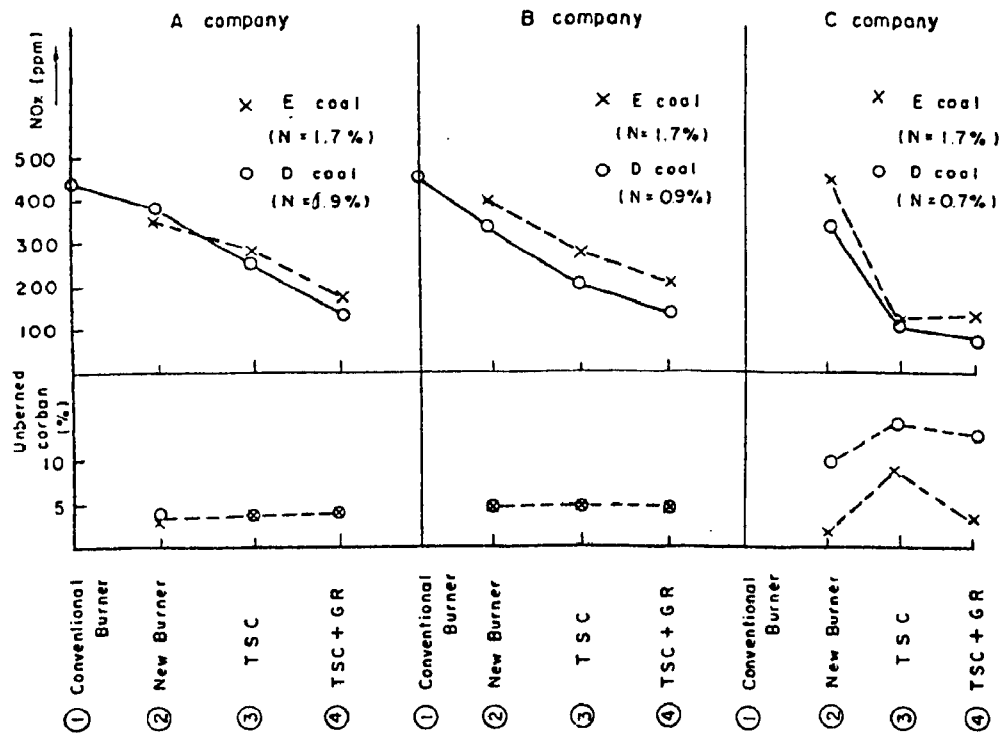
FIGURE 5

Corelation of NOx concentration vs P.O.M. Emission
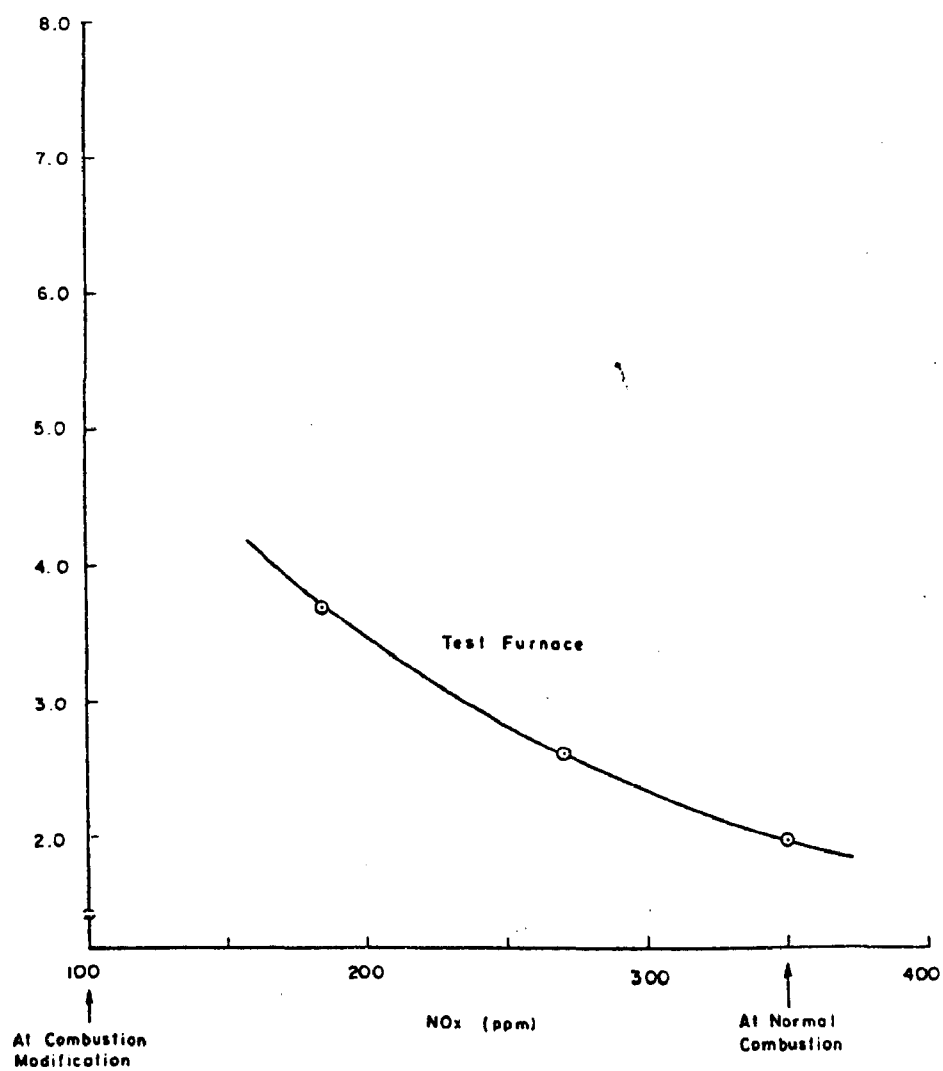
NOx Concentration of Test Furnace is the average value of
maximum and minimum values.

301

FIGURE 6

IHI'S ORIGINAL BURNER

Secondary
Air

Outer Sleeve

Inner Sleeve

Tertiary Air

Oil Burner

Wind Box

Secondary
Air Vane

Furnace Wall Tube
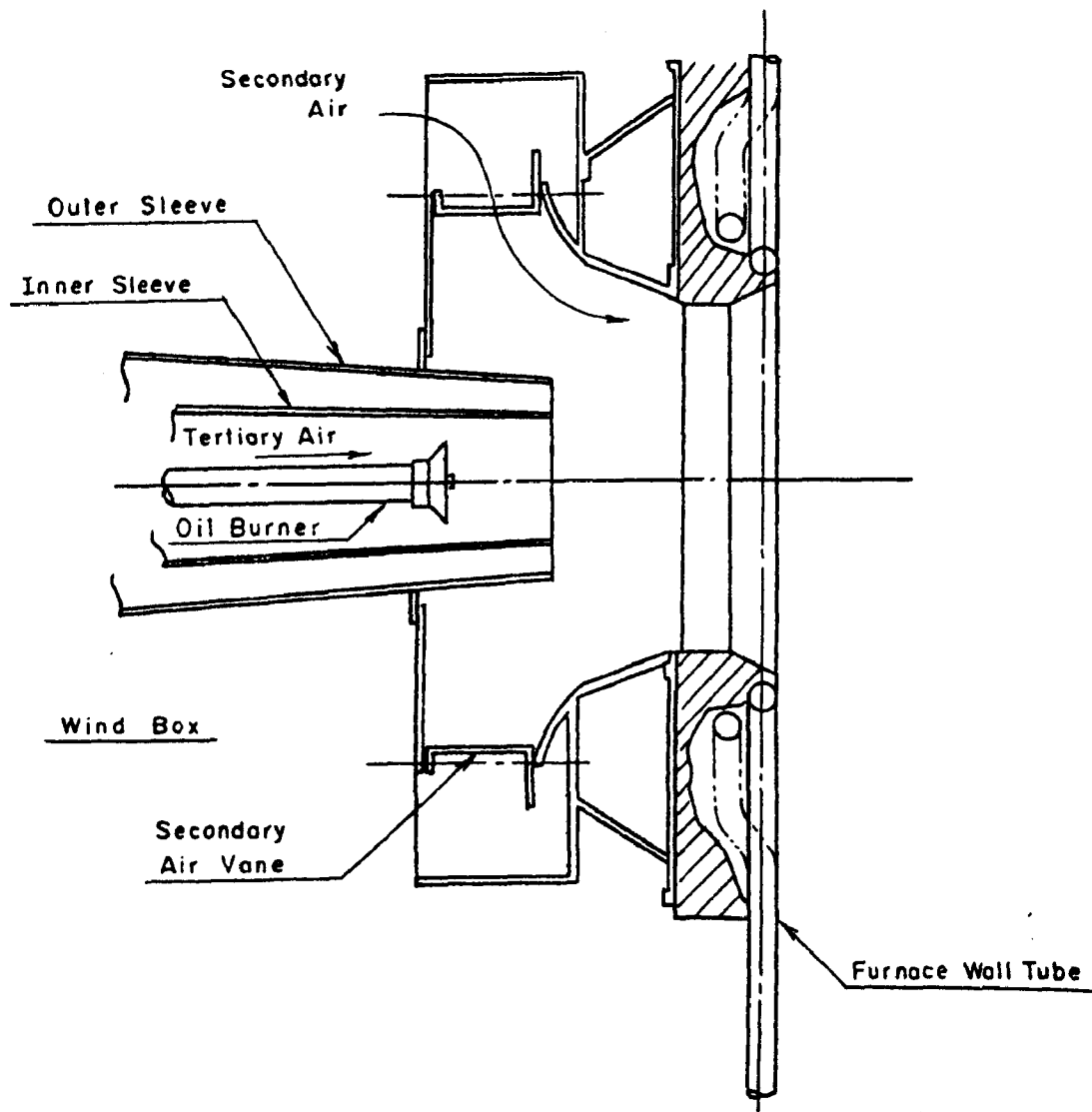
FIGURE 7

IHI'S DF-CN BURNER
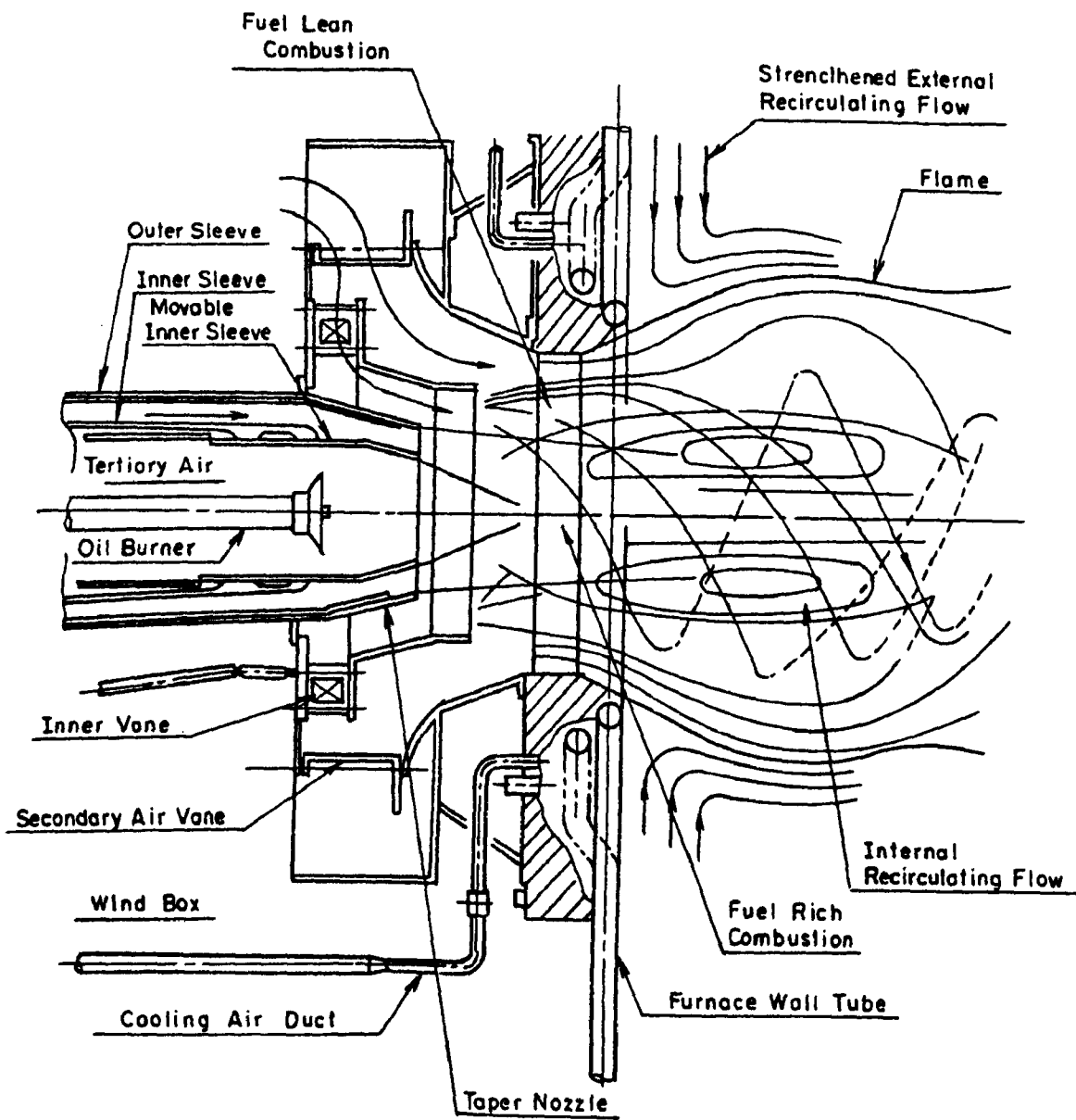
FIGURE 8

IHI'S BOUNDARY AIR SYSTEM

Over Air Port

DF Burner

Curtain Air

Cooling Air Nozzle

Burner Throat

Burner Throat Cooling Device
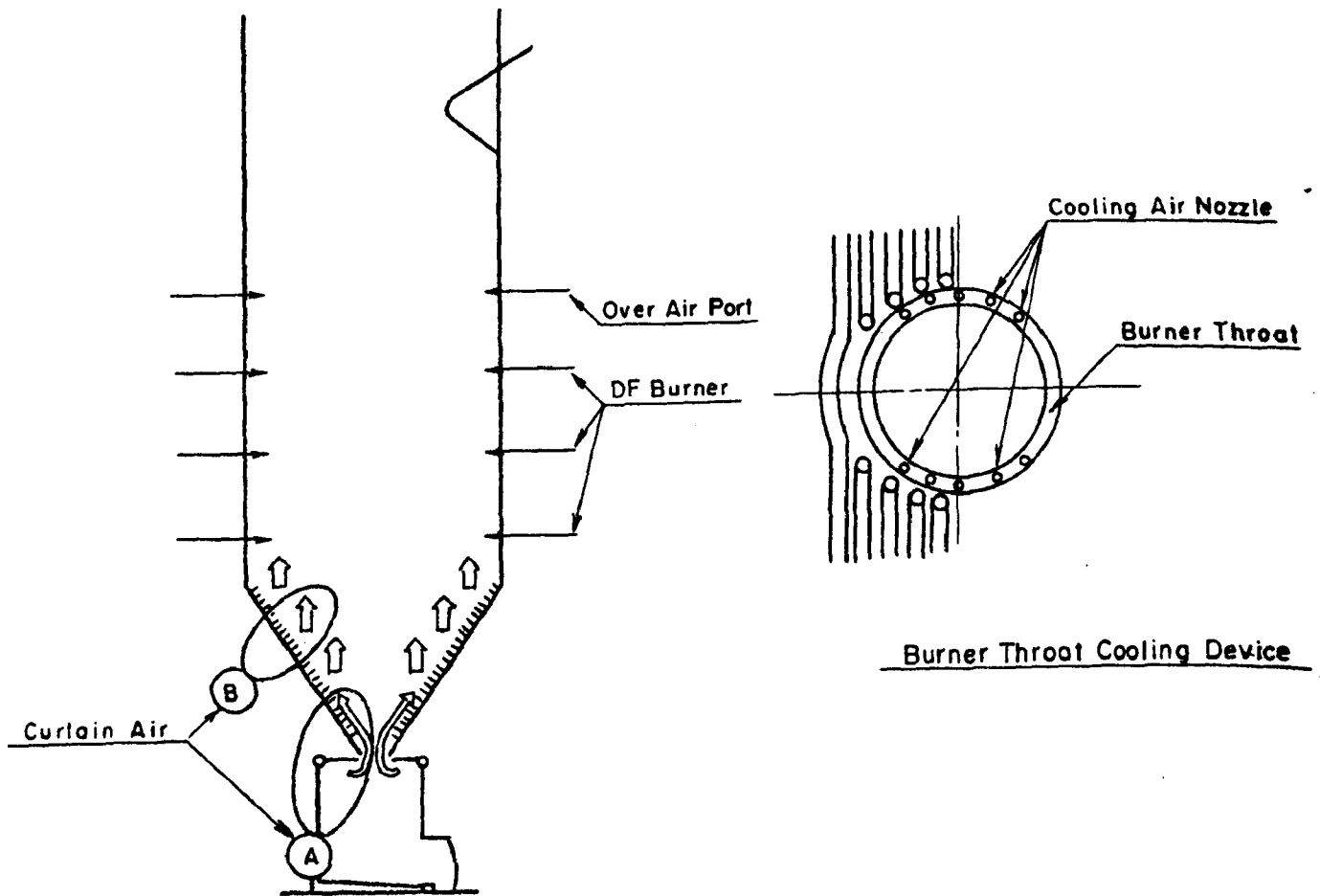
(Figure 9 omitted by author)

304

Fig.10 OAP Damper Open Ratio Versus NOx Emission

□ Predicted level with additional
   OAP's and steam injection equipment

● Test results

○ Boos of two burner cut results

p.p.m.

NOx Emission (@ 6% O2)

Steam
injection

Actual
data

Predicted data

OAP Damper Open Ratio

Figure 11 Actual Data of NOx

Load change ($140^{MW} \rightarrow 265^{MW}$)

Load change ($265^{MW} \rightarrow 140^{MW}$)

— Date Feb. 18 '80

O2 at Stack

NOx Level ($O_2 = 6\%$)

— Time (O'clock)
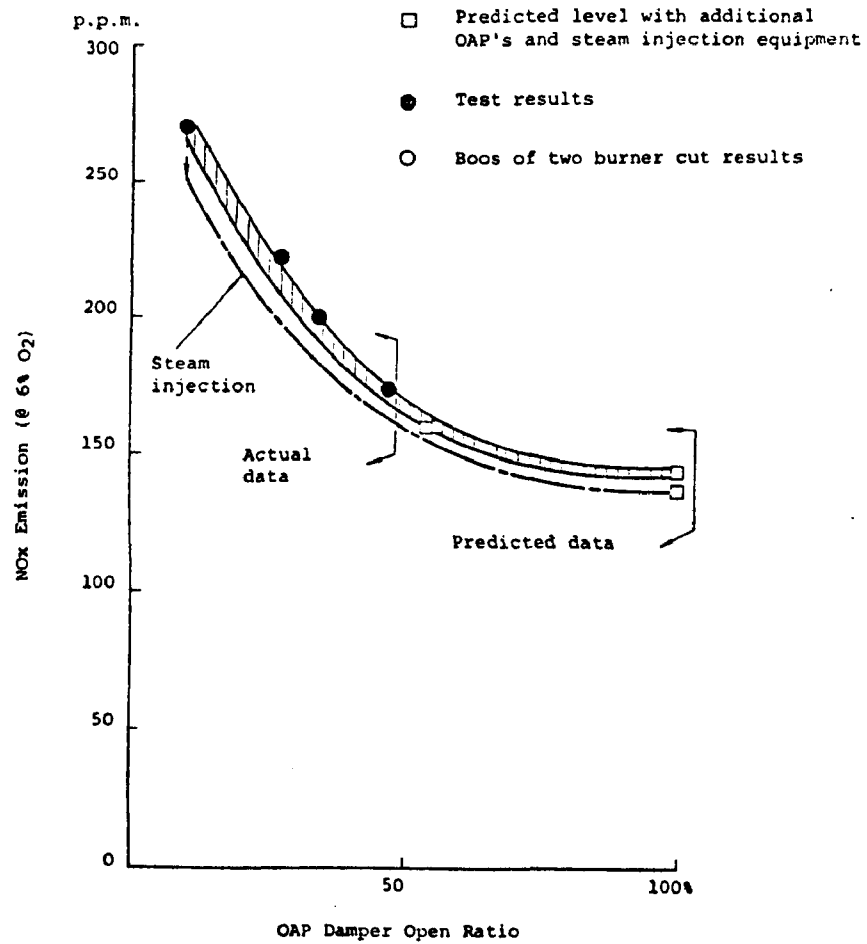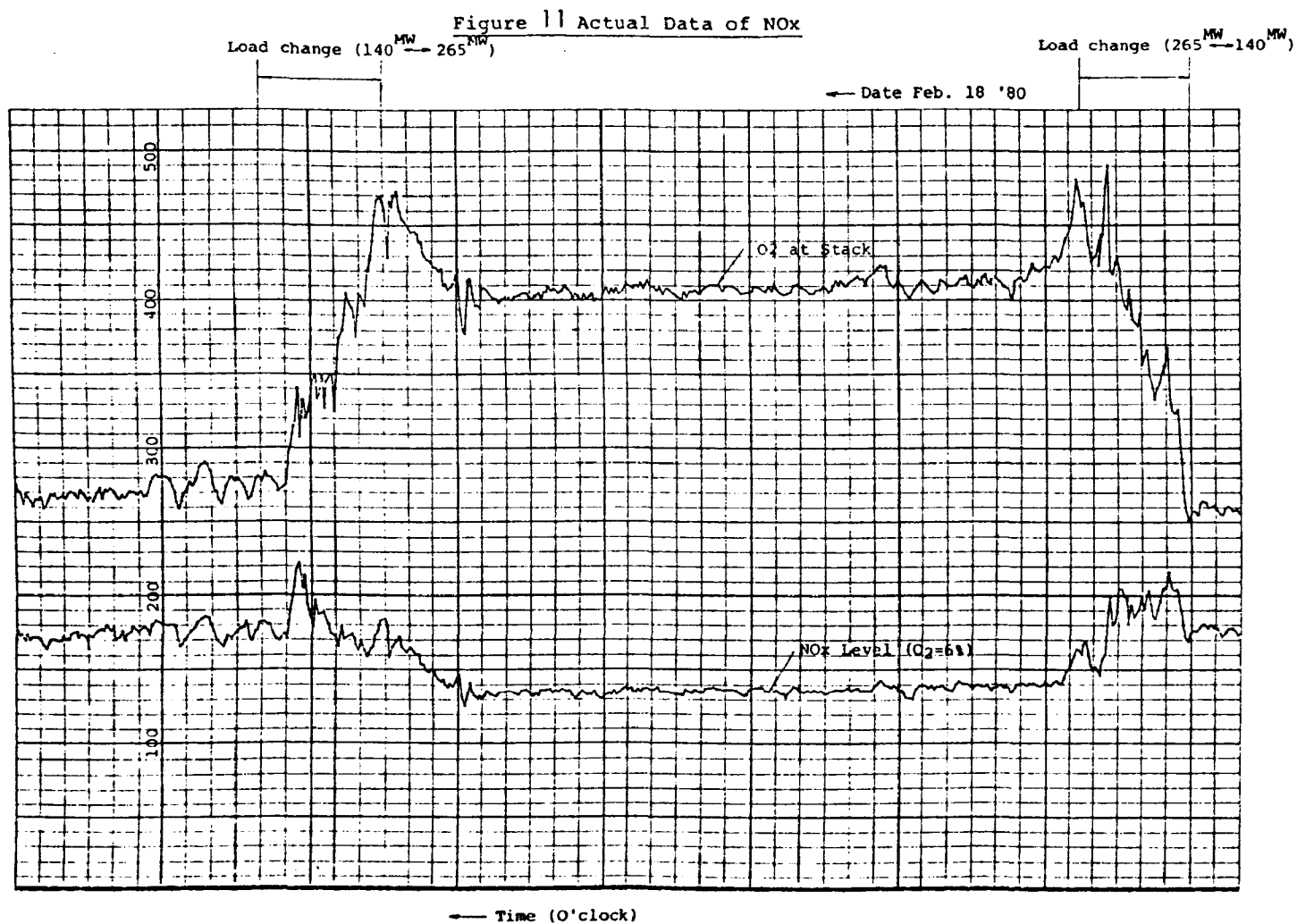
FIGURE 12

SH SYSTEM AND IMPROVEMENT

FIGURE 13

SGR Burner
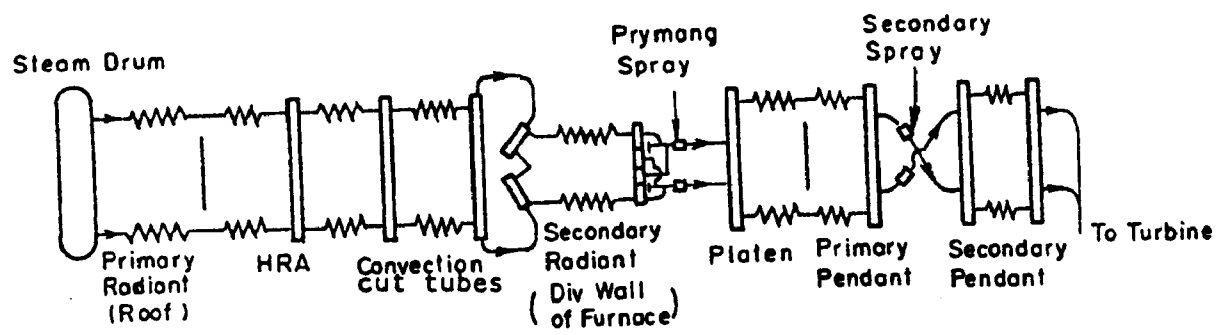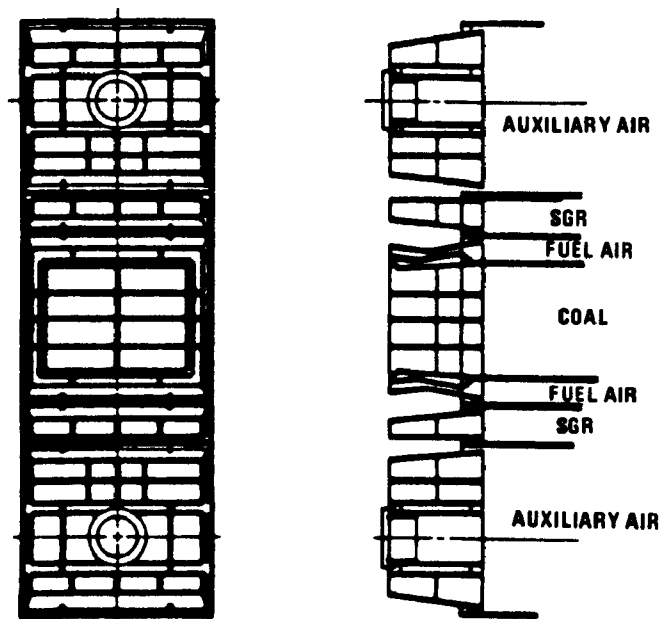
Labels in figure:
AUXILIARY AIR
SGR
FUEL AIR
COAL
FUEL AIR
SGR
AUXILIARY AIR

FIGURE 14

Comparison of NOx Emission

- Laboratory Test Results vs. Field Data -
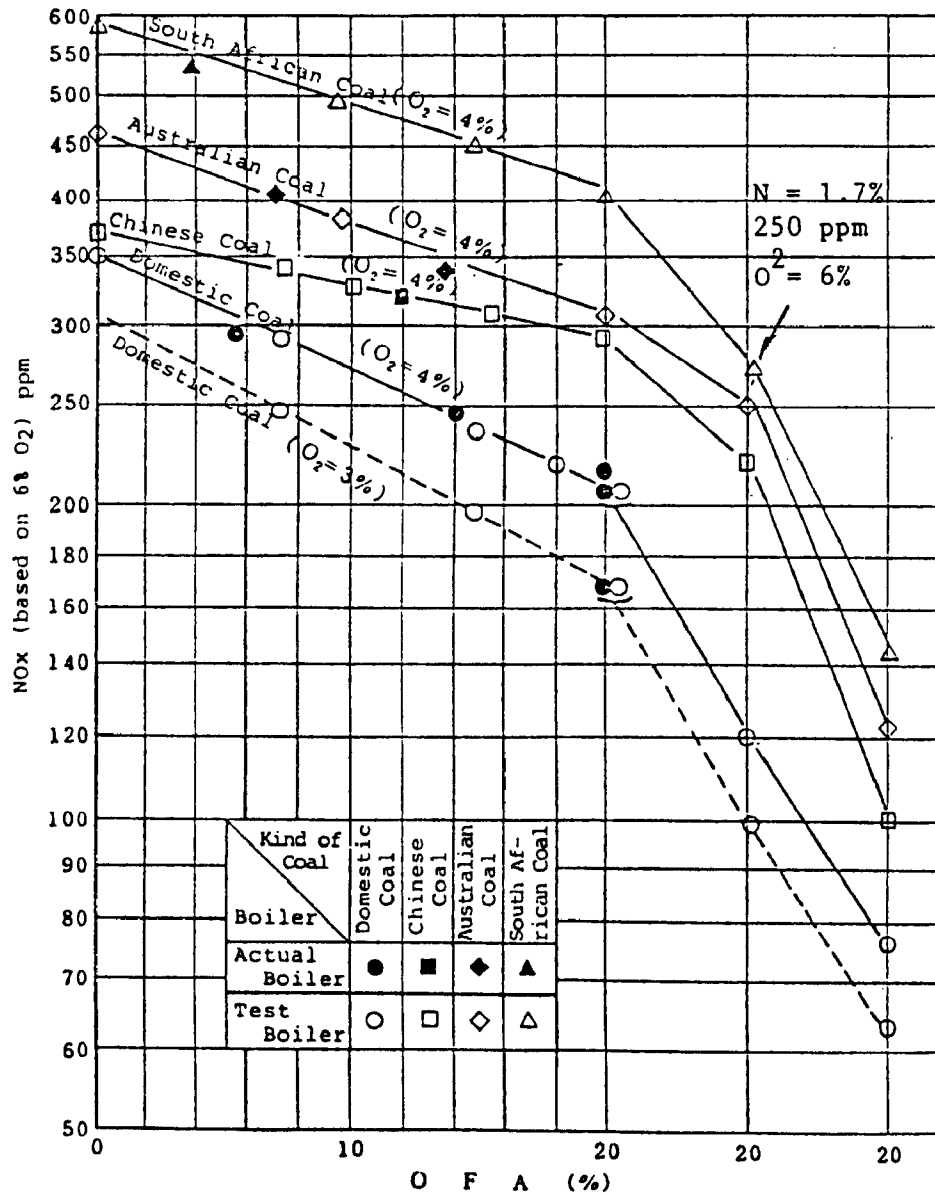
Figure 15   BHK   Low   NOx   Burner

Secondary air resister

Thertiary air resister

Ventry

Oil burner

310

Primary gas vane

Secondary air

Thertiary air

Inlet of primary gas

Secondary air vane

Primary air and pulverlized coal
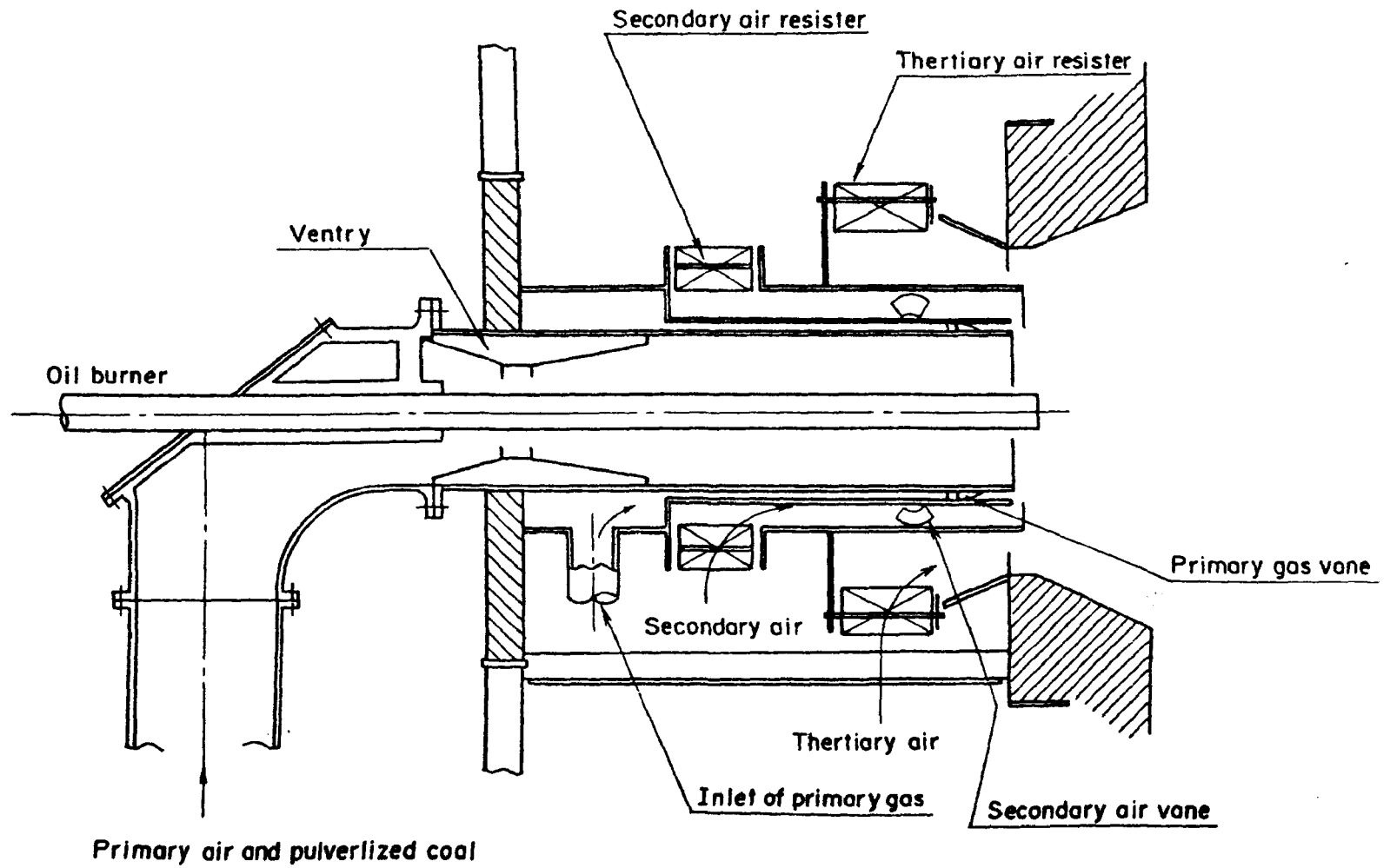
FIGURE 16

HEAT RELEASE RATE AT BURNER ZONE VS NOx LEVEL
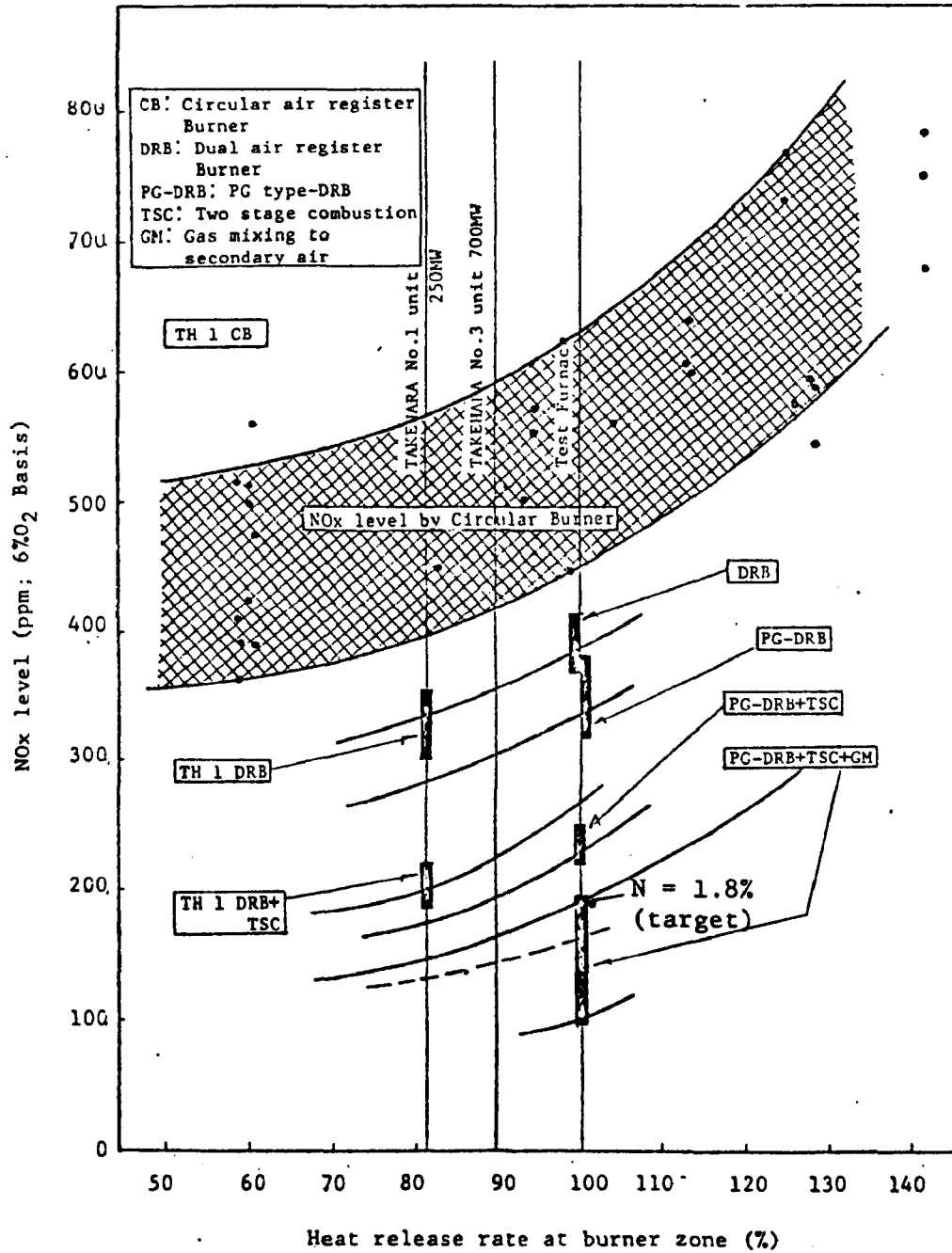
TABLE I

NO$_2$ ENVIRONMENTAL STANDARDS IN JAPAN

	NO$_2$ Environmental Standards announced as of May 8, 1973	No$_2$ Environmental Standards revised as of July 11, 1978	Remarks
NO$_2$ high pollution areas	Intermediate target level: (effective through May, 1978) NO$_2$ level in the atmosphere should be less than 0.04 PPM on the hourly level. Final target value: (effective through May, 1981) NO$_2$ level in the atmosphere should be less than 0.02 PPM on the hourly level.	Final target level: (effective within seven years of the date of revision) NO$_2$ level in the atmosphere should be reduced to a range of 0.04 PPM to 0.06 PPM or less on the hourly average.	(1) The Japanese NO$_2$ Environmental Standards, which are much more rigid than those now in force in many foreign countries, have been disputed in Japan. (2) Nine per cent of the target level based on the original standards was attained as of fiscal 1976.
NO$_2$ low pollution areas	Final target value: (effective through May, 1978) NO$_2$ level in the atmosphere should be less than 0.02 PPM on the hourly level.		

TABLE 11

CHANGES OF NOx EMISSION STANDARD

(1st Standard Value : Aug. 10, 1973 start)
(2nd Standard Value : Dec. 10, 1975 start)
(3rd Standard Value : Jun. 18, 1977 start)

(Standard Valve ppm)

Scale of Facilities	Installation Time / Clarification of Restriction / Applicable Time	Before Aug. 9, 1973			Aug. 10, 1973~Dec. 9, 1975			Dec. 10, 1975~ Jun. 17, 1977		After Jun. 18, 1977	Notes
		1st Existing	2nd Existing	3rd Existing	1st New	2nd New	3rd Existing	2nd New	3rd Existing	3rd New	
		From Jul. 1, 1975	From Dec. 1, 1977	From May. 1, 1980	From Aug. 10, 1973	From Dec 1, 1977	From May. 1, 1980	From Oct. 10, 1977	From May 1, 1980	From Jun. 18, 1977	
Gas Firing (O_2 : 5%)	million 0.5 Nm³/h over	170	130	130	130	130	130	100	100	60	
	million 0.1~0.5	170	130	130	130	130	130	100	100	100	
Solid Firing (O_2 : 6%)	million 0.1 over	600 (750)	600 (750)	480	480	480	480	480	480	400	( ) indicates combustion with low calorific value coal(5,000 Kcal/kg under) ∴ Ceiling burner 650 ppm Devided wall type 550 ppm
Fluid Firing (O_2 : 4%)	million 1 over	230 (280)	230 (280)	180	180	180	180	150	150	130	( ) indicates combustion with crude oil and tar
	million 0.5~1	230 (280)	230 (280)	180 (210)	180	180	180	150	150	130	( ) indicates plant equipped with DeSOx system
	million 0.1~0.5	230 (280)	230 (280)	190 (210)	130	180	180	150	150	150	

Table III

Present State of NOx Emission Control
for Existing Coal Fired Boiler

		Isogo P.S	Takasago P.S	Takehara P.S #1 unit
Law		400	400	400
Ordinances agreement		151 (under negotiatun)	300	410
Refferences	Output	265^{MW} x 2	250^{MW} x 2	250^{MW} x 1
	Fuel	coal	coal	coal
	N content	1.1	1.0	1.0

Table IV
Sample of NOx Emission Control
for New Coal Fired Boilers

	Matsushima P.S	Takehara P.S		
Law (O_2=6%)	400 ppm	400 ppm		
			No.1	No.2	No.3
Ordinances agreement (O_2=6%)	300 ppm	1980	—	—	—
		1982	112	175	60
		1983	79	175	60
		1984	72	115	60
		1987	60	81	54
Remarks			250MW	350MW	700MW
			coal	oil	coal

TABLE V

NOx REDUCTION PROGRAM
IN TAKEHARA AREA

(%)

☐ EPDC Takehara P/S
    Total Emission Volume

100

Takehara
No. 2
350MW
(Oil)

Takehara
No. 1
250MW
(Coal)

Present

79

Takehara
No. 3
700MW
(Coal)

Takehara
No. 2
350MW
(Oil)

Takehara
No. 1
250MW
(Coal)

**No. 3 Takehara
commercial
operation(1982)**

79

AP/56

73
Takehara
No. 3
700MW
(Coal)

Takehara
No. 2
350MW
(Oil)

Takehara
No. 1
250MW
(Coal)

**A P/S
commercial
operation
(1983)**

79

BP/58

AP/56

65
Takehara
No. 3
700MW
(Coal)

Takehara
No. 2
350MW
(Oil)

Takehara
No. 1
250MW
(Coal)

**B P/S
commercial
operation
(1984)**

315

TABLE VI
Nitrogen Content of Planning Coal

China	A	B
N (%)	1.4	0.8

Australia	A	B	C	D	E	F	G	H	I
N (%)	1.6	1.7	1.6	1.5	1.6	1.6	1.5	1.6	1.7

The others	A	B	C-1	C-2	C-3	D
N (%)	1.8	1.7	1.6	1.4	1.4	1.42

Domestics	A	B
N	0.8	1.0

TABLE VII

Outline of R & D Programs on Combustion NOx Control Technology

	Test Location	Test furnace Capacity	Test conditions	Scheduled				
				1977	1978	1979	1980	1981
M H I	Nagasaki	1.3 kℓ/H (oil base)	TSC , GRF , GM , SGR & PM burner					
B H K	Kure	2.0 t/H (coal base)	TSC, GRF, GM, PG burner					
I H I	Aioi	1.0 t/H (coal base)	TSC, GRF, DF (E) burner					
K H I	Shiga	3.7 t/H (coal base)	TSC, GRF, GM V-D burner					

TSC : Two Stage Combustion

GM : Gas Mixing

Table VIII

Measurement Results of P. O. M. at Furnaces

Unit ug / Nm^3

Combustion Condition / P. O. M. Component	Normal Combustion	2 stage Combustion	2 stage + FG mix + Primary Gas	PGM	Partial Load
Naphthalene	0.22	0.18	0.22	0.24	0.24
Fluoranthene	—	0.40	0.88	0.78	0.84
Pyrene	0.65	0.64	0.87	0.87	0.84
Benzo (a) pyrene	0.48	0.59	0.66	0.58	0.62
Total P. O. M.	1.99	2.62	2.46	3.15	3.49
(Percentage when Normal combustion is 100)	(100)	(132)	(124)	(158)	(175)

TABLE IX.   SUMMARY OF ISOGO 265 MW PULVERIZED
             COAL FIRED BOILER (NO. 1 and NO. 2)

Type   : IHI-FW single drum, radiant type,
                                     natual circulation, reheat boiler
                                     (Indoor service)

Evaporation (at M.C.R.)   : 840,000 kg/h

Steam pressure (at M.C.R.)
     Superheater outlet   : 176 kg/cm^{2}g
     Reheater outlet   :   34 kg/cm^{2}g

Steam temperature (at M.C.R.)
     Superheater outlet   : 571°C
     Reheater outlet   : 571°C

Fuel   : Bituminous coal
                                     (Equipped with 50% MCR heavy oil
                                       firing system)

Number of burner   : 24 set
                                     (4 rows and 3 stages on boiler
                                     front and rear walls)

Draft System   : Balance draft system

TABLE X Countermeasure for NOx Control for Isogo Power Station NO.2 Unit

Month. Year	NOx Emission Level by Regulation, etc. (ppm)	Achieved NOx Level (ppm)	Countermeasure
Before May, 1973	600	570	None
June, 1973	600	380 ∿ 510	Two Stage Combustion
Apr., 1977	480	240 ∿ 250	Low NOX Burner Curtain Air
Apr., 1979	400	170 ∿ 190	Strength of Two Stage Combustion, etc.
Apr., 1980	159* Yokohama city's Requirement	170 ∿ 190	

TABLE XI

TYPICAL ANALYSIS ISOGO'S COAL

Higher heating value	6,200 kcal/kg
Ash	16.5%
Volatile matter	39.6%
Fixed carbon	39.4%
Sulfur	0.4%
Hydrogen	5.5%
Nitrogen	1.0%

EMPIRICAL EVALUATION OF SELECTIVE CATALYTIC REDUCTION
AS AN NO_x CONTROL TECHNIQUE

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ABSTRACT

Selective catalytic reduction (SCR) has been proposed as a technique for control of NO_x emissions to levels significantly below those mandated by NSPS for coal-fired utility steam generators. EPRI is conducting an empirical assessment of the feasibility and cost-effectiveness of SCR, using a pilot scale system at the EPRI Arapahoe Emission Test Facility to simulate authentic coal-fired utility operating conditions. The program is a logical extension to earlier EPRI work defining economic feasibility of postcombustion control, and complementary to other pilot scale studies in the United States and Japan.

The test program was initiated in September 1980 on a facility capable of treating 5,000 scfm of coal-fired flue gas, equivalent to 2.5 MW of electrical generating capacity. The facility employs a regenerative air heater in series with a catalytic reactor to assess potential impacts on air heater performance. The tests will focus on four major issues important to the evaluation of SCR technology: (1) process performance as defined by NO_x removal capabilities at conditions representative of authentic utility application; (2) process operating demands including the need for monitoring and control systems, consumables such as ammonia, energy (pressure drop and auxiliary power), operating and maintenance requirements to maintain process performance, catalyst lifetime; (3) environmental impacts due to emissions of residual ammonia, SO_3, and sulfates and bisulfates of ammonia; and the potential effects on SO_2 and particulate control; and (4) systemwide operating effects such as increased operating and maintenance of downstream surfaces (particularly the air heater), heat rate penalty, limitations in load-following, etc.

Results are presented for the initial tasks dealing with the evaluation of measurement techniques, and preliminary data describing reactor and air heater performance.

ACKNOWLEDGEMENTS

324

EMPIRICAL EVALUATION OF SELECTIVE CATALYTIC REDUCTION
AS AN NO_x CONTROL TECHNIQUE

INTRODUCTION

The Environmental Protection Agency (EPA) has cited as goals the reduction of New Source Performance Standards (NSPS) for oxides of nitrogen (NO_x) emissions from coal-fired utility power plants from current levels of 0.5-0.6 lbs/million Btu's (depending on coal properties) to 0.2. Under certain circumstances, coal-fired power plants could be required to further reduce NO_x emissions below NSPS levels, such as in Air Quality Regions (AQRs) in noncompliance with the proposed Federal ambient NO_2 standard, or to prevent significant deterioration of Class I AQRs. Such regulations have already been promulgated for certain classes of oil- and gas-fired steam generators in California's South Coast Air Basin. Postcombustion methods of NO_x control (alternatively known as flue gas treatment) have been proposed to achieve such stringent standards for both clean fuels (such as natural gas and fuel oil) as well as coal. Accordingly, the electric utility industry through EPRI is conducting an empirical evaluation of the feasibility of postcombustion NO_x control processes for coal-fired utility boilers.

Development efforts in postcombustion control have been conducted predominantly in Japan and in the last decade. This is due to stringent Japanese emissions standards; and to the predominant use in that country of natural gas and fuel oil, which due to low ash and sulfur content, offer greater prospects for successful application. Extensive laboratory and pilot scale work has been conducted for these "clean" fuels, and recently has been expanded to consider coal. Most of this development work is typified by well-controlled operating conditions necessary for fundamental process development, but not representative of authentic utility application. Extrapolation of Japanese pilot plant experience with coal to U.S. utility systems is complicated not only by significant scale factors but also by differences in coal properties

325

(i.e., ash characteristics and chemistry) between coals used in Japan and the United States. Experience with full-scale utility systems is limited exclusively to clean fuels, and thus does not reflect the problems inherent to high particulate loading, SO_2 concentration, and ash chemistry.

SUMMARY OF RELEVANT EPRI EXPERIENCE

Prior work conducted by EPRI has consisted of preliminary technical and economic assessments of the feasibility of postcombustion processes for U.S. utility coal-fired application. In two initial studies (1,2), approximately 50 processes were categorized as to technical basis and screened according to potential merits and economics of operation. Follow-on studies considered a limited number of processes in more detail through design studies of specific applications. Seven postcombustion processes were evaluated by the Tennessee Valley Authority (TVA) through a jointly funded program with the EPA; the results identified the dry, ammonia-based selective catalytic reduction (SCR) process as a leading candidate for near-term commercial acceptance (3,4). A further study conducted by Stearns-Roger for EPRI examined two dry SCR processes in addition to the Shell/UOP simultaneous SO_2/NO_x and the Exxon Thermal DeNO$_x$ process (5). Both the TVA and Stearns-Roger studies identified for each process (a) the technical merits and potential obstacles to application to new coal-fired utility boilers, and (b) the economics of operation, necessarily limited to the costs of process equipment procurement, installation, and operation. Only the most obvious impacts of SCR on powerplant design and operation that could be identified with the limited level of experience were included. A study similar in scope and depth has been recently completed, also by Stearns-Roger, to assess costs of retrofit application of SCR systems from two process vendors to an 80 MW boiler (6).

One of these preliminary investigations (5) has identified the minimum cost of SCR application to new 500 MW coal-fired power plants, for the case of 90% NO$_x$ removal from initial NO$_x$ concentrations representative of present NSPS levels. These results, summarized in Table 1 for the Kawasaki Heavy Industries (KHI) process, are preliminary and therefore incomplete as all potential impacts on plant operation attributable to SCR have not been identified. This can only be accomplished through a pilot-scale evaluation of a commercially representative system on a coal-fired utility boiler at operating conditions

that reflect authentic utility application. The remainder of this paper provides a status report of such an effort at the EPRI Arapahoe Emission Test Facility.

POTENTIAL SCR EFFECTS ON FLUE GAS FROM COAL

Figure 1 presents a diagrammatic path for the potential fates of the major nitrogen and sulfur species in flue gas subjected to SCR treatment. The temperature range of interest spans from typical catalyst temperatures (specific for one process, but representative of other SCR processes) to typical air heater exit temperatures. The process inputs are indicated at the reactor inlet as are the desired products of the NH_3/NO_x reduction reactions, and the residual and by-product emissions of NH_3 and SO_3. As the flue gas proceeds through the reactor and downstream equipment and cools, the following fates of major nitrogen and sulfur species are possible:

(1) SO_2 can be

   (a) oxidized to SO_3 within the reactor (usually 1-5% inlet SO_2);

   (b) collected in the SO_2 scrubber and converted to the liquid or solid scrubber effluent (ultimately to be transferred to the scrubber waste disposal site);

   (c) emitted

(2) SO_3 can

   (a) be collected in the scrubber and transferred to the liquid or solid scrubber effluent, and ultimately to scrubber waste disposal site;

   (b) be emitted, either in gas phase or liquid if the dew point is reached;

   (c) condense or be adsorbed on internal surfaces; or on fly ash, and thus collect in the particulate control device (and ultimately the ash disposal site), or penetrate the control device.

327

(3) NH_3 can remain in gaseous form and be

(a) emitted;

(b) absorbed in the scrubber (disposal site);

(c) absorbed by fly ash and thus collect in the particulate control device (ash disposal site), or penetrate the control device.

(4) NH_3 and SO_3 can combine and form (depending on relative NH_3, SO_3, and H_2O concentration, and temperature) ammonium sulfate or ammonium bisulfate (liquid or solid phase) which can:

(a) pass through the air heater and collect in either the scrubber or particulate control device (disposal site), or penetrate the control device;

(b) impact and lodge on air heater or other internal surfaces and subsequently be removed by sootblowing and endure the fate described in (a), or be removed through water washing and transferred to the wash effluent;

(c) be absorbed by fly ash, and collect in the particulate control device (ash disposal site), or penetrate the control device and be emitted.

Based upon these potential paths, at least four ultimate fates for nitrogen and sulfur residual and by-product species can be identified:

● airborne emission

● retained on surfaces within system (possibly removed through routine washing maintenance procedures)

● SO_2 scrubber/effluent disposal site

328

- particulate collection device/ash disposal site

Each of these affected areas has been the focus of considerable atten-
tion, and the added impact of SCR by-products could raise new issues requiring
additional corrective action.

Table 2 presents a compilation of the issues of concern attributable to
SCR that must be addressed before the feasibility of SCR can be assessed.
These issues are attributable to the operation and maintenance of both the SCR
process and the entire power plant, as determined by the four potential fates
of major nitrogen and sulfur species. These issues are categorized as to
(a) process performance, (b) process operating demands, (c) environmental
impacts, and (d) system-wide operating effects. For these issues of concern,
the data necessary from the test program for an empirical assessment is cited,
as well as the economic implications for power plant operation.

This table has been used as the basis for the test plan which is presen-
ted in a later section.

DESCRIPTION OF FACILITY

The empirical assessment of SCR for coal-fired utility boilers is being
conducted at the EPRI Arapahoe Emission Test Facility. This facility,
operated in cooperation with the Public Service Company of Colorado (PSCCo),
is located in Denver, and was commissioned in 1977 to support the testing and
evaluation of advanced particulate control technology. The direction of work
at Arapahoe has been expanded to include the present evaluation of NO_x
control, and in the future (1981) will involve testing and evaluation of SO_2
scrubbers, and address the integrated design of all components in an emission
control train.

In December of 1978, EPRI contracted with KHI to provide a 2.5 MW
(electrical equivalent) SCR pilot plant. The selection of KHI does not
represent an endorsement or preference by EPRI for that process, but rather an
acknowledgment that the process is representative of SCR systems currently
available. Similarly, the C-E Air Preheater Company was selected to supply
for the same flow capacity a Ljungstrom regenerative air heater which is

considered representative of air heater designs in current and anticipated usage.

Figure 2 presents an outline arrangement of the pilot scale reactor and air heater. Coal-fired flue gas is extracted from PSCCo Unit No. 4 at the economizer exit (approximately 650°F) and ducted to a control valve, venturi for flow measurement, and an electrical resistance heater for control of inlet gas temperature (not shown in figure). The ammonia vaporizer and injection assembly is located at the base of the flue duct riser. The catalyst is housed in three reactor modules arranged in series, each with an equivalent quantity of catalyst. The regenerative air heater is located downstream, and oriented for a horizontal axis of rotation.

Specifications for the KHI SCR process are presented in Table 3. The major active catalytic ingredient is vanadium pentoxide, stabilized or supported in a titanium dioxide base. The material is formed in cylindrical shapes, and arranged as shown in Figure 3, with spacing selected to minimize particulate accumulation and plugging. Total catalyst volume is 120 ft^3, corresponding to a design space velocity of 2500 hr^{-1} at the rated flow capacity of 5000 scfm.

The ammonia vaporizer and delivery system have been designed to simulate the hardware and operation of the full-scale systems proposed by KHI for commercial application. The ammonia is transported from a storage tank to the vaporizer, and then mixed with carrier air (approximately 20/1 air/NH$_3$ ratio) preheated to 120°F and injected into the flue gas via a mixing grid.

Design specifications are presented in Table 4 for the regenerative air heater, which is designed to simulate the heat transfer and sootblowing characteristics of full-scale utility operation. In this context, the temperature history of the wheel elements and the mass flux per unit time of sootblowing media have been selected to represent full-scale values. An evaluation of the tolerance and susceptibility of three materials of wheel basket construction to plugging/fouling/corrosion by fly ash and SCR residual and by-product emissions is possible. Stainless steel, hard-rolled steel with baked enamel finish, and Corten are all employed in several arrangements of wheel basket construction.

The facility is equipped with process control systems to (a) facilitate pilot plant operation and provide for well-controlled test conditions, and

(b) evaluate typical control systems that could be necessary for commercial acceptance of SCR. Control systems for the catalytic reactor are necessary to adjust the mass NH_3/NO_x ratio according to changing input reactor conditions.

Five control modes will be employed at Arapahoe to both facilitate pilot plant operation and simulate the actual conditions of SCR operation in a full-scale commercial application. Each of these modes is listed in Table 5, which identifies for each the continuous on-line processing required, and EPRI experience to date. The least on-line processing is required for the first two modes that maintain either a specified NH_3/NO_x ratio or NO_x removal efficiency. The most processing is required for the latter three (which all require continuous measurement of NH_3 at the reactor outlet) to limit the mass of NH_3 injection to an amount that maintains NH_3 carryover below a prescribed level.

Continuous measurement of NH_3 in flue gas is being attempted with a special-purpose sampling probe/catalytic converter. This apparatus selectively oxidizes NH_3 to NO, permitting NH_3 concentration to be inferred from the difference in NO measurement before and after NH_3 oxidation. A schematic of the sampling probe and the analytical system is presented in Figure 4. Results to date with this system have not been successful, thus prohibiting any of the latter three control modes in Table 5 to be employed.

Two control systems are employed to drive air heater operation, and are primarily used to provide well-controlled test conditions over the long time periods required for assessment of air heater operation. Both controls vary air side flow rate and static pressure to maintain a prescribed (a) flue gas exit temperature, and (b) air side/gas side pressure differential (i.e., leakage) independent of flue gas inlet temperature, pressure, and flow rate.

TEST PLAN

A test plan has been developed to fulfill the project objectives in a time- and cost-effective manner. Table 6 defines the tasks of the test plan and identifies for each the primary and secondary variables, and those parameters that remain constant. As indicated in Table 6 the tests will evaluate the issues over the following operating conditions:

● baseline conditions, or those at or near the design conditions that could be encountered during commercial operation (Task 3);

● transient, or nonsteady conditions, simulating load swings, excess air changes, changes in boiler operating conditions, etc., (Task 4);

● upset conditions, characterized by high carbon monoxide (CO) and unburned hydrocarbon (HC) concentration, such as experienced in rapid shutdown or when encountering problems in fuel preparation (pulverizer or mill malfunctions) (Task 5);

● high particulate and SO_2 conditions, providing an approximation of the effects of ash loading and SO_2 concentration (Tasks 5, 6).

The test plan will also provide information regarding:

● catalyst lifetime, by documenting changes in catalyst performance over a 12 month period, employing well-controlled, repetitive performance tests at comparable operating conditions (Task 7), and

● air heater performance, consisting of both continuous analysis of daily performance data as well as repetitive tests at well-controlled, comparable test conditions (Task 8).

Tasks have been scheduled in a parallel sequence so as to maximize the utilization of the facility. The pilot facility operates on a 24 hour basis, with most parametric testing conducted during daytime hours when boiler conditions are generally steady-state and flue gas characteristics relatively constant. During evening hours, boiler conditions are generally not steady providing realistic transient conditions which can be used for evaluation of ammonia injection control schemes.

RESULTS

The initial phases of this project which have been completed (Tasks 1 and 2) are concerned with the procurement of the sampling/analytical equipment and development of appropriate test methodologies. Preliminary results at limited

332

test conditions are available describing SCR reactor and air heater performance.

Tasks 1 and 2 efforts served to (a) verify conventional sampling/analytical techniques for major stable combustion products, and (b) evaluate a limited number of unconventional sampling/analytical techniques for the major species of concern (NH_3, SO_3, and $(NH_4)HSO_4$ and $(NH_4)_2SO_4$). Once the specific technique best suited for field testing was selected, the exact configuration of sampling trains and the specific sampling/analytical methodologies were determined. Detailed methodologies were identified for sampling gas phase NH_3 and total NH_4^+ (impinger collection with analysis by specific ion electrode) and gas phase SO_3 (sampling by controlled condensation, analysis by titration for $SO_4^=$ using lead perchlorate). These methodologies were determined for application at the reactor inlet, reactor outlet, and air heater outlet.

A summary of the preliminary results is presented in Figure 5, which indicates NO_x removal, NH_3 carryover, and SO_2 to SO_3 oxidation (as percent of inlet NO_x, NH_3, and SO_2, respectively). Results are displayed from KHI tests in Japan and preliminary Task 3 results from Arapahoe (data in parentheses). Results from Arapahoe are presented for one temperature; the temperature effect determined by KHI when available is indicated. Figure 5 indicates the results from KHI and preliminary Arapahoe results are similar.

Simultaneously with Tasks 2 and 3, a preliminary evaluation of the influence of SCR residual and by-product emissions on air heater performance was conducted. Initially, baseline performance was documented for over three weeks, while flue gas passed through the reactor but without ammonia injection. Measurements confirmed air heater performance (thermal efficiency and pressure drop) to be as predicted by C-E Air Preheater. Figure 6 presents the inlet/outlet gas side pressure differential as a function of continuous operating time for the baseline tests and after three weeks of operation with NH_3 and SO_3 in the flue gas. The significant increase in pressure drop (approximately 3-6 inches H_2O) was observed with sootblowing frequency maintained as recommended by the manufacturer, but with a reduced air pressure and mass flux (due to limitations in the air delivery system, since rectified). At the conclusion of the three week testing period with NH_3 injection, the pilot plant was removed from service and the wheel baskets disassembled (Figure 7), revealing significant accumulation of deposits at the cold-

333

intermediate basket interface. Figure 8 shows a close-up of the deposit buildup on an intermediate basket face constructed of mild steel coated baked enamel. Qualitative analysis of a deposit sample indicated the presence of ammonia suggesting ammonium sulfate/bisulfate constituents.

FUTURE PLANS

The test plan is currently being carried out at the Arapahoe Emission Test Facility. It is anticipated that testing will be complete by Fall 1981.

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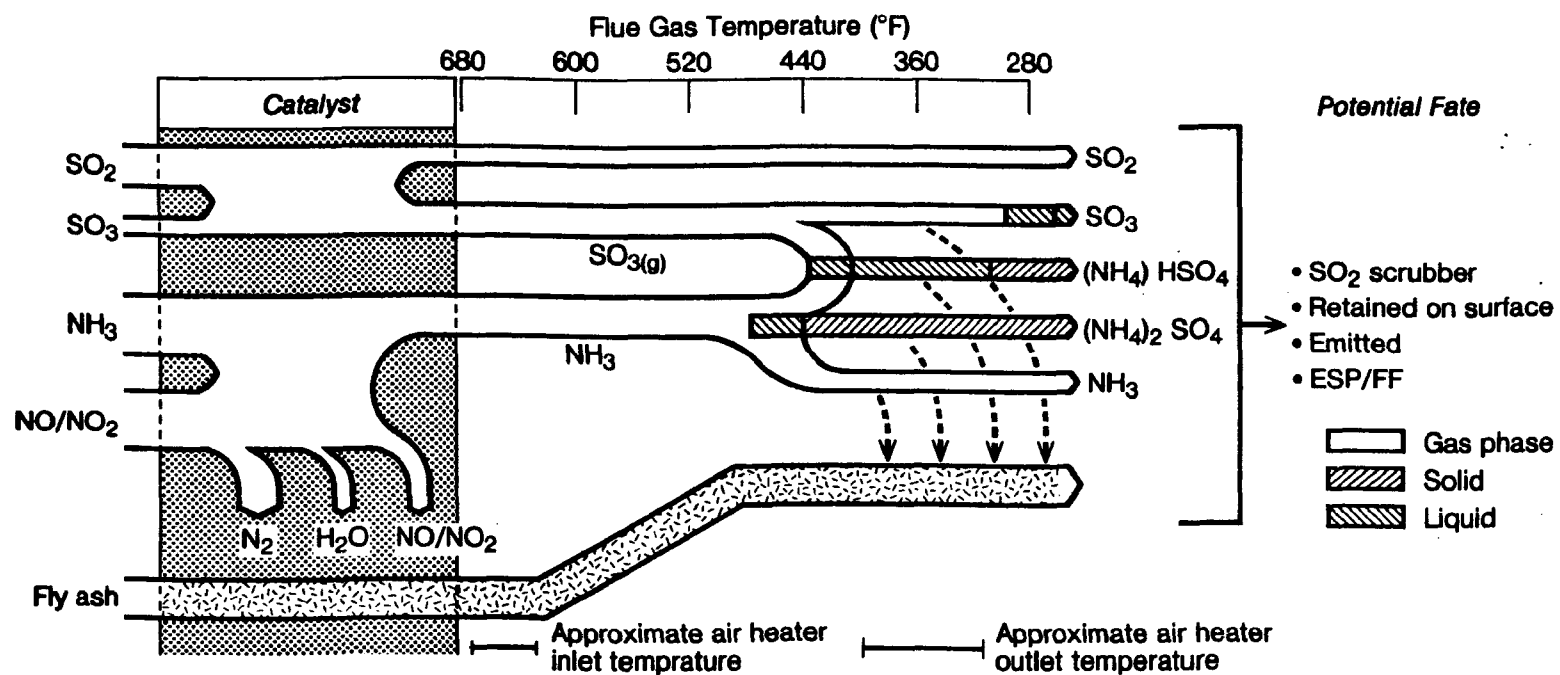
Figure 1. Fate of Major Nitrogen and Sulfur Species
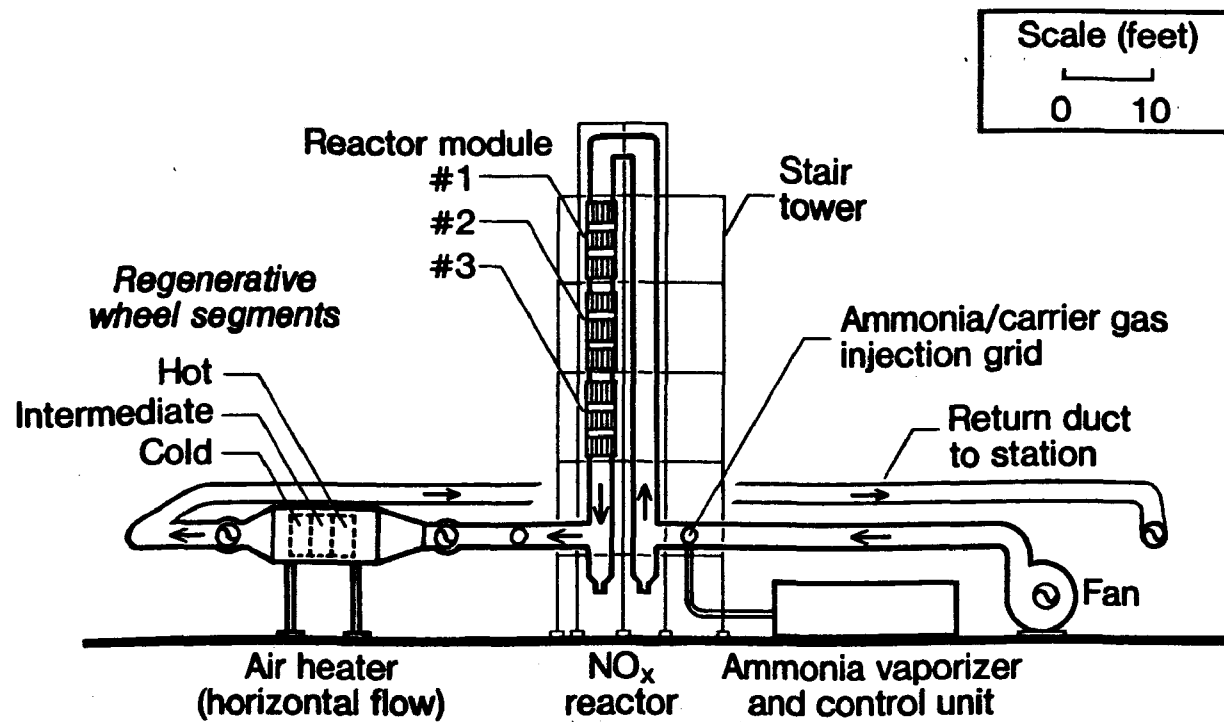
Figure 2. NO$_x$ Reactor and Air Heater
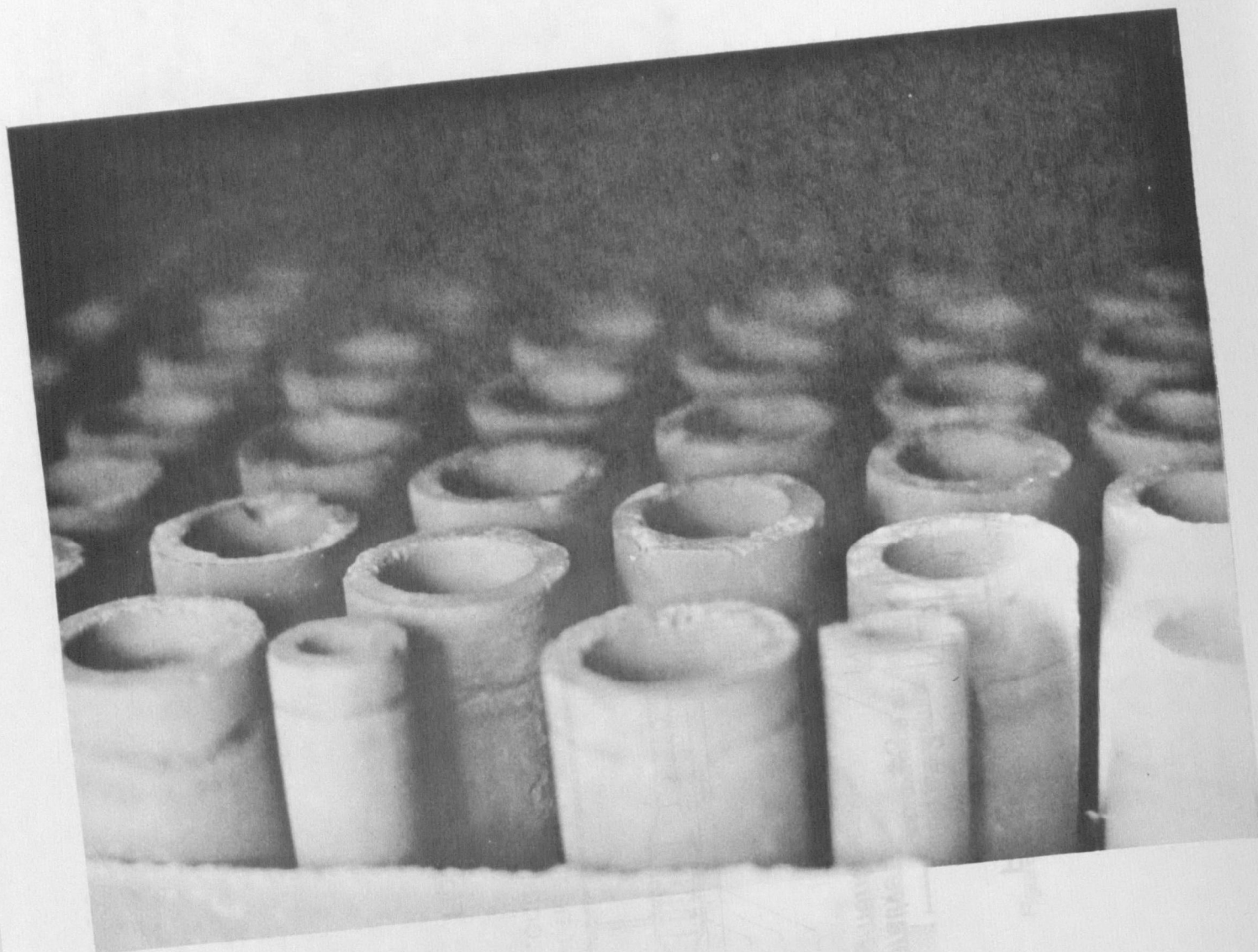
Figure 3. Cylindrical Shaped Catalyst

Figure 4. Continuous NH₃ Analyzer

2350 space velocity
$NH_3/NO_x \cong 0.95$

Reactor Temperature (°F)

520   560   600   640   680   720   760   800   840

NO_x removal (% inlet NO_x)   93 ⟶ 95

Residual NH_3 (% inlet NH_3) ⟵ 1.5 (1.5) ⟶

SO_3 oxidation (% inlet SO_2)   <1% (<2%) ⟶ 4%

Minimum continuous; catalyst ⟶
damage from deposited sulfates

Maximum continuous; ⟵
SO_3 formation excessive

Permanent deterioration ⟶
(minimum 12 hours)

Sintering ⟵
(maximum 1 hour)

Approximate economizer
outlet temperature ⟵⟶
(minimum load)   (full load)

Figure 5. Influence of Reactor Temperature on Operation and Performance

Gas Side Pressure Drop (in)

Sootblowing

Air
8-hour cycle
90–100 psig

With NH₃/SO₃
in flue gas

Without NH₃
in flue gas

Days of Continuous Operation

341
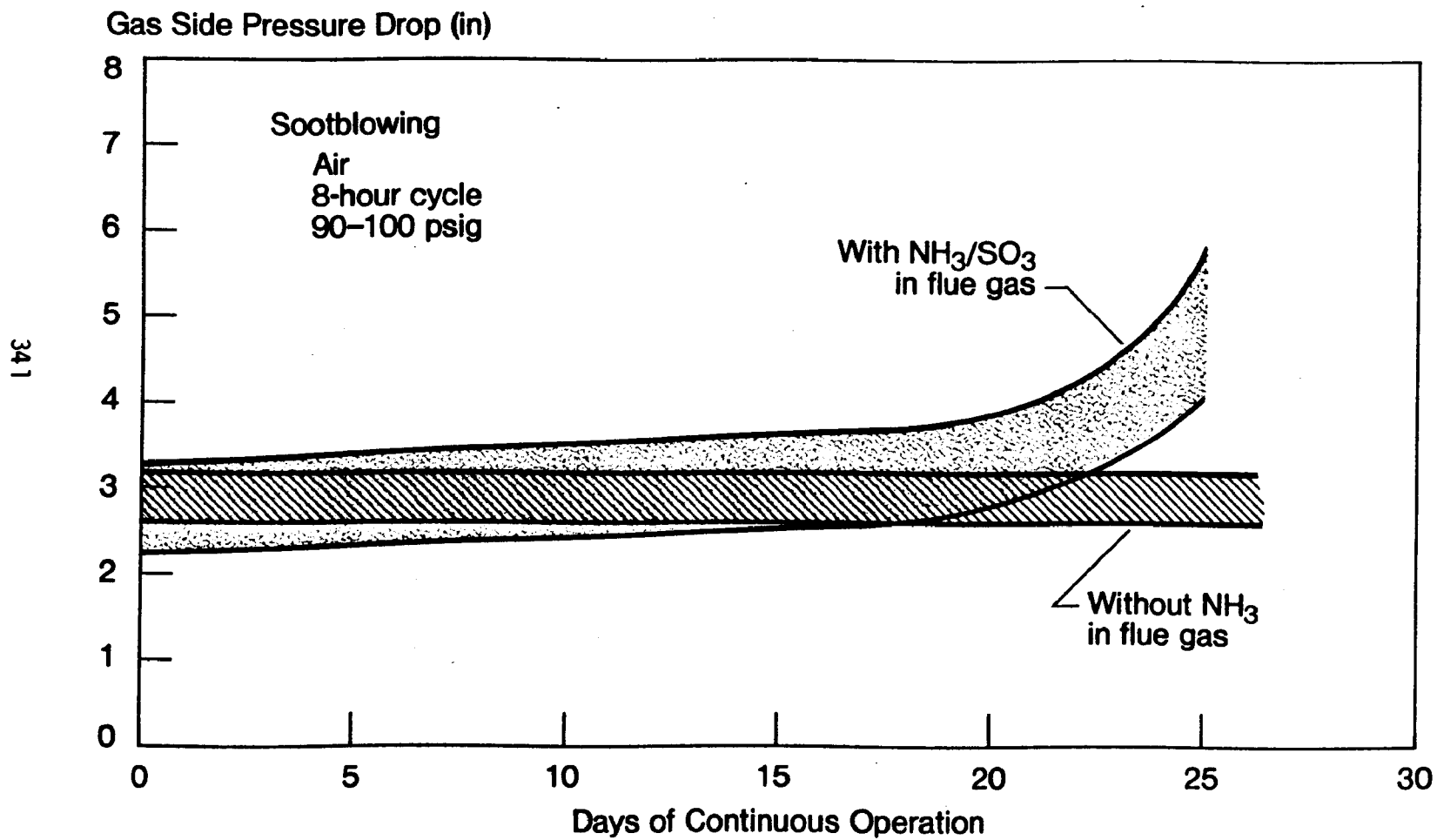
Figure 6. Influence of SO₃/NH₃ in Flue Gas on Air Heater Pressure Drop
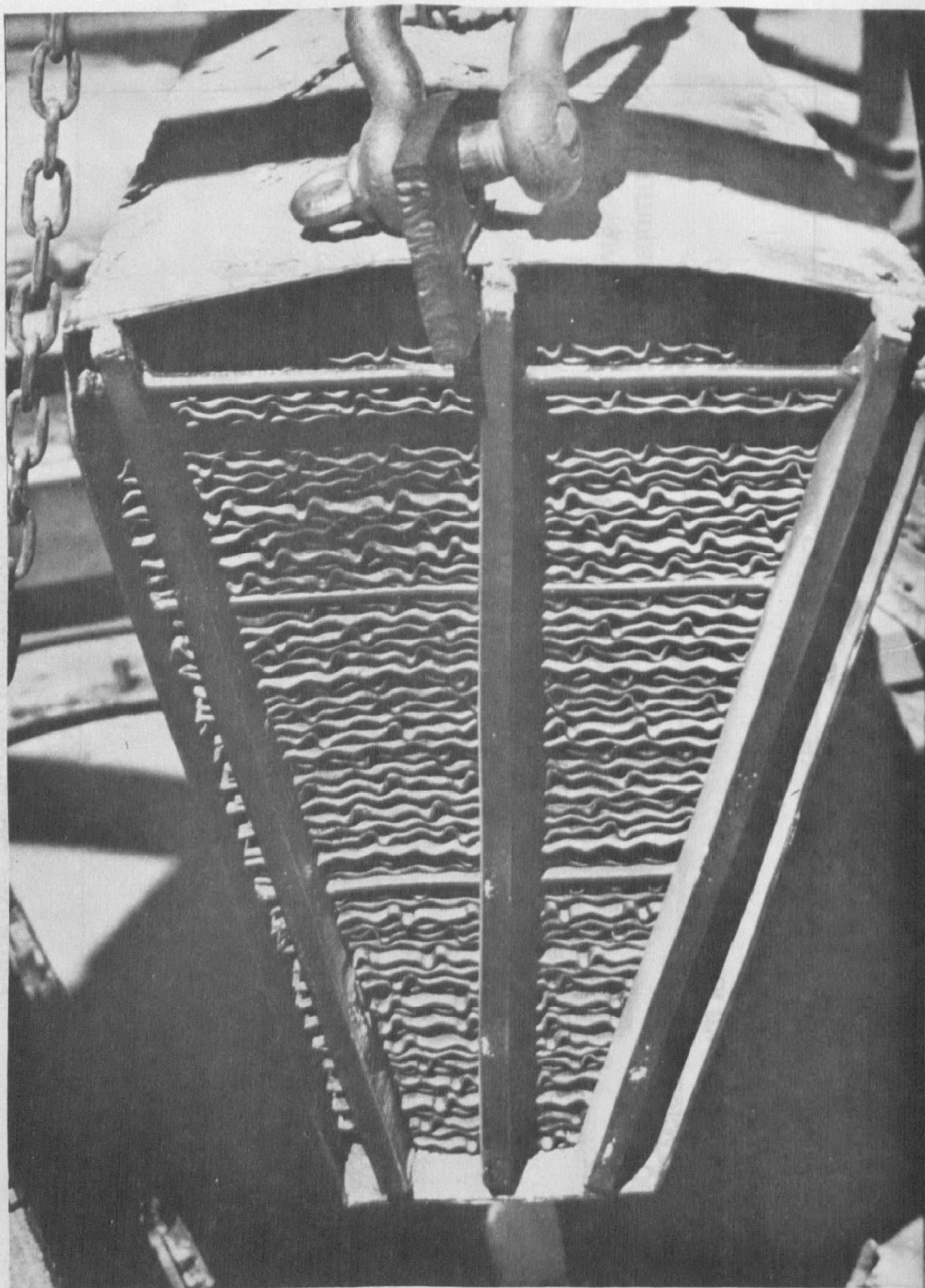
Figure 7. Regenerative Wheel Basket
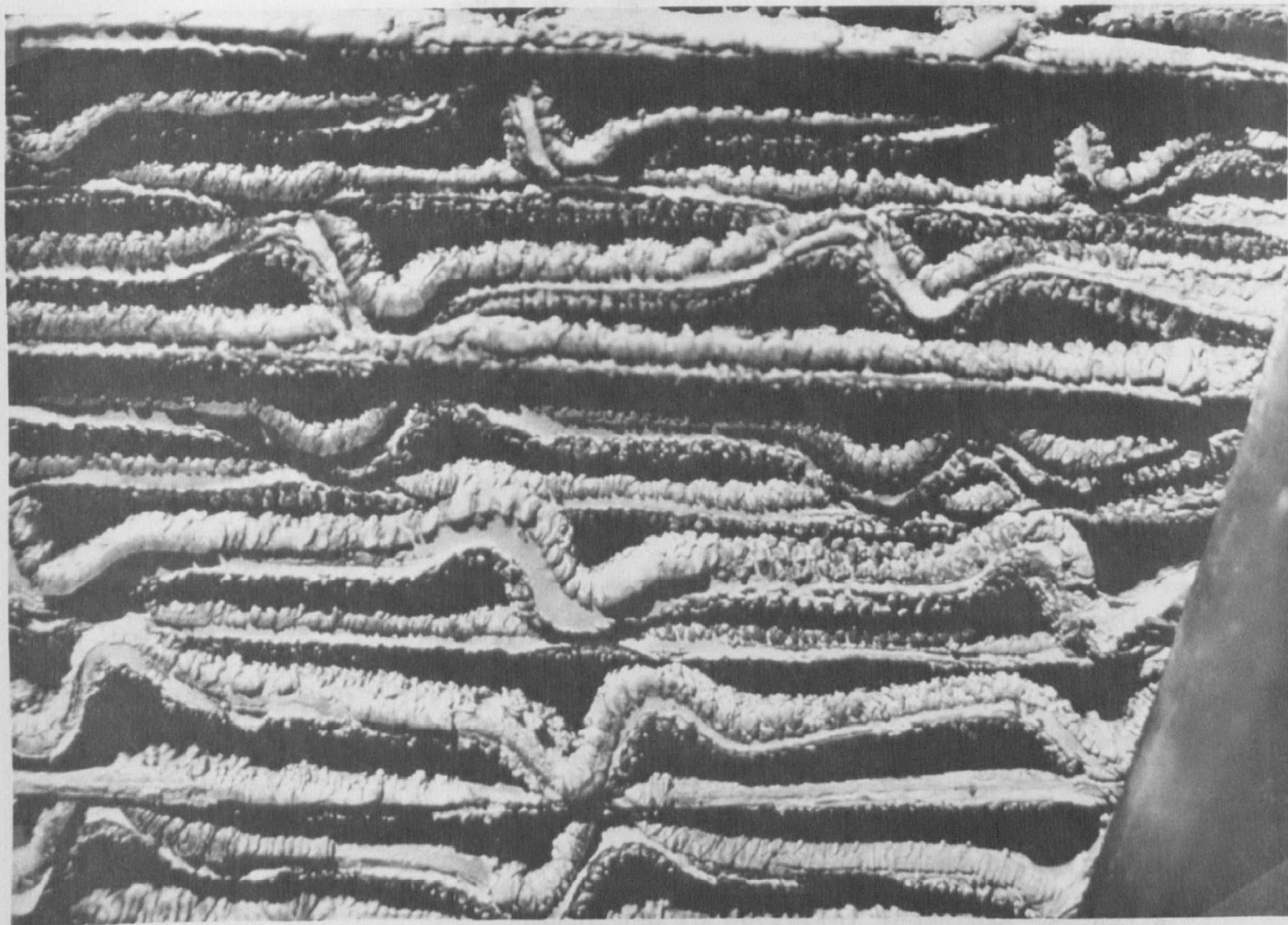
Figure 8. Deposit Accumulation on Regenerative Wheel Basket
(cold face of intermediate segment)

343

TABLE 1

MINIMUM IDENTIFIABLE COSTS OF KAWASAKI HEAVY INDUSTRIES SELECTIVE CATALYTIC REDUCTION PROCESS

*CAPITAL REQUIREMENT:	41 - 60 $/Kw
*LEVELIZED OPERATING COST:	4.0 - 5.9 mills/kwh

Study Basis

Design Premises

- 90% NO_x removal (300 ppm @ 5% O_2 initial NO_x)

- 500 MW (net), 548 (gross) generating capacity

- Midwest location

- Economizer bypass employed for low loads (40 - 60% Maximum Rated Capacity)

- Low-sulfur, sub-bituminous coal (typical of Powder River Basin in Wyoming, Montana)

Economic Premises

- 1979 dollars

- Escalation factor 6% per annum

- Capital equipment inflation 6% per annum

- Levelizing period 30 years

* from Reference No. 5, "NO_x Control for Western Coal-Fired Boilers-Feasibility of Selected Postcombustion Systems"

Table 2

SCR OPERATING ISSUES

Operating Issues To be Addressed	Information Required	Economic Implications for Plant Operations
1. Performance (de-nitrification efficiency)	• inlet/outlet NOx	• quantity of catalyst required for given NOx emission level
2. Process Operating Demands		
a. ammonia	• ammonia demand vs SCR operating parameters	• cost of continuous ammonia supply
b. heat rate penalty	• restrictions in flue gas exit temperature due to limitations in catalyst operating temperature • auxiliary power, additional flue gas pressure draft	• increased fuel cost
c. reactor sootblowing and waterwashing	• influence of sootblowing frequency on deposit accumulation	• capital and operating costs of sootblowing facilities; and effluent disposal
d. catalyst life	• change in catalyst activity	• catalyst replacement
3. Environmental Impacts		
a. SO_3	• oxidation of SO_2 to SO_3 across catalyst, preheater exit concentration	• cost of SO_3 removal and disposal
b. NH_3	• carryover or breakthrough of ammonia to reactor outlet; preheater exit concentration	• cost of NH_3 removal and disposal
c. ammonium sulfate and bisulfate	• preheater exit concentration • concentration in air heater waterwash effluent	• cost of ammonium sulfate and bisulfate removal, and disposal • capital and operating costs of waterwash effluent treatment

d. interference with particulate collectibility	• influence of NH_3/SO_3 and by-products on
	  - resistivity
	  - physical and chemical ash characteristics
		• capital cost of electrostatic precipitators
		  - specific collecting area
		  - ash hoppers
		• capital and operating cost of fabric filters
		  - air/cloth ratio
		  - cleaning cycle, pressure drop
		• ash disposal costs

e. N_2O, HCN emissions	• inlet/outlet N_2O and HCN concentration	• cost of N_2O and HCN removal
4. System-Wide Effects		
a. air heater sootblowing and waterwashing requirements	• degradation in thermal performance or pressure drop with deposit accumulation	• increased fuel costs (heat rate penalty) • capital and operating costs of sootblowing/waterwashing facilities
b. air heater operation and maintenance	• degradation in thermal performance or pressure drop with wheel basket corrosion/fouling	• increased capital and operating costs of corrosion/fouling resistant air heaters

TABLE 3

KAWASAKI HEAVY INDUSTRIES
SELECTIVE CATALYTIC REDUCTION
PROCESS-DESIGN CONDITIONS

- Flow capacity   5000 scfm (8000 Nm^3/hr)

- Catalyst quantity,space velocity 120.1 ft^3 (3.4 m^3), 2500 hr^{-1}

- Flue gas temperature $680^{\circ}F$ ($360^{\circ}C$)

- Fly ash loading 3.3 gr/scf ($7.5gm/Nm^3$)

- Flue gas composition

Specie	Volume Concentration
O_2	5%
NO_x	600 ppm
SO_x	350 ppm
CO_2	11%
H_2O	9%
CO	15%

- NO_x removal - 90% of inlet
  for design flue gas conditions

  - $NH_3/NO_x \leq 1$

  - NH_3 ≤ 10 ppm (prediction only, not guaranteed)

TABLE 4

LJUNGSTROM AIR HEATER DESIGN SPECIFICATIONS

Flue Gas

Mass in	23,000 lb/hr
Mass out	26,700 lb/hr
Temperature in	675°F
Temperature out	300°F
Pressure drop	3.2 in H_2O

Air

Mass in	19,850 lb/hr
Mass out	16,150 lb/hr
Temperature in	85°F
Temperature out	618°F'
Pressure drop	1.3 in H_2O

Controlling Parameter	Continuous On-Line Measurements and Processing Required	EPRI Experience to Date
NH_3/NO_x	1. Flue gas flow rate and temperature	
	2. NO_x concentration	Limited
	3. Ammonia mass flow	
NO_x removal	1, 2	None
Residual NH_3	4. NH_3 flue gas concentration	None
NH_3/NO_x, maximum limited by NH_3	1, 2, 3 and 4	None
NO_x removal, maximum limited by NH_3	1, 2, 3 and 4	None

Table 5. Ammonia Injection Control Schemes Under Evaluation

Table 6.

TASK DEFINITION

TASK	Primary Variables	Fixed Parameters and/ or Secondary Variables

3. Baseline Characterization	• SCR operating parameters
	  - NH_3/NO_x ratio
	  - NO_x
	  - O_2
	  - flue gas/catalyst temperatures
	• space velocity
		• fuel type
		• particulate characterization
		• minor gas species
		  - SO_2
		  - HC
		  - CO

4. Transient Mode Operation	• control system logic
	• excursions in process gas
	  - flowrate
	  - temperature
	  - composition
		• fuel type
		• particulate characteristics
		• minor gas species

5. Influence of Minor Species	• SO_2 • CO • HC	• particulate characteristics • fuel type • SCR operating parameters
6. Influence of Particulates	• particulate mass loading • particulate size distribution • sootblowing schedule (accumulated solids)	• minor gas species • SCR operating parameters
7. Catalyst Activity	• erosion, aging of catalyst (hours of operation)	• particulate characteristics • minor gas species • SCR operating parameters

8. Air heater performance	• air heater operating parameters
	
	  - pressure differential
	  - wheel speed
	  - inlet temperature
	  - flue gas/combustion air flowrate
	  - sootblowing frequency
		• particulate characteristics
		• sootblowing: medium and momentum

DEVELOPMENT OF FLUE GAS TREATMENT IN JAPAN

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350

ABSTRACT

The Electric Power Development Co., Ltd. (EPDC) has been executing a research and development program on selective catalytic reduction (SCR) systems through joint research with the equipment manufacturers since 1975.

As a result of this R&D program, EPDC believes there is a strong prospect for commercialization of the Low Dust SCR System (LDSS) for coal-fired power plants. At present, EPDC is constructing demonstration test equipment for such a system at the Takehara Thermal Power Station No. 1 Unit (250 MW coal-fired) and plans to construct full scale commercial SCR equipment at the Takehara Thermal Station No. 3 Unit (700 MW coal-fired).

Alternatively, the High Dust SCR System (HDSS) is also a candidate for commercialization, requiring only the establishment of NH_3 removal technology for ash collected by a cold-side electrostatic precipitator.

This report describes the results of the R&D program executed by EPDC concerning the SCR and air preheater problems, overall flue gas treatment technology for coal-fired boilers, and the outline of Takehara's SCR Systems.

Section 1
INTRODUCTION

The oil shortage which gripped the world in the fall of 1973 triggered a series of oil supply uncertainties in the years that followed, emphasizing the importance of renewed efforts to increase the utilization of coal.

Coal-fired thermal power generation will be the major focus of this shifted emphasis to coal. A coal-fired thermal power plant, however, must be well controlled in order to satisfy all environmental protection requirements. Otherwise, the utility may encounter resistance from governmental agencies or local residents, resulting in failure to obtain a site.

A thermal power plant using coal as fuel, compared to one using other fossil fuels, emits larger quantities of dust (particulates), SO_x, and NO_x from its boiler, necessitating special measures to hold down these emissions. Such controls include auxiliary equipment for dust collection, desulfurization and denitration, including combustion modifications.

Electric Power Development Co. (EPDC), in cooperation with certain Japanese manufacturers, has been conducting research and development on technologies for the control of emissions from thermal coal-fired power generation plants. Currently, assured of successful commercialization of boiler denitration technology, EPDC is installing SCR demonstration equipment on a coal-fired thermal power plant. In addition, EPDC has just started construction of a 700 MW coal-fired thermal power plant featuring similar SCR equipment.

In this paper, we introduce several problems encountered in placing denitration equipment in commercial operation together with remedial measures, as well as details about denitration performance, ammonia injection control, and other parameters. Also, we will outline our progress in the development of emission control technologies for other emission from a coal-fired thermal power plant.

Section 2

GENERAL DESCRIPTION

INSTALLATION OF SCR EQUIPMENT FOR ELECTRIC POWER UTILITIES IN JAPAN

Table 1 shows a list of Selective Catalytic Reduction (SCR) equipment
installed or in the planning stage by Japanese electric power utilities.
Of the plant sites shown in the table, two are operating with SCR equip-
ment for coal-fired power generation, and another two are being installed
with similar equipment. Of the coal-fired power generation plants listed
in the table, the Tomatoazuma Power Plant of the Hokkaido Electric
Power Co., Inc. is provided with SCR equipment designed on a 1/4-scale
capacity; the Shimonoseki Power Plant of the Chugoku Electric Power Co.,
Inc. with equipment designed for full capacity.

EPDC has been commissioned by the government to construct SCR equip-
ment designed for the full capacity of the No. 1 boiler (250 MW) of the
Takehara Thermal Power Plant. This demonstration SCR equipment is
designed to operate at 80 percent or more NO_x removal. In addition,
EPDC plans to provide the recently constructed No. 3 thermal power
generation boiler (700 MW) with similar SCR equipment designed to
operate at 80 percent or more NO_x removal. These plans should be
considered representative of future programs for construction of coal-
fired thermal power generation plants.

EVALUATION OF DENITRATION PROCESS

Studies of the denitration process directed to coal-fired thermal
systems have evaluated the following:

- economic efficiency

- performance

354

o   reliability

o   secondary environmental emissions

o   retrofit capability

Japanese NO_x regulations are stringent; thus it was important that the $DeNO_x$ Process be quickly evaluated, and brought to commercialization in a short period of time. As a result of a comprehensive analysis, EPDC concluded that selective catalytic reduction (SCR) using ammonia was the most suitable process for near-term application.

The comparison of results between SCR and selective non-catalytic reduction (SNR), including the practical use of wet $DeSO_x$, is shown in Table II.

CATALYST COMPARISON BY TYPES OF FUEL

Research and development of the SCR process for oil-fired boilers has been executed since 1973, and for coal-fired boilers since 1975. Process development for power plants has focused on the development of a suitable catalyst. Coal combustion results in large quantities of dust and SO_x becoming entrained in the flue gas, thus, catalyst development for coal combustion has special problems such as deterioration and plugging. Table III shows catalyst features for different types of fuel.

DEVELOPMENT OF SCR FOR COAL-FIRED BOILERS

It is not possible to apply the results of SCR development from LNG and oil-fired boilers to coal-fired boilers because of differences in flue gas components; thus there is a need to assess the practicality of several catalysts for coal-fired boilers.

Among power utilities in Japan, EPDC, Tokyo Electric Power Company (TEPCO), and Hokkaido Electric Power Company (HEPCO), have individually tested the SCR process through pilot tests at their own power plants. Table IV shows the outline of the pilot tests.

Section 3

DEVELOPMENT OF AN SCR SYSTEM

EPDC, in developing the SCR system has identified the following needs:

- catalyst life must be greater than one year
- the system must be appplicable to both high and low dust loading
- continuous measuring instruments for leak ammonia and counter-measures for leak ammonia influence on downstream equipment are required.
- recycle or reutilization of spent catalyst

DEVELOPMENT OF CATALYST LIFE OVER ONE YEAR

For practical use of SCR, the following targets must be satisfied during the one year of pilot tests:

- maintaining more than 80% efficiency

- leak ammonia should be less than 5 ppm

The following discussion details how these targets have been met by the 5 joint researchers of EPDC.

Catalysts with 2 years of life have been promised by the manufacturers, although no experiments have yet been performed testing catalysts continously for over 2 years. The catalyst cost is relatively high, comprising 40-60% of the total SCR equipment cost. Whether catalyst life is 1 or 2 years will be a significant influence on electricity cost; therefore, it is important to develop long life catalysts. At this time no assessment of catalyst life is possible as pilot tests of sufficient duration have not been conducted. However, the following catalyst performance test results suggest extended life is probable:

- Performance decreased slightly from initial values but stabilized after 500 - 3000 hours.

- Significant performance drop was observed using catalysts without treatment for SO_x poisoning; treated catalysts performed slightly better.

Catalyst performance drop is thought to be caused by the following:

(a) plugging of catalyst pores by NH_3/SO_3 compounds

(b) plugging of catalyst layer and catalyst pores by dust

(c) catalyst erosion by dust

(d) permanent posion by fluorine, chlorine and calcium

Our experience from pilot and laboratory tests indicates neither significant plugging of the catalyst layer and pores nor dust erosion. Thus, poisoning by calcium or similar elements is suggested, making it necessary to check the fuel calcium content before applying SCR to power plants.

Catalyst damage caused by temperature variation associated with daily load changes or start-up and shut-down is of concern and also will have to be evaluated through long term testing.

SCR SYSTEM

Two systems for SCR have been developed, a Low Dust SCR System (LDSS), which removes NO_x after removing dust (by a hot-side electrostatic precipitator), and a High Dust SCR System (HDSS), which removes NO_x before removing dust (by a cold-side electrostatic precipitator). These systems are shown in Figure 1.

Low Dust System vs. High Dust System

The low dust and high dust SCR systems each have their own merit and demerits. For comparison of these systems, it is necessary to examine not only the SCR equipment, but also the entire coal-fired thermal power generation system, in accordance with Table V.

Before details about the results of these studies are discussed, it must be pointed out that the choice between HDSS and LDSS, aside from the technical details involved, depends on a combination of several factors, such as environmental goals, relevant regulatory standards, and the goals of individual electric power corporations. Under these circumstances, it is yet to be determined which of these two systems will be adopted in Japan.

Overall Thermal Power Plant System

The following lists several problems characteristic of LDSS and HDSS SCR equipment:

- Compared with HDSS, LSDD offers a greater potential for the air-preheater being blocked, necessitating the conventional type air preheater to be replaced with a special one intended for SCR.

- The LDSS, in which a precipitator (hot side) is installed upstream of SCR, will not contaminate collected ash with NH_3; the HDSS, in which a precipitator (cold-side) is installed downstream of SCR, will collect NH_3 ash contaminated.

To use NH_3 contaminated ash as landfill material could require certain countermeasures, depending on the quantity of NH_3 entrained and the specific diposal circumstances.

The Table VI shows the results of examination with reference to other items.

Precipitator

A major problem associated with the HDSS system concerns the possibility of leak ammonia mingling with fly ash, leading to a possible decline in quality of the fly ash. It seems technically possible to minimize the leak ammonia to the low levels of 5 ppm or less, which, in our opinion, will not cause any deterioration in fly ash quality.

SCR Equipment

Table VII shows the results of comparing the HDSS and LDSS. Of particular interest is the fact that both these systems are free from the problem of the catalyst layer being blocked, provided special consideration is given to the catalyst shape and the gas flow speed. LDSS also appears more tolerant to surface masking by fine particulates than the HDSS. The latter phenomenon was witnessed using a scanning electron microscope to examine the catalyst surfaces. Thus, LDSS requires the installation of a soot blower.

However, EPDC, in cooperation with certain Japaneses manufacturing firms, has developed a catalyst capable of maintaining a specified NO_x removal capacity for a period of one year without a soot blower. Thus, EPDC presently has no intention of using a soot blower at this time.

Desulfurization Equipment

Another problem characteristic to SCR lies in the possibility of the ammonia entering the desulfurization system and becoming concentrated in the rejected solid waste. In such a case, it is necessary to install additional NH_3 removal equipment for the LDSS system. However, the HDSS allows the leak ammonia to be almost fully adsorbed by the fly ash and removed through the cold-side ESP, thus eliminating the need to install equipment for significant removal of NH_3.

The Table IX shows the results of comparing LDSS and HDSS.

LEAK NH_3 FROM SCR EQUIPMENT - POTENTIAL IMPACTS AND COUNTERMEASURES

The following discussion is directed to the problems attributable to leak NH_3 from SCR equipment. EPDC has been executing R&D programs to establish countermeasures for:

- Concentration of ammonia in Wet $DeSO_x$ (HDSS and LDSS).

- Plugging of the air preheater (HDSS and LDSS).

- Fly ash contaminated with NH_3 and collected by electrostatic precipitators (Refer to Figure 2).

EPDC has executed R&D programs in cooperation with Japanese manufacturers for removing NH_3 and N concentrated in Wet $DeSO_x$ System. This R&D was successful, resulting in total waste water nitrogen (N) less than 10 ppm.

Presently, EPDC is constructing N and NH_3 removal processes for the SCR demonstration test equipment at Takehara power station No. 1 unit. Specifications of the process are as follows:

- Capacity   1,000 m^3/day

- Quantity of NH_4+ 198 Kg-N/day

- Total N at Outlet   10 ppm and below

Plugging and Corrosion of the Air Preheater

Plugging and corrosion of air preheaters has been addressed since the initial phases of SCR development. EPDC has been executing R&D programs for this problem in cooperation with air preheater manufacturers, using Ljungstrom or Rothemulle pilot test equipment. To date, results have been obtained on the Ljungstrom equipment. For the HDSS case, plugging was not observed, because of the self cleaning and scouring action of the dust. For the LDSS case, this scouring action does not exist; thus some countermeasures to plugging are necessary. Countermeasures investigated shown in Table XII.

Plugging tendencies of air preheaters with the LDSS system were confirmed in 1976. Work since then has not identified the plugging problems even after one year of testing. Additional tests to define countermeasures for LDSS air preheater plugging and the effects of such countermeasures have been conducted and the results are shown in Figure 5.

Major countermeasures being evaluated for plugging include:

- Pressure, steam quantity and time of soot blowing,
  and improvement of the soot blower design

- Change from DF to NF type of inter-element, and a
  one piece element for intermediate and cold segments.

The air preheater for LDSS applications is larger than that for HDSS and therefore less economical. Future plans call for continued development of a new soot-blower, with pilot tests in near future. For the Rothemulle air preheater, detailed results are described in IHI's paper in this symposium proceedings.

REGENERATION OF THE CATALYST

EPDC has been executing an R&D project in cooperation with Kawasaki Heavy Industries concerning regeneration of spent catalyst. The objective is to imporve catalyst utilization and thus the economics of the SCR system. Four methods of regeneration have been evaluated, based on (1) steam heating, (2) purging with high temperature flue gas, (3) water cleaning, and (4) water cleaning using sonic impulses. Each of these methods was applied to catalysts forced to deteriorate in pilot test plants. The results have confirmed that reactivation of the deteriorated catalyst to the initial performance level is possible.

Tests are currently being conducted with the reactivated catalyst in the pilot plant, and no deterioration of catalyst performance has been observed after 3,000 hours.

SCR PERFORMANCE

EPDC has specified 80% NO_x removal as design conditions for performance. However, we are targeting for levels as high as 90% and above while simultaneously maintaining a maximum of 5 ppm leak NH_3 by employing changes in catalyst volume and NH_3/NO_x ratio. An increase in NO_x removal efficiency from 80% to 90% under these conditions requires an increase in catalyst volume of 30-50%. Thus, high removal efficiencies require greater capital expenditure, and necessitate higher draft loses, and higher SO_2 to SO_3, conversion rates. This trend is exhibited in Figure 6 which shows the relationship between space velocity (SV) and NO_x removal efficiency. These data indicate that the increase in catalyst volume, required from to move from 80% removal (.8 NH_3/NO_x) to 90% removal (.9 NH_3/NO_x) is approximately 50% (5,400 + 3,800 h $^{-1}$).

A systemwide analysis of SCR operation at 80% removal efficiency will
be conducted on the demonstration test equipment of Takahara Unit No. 1.
Depending on these results, a similar analysis of systemwide operation at
90% removal efficiency may be conducted.

DEVELOPMENT OF A CONTINUOUS NH3 ANALYZER

Continuous analysis of NH_3 in flue gas is required to (a) precisely
measure the concentration of injected NH_3, and (b) monitor residual NH_3
to indicate the potential for air heater problems and upsets in SCR operation.
Continuous analysis for NH_3 on both a conductivity and infrared gas basis
has been explored. However, these methods appear to be unfavorable for use
as process-monitoring devices due to unacceptable response time, limits
of detection, and stability.

Recently, a method employing the conversion of NH_3 to NO was developed.
This method infers the NH_3 concentration by measuring the difference in the
sample before and after converison of NH_3 to NO. Difficulties with this
technique include (1) a large measurement error due to high background NO
levels, and (2) short lifetimes of the NH_3 to NO converter. '

Conditions are most favorable for this method when the gas sample line
length is relatively short. Otherwise, ammonia is adsorbed in the inner
surface of the sampling line at low temperature, or lost by the chemical
reaction between NH_3 and SO_3. For coal-fired flue gas, this approach appears
capable of NH_3 measurement with dust in the sample gas while requiring
acceptable levels of maintenance.

EPDC has also evaluated a continuous NH_3 analyzer developed by Anritsu
Electric Co., Ltd. based on the self-modulated derivative spectrometry of
the ultraviolet absorption of NH_3 molecules. The NH_3 analyzer has been used
since 1977 in SCR tests executed by EPDC and the Hitachi Shipbuilding and
Engineering Co., Ltd. (HZ).

The principle of this NH_3 analyzer is based on the following:

1. Ammonia molecules have a periodic absorption spectrum (shown in Figure 7)

2. The light transmitted into the ammonia gas also has a periodic spectrum (shown in Figure 8a).

3. The wavelength is modulated around the intensity minimum (Figure 8b).

4. Intensity-Modulated Light Single (IMLS) is obtained (Figure 8c) and the amplitude of IMLS is proportional to the depth of the intensity minimum (the depth is proportional to the concentration of NH_3).

5. The concentration of NH_3 can be measured by the amplitude of IMLS.

A good correlation (correlation coefficient (q) of 0.997) is obtained between the analytical values obtained by the NH_3 analyzer and those by the standard method (indophenol). The scattering deviation for coal-fired flue gas observed by the standard method (s = 10.2 ppm) is larger than the value obtained by the NH_3 analyzer (s = 2.9 ppm). The results obtained by using the NH_3 analyzer for coal-fired flue gas are shown in Figure 9.

Interference from SO_2 is shown in Figure 10. By subtraction of the interference signal, good correspondence has been obtained between the analytical values using the standard method and those obtained by the NH_3 analyzer.

To prove the reliability of the NH_3 analyzer, the device will be used in the demonstration test at Takehara No. 1 unit.

Future study of the NH_3 analyzer will concern:

1. The reliability of the measured value at low concentrations (such as 1 or 2 ppm).

2. Interference from SO_2 concentrations over 1,000 ppm compensated by employing an automatic calculation method.

3. Locating the NH_3 analyzer near the sample probe.

Section 4

DEVELOPMENT STATUS FOR FLUE GAS TREATMENT TECHNOLOGY
AND LOW POLLUTION COAL-FIRED POWER STATIONS

COMMERCIALIZATION CLASSIFICATION AND DEVELOPMENT STAGE OF FLUE GAS TREATMENT
TECHNOLOGY FOR COAL-FIRED BOILERS IN JAPAN.

EPDC has been executing R&D programs on flue gas treatment technology
concerning emissions of dust, SO_x, and NO_x from coal-fired boilers. As
a result there are numerous processes (specified in Table XIII) both under
development and in the commercialization stage for application in Japan.
The current status of development and/or commercialization is show in Table XIV.

MODEL OF A LOW POLLUTION COAL-FIRED POWER STATION

Numerous combinations of flue gas treatment systems are possible for
the control of dust, SO_x, and NO_x from coal-fired power stations. Models
of three combinations are shown in Figure 11, and are anticipated to meet
target emission levels similar to that from oil-fired power stations (i.e.,
60 ppm NO_x, 50 ppm SO_x, and 10 mg/Nm3 dust). Detailed specifications of
these three models are presented in Table XV.

Among the three cases for SO2 removal, the Dry $DeSO_x$ System (Case 3)
is quite attractive to EPDC in terms of simplicity, economy, performance,
and reliability. Thus, EPDC is highly interested in R&D for Dry $DeSO_x$
and it is a key project of Case 3. EPDC is planning to perform a demonstra-
tion test at the EPDC Matsushima Power Station (500 MW coal).

TREND OF EPDC'S R&D PROGRAM IN THE FUTURE

R&D on NO_x and SO_x is scheduled to be virtually complete by March
1981. However, dust emission control in Japan may be tightened, thus
altering this schedule. Accordingly, dust collecting technologies such as
bag houses and high performance ESPs with particle charging system are
drawing attention.

364

EPDC has been promoting R&D of emission control technology for modern coal-fired power plants necessary to meet social needs. Establishing such technologies has received formost attention. In the near future, R&D will be directed to optimizing such processes for economy, reliability, and performance.

Section 5

DEMONSTRATION TEST AND COMMERCIALIZATION PLAN

After assessing the commercialization potential through pilot-scale development efforts, a demonstration test to identify commercial capabilities is needed. The Japanese government is sponsoring demonstration tests conducted by EPDC to achieve this end.

THE DEMONSTRATION DeNO$_x$ TEST OF TAKEHARA POWER STATION NO. 1 UNIT

EPDC's demonstration DeNO$_x$ plant sponsored by the Japanese government and initiated in 1978, is now under construction. Construction is 20% complete, and testing will be initiated in July 1981.

The concept of the Takehara No. 1 unit demonstration test is shown in Table XVI.

NH$_3$ Injection and Its Control

As the NH$_3$ injection system of the SCR demonstration equipment at Takehara No. 1 unit shows (Figure 12), NH$_3$ is mixed and diluted with air in the dilution mixing chamber and injected before the SCR. To keep the NH$_3$ concentration constant, the NH$_3$ injection system is designed as follows:

- Sufficient distance is maintained between the NH$_3$ injection point and the SCR unit to mix NH$_3$ adequately.

- Uniform velocity distribution is maintained by means of guide vane installation at duct bends, or installation of a gas adjustment grid upstream from the NH$_3$ injection point.

- A constant mixing ratio between NH$_3$ and dilution air is maintained or the diameter of the NH$_3$ injector nozzle can be optimized to keep this dilution concentration and dilution gas speed constant.

Control of the NH$_3$ feed rate is accomplished by injecting NH$_3$ at a constant ratio to the NO$_x$ quantity in the flue gas. An input control defines the set value for NH$_3$/NO$_x$ ratio. NO$_x$ concerntration at reactor outlet is monitored with the NH$_3$ feed rate controlled by feed-back signals from the reactor outlet NO$_x$ concentration. Figure 13 shows the control system for NH$_3$ injection.

366

TAKEHARA NO. 3 UNIT PLAN

Takehara No. 3 unit initiated construction in May 1980. Commercial operation will begin in March 1983. The Takehara No. 3 unit flow system (LDSS) is shown in Figure 14, with the layout in Figure 15. This facility will be largest coal-fired power plant in Japan. Levels of NO_x, SO_x, and dust anticipated to be emitted are shown on Table XXII and, as can be seen, are extremely low.

DRY DeSO$_x$ DEMONSTRATION TEST

EPDC is planning to install dry DeSO$_x$ demonstration test equipment at the Matsushima Power Station (700 MW coal) in April 1983. This demonstration test is funded by the Japanese Government. EPDC had designated Sumimoto Heavy Industries (SHI) to build the dry DeSO$_x$ system since EPDC has been executing an R&D project on dry DeSO$_x$ in cooperation with SHI.

Table XVIII shows the schedule and Table XIX shows outline of this demonstration.

REFERENCES

1. Y. Nakabayashi, Status of R&D on NO_x removal in Japan and results of EPDC's R&D for DeNO$_x$ Process.

   Second EPRI NO_x Control Technology Seminar, Denver Colorado, Nov. 1978.

2. T. Kimura, Y. Nakabayashi, K. Mouri, Overall Flue Gas Treatment Technology from Coal Fired Power Plant in Japan, ICCR 5th Conference Dusseldorf, Sept. 1980.

Figure 1

High Dust Denitration System (HDDS) and Low Dust Denitration System (LDDS)

[1] HDDS

Boiler — SCR — Air Preheater — C-ESP — GGH — Wet FGD — To Stack

[2] LDDS

Boiler — H-ESP — SCR — Air Preheater — Wet FGD — To Stack
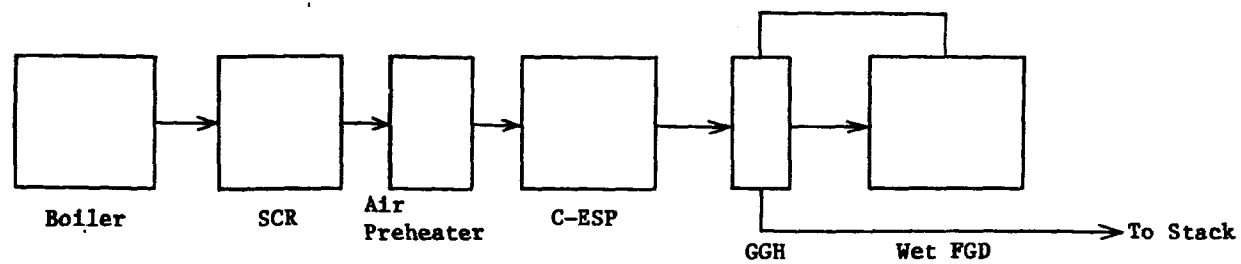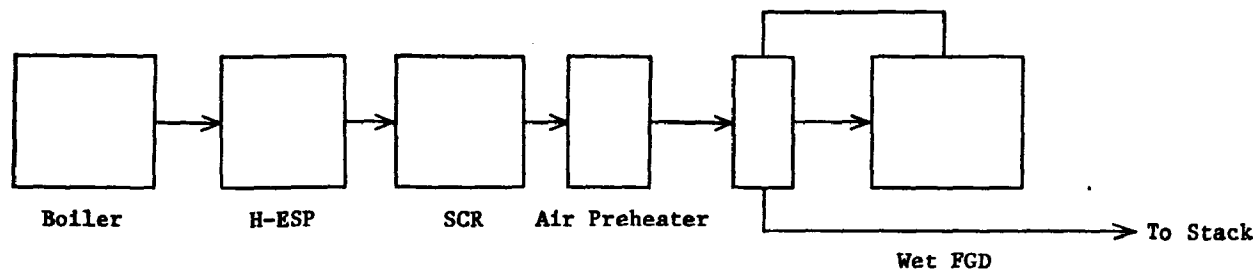
Figure 2

Problems Depend on Leakage NH_3 from SCR Process
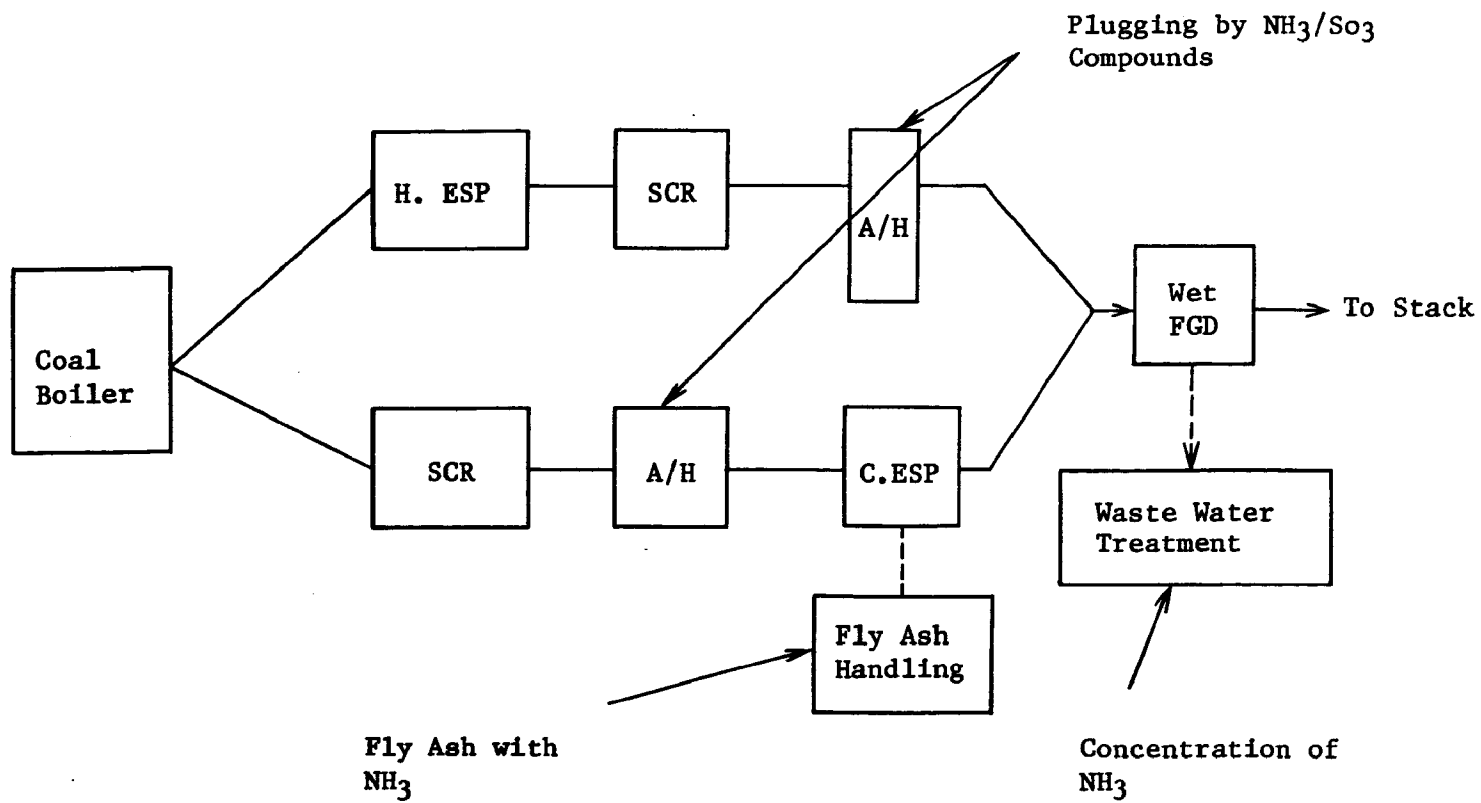
Figure 3

Biological Nitrogen Removal Method
in Waste Water from De-SOx Process

Simple Sludge Type

Organic Carbon Source
(Living Energy
 Increasing Energy

pH Control

Increase of
(BOD Oxidation Germ
 Nitration Germ

Increase of Nitrogen
Removal Germ
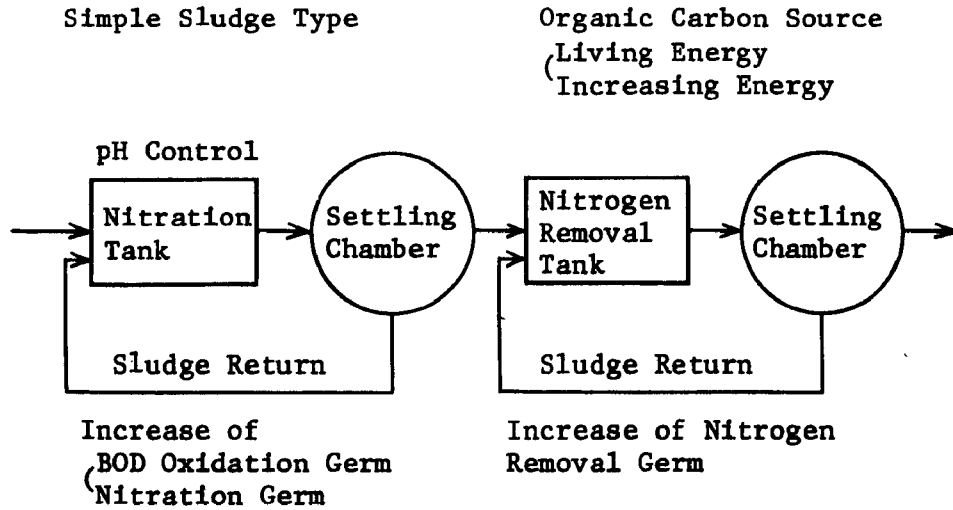
Figure 4

Experiment Flow Diagram of Air Preheater for Denitration Process

370
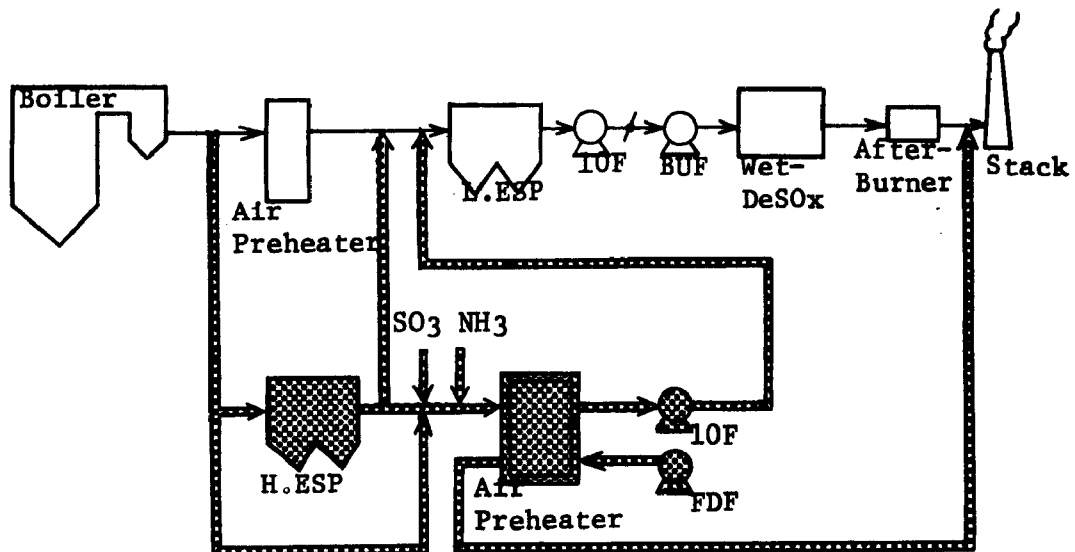
Figure 5

Draft Loss Trend of Test Air Preheater and Conditions (Ljungstrom Test)
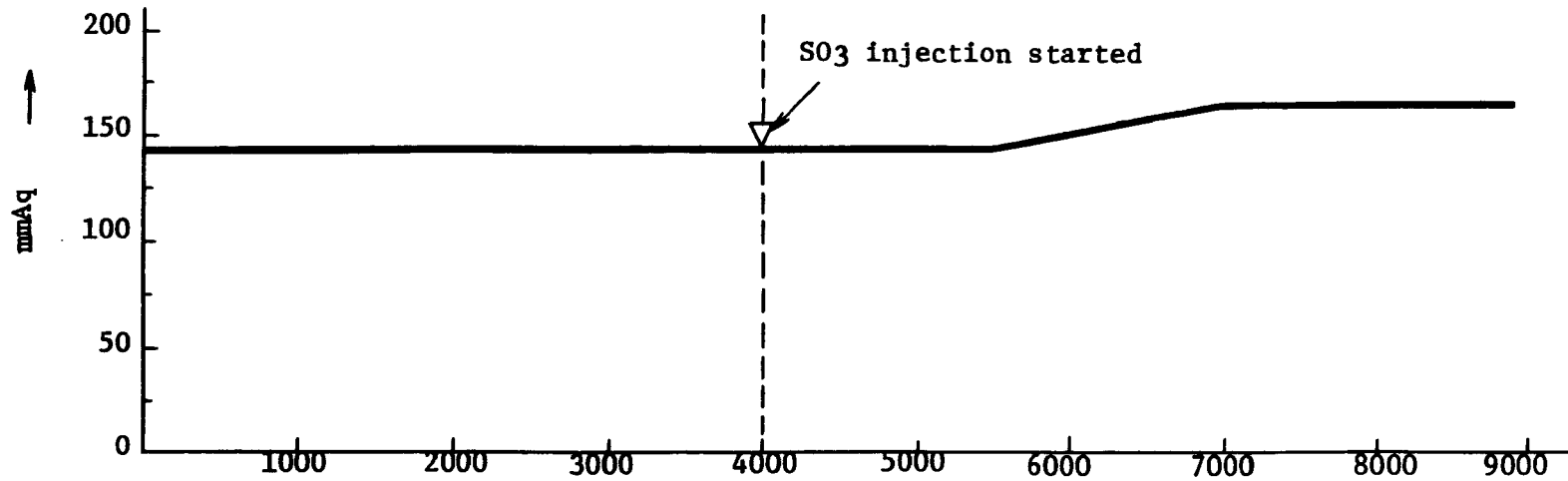
Gas Condition

SO$_2$	1200 - 1300 ppm	SO$_2$	1200 - 1300 ppm
SO$_3$	3 - 5 ppm	SO$_3$	20 ppm
Dust	0.1 - 0.2 g/Nm$_3$	Dust	0.1 - 0.2 g/Nm$_3$
NH$_3$	10 ppm	NH$_3$	10 ppm
Gas Temp of AH inlet	325–337°C	Gas Temp of AH inlet	325–337°C
Gas Temp of AH outlet	145–165°C	Gas Temp of AH outlet	145–165°C

Figure 6

One Sample of

SV vs Nox Curves
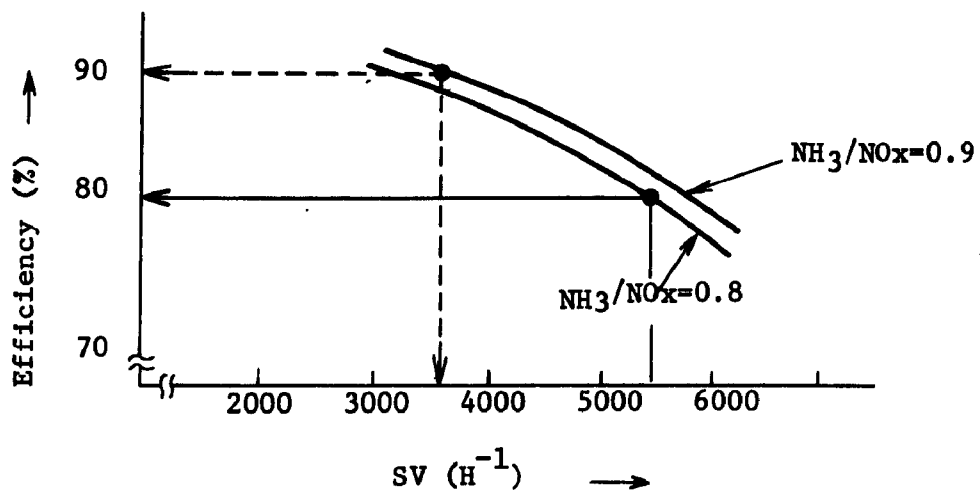
Figure 7

Absorption Spectrum of Ammonia

Wavelength (mm)
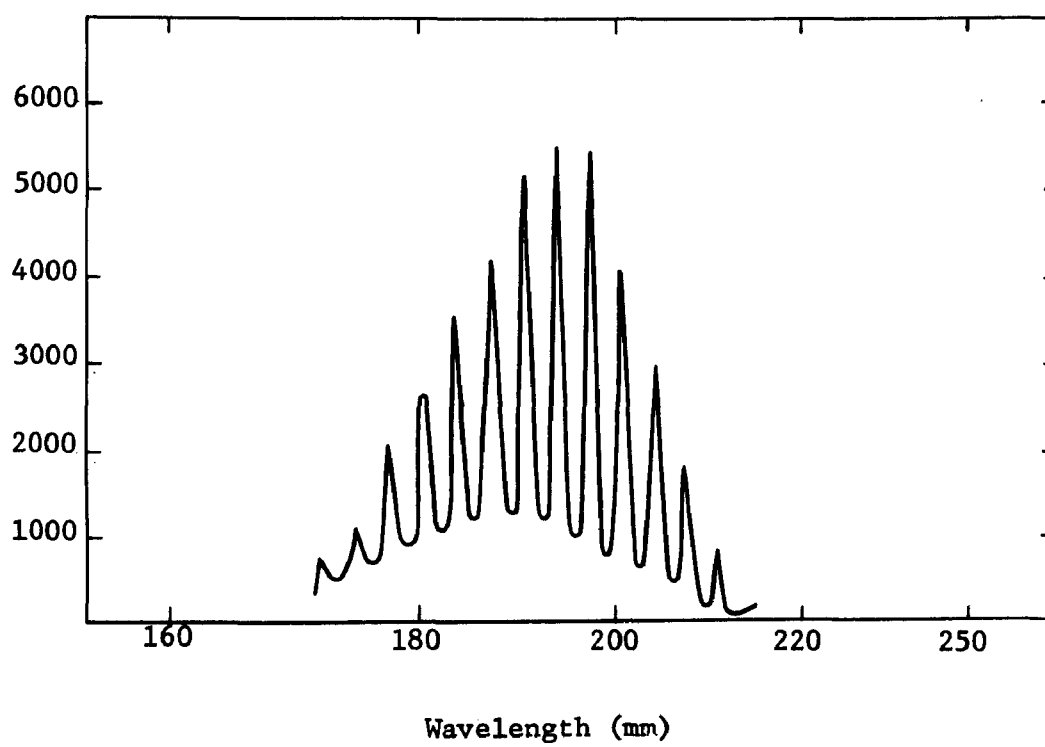
Figure 8

Principle

(a)

Spectrum of transmitted light

Intensity

Wavelength

I(t)

Intensity-modulated light signal
(2wt)

Intensity I

Wavelength
Modulation (wt)

λ_1 λ_0 λ_2

Wavelength

Time   t

(b)   (c)

Figure 9

$y = 0.980 \ x + 0.01$

$= 0.997$

$= 10.2$ ppm

$n = 14$

Concentration of NH_3 (ppm)

Figure 10

9 ppmNH_3

7 ppmNH_3

Concentration of SO_2 (ppm)
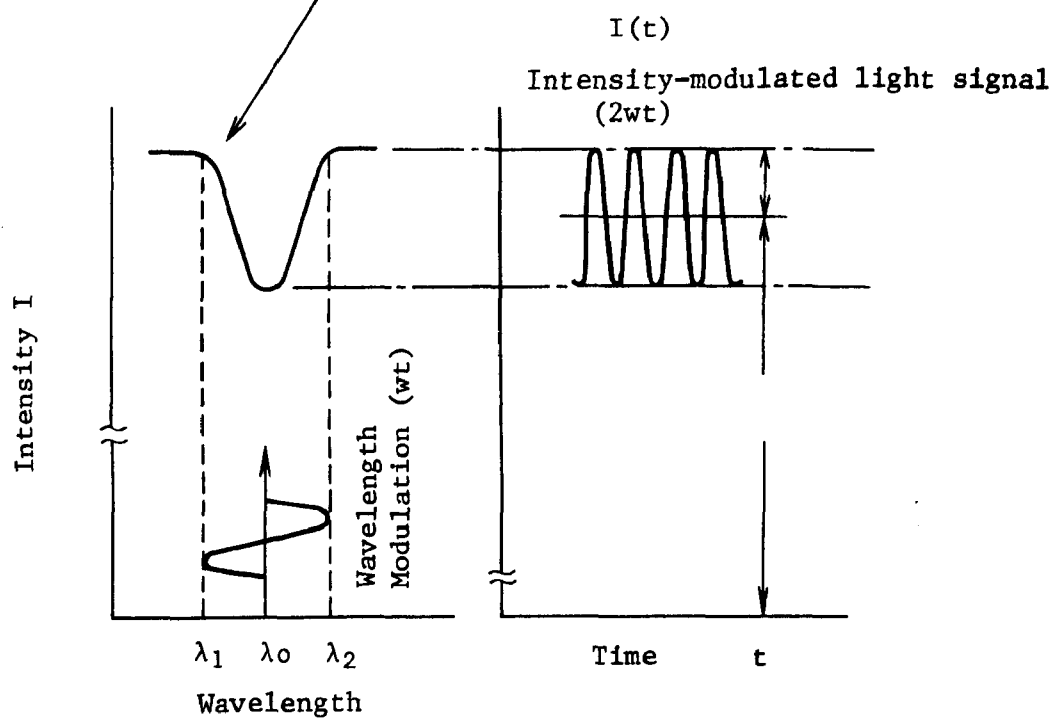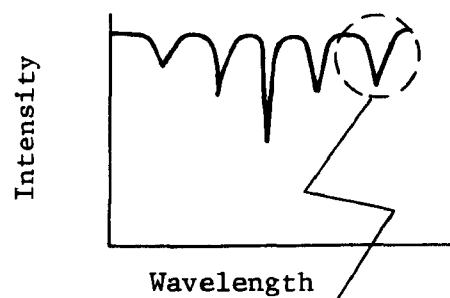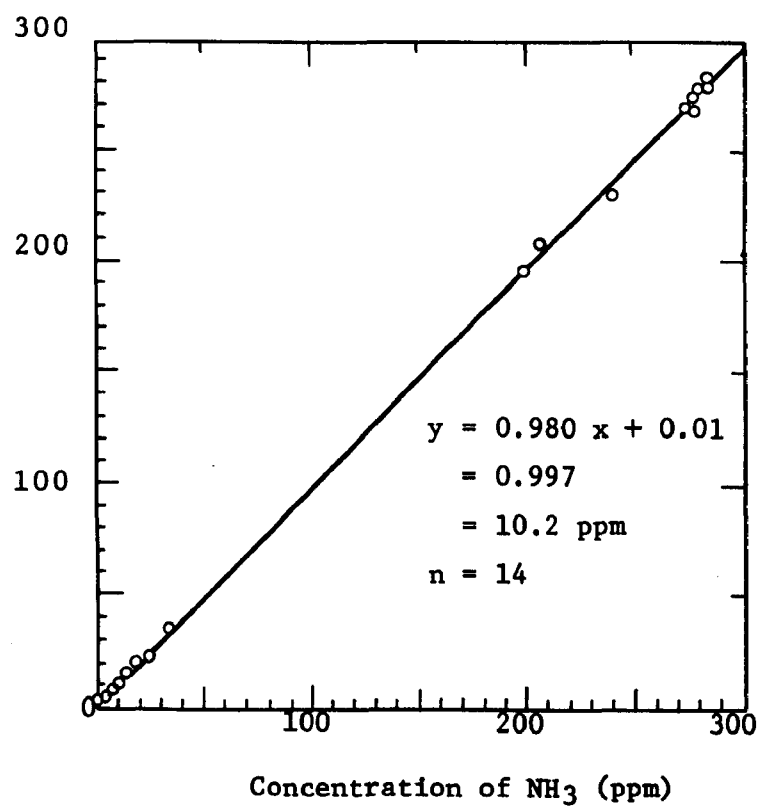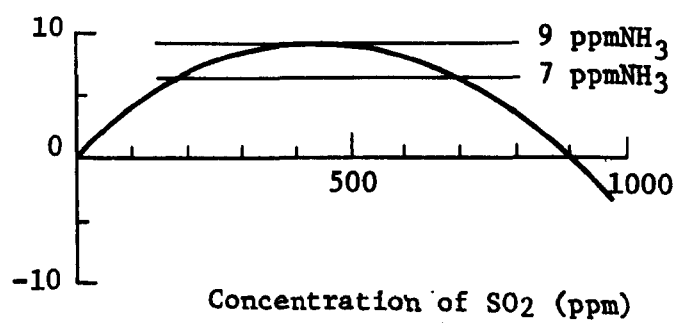
Figure 11

Model Anti-pollution Coal-fired Thermal Power Plant

Case	System	Power Plant Flow	Con-centration	Remarks
1	Low Dust Denitration System	NH₃ ... Boiler H.ESP SCR A/H GGH Wet FGD WWT Water	—	H.ESP:Hot-side Electrostatic Precipitator SCR: Selective Catalyst Reduction Equipment
2	High Dust Denitration System	Boiler SCR A/H NH₃ Ash Treatment GGH Wet FGD WWT Water	—	A/H: Air Preheater GGH: Gas-Gas Heat Exchanger FGD: Flue Gas Desulfuriza-tion
3	Dry FGD System	Boiler A/H BH/New EP NH₃ Dry FGD BH	—	W.WT: Waste Water Treatment Equipment BH: Bag House O: Fan

Figure 12

NH₃ Injection Flow
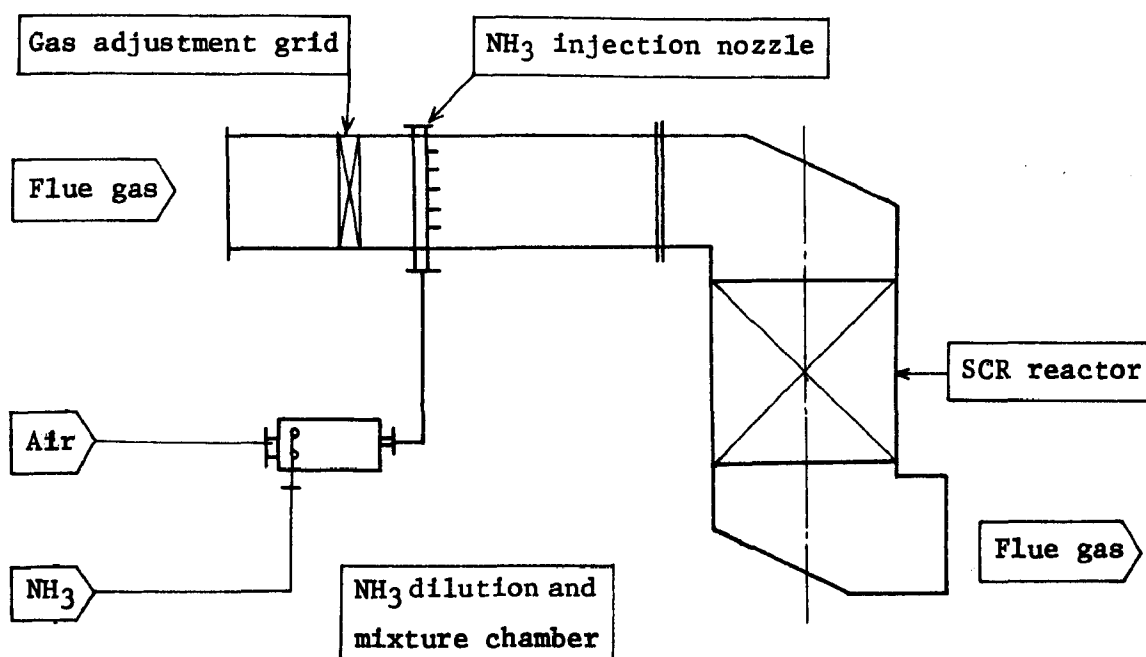
Figure 13

Fundamental Control System for NH₃ Injection
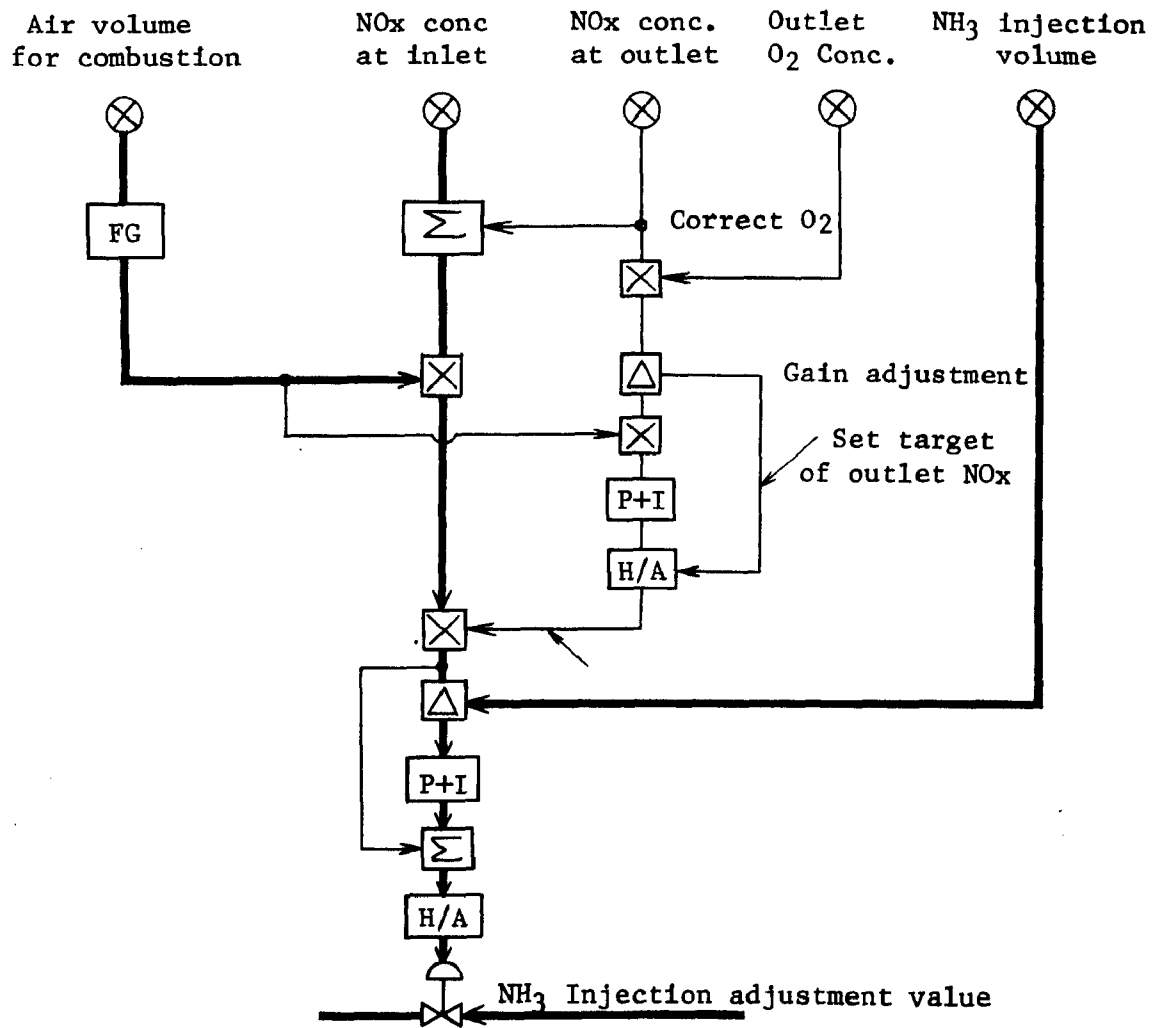
Figure 14

Overall Flue Gas Treatment System
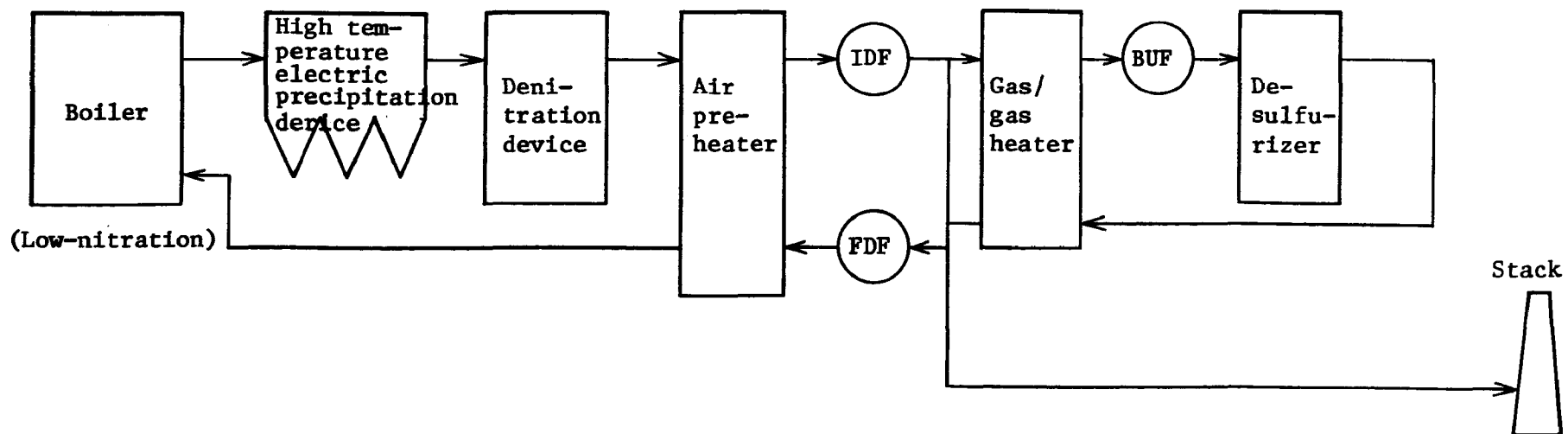
Figure 15

Layout of Takehara No. 3

Route 185

raw water tank

No. 3 denitrification dephosphorisation treatment

emergency blow tank

indoor coal stockyard

heavy oil tank

heavy oil tank

indoor switchyard

raw water tank

No. 1 unit outlet

No. 2 unit outlet

unloading site

No. 1 unit main building (turbine)

No. 2 unit main building (turbine)

No. 1 unit main building (turbine · boiler)

service building

boiler

boiler

No. 1 unit coal stockpile

fly ash storage

FGD

start

No. 3 unit outlet

No. 3 unit intake channel

No. 3 unit intake

No. 2 unit intake channel

No. 2 unit intake

No. 1 unit intake channel

No. 1 unit intake

No. 1 coal unloading wharf

oil unloading wharf

coal unloading bridge

No. 3 unit extension

1:4,000

Table I   DeNOx Installation in the Power Utilities of Japan

Power Company	Process	Manufacture	Power Plant	Unit	Out Put (MW)	Fuel	Start-up	Gas Volume (Nm3/H)	Capacity (%)	Efficiency (%)	Remarks
Hokkaido EPCO	SCR	BHK	Tomato-Azumi P/S	1	350	Coal	Sep. 1980	280,000	25	90	Test Equipment
Tohoku EPCO	SCR	IHI	Higashi-Niigata P/S	2	600	H.O, Crude, LNG	Aug. 1981	1,660,000	100	—	
Tokyo EPCO	SCR	MHI	Yokosuka	4	350	H.O	Feb. 1978				
Chubu EPCO	SCR	BHK	Chita	5	700	LNG	Mar. 1978	1,910,000	100	80	
	SCR	BHK	Chita	6	700	LNG	Mar. 1978	1,910,000	100	80	
	SCR	MHI	Chita	4	700	H.O	Nov. 1979	1,960,000	100	80	
	SCR	MHI	Atsumi	3	700	H.O	Dec. 1980	1,900,000	100	80	
	SCR	MHI	Atsumi	4	700	H.O	Feb. 1981	1,900,000	100	80	
	SCR	MHI	Shin-Nagoya	3	220	H.O	Jul. 1980	650,000	100	80	
	SCR	IHI	Shin-Nagoya	6	500	H.O, Crude, etc.	Jun. 1980	1,316,000	100	—	
Hokuriku EPCO	SCR	IHI	Toyama-Shinko	2	500	H.O, Crude	Nov. 1981	1,370,000	100	—	
Kansai EPCO	SCR	BHK	Kainan		450	H.O	Jun. 1977	300,000	25	80	
	Compact SCR	BHK	Amagasaki-Higashi	1	156	H.O	Jul. 1978	466,000	100	30	
	Compact SCR	MHI	Osaka	1	156	H.O	Jun. 1978	490,000	100	30	
	SCR	MHI	Osaka	3	156	H.O	Jul. 1980	552,000	100	80	
	SCR	MHI	Osaka	4	156	H.O	Dec. 1979	552,000	100	80	
	SCR	MHI	Sakaiko	1	250	H.O	Jul. 1980	800,000	100	80	
	SCR	MHI	Sakaiko	6	250	H.O	Dec. 1979	800,000	100	80	
	SCR	MHI	Osaka	2	156	H.O	Jul. 1981	530,000	100	80	
	SCR	MHI	Tanagawa	3	156	H.O	Aug. 1981	520,000	100	80	
	SCR	MHI	Tanagawa	4	156	H.O	Mar. 1981	520,000	100	80	
	SCR	MHI	Sakaiko	2	250	H.O	Sep. 1981	800,000	100	80	
	SCR	MHI	Sakaiko	4	250	H.O	Feb. 1981	800,000	100	80	
	SCR	MHI	Sakaiko	7	250	H.O	Sep. 1981	800,000	100	80	
	SCR	IHI	Himeji	5	156	H.O	Jun. 1978	490,000	100	—	
Chugoku EPCO	SCR	MHI	Iwakuni	2	350	H.O	Dec. 1980	980,000	100	80	
	SCR	MHI	Iwakuni	3	500	H.O	Apr. 1981	1,400,000	100	80	
	SCR	MHI	Shimonoseki	1	175	Coal	Apr. 1979	550,000	100	60	(80% in near future)
	SCR	IHI	Kudamatsu	2	375	NGL, H.O, Crude	Apr. 1979	1,050,000	100	—	
	SCR	IHI	Kudamatsu	3	700	NGL, H.O, Crude	Sep. 1979	1,900,000	100	—	
Kyushu EPCO	SCR	MHI	Shinkokura	3	600	LNG	Jun. 1978	1,690,000	100	>75	
	SCR	MHI	Shinkokura	4	600	LNG	Jun 1979	1,690,000	100	>75	
EPDC	SCR	BHK, KHI	Takehara	1	250	Coal	Jul. 1981	400,000×2	100	80	
	SCR	Not decided	Takehara	3	700	Coal	Mar. 1983	2,414,000	100	80	
Joban Kyodo TPCO	SCR	IHI	Nakoso	9	600	Coal, H.O	Apr. 1983	1,700,000	100	—	
	SCR	MHI	Nakoso	8	700	Coal, H.O	Dec. 1982	1,700,000	100	>50	(80% in near future)
		BHK	—	—	Total	H.O	July, 1978~ July, 1980	Total 2,586,600	—	—	
		MHI	—	—	Total 306	Coal	June, 1982~ July, 1982	Total 1,166,000	—	—	
		IHI	—	—	Total 2387	H.O, Crude	April, 1978~ May, 1982	Total 6,848,000	—	—	

Table II Comparison of DeNOx Processes

| Process | Economy | Performance | | Secondary Pollution | Reliability | | | Development |
		NOx	SOx		Operation	Maintenance	Danger	
SCR	3	>80%	>90%	None	Easy	Easy	None	1∿2 years
SNR	1	>30%	>90%	None	Easy	Diffi-cult	Hydro-gen use	1∿2 years
SCR+SNR	2	>60%	>90%	None	Easy	Diffi-cult	None	1∿2 years
Dry DeSOx/ DeNOx (CuO Type)	4	>80%	>80%	None	Dif-fi-cult	Diffi-cult	Hydro-gen use	3∿4 years
Wet DeSOx/ DeNOx	5	>80%	>90%	By Pro-duct as NO_3	Dif-fi-cult	Diffi-cult	None	1∿2 years

382

Table III Feature of Catalyst for LNG, Oil
and Coal

AV: Area Velocity

Fuel	Countermeasure		Shape	Cost to 1 unit
	Dust	Sox		
LNG	None	None	Pellet	1
Oil	None	None or Need	High AV Honeycomb, pipe board etc.	2
Coal	Need	Need	Low AV Honeycomb, pipe board etc.	3

Table IV SCR Pilot Tests for Coal Fired Boiler

Company	Joint research	Power plant	Capacity (Nm^3/H)	Shape of catalyst	HDSS or LDSS	Schedule (Fiscal Year)					
						1976	1977	1978	1979	1980	1981
EPDC	IHI	Isogo	1000 x '2	Honeycomb	HDSS			▬	▬	▬	▬
			1000 x 2		LDSS			▬	▬	▬	▬
	H Z	Isogo	230	Honeycomb	HDSS	▬	▬	▬	▬	▬	▬
			140 x 2		LDSS	▬	▬	▬	▬	▬	
	MHI	Takasago	200 x 2	Honeycomb	HDSS		▬	▬	▬		
			600 x 2		LDSS	▬	▬	▬	▬	▬	
	KHI	Takehara	250 x 2	Pipe	HDSS	▬	▬	▬	▬	▬	▬
			4200		LDSS				▬	▬	
	BHK	Takehara	2300	Board	LDSS				▬	▬	
			1330		HDSS					▬	▬
Tokyo EPCO	MHI	Nakoso (1)	4000	Honeycomb	HDSS				▬	▬	
			4000		LDSS				▬	▬	▬
Hokkaido EPCO	BHK	Ebetsu	2000	Ring (Moving Bed)	LDSS	▬					

(1) Fuel of Nakoso is 70% oil and 30% coal.

384

Table V   Comparative Items between
HDSS and LDSS

Equipment	Items
(1) Overall System	Plant Efficiency, Layout, Duct Work Countermeasure for GRF erosion Countermeasure for A/H Plugging and Draft Loss, Treatment of Fly Ash with NH_3, Behavior of SO_3
(2) Precipitator	Treated Gas Volume, Efficiency, Size Heat Expansion, Quality and Properties of Fly Ash
(3) S C R	Erosion of Catalyst, Shape of Catalyst Catalyst Volume, Catalyst Life, Production Method of Catalyst, Gas Velocity Reactor Structure, Draft Loss, Leakage NH_3
(4) Wet DeSOx	Gas Heat Exchanger Waste Water Treatment

Table VI   Comparison between HDSS and LDSS
(Overall System)

Items	HDSS	LDSS
° Plant Efficiency	Base	Decline
° Layout	Base	Larger
° Countermeasure for Erosion	Use Multi Cyclone	Not necessary
° Countermeasure for A/H Plugging	① Reduction of leakage NH₃	① ditto ② Low SO_2/SO_3 conversion catalyst ③ Improved A/H for SCR
° Draft Loss	Base	Increase
° Treatment of Fly Ash with NH₃	Contained NH₃ into Fly Ash Need NH₃ removal treatment under centain circumstances.	No trouble

Table VII   Comparison between HDSS and LDSS (II)
(Precipitator)

Item	HDSS	LDSS
o Gas Volume	Base (130 - 150°C)	Approx. 1.8 times (370 - 380°C)
o Efficiency	Base	Applicable to various kinds of coal.
o Size	Base	Generally bigger
o Heat Expansion	Small	Large
o Quality of Fly Ash	Contain NH₃ but No trouble	No problem
o Treatment of Fly Ash	Simple device as low temperature ash	Need insulator, burn protections and ash cooler for high temperature ash.

Table VIII   Comparison between HDSS and LDSS (III)
(S C R)

Item	HDSS	LDSS
o Influence by Dust	Need anti-erosion for catalyst	No problem
o Shape/peculiarity of Catalyst	Parallel passage type Such as honeycomb, pipe board etc. and low erosion material	Same
o Catalyst Quantity	Base	Nearly Same
o Catalyst Life	2 - 3 years (Presumption)	3 - 4 years (Presumption)
o Product Method of Catalyst	Base	Same
o Gas Velocity	Base	Same
o Draft Loss	Base	Same
o Leakage NH_3	Base	Same

Table IX Comparison between HDSS and LDSS (IV)
(DeSOx)

Item	HDSS	LDSS
o DeSOx	*No problem*	*No problem*
o GGH Plugging/ Corrosion	Less countermeasure for plugging/corrosion to LDSS as NH_3 and SO_3 is precipitated by ESP	Need the counter-measure such as strong soot blow, element material etc.
o Waste Water Treatment	Need De-N device to blow dow	De-N device is 2 or 3 times to HDSS

Table X De-N Development for DeSOx Waster Water

Company	Joint Researcher	Process	Capacity	Test Location	Schedule (Fiscal year)			
					1977	1978	1979	1980
EPDC	Hitachi Zosen (HZ)	Biological	Labo. test MAX 20ℓ/D	HZ's Labo	▬			
			Field test MAX 5 m³/D	Takehara P/S		▬		
			Labo. test 3ℓ/D	HZ's Labo (1)			▬	
	Mitsui-Miike Machinery (MMM)	Biological	Labo. test	MMM's Labo	▬▬			
			Field test	Ditto		▬		
			Labo. test	Ditto (1)			▬	
	Ebara Infilco	Biological	Labo.test	EI's Labo	▬▬			
			Field test	Ditto		▬		
			Labo. test	Ditto (1)			▬	
	Kirita (K)	Biological	Labo. test	K's Labo	▬▬			
	Organo	Biological	Labo. test	O's Labo	▬▬			

Note: (1) De-N and De-COD simultaneously.

390

Table XI Outline of Air Preheater Test

Company	Joint Researcher (Type of A/H)	Test Location	HDSS or LDSS	Capacity (Nm^3/H)	Schedule (Fiscal year)				
					1976	1977	1978	1979	1980
EPDC	Gadelius (Ljungstrom)	Takasago P/S	HDSS	10,000	▬				
			LDSS	5,000		▬			
			LDSS	5,000			▬		
			LDSS	8,000				▬▬	
	Hitachi Zosen (HZ) (Rothemühle)	Takehara P/S Isogo P/S	LDSS LDSS	2,000 –			▬▬		====
	IHI (Rothemühle)	Isogo P/S	HDSS	2,000			▬▬▬▬▬▬		
			LDSS	2,000			▬▬▬▬▬▬		
Tokyo EPCO	MHI	Nakoso P/S	HDSS	4,000				▬▬▬▬	
			LDSS	4,000				▬▬▬▬	

Table XII Identification of A/H Plugging

Condition	High dust No NH$_3$ injection	High dust NH$_3$ injection	Low dust NH$_3$ injection	Low dust NH$_3$ injection
Plugging	None	None	None	Yes
Test Condition	15g/Nm^3	15g/Nm^3 10 ppm	0.1g/Nm^3	0.1g/Nm^3 10 ppm

Table XIII Flue Gas Treatment Techniques

```
                                                            ┌─ Two-stage combustion
                                                            │
                              ┌─ Combustion modification────┤─ Low NOx burner
                              │                             ├─ Gas recirculation
                              │                             │
                   ┌─ NOx─────┤                             ├─ Gas mixing
                   │          │                             │
                   │          │                             ├─ Combined measures
                   │          │                             │
                   │          │                             └─ Others
                   │          │
                   │          │                      ┌─ SCR ──────┬─ High dust system
                   │          │                      │            └─ Low dust system
                   │          └─ Denitration─────────┤─ SNR
                   │                         │        ├─ Hybrid denitration (SNR+SCR)
                   │                         │        └─ Dry simultaneous desulfurization
                   │                         │              and Denitration
Coal Flue Gas ─────┤                         │
                   │                         └────────── Wet flue gas denitration
                   │          ┌─ ESP
                   │          │                         ┌─ Boxer charger
                   │          ├─ H. ESP                 │
                   ├─ Dust────┤─ L. ESP                 ├─ 3rd electrode
                   │          ├─ New ESP────────────────┤
                   │          │                         ├─ Pulse charge
                   │          ├─ BH                      │
                   │          │                         └─ Ionizer
                   │          │  Desulfurization/       ┌─ Mixing tower system
                   │          └─ dust collecting────────┤
                   │                                     └─ Separating tower system
                   │
                   │                                     ┌─ Mixing tower system
                   │          ┌─ Wet flue gas ──────────┤
                   └─ SOx─────┤    desulfurization       └─ Saparating tower system
                              └─ Dry flue gas desulfurization
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393

Table XIV Present Status of Research and Development (1/2)

	Boiler		H.EP	S C R			A/H		Remarks
	Combustion modification	S N R		High dust	Low dust	Regeneration	High dust	Low dust	
(1) Steps of research and development	Under R & D	Ditto.	in practical use	under R & D	practicable	R & D	practicable	practicable	SNR: Selective Non-Catalytic Reduction SCR: Selective Catalytic Reduction
(2) Co-researchers	Babcock Hitach, IHI, MHI, KHI	MHI, IHI	SHI,(Gadelius Hitachi, MHI)	HZ, IHI, MHI, KHI, Hitachi	Ditto	KHI	Gadelius IHI	Gadelius, IHI, HZ	
(3) Development targets	100ppm and below ($6\%O_2$) 5% and below in unburned carbon, with CO and HCN showing no increase.	40% and above 100ppm and below	$100mg/Nm^3$ and below	80% and above 5ppm and below 0.5 - 1.0% and below (performance after the lapse of one year) } Ditto		} Ditto	To operate stably for one year or more.	Ditto.	
(4) Results so far achieved	Guidelines for NOx reduction measures have been set up and improvements have been made through testing by type of coals.	° NOx is not affected by fly ash. ° Furnace temperatures have been actually measured. (Isogo P/S)	° Specifications necessary for design of H.ESP have been obtained.	Development targets have been cleared.	Ditto	° Fundamental techniques for regeneration have been established. ° Secular changes in performance are being checked after completion of flue gas regeneration testing.	° Tendency toward plugging has been confirmed.	° Soot blowing has been intensified. And element has been improved.	
(5) Subjects in the future	To develop a boiler of 100ppm and below ° To develop an ultra-low NOx burner ° To make a survey of optimum condition	° To study a simple denitration means, ° To study cooling systems and ° To develop an NH_3 ash disposal process.	° To investigate the effects of Na and Ca.	° To develop ammonia ash disposal process	(Optimum design)	° Secular change after regeneration	° Concrete ideas to improve commercialized equipment	To make a survey of the optimum design	
(6) Time of putting into practical use	200ppm can be guaranteed at present.	° After developing the NH_3 ash disposal process	Under construction in Matsushima Power Station	After developing the ammonia ash disposal process	Demonstration test plant is under construction in No.1 unit, Takehara Power Station.	Not fixed yet	Practicable	Demonstration test plant is under construction in No.1 unit, Takehara Power Station.	

394

Present Status of Research and Development (2/2)

	Dust Collector		G G H	Desulfurization		Wet EP	A/B	B H	Remarks
	Boxer Charger	B.H.		Wet	Dry				
(1) Steps of research and development	Under R & D	Ditto.	In practical use	Already put into practical use	Under R & D	Ditto	Already put into practical use	Under R & D	
(2) Co-researchers	IHI(Toshiba) Hitachi	SHI(IHI)	Gade, IHI	-	SHI,(IHI)	IHI(SHI)	-	SHI	
(3) Development targets	10mg/Nm^3 and below	10mg/Nm^3 and below	To operate stably for one year or more.	(95% and above)	95% and above (ηnox 40% and above)	10mg/Nm^3 and below	-	10mg/Nm^3 and below	
(4) Results so far achieved	Basic data has been gathered	Laboratory tests have been completed.	Design conditions with and without NH$_3$ have been confirmed.	-	ηSOx and SOx performance has been already confirmed.	-	-	Performance confirmation	
(5) Subjects in the future	Testing with pilot plant for confirmation of practical use	To make sure of filter cloth life and performance and to optimize design conditions	Optimum design (measures for clogging with NH$_3$)	Performance of collecting submicron particules, SO$_3$, etc.		Performance confirmation		Optimum design	
(6) Time of putting into practical use	Not fixed yet	Not fixed yet	Under construction in Matsushima Power Station (Case without leakage of ammonia) No.3 unit under construction in Takehara Power Station (Case with leakage of ammonia)	Already put into practical use	Demonstration test plant is expected to be provided in Matsushima Power Station. (Entrusted by government)	Not fixed yet	-	Demonstration test plant is expected to be provided in Matsushima Power Station. (In a combination with dry FGD)	

Table XV Features of Anti-Pollution Coal-Fired Power Plant by System

Case	System	Flue Gas Emission Level	Prospects of Practical Use	Denitri-fication	Counter-measure for A/H	Ammonia Ash Treatment	Lay-out	Combustion Modification
1.	Low dust denitration	NOx 60 ppm and below SOx 100 ppm and below Dust 30 mg/Nm^3	Practicable (700 MW under construction in Takehara P/S)	Required	Required	Not required	Base	Combustion modified to 300 ppm and below in NOx. Already put into practical use.
2.	High dust denitration	Ditto	Within several years. (Ammonia ash treatment techniques have not been established yet.)	Required	Not especially required.	Required	Better	Ditto
3.	Dry Desulfurization	NOx 60ppm and below SOx 100ppm and below Dust 1 mg/Nm^3	Within several years	Not required	Not required	Required	Best	NOx must be reduced to 100 ppm. A modification means is being developed.
	Existing							

Table XVI Outline of SCR Demonstration Plant at Takehara No. 1 Unit

Item	Manufacture	Type	Capacity	Efficiency	Remarks
(1) Existing Plant		Reheat Type Radiant			
(a) Boiler	BHK	Boiler	810 T/H	–	Fuel: coal
(b) Plant output	–	–	250 MW	–	
(2) Demonstration Plant					
(a) SCR	BHK	Board Cat.	400,000 Nm^3/H	>80%	
	KHI	Pipe Cat.	400,000 Nm^3/H	>80%	
(b) Air Preheater	Gadilius	Long element Ljumgstrom	800,000 Nm^3/H	–	Now Air Preheater
(c) De-N	HZ	Biological Process	1,000 m^3/Day	<10ppm as total N	

Table XVII Flue Gas Emissions from Takehara No. 3 Unit

ITEM	Unit	Numerical Value
Gas volume (Wet) (Dry)	Nm^3/H	2,414,000 2,169,000
Discharge temperature	°C	100
Stack height	m	200
SOx concentration	ppm	100
NOx concentration	ppm	60(O2=6%)
Dust	g/Nm^3	0.03

Table XVIII   The Demonstration Schedule

Item	1981	1982	1983	1984
Foundation	1 — 8			
Installation	8 ———	——— 8		
Trial Operation		▭		
Test Operation			▭———	

Table XIV

Outline of Dry DeSOx Demonstration Test Equipment

Item	Contents
° Process	Dry Type Activated Carbon Absorption
° Gas Volume	300,000 Nm^3/H
° Gas Temp.	135°C
° SO_2 (Inlet)	1,000 ppm
° SO_2 (Outlet)	50 ppm and below
° NO_x (Inlet)	300 ppm
° NO_x (Outlet)	225 ppm and below
° Dust (Inlet)	300 mg/Nm^3
° Dust (Outlet)	10 mg/Nm^3
° By product	Element Sulfur (purity 99.9% <)

TREATING FLUE GAS FROM COAL-FIRED BOILERS FOR NO_x REDUCTION
WITH THE SHELL FLUE GAS TREATING PROCESS

By:

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ABSTRACT

Copper as copper sulfate ($CuSO_4$) is one of the group of metals which at tempeatures of 350-450°C catalyzes the selective reduction of NO_x in flue gas to nitrogen and water with ammonia (NH_3). Conversions and efficiency (ammonia utilization) are high, resulting in low concentrations of both NO and NH_3 in the treated gas.

If flue gas containing both sulfur and nitrogen oxides and the reductant ammonia is processed over copper at 400°C, the copper is converted first to the oxide, then to the sulfate, and NO_x reduction begins. As the conversion to copper sulfate continues, the NO_x content of the treated gas decreases to a minimum value and the SO_x increases.

Copper sulfate can be reduced with a variety of fuels, e.g., H_2, CO, CH_4, etc., at 400°C, yielding a concentrated stream of SO_2, along with water and the copper in elemental form.

Thus, the copper system provides the technical base for flue gas treating capable of SO_x reduction, NO_x reduction, and the simultaneous reduction of both. It offers the potential of a dry process, without by-products, and with modest energy requirements.

SFGT PROCESS

The application of this technology to a NO_x-only process is in the form
of a fixed bed reactor with provisions for ammonia introduction and mixing.
The reactor is of special design to accommodate fly ash. The catalyst is
contained in woven wire baskets suspended in the gas stream in such a way
that the gas flows in the open channels between baskets (see Figure 1). The
reactants enter and the products leave the catalyst bed by radial diffu-
sion. The design is modularized in units or cells, one-half meter square by
one-meter long, which can be stacked one atop the other for the required
space time. The flue gas from one half MW, i.e., 1,000 SCFM, is processed in
a single stack of cells.

For SO_x removal, the operation is cyclic and requires that the reactor
be isolated from the flue gas circuit for regeneration, producing a concen-
trate of SO_2 and restoring the copper to elemental form. Continuous flue gas
processing is achieved with multiple reactors, at least one of which is
always in regeneration. A unit designed for SO_x removal can operate with NO_x
reduction only by elimination of the regeneration step, and as a simultaneous
NO_x/SO_x unit by addition of ammonia.

This reduction practice is called the SFGT process. Commercial
applications have been in operation since 1973 treating flue gas from various
fuels not including coal.

PILOT/DEMONSTRATION UNIT

UOP has operated an SFGT pilot plant for several years at the Tampa Electric Company's Big Bend Station near Ruskin, Florida. The pilot unit treats a slip stream of flue gas from one of the station's coal-fired boilers as the gas leaves the economizer. A simplified process flow is shown in Figure 2. De-SO_x only, simultaneous de-SO_x/de-NO_x and, most recently, de-NO_x-only operations have been conducted. The current program is sponsored by the U.S. Environmental Protection Agency.

The demonstration has involved two acceptor/catalysts: the first is in commercial application, the second, a prototype, is a more active formulation. The standard experimental procedure for each has been to establish a reference performance under fixed operating conditions using air plus pollutants followed by an evaluation on flue gas. Reference performance is again obtained with air plus pollutants before completion of the run. These tests are supported by similar evaluations in a laboratory unit.

SUMMARY OF DEMONSTRATION PROGRAM

NO_x-only evaluation of the first acceptor/catalyst was made on a fully sulfated acceptor. For four weeks, 90% NO_x reduction was achieved with a 1.25 ratio of ammonia to NO_x. The effect of the ratio on the de-NO_x performance in the reference test with air is shown in Figure 3; with flue gas, the result is the same but for a translation of the curve requiring an increase in the ratio of 10%. It has been characteristic of this system in this service that introduction of flue gas is followed by an immediate drop in performance and then stable operation.

Another characteristic of the system is that space time has little effect on NO_x reduction, that is, an increase of gas rate by 50% is accompanied by a similar percent increase in the de-NO_x reaction rate resulting in the same NO_x reduction. Both these characteristics suggest that the reactor is limited by the depletion of a reacting component which in this case is expected to be ammonia.

In the simultaneous NO_x/SO_x testing with the first acceptor/catalyst, the unit was operated for a period of approximately four weeks with 90% SO_x reduction and 70% NO_x reduction with a 1.25 ratio of ammonia to NO_x. As in the NO_x-only tests, introduction of flue gas into a clean reactor system results in an immediate drop in performance followed by stable operation. The change in performance is due to a partial blinding of the screens and the filling of the interstitial volume with fly ash.

Reference performance for the more active acceptor/catalyst with air plus pollutants is shown in the on-line analyzer strip charts in Figure 4. Time is right-to-left and was arbitrarily chosen at 99 minutes. Half-way through the acceptance, SO_x/NO_x instantaneous reduction is 98/91%; cumulative reduction at 99 minutes is 96.0/89.7.

In Figure 5 is shown the same strip charts when processing flue gas at the same conditions. The corresponding values of SO_x/NO_x reduction are 90.6/92.5 and 88.9/85.2. Note that de-SO_x performance shows the usual decline with high loadings of fly ash and SO_2 content (loading of copper with sulfur), but the instantaneous de-NO_x performance remains high and the cumulative reduction is decreased due to the "slip" of NO in the first ten minutes of the cycle while the copper is converted to copper oxide.

In Figure 6, also with flue gas, the rate of formation of $CuSO_4$ has been reduced to achieve 90% de-SO_x in 99 minutes, and the initial slip of NO_x decreased by delaying the injection of NH_3 for a few minutes into acceptance and with a preoxidation of the copper following regeneration. After 99 minutes, the cumulative reduction of SO_x/NO_x was 90.9 and 90.0.

The acceptor/catalyst has proven to be quite stable in this service. During stability tests carried out in 1974-1976, there was 13,000 cycles of oxidation-reduction with no significant deterioration in performance. This stability has been further supported in the current demonstration work, both in the field and the laboratory.

Operation of the TECO unit will be concluded with the testing of a de-NO_x catalyst of high activity that can function over the temperature range of 200-450°C. This catalyst is at present in commercial service at 200°C but not on coal. The performance will be determined in the parallel-passage reactor over a range of temperatures, space velocities, and NH_3/NO_x ratios with coal-derived flue gas.
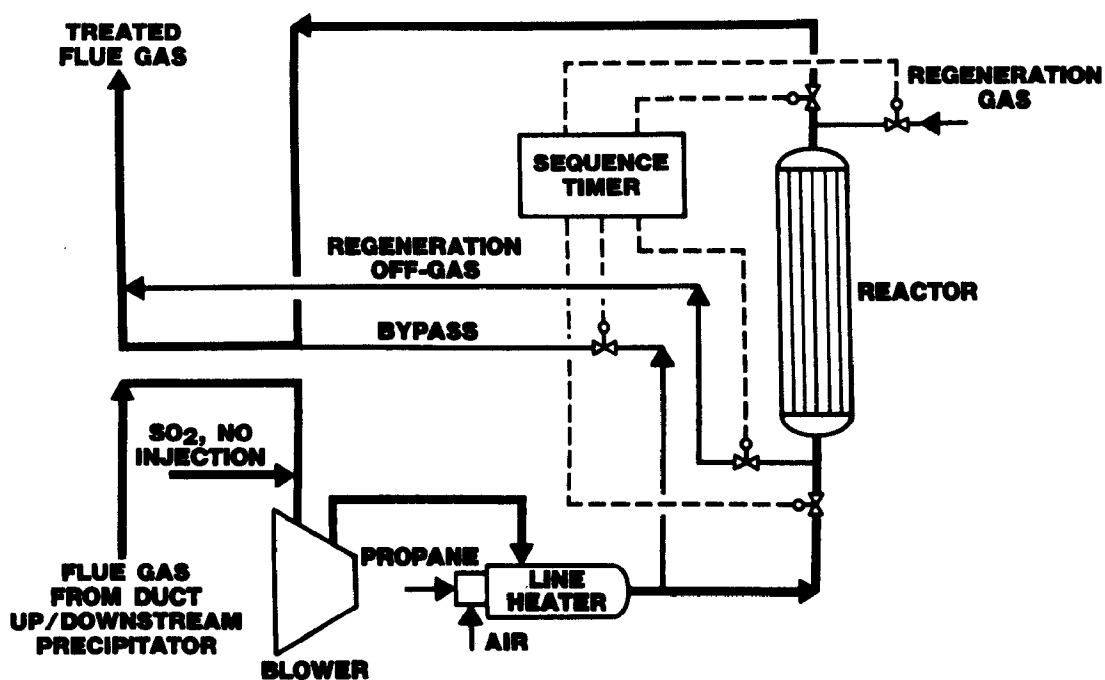
FIGURE 1
THE PARALLEL PASSAGE REACTOR

REGEN. GAS

PURGE OFF-GAS

TREATED FLUE GAS

FLUE GAS

REGEN. OFF-GAS

PURGE STEAM
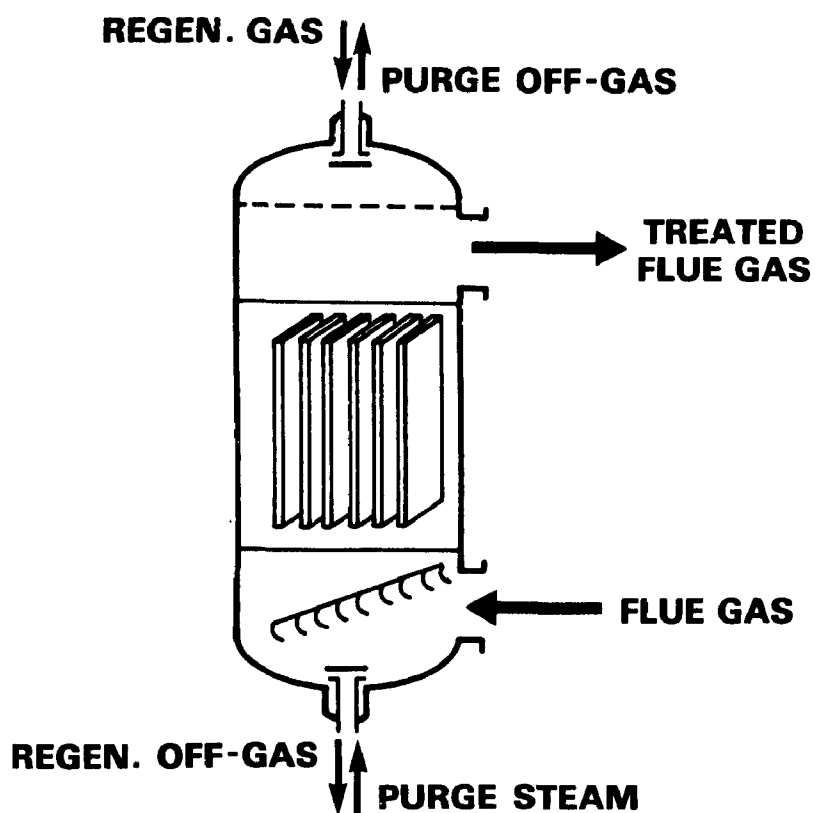
UOP 163-3
UOP 576-1

FIGURE 2

SIMPLIFIED FLOW SCHEME
OF SFGD DEMONSTRATION UNIT FOR COAL FIRED
UTILITY BOILER AT TAMPA ELECTRIC, FLORIDA

UOP 576-2

FIGURE 3

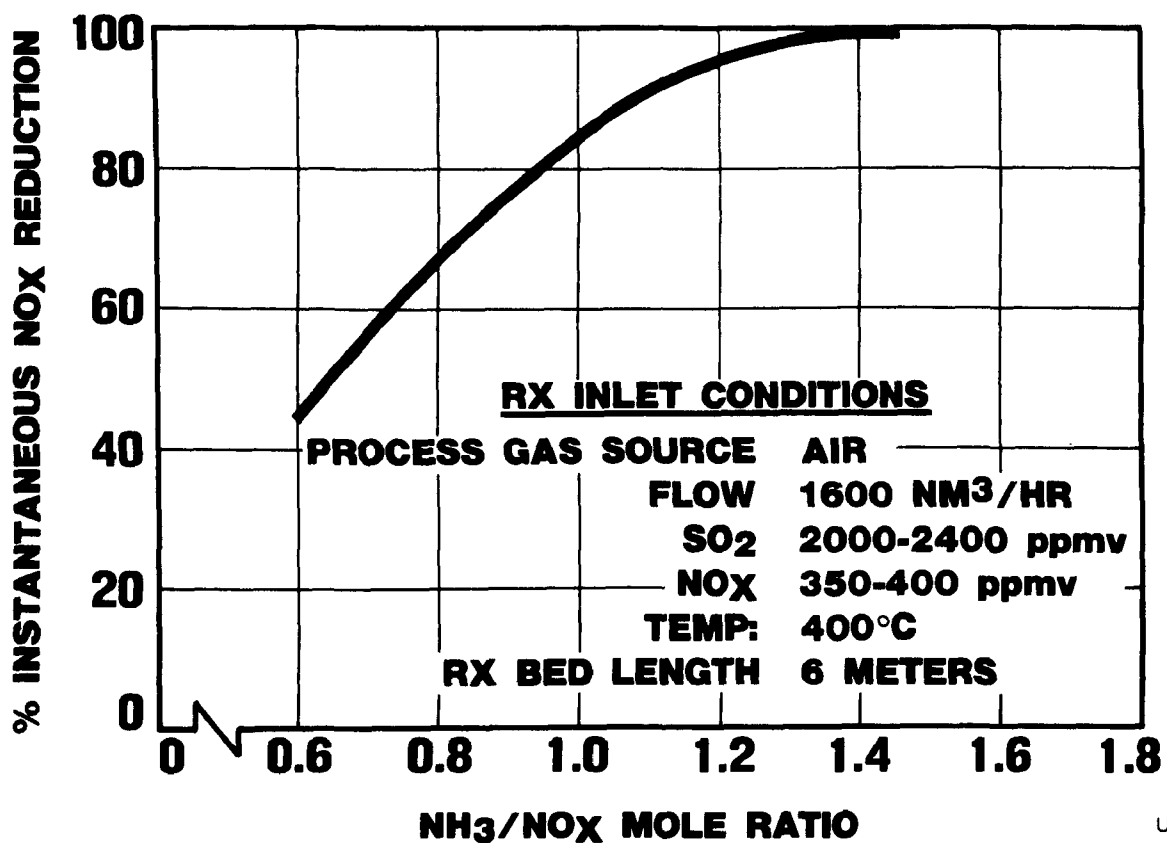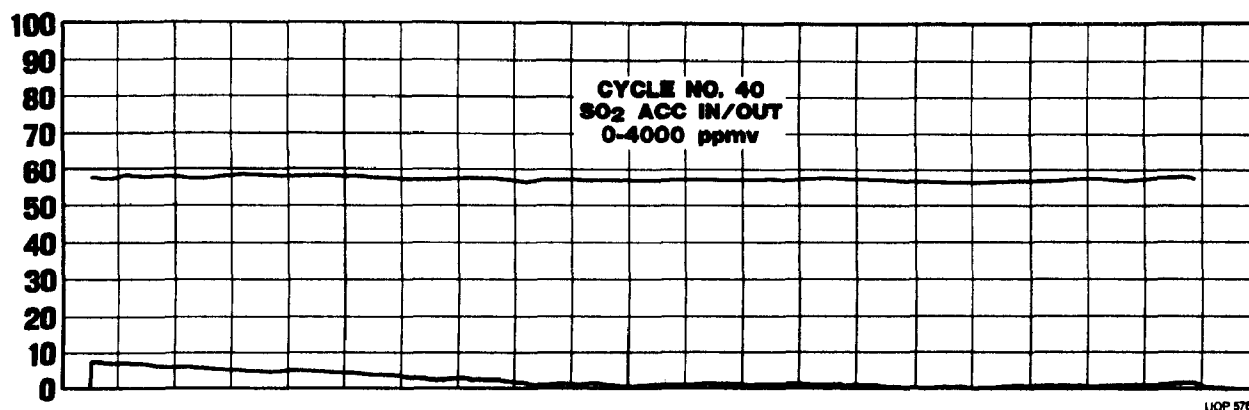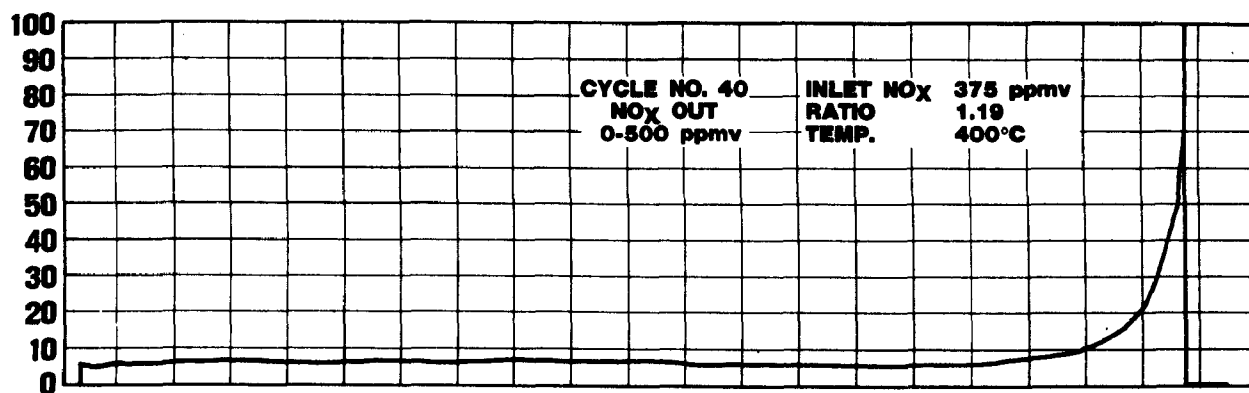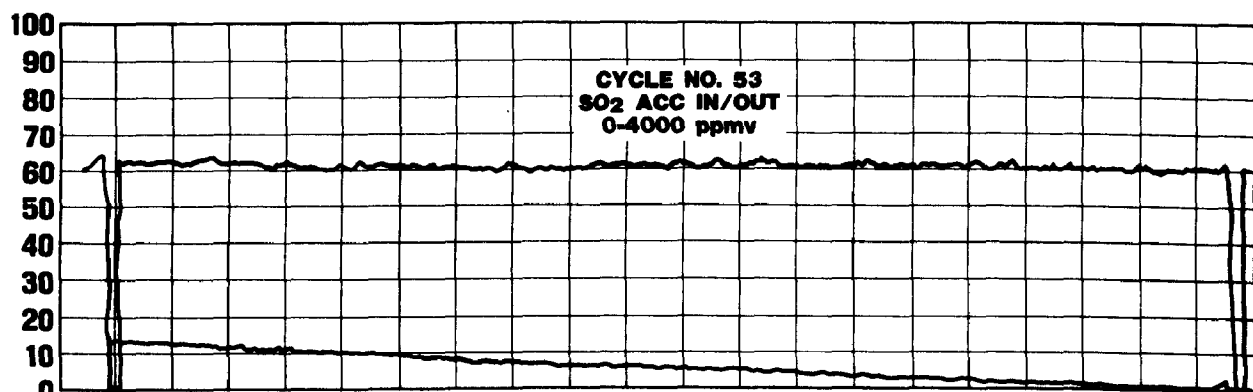# NOx REDUCTION vs. NH3/NOx RATIO AT TAMPA ELECTRIC DEMONSTRATION UNIT WITH A COMPLETELY SULFATED BED

RX INLET CONDITIONS

PROCESS GAS SOURCE	AIR
FLOW	1600 NM3/HR
SO2	2000-2400 ppmv
NOX	350-400 ppmv
TEMP:	400°C
RX BED LENGTH	6 METERS

UOP 576-3

FIGURE 4

CYCLE NO. 40
NOₓ OUT
0-500 ppmv

INLET NOₓ   375 ppmv
RATIO   1.19
TEMP.   400°C

CYCLE NO. 40
SO₂ ACC IN/OUT
0-4000 ppmv

UOP 576-4

409

FIGURE 5

410

FIGURE 6

CYCLE NO. 189
NOx OUT
0-500 ppmv

INLET NOx   465 ppmv
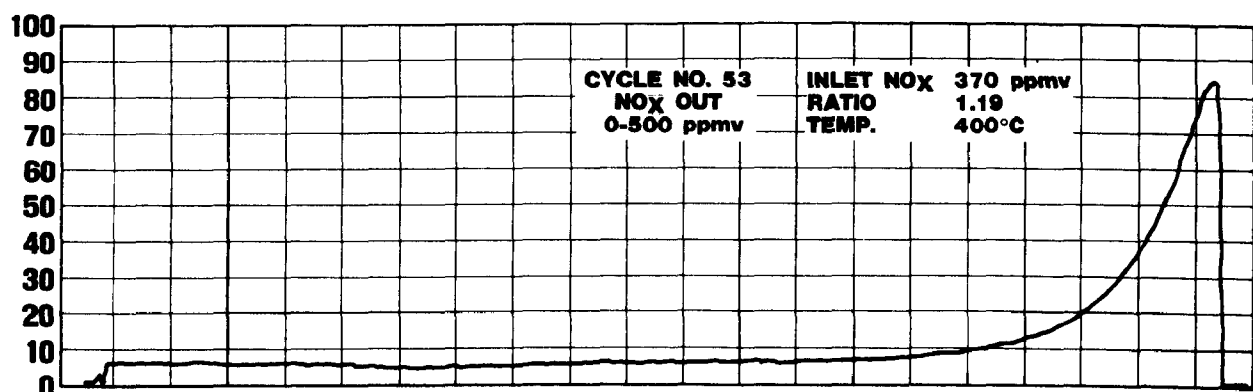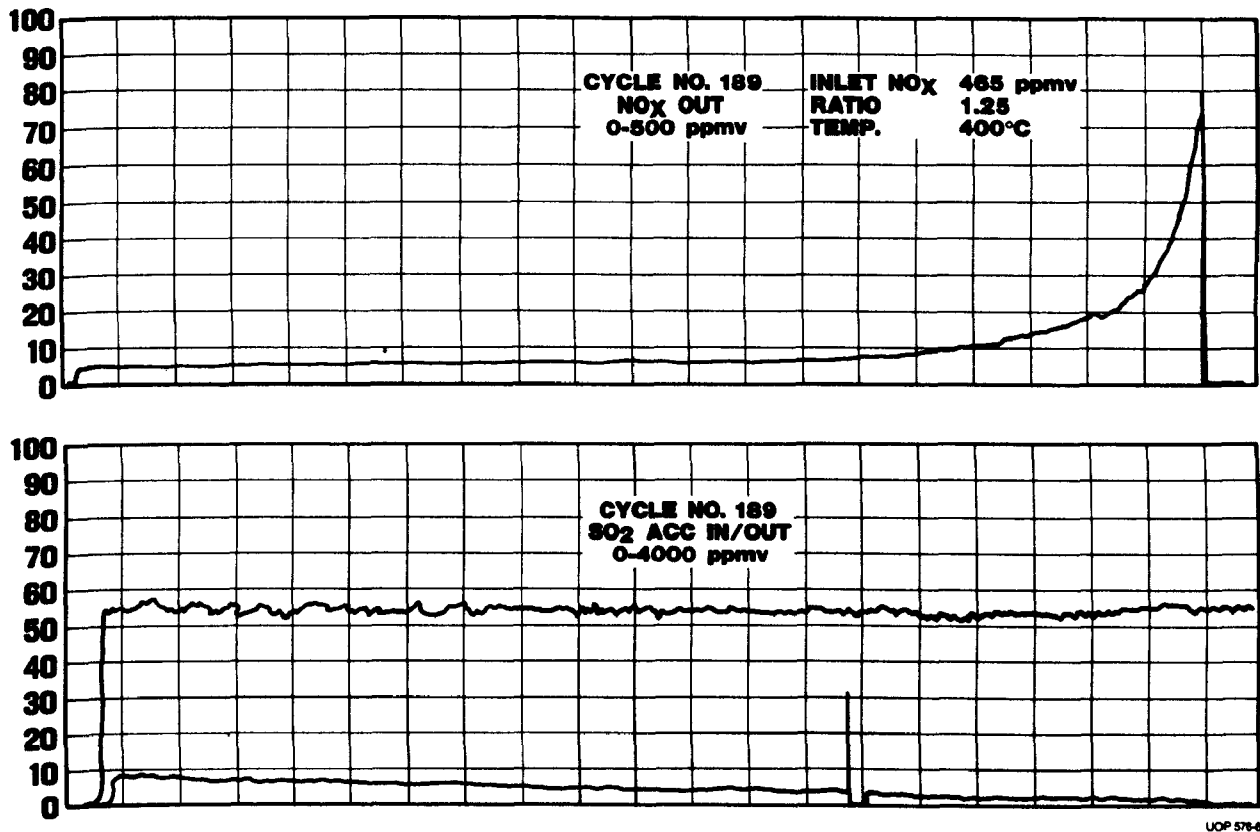RATIO   1.25
TEMP.   400°C

CYCLE NO. 189
SO2 ACC IN/OUT
0-4000 ppmv

UOP 576-6

411

THE DEVELOPMENT OF A CATALYTIC NO_x REDUCTION SYSTEM
FOR COAL-FIRED STEAM GENERATORS

By:

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ABSTRACT

     Work done recently by Mitsubishi Heavy Industries in Japan has
resulted in the design and successful operation of a full scale
catalytic NOx reduction system for coal-fired utility steam generators.
This paper describes the program carried out to evaluate the
commercial feasibility of catalytic nitrogen oxides removal from
coal fired power plant flue gases. Also discussed is the design
of a catalytic removal system for a large modern coal-fired central
station.

     Testing of pilot catalytic systems on coal fired steam generators
was initiated at the Takasago station of EPDC in early 1977 using
plate type catalysts. After two stages of testing, the plate type
catalysts were replaced by grid type catalysts and testing was
resumed (fall 1979). Since the conversion to grid type supports,
more than 5000 hours of operation has been logged while maintaining
more than 80 percent NOx removal in both low and high dust load
environments.

     At the Nakoso station of the Joban Joint Power Co. a grid type
pilot catalytic system has been operating for over 10,000 hours with
a removal efficiency of 84 percent. Operating under both high and low
dust loads, draft losses (as at Takasago) have been maintained at
low levels with only limited soot blowing during low dust loading
and no soot blowing during high dust loading.

     At the Shimonoseki station of the Chugoku Electric Power Co.,
the first full scale system for a coal-fired boiler (175-MW) in the
world has run smoothly since startup in April of this year. Removal
efficiency has been 51 percent, as expected, and the ammonia slip
less than 1 ppm.

     The paper also discusses ammonia slip, gas flow requirements,
catalyst life and catalyst blinding from fly ash. The design of
a 500-MW commercial unit based on the results of the test program
is described and the various factors affecting large commercial design
are discussed as well.

INTRODUCTION

In most nations, SOx, NOx and particulates contained in flue gas from steam generators must be minimized to meet environmental regulations. Particulates are normally removed by electrostatic precipitators or bag filters and SOx by tail-end flue gas treatment systems, but NOx removal is somewhat different. The NOx levels in flue gas have been reduced considerably by combustion modifications. However, there is a minimum level of NOx concentration beyond which further reduction is not possible using these combustion modification techniques. By using a catalyst and a reductant (NH_3), however, the NOx generated in steam generators can be reduced by a process of dissocation to form N_2 and H_2O. This is known as the Selective Catalytic Reduction (SCR) process and is recognized as the most effective method for NOx reduction in Japan. The SCR process is performed at a gas temperature of about 300 to 400 C, which usually exists just upstream of the boiler air heater.

Since 1952, Mitsubishi Heavy Industries, Ltd. (MHI) has manufactured boilers for electric power plants under a technical license with Combustion Engineering, Inc. Almost all the boilers are tangentially fired. While combustion modification in tangentially fired steam generators has been adequate to meet the regulated NOx emission limits in the United States, the more stringent NOx emission regulations in Japan have led MHI to develop additional methods of NOx reduction: the very low NOx PM burner and the Selective Catalytic Reduction process.

To comply with increasingly stringent NOx regulations in the U. S. this MHI technology was licensed by C-E in April 1980 and will be available through C-E for steam generators in the U. S.

The very low NOx burner technology has been presented in another paper (1) at this conference, while this paper deals with MHI's SCR technology, focusing especially on its application to coal fired steam generators.

HISTORY OF DEVELOPMENT

MHI began developing a dry NOx removal process for boilers in 1971, concentrating efforts on the SCR process in 1973. The first application was for clean flue gas from liquefied natural gas (LNG) fired units, the second for semi-dirty flue gas from low sulfur oil fired boilers, and finally for dirty flue gas from high sulfur oil and coal fired boilers. Table I shows the SCR systems supplied by MHI.

As the clean flue gas from an LNG fired boiler does not contain particulate, it was possible to use a pellet type catalyst of 3 mm diameter packed in fixed bed reactors. A pilot plant with a capacity of 10,000 Nm^3/h^* was constructed at a 350-MW boiler at the Tokyo Electric Power Co's, Minami-Yokohama power station. This unit demonstrated a 10,000-hr catalyst life by the end of 1975, without any performance deterioration (2). This successful test was MHI's first experience with the SCR process and it provided the basic technical information for further development. The results of this test were applied in the first, large full-scale system at the newly installed 600-MW unit at Kyushu Electric Power Co's, Shinkokura station. It began operation in June 1978 and has operated successfully since then.

In applying the process to the semi-dirty light oil firing flue gas, an intermittent moving bed reactor was first developed using a pellet type catalyst, but it was later concluded that fixed bed reactors using parallel passage catalysts, such as plate or grid types, would be more suitable and practical for both operation and maintenance. MHI carried out an evaluation program for both types of catalyst simultaneously and, after considerable studies, concluded that the grid catalyst is more economical for both oil and coal firing, primarily because of the compactness of the reactor chamber.

Grid shaped catalysts used in parallel passage reactors are manufactured by extrusion molding. Two types are commercially available; one is a homogeneous type,

*Normal cubic meters per hour

415

where the catalyst is formed by a uniform blend of active and support material, the other is a coated type, in which the active catalyst material is coated on a ceramic support structure (substrate). Either type of catalyst may be mass-produced through a series of processes to be within a predetermined tolerance of dimension, strength and activation performance. Figure 1 shows one element of the grid type catalyst.

The first commercial system using a grid catalyst was for an oil-fired boiler at the Sodegaura Refinery of the Fuji Oil Co., a 160 t/h boiler (Fig. 2) put into operation in December 1977 (3). This unit has operated smoothly for more than two years without the replacement of the original catalyst. In January 1980 a 700 MW oil-fired unit, Chita 4, owned by the Chubu Electric Power Co., was put into service. It is the largest SCR application to an oil-fired boiler in the world.

To develop the SCR system for coal fired boilers, MHI constructed a pilot plant known as the "DM-600 project" on a coal-fired boiler at the Takasago Power Station of the Electric Power Development Co. (EPDC) and put it into operation in January 1977 as a joint development project with EPDC. In March 1979, the second pilot plant was put into operation at Nakoso Power Station of the Joban Joint Electric Power Co. sponsored by Tokyo Electric Power Co., Tohoku Electric Power Co., and Joban Joint Electric Power Co. and called the TTJM project. This pilot plant consists of a precipitator to be usable either in the hot or cold temperature mode, two SCR systems, one for high dust and another for low dust loads, a wet desulfurization scrubber, and water treatment systems. The purpose of this project was to investigate the overall performance of the total pollution control package as well as individual systems. This configuration permitted testing with the low dust conditions in the case of the hot electrostatic precipitator upstream of the SCR reactor and with high dust conditions in the case of the low temperature electrostatic precipitator downstream of the air heater.

The test results of the TTJM project were used in designing the first SCR system for a full-scale coal-fired commercial unit, the Shimonoseki 1 boiler owned by the Chugoku Electric Power Co. This is a 175-MW unit with a high concentration of fly ash. It was put into operation in April 1980 and has operated trouble free.

These projects are summarized in Fig. 3 and the test results are described in a later section of this paper.

DEVELOPMENT OF CATALYST

FEATURES

The catalyst for the SCR process is made of a mixture of active material and support material. The active material has to be highly active, durable, and formed to have sufficient surface and porosity to be efficient. In addition, it must not adversely affect the boiler. Both materials must be low in captial and replacement costs. The overall structure must be strong, compact, and low in draft loss. A special consideration is that in most chemical processes, temperature and pressure can be controlled for the most suitable reaction conditions for the catalyst, but in flue gas treatment, the catalyst must be developed to meet the boiler's operating conditions.

PROCEDURE TO DEVELOP THE CATALYST

MHI's policy regarding the production of catalysts for SCR plants is to develop them with well established catalyst manufacturers who then manufacture them in accordance with MHI specifications. To do this, MHI established a total evaluation program of the catalyst development including trial formulation, evaluation of chemical activity and physical properties, and testing for durability. This is illustrated in Fig. 4.

The first step in developing a catalyst is to select its composition and determine the preparation method, then, with the catalyst manufacturer's cooperation, to establish the specification after evaluation of bench scale testing program carried out at MHI's Hiroshima Technical Institute.

The catalyst manufacturers provide MHI with catalysts suitable for each specific application. MHI carries out pilot tests to confirm the catalysts' durability in actual flue gas. These tests consist of accelerated deterioration tests, such as alkaline dust heating to predict the life expectancy of various

fundamental tests, such as adhesion, clogging, and abrasion with different kinds
of dust, and testing the rejuvenation response of deteriorated catalyst. Moreover,
MHI is making a considerable effort to find the causes of catalyst deterioration
by evaluating various results of analyses such as X-ray diffraction, X-ray fluor-
escence, X-ray micro probe analysis, X-ray photoelectron spectroscopy, and mass
spectrometry. Physical properties are tested, such as surface, area, pore volume,
and strength against crushing, bending, abrasion, thermal shock, etc.

CONDITIONS FOR SELECTING CATALYSTS

There are large differences in SOx and dust concentration among exhaust
gases from various fuels. It is essential to select the most suitable catalyst
for each specific exhaust gas. The basic approach to the selection of the
catalyst for use with coal fired boiler exhaust gas is summarized as follows.

RESISTANCE TO SOx

Since coal-fired boiler exhaust gas normally contains high concentration
of sulfur oxides, the catalyst should be tolerant to SO_2, the formation of SO_3
by the catalyst becomes a particularly important problem because of its detri-
mental effect on the equipment downstream. A catalyst should be selected that
is capable of minimizing the SO_2 oxidization rate. Figure 5 shows a comparison
between restrained and non-restrained catalysts in the formation of SO_3.

WORKING TEMPERATURE

With an exhaust gas containing NH_3 and SO_3, the catalyst can deteriorate
from a low gas temperature. The boiler may have to be modified so that the
NOx removal plant can be continuously operated at a temperature above the allow-
able minimum working temperature of the catalyst. These minimum working
temperatures for various SO_3 concentrations are known for operational results
obtained in the past.

LONG LIFE

It is necessary to select a catalyst that is stable thermally and stable
with regard to alkali compounds (K_2O in particular), contained in dust that
can cause deterioration. As shown in Fig. 6, according to the forced deter-
ioration test using the alkali compounds as a pollutant, a catalyst of MHI

specification, which consists of TiO_2 as the support material and a proprietary blend of two other active materials X and Y shows a much more stable performance than normal catalyst of a single active component.

FREEDOM FROM DUST DEPOSITION

It is necessary to select a catalyst with a structure (pitch) that will not become plugged by dust contained in exhaust gas. Experience with catalysts with 7 to 10 mm nominal pitch have shown satisfactory results even with high concentration of dust.

SOOT BLOWING RESISTANCE

If dust should adhere to the catalyst, soot blowing is the most effective way to remove it. The catalyst must be strong enough to withstand this soot blowing. Figure 7 shows a comparison between our improved erosion resistant type and a common catalyst.

RESISTANCE TO EROSION

Erosion of the catalyst from fly ash in exhaust gases cause a decrease in the life of the catalyst. It is necessary to give special consideration to this, especially when exhaust gases contain a high concentration of dust. Without any counter measures for the catalyst, the leading ends of catalyst can be severely eroded. MHI uses a catalyst with a high erosion-resistance made by a propietary method. In addition to this, a section of dummy catalyst support located upstream of the active catalyst can be used to absorb the end impact and act as guide vanes, thus protecting the active catalyst downstream. If the above measures are used and the appropriate gas velocity provided, the erosion of the catalyst can be eliminated. Figure 8 shows the test results comparing erosion resistant catalyst with common types.

OUTLINE OF RESULTS IN FIELD TESTS

The operation of three coal-fired test plants as shown in Fig. 3 has provided us with extensive information in establishing the design philosophy of NOx removal systems. We can summarize these operating results as follows:

DM-600 Project

This pilot plant project was initiated in January 1977, as a joint research program between MHI and EPDC for the purpose of establishing the selection and durability criteria for catalysts for coal fired boilers. A flue gas slipstream was taken from the 250-MW No. 1 coal-fired unit at the Takasago power station of EPDC. In the first and second stages of this program, the plate type catalyst developed by MHI was tested and it was proven that parallel flow, fixed bed type reactors would work very will for either high or low ash laden gas. These two stages of the program involved continuous operation of more than about 10,000 hours.

As the third stage of the program, a grid type catalyst with 10 mm pitch square holes was tested beginning in August of 1979. The composition of the flue gas at the inlet of the reactor for the high dust system included $\sim$12 to 15 g/Nm^3 of dust, about 1500 ppm of SO_x and about 250 ppm of NO_x. Analysis of fly ash showed about 48% SiO_2 and 23% Al_2O_3.

As shown in Fig. 9, it was confirmed that the NOx removal efficiency could be maintained at more than 84% with less than 3 ppm of ammonia slip at NH_3/NO_x ratio 0.85. The draft loss across the reactor did not change throughout the test period for the high dust system. For the low dust system, where the dust loading was about 50 mg/Nm^3, there was a slight increase in draft loss across the reactor after 1000 hours operation, and it reached a 40mm H_2O increase after 3000 hours operation. But after soot blowing, the draft loss increase was completely eliminated. Except for this, the low dust system operation showed almost the same performance as the high dust system.

These tests are being continued until the end of 1980.

Prior to pilot plant operation it was feared that alkaline compounds espe-
cially those of sodium and potassium could impair actibity of the catalyst by
chemical reaction with active catalyst materials. Such alkaline compounds
in fly ash are known to form a glassy complex of Al_2O_3-CaO-Na_2O-K_2O in the
liquid phase and become non-active when cooled. After laboratory inspection
of catalysts taken from the pilot plant, we found no accumulation of alkaline
compounds in the catalysts, indicating that alkaline poisoning of the
catalysts can be eliminated.

According to laboratory experiments, the rate of catalyst erosion in-
creases rapidly when the gas velocity is greater than 10 meters/sec or when
the particulate size is over 40 microns in diameter. In the case of the high
dust system, while the average diameter of fly ash particle is about 20 microns,
considerable particles of more than 40 microns are present. This results
in an erosive condition. In a test with the gas flow rectified by an up-
stream dummy layer of catalyst support material and the gas velocity below
10 m/s, we eliminated the erosion of catalysts.

The smaller the particle size of fly ash and the more alkaline compounds
it contains, the more adhesive the fly ash will be. In the case where the
SCR reactor was located downstream of the hot precipitator, the dust particles
that escaped capture were mostly 3 microns or less in size. This material
proved to be somewhat sticky therefore soot blowers have had to be operated
periodically to remove this fine fly ash that collected on the surface of
catalysts.

TTJM Project

This project was initiated to establish an integrated flue gas treatment
system for coal-fired power plants. The pilot plant was installed at the
Nakoso power station of Joban Joint Power Co., Ltd. This boiler used mixed
combustion of coal and heavy oil (Coal amounting to about 40 percent during
the day time and to about 70 to 80 percent during the low load period at
night.) As shown in Fig. 3, the pilot plant consists of not only high and
low dust NOx removal equipment, but also includes wet desulfurizing equipment
but also includes wet desulfurizing equipment and waste water treatment
equipment so that the overall performance of the integrated clean-up system
in various combinations could be thoroughly tested. Testing was started in

April 1979. At full boiler load, the flue gas in the high dust system contains about 7 grams/Nm^3 of dust, about 240 ppm of SOx and about 300 ppm of NOx with fly ash composition having about 55% SiO_2 and 27% Al_2O_3. As shown in Fig. 10 with a vertical reactor chamber using a grid catalyst with an Sv of 2200 H^{-1} NOx removal efficiency was maintained at more than 84% and less than 2 ppm of ammonia slip with NH_3/NOx ratio of 0.85 after about 10,000 hours operation. The draft loss across the reactor chamber did not increase during the period of high dust load operation. In the low dust system (100-300 mg/Nm^3 dust loading) the draft loss showed a gradual increase and reached about 60 mm H_2O increase after 3000 hours operation. At this point, the draft loss was successfully reduced to the initial value through soot blower operation.

The regenerative air heater in the high dust system has the normal arrangement of heating elements, DU type for high and middle temperature zones and NF type for the low temperature zone. Air heater plugging due to the deposit of ammonia bi-sulfate did not occur. This was attributed to the sand blasting effect of highly concentrated fly ash and operation of the soot blowers once a day. In the low dust system, the arrangement of air heating elements was revised to use the SNF type (3.5 mm pitch) for the middle and low temperature zones because draft loss increase across the airheater had been observed with original airheater. With this modification and by operating soot blowers both up and dwonstream three times per day, continuous pluggage-free operation was attained. This is shown in Figs. 11 and 12.

FULL SCALE DEMONSTRATION

The Shimonoseki Unit of Chugoku Electric Power Co. is a 175-MW coal-fired boiler and was constructed in 1967. The NOx removal equipment was installed in 1980 with grid catalysts having 10-mm pitch square holes. The reactor chamber is a vertical down flow unit and is located at the side of air heater and precipitator. High dust laden flue gas is taken from the economizer outlet and directed to the top inlet of the reactor and returned to the inlet of the air heater. A provision has been made to keep the inlet gas temperature above $330^{o}C$ at lower loads by gas bypassing of the economizer.

The system began operation in April, 1980 as the first full scale coal fired SCR system in the world. The plant has been running since then without any trouble at above design NOx removal efficiency, and ammonia slip concentration less than 1 ppm. The design removal target for this system was at least 50 percent. Design conditions are shown in Table II and plant layout in Fig. 13.

The initial test results for NOx removal efficiency and ammonia slip concentration at various boiler loads are shown in Fig. 14. This data was taken after one month operation, when the catalyst was in a fresh condition. However, we are sure that deterioration of catalyst activity will not occur at least within one year operation, judging from our test results at other pilot plants.

$$NO_X \text{ REMOVAL SYSTEM FOR 500-MW BOILER}$$

OUTLINE OF DESIGN

The following outlines the design of a NOx removal system to be applied to a new 500-MW coal-fired steam generator. The flue gas capacity is 1,553,000 Nm^3/h at 4.3% O_2 when firing a typical sub-bituminous coal at the maximum continuous rating of the boiler. Design conditions for two cases, NOx removal efficiency of 80% (Case I) and 90% (Case II) are shown in Table IV.

MHI has decided to use a 7 mm pitched catalyst for high dust systems on coal fired boilers since it was proven that dust clogging would not occur on the TTJM project. In this instance the reactor is located between economizer and air heater and high ash-laden gas will be treated.

The specification of the equipment is shown in Table IV. The reactor chamber is a vertical type where flue gas enters the chamber from the top and passes downward through three or four stages of catalyst (Case I & II respectively). Each catalyst layer consists of a group of catalyst modules having a cross-sectional dimension of about 2 x 1 meters a height of 1.65 meters, the weight of a single module is about 3 tons and 216 or 288 modules are required for Cases I & II respectively. Each catalyst module can be carried in and out of the reactor chamber using an electric traveling hoist installed within the steel structures of reactor chamber. One element of the catalyst is 150 x 150 mm square, about 650 millimeters in length, and about 14 kg in weight. A total of 25.920 elements are required in Case I and 34,560 elements in Case II.

423

Eighteen traveling frame soot blowers in Case I or 24 sets in Case II using steam as a blowing medium are installed for cleaning the catalysts. Low pressure, orifice-type ammonia injection nozzles are installed upstream of the reactor chamber, followed by an ammonia/flue gas mixing device. The plant layout for Case I is shown in Fig. 15 and Figure 15 shows a schematic flow diagram of the system. The predicted NOx removal efficiency and ammonia slip concentration curves are shown compared to boiler load in Fig. 17 for both cases, and Fig. 18 shows the relationship between ammonia to NOx ratio and NOx removal.

PROCESS DESIGN CONSIDERATIONS

There are three types of fixed bed catalyst reactor chambers where grid catalyst elements are used: vertical up-flow, vertical down-flow and horizontal flow. The vertical down-flow type is generally preferred in SCR systems for coal fired boilers because it offers the following advantages:

(1) Less dust deposition on the catalyst surfaces and less plugging risk than the horizontal flow type reactor chamber.

(2) Less dust deposition on the tope ends of the catalyst element than the gas up-flow type reactor chamber.

There are two major factors to be carefully considered when the gas velocity through the system is determined; one is the erosion of catalyst elements and the other is the dust deposition on the catalyst during low load operation with reduced gas velocity. The following are the results observed in the pilot plant tests:

(1) There is no accumulation of dust deposits on the ends of catalyst layers in vertical flow reactors when the gas superficial velocity is 2 m/sec or greater. (Even on the inside surfaces of catalyst there is no growth of dust deposit with such a low gas velocity.)

(2) A low gas velocity is desirable for minimizing erosion of the catalyst elements. However, the catalyst elements developed by MHI can be used without trouble with dust laden gas flows of up to 10 m/sec.

In designing a NOx removal system, therefore, the gas velocities are selected taking the anticipated minimum and maximum load of the plant into careful consideration. In the case of heavily dust-laden flue gas, an erosion resistant dummy layer should be provided ahead of the catalyst layers to rectify the stream of gas and dust.

If the flue gas temperature becomes too low, the reaction products of SO_3 and HH_3 are formed on the active surfaces of the catalyst, impairing the capability of the catalyst. However, should the flue gas temperature return to a high level the deposits can be carried away by the gas stream, restoring the capability of the catalyst. The degree of reduction in NOx removal capability and the period of time required for its restoration largely depend upon the gas temperature and the SO_3 concentration of the flue gas. Thus, the operating temperature range of the catalyst should be determined to be suitable for the flue gas condition.

When the flue gas has a high SO_3 concentration, there is a possibility of corrosion and plugging in the air preheater due to the ammonia-sulfur compound. The dust in the stack gas will also be adversely affected by SO_3 leaving the air preheater. To avoid such difficulties, the SO_2 to SO_3 conversion due to the catalyst should be controlled to a minimum. Therefore, the catalyst should be controlled to a minimum. Therefore, the catalyst used in the NOx removal systems should be tested to meet a maximum rate of conversion criterion of SO_2 to SO_3 of about 1% when treating a 1500 ppm SO_2 concentration flue gas.

STRUCTURAL DESIGN

Figure 19 shows a cut-away view of the vertical type reactor chamber. As the reactor chamber is a massive high temperature structure, its supporting points at four corners are allowed to slide to permit thermal expansion of the structure. The reactor chamber is fixed only at a point in the middle of its front wall. The midpoints of the other three walls are provided with guide stoppers through which the horizontal forces exerted to the chamber are conveyed to the supporting steel.

A number of catalyst elements are packed into steel grids to form catalyst modules and these catalyst modules are placed on a rack having several shelves. The gaps between modules are sealed to prevent short circuiting of the gas; attention is also paid to prevent ash deposits. The racks are fabricated from steel and supported at four bottom corners by the main frame, which forms a part of the boiler house supporting steel structure. The catalyst modules may be moved in and out of the reactor chamber through openings on the side of the chamber by removing cover plates. To facilitate handling of the catalyst modules, platforms are provided at the heights of the respective module shelves. A hoist is provided to lift the modules to

and from these platforms. Soot blowers are provided for each shelf of catalyst modules and located at a right angle to the direction of module removal and re-placement.

The ammonia distribution and mixing devices are located immediately up-stream of the catalyst. These are constructed from mild steel pipe and structural members to form a grid arrangement which assures thorough mixing of ammonia with the entering flue gas.

CONCLUSION

To meet the increasingly stringent NOx emission regulations in highly industrialized countries, a combination of combustion modification and flue gas treatment will soon be necessary. To that end the development of the Selective Catalytic Reduction system for boiler application has been success-fully demonstrated in full scale commercial units for all fossil fuels.

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2. Mitsubishi Heavy Industries, Ltd., "Development of NOx Removal Processes with Catalyst for Stationary Combustion Facilities, Mitsubishi Technical Bulletin No. 124, May 1977.

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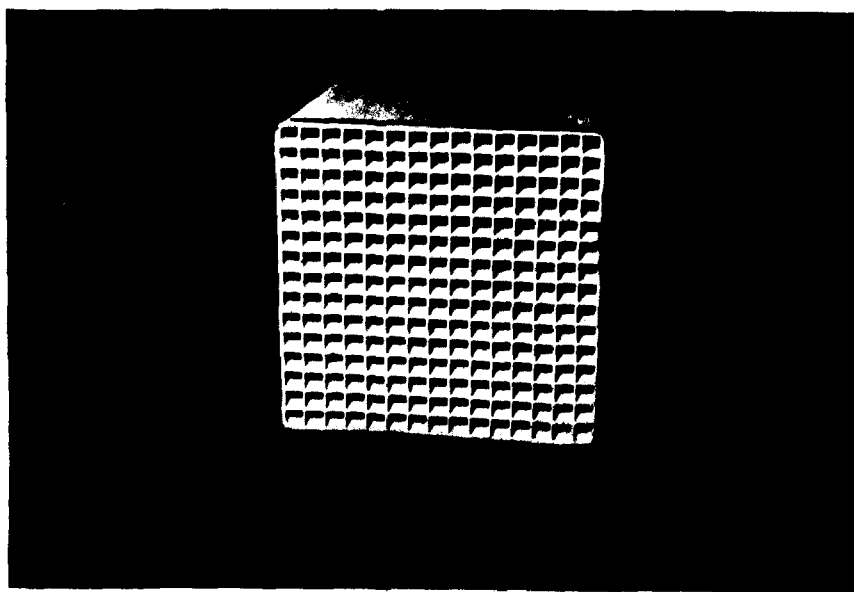
Fig. 1: Grid-type catalyst
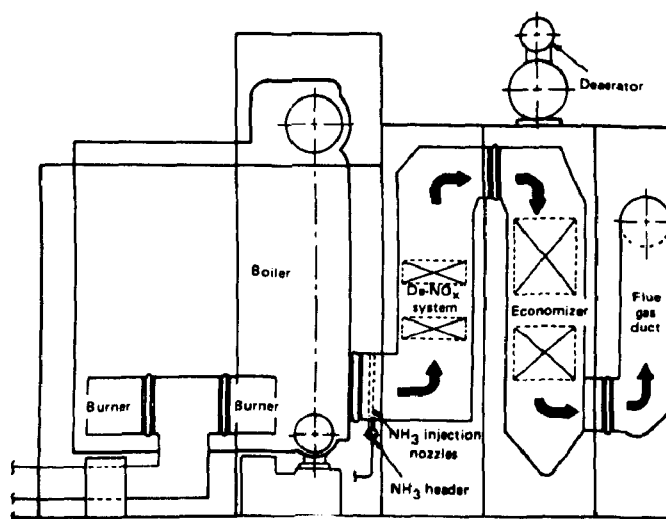
Fig. 2: General arrangement of 160 t/h oil-fired boiler
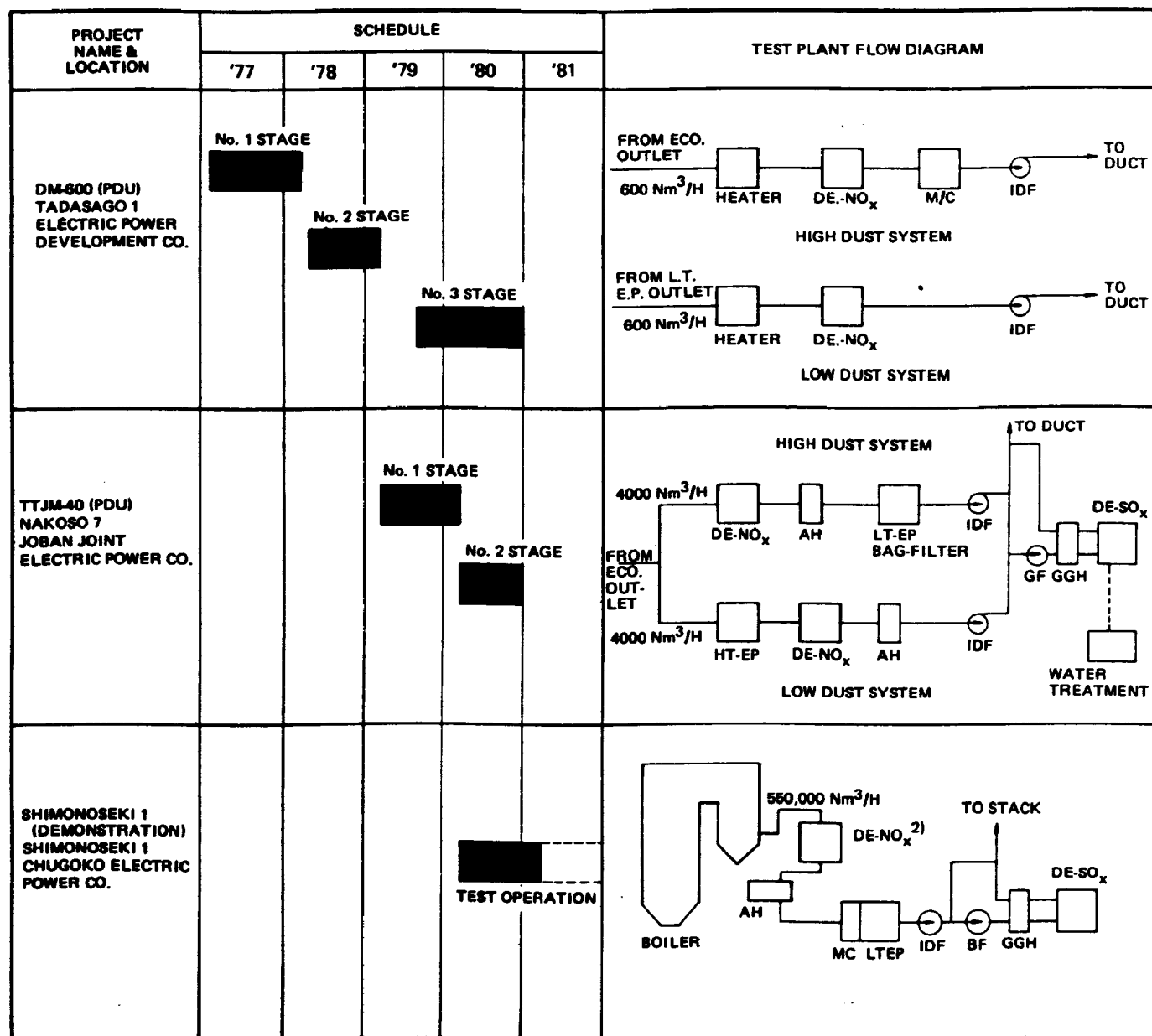at the Sodegaura Refinery of the Fuji Oil Co.

PROJECT NAME & LOCATION	SCHEDULE					TEST PLANT FLOW DIAGRAM
	'77	'78	'79	'80	'81	
DM-600 (PDU) TADASAGO 1 ELECTRIC POWER DEVELOPMENT CO.	No. 1 STAGE ▮	No. 2 STAGE ▮	No. 3 STAGE	▮		FROM ECO. OUTLET — 600 Nm³/H — HEATER — DE.-NO$_x$ — M/C — IDF — TO DUCT — HIGH DUST SYSTEM / FROM L.T. E.P. OUTLET — 600 Nm³/H — HEATER — DE.-NO$_x$ — IDF — TO DUCT — LOW DUST SYSTEM
TTJM-40 (PDU) NAKOSO 7 JOBAN JOINT ELECTRIC POWER CO.			No. 1 STAGE ▮	No. 2 STAGE ▮		HIGH DUST SYSTEM / 4000 Nm³/H — DE-NO$_x$ — AH — LT-EP BAG-FILTER — IDF / FROM ECO. OUTLET / 4000 Nm³/H — HT-EP — DE-NO$_x$ — AH — IDF / LOW DUST SYSTEM — TO DUCT — GF GGH — DE-SO$_x$ — WATER TREATMENT
SHIMONOSEKI 1 (DEMONSTRATION) SHIMONOSEKI 1 CHUGOKO ELECTRIC POWER CO.				▮ TEST OPERATION		550,000 Nm³/H — DE-NO$_x$ [2] — TO STACK — AH — BOILER — MC LTEP — IDF — BF GGH — DE-SO$_x$

Fig. 3: Test schedule for pilot and demonstration SCR systems for coal-fired boilers
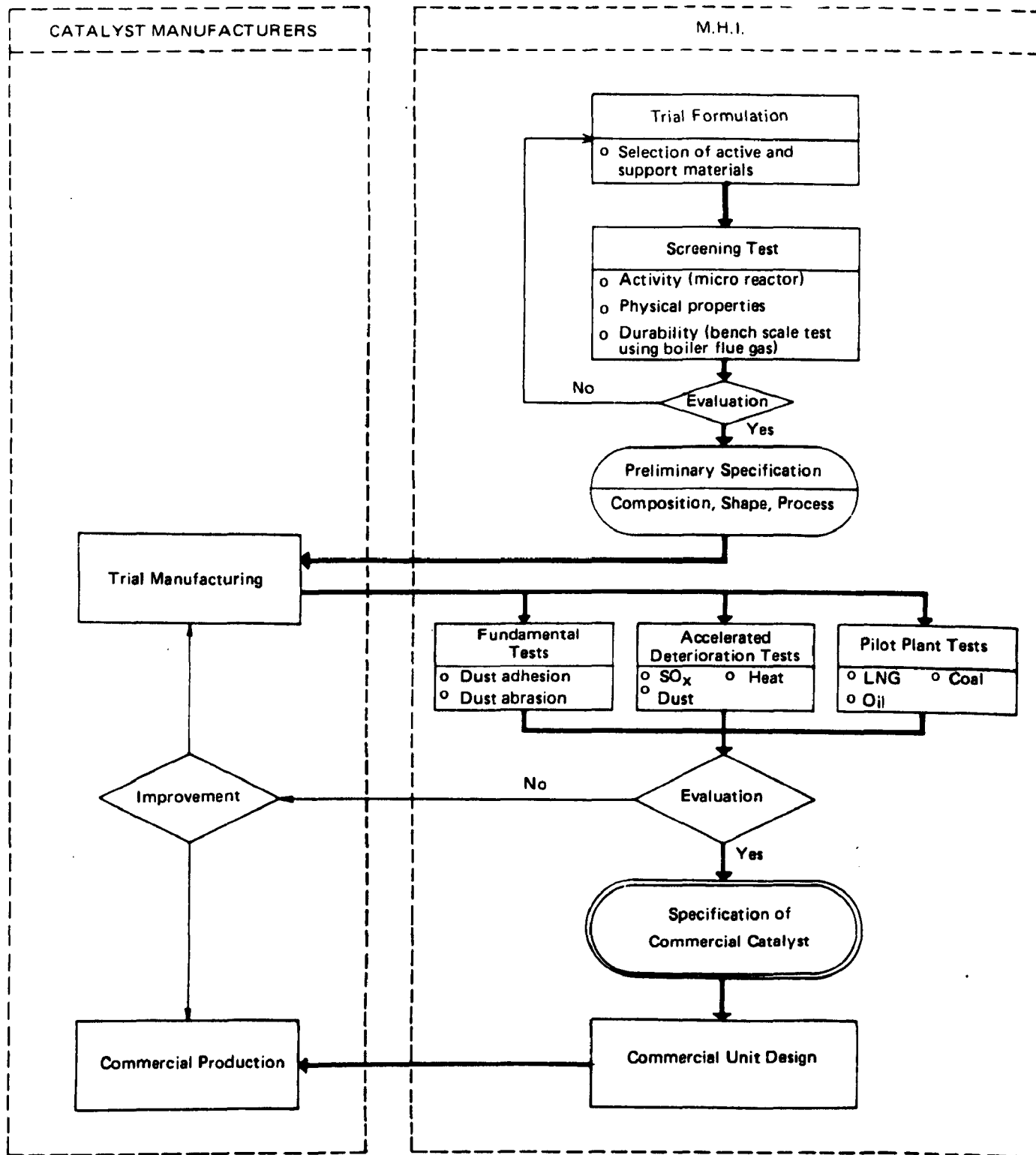
Fig. 4: Development of NOx reduction catalyst
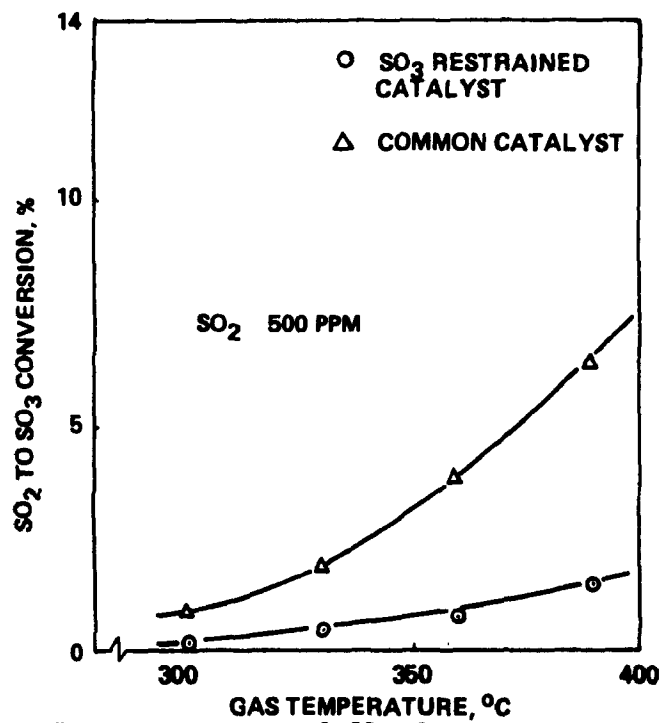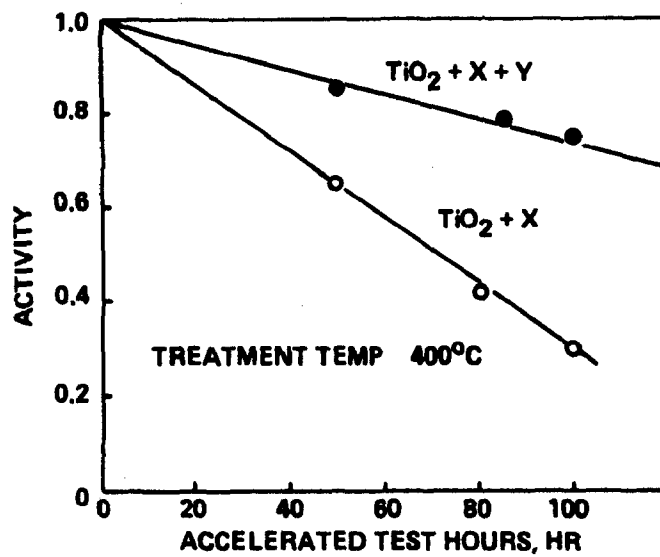
Fig. 5: Generation of SO_3 due to catalyst

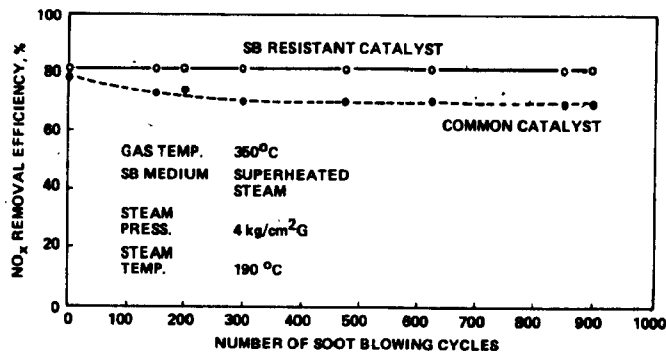Fig. 6: Test results of accelerated deterioration test with alkalimetal sulfat
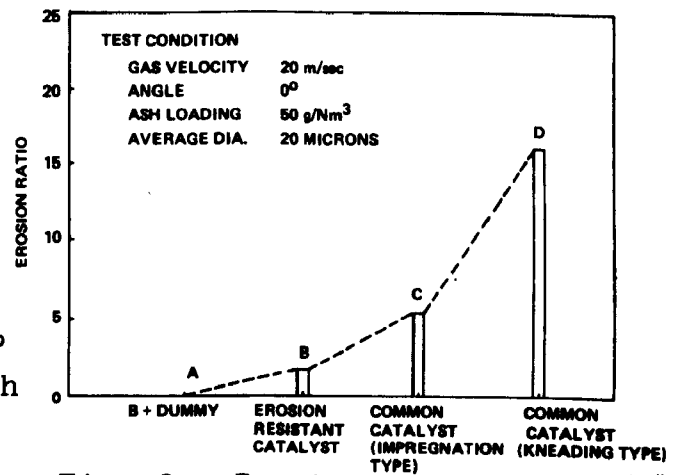
Fig.7: Endurance test results with soot blowing
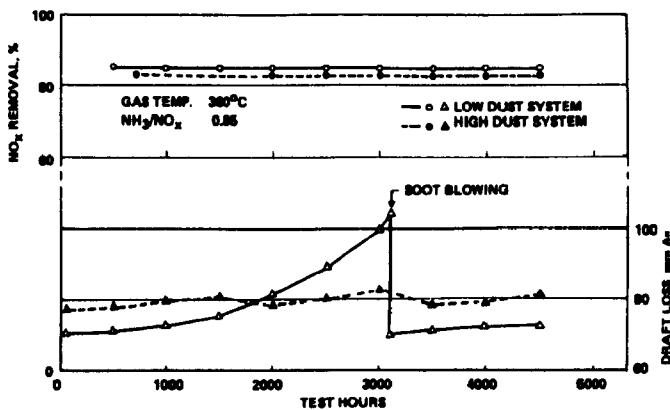
Fig. 8: Results of accelerated erosion test
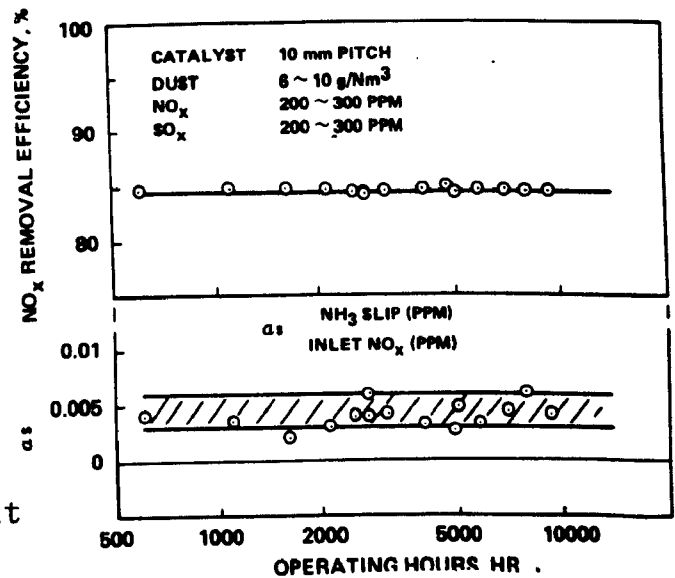
Fig. 9: Test results of pilot plant at DM-600 project

Fig. 10: Test results of TTJM project

432

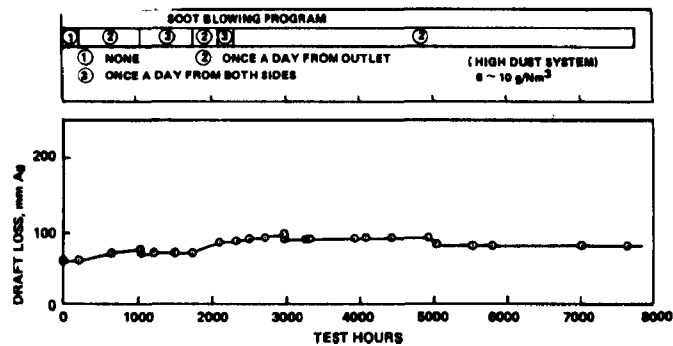**SOOT BLOWING PROGRAM**

① NONE   ② ONCE A DAY FROM OUTLET   (HIGH DUST SYSTEM)
③ ONCE A DAY FROM BOTH SIDES   8 ~ 10 g/Nm³

Fig. 11:   Results of air heater air side draft loss versus soot blow-
ing at TTJM

SOOT BLOWING PROGRAM

① NONE   ② 3 TIMES A DAY FROM OUTLET   (LOW DUST SYSTEM)
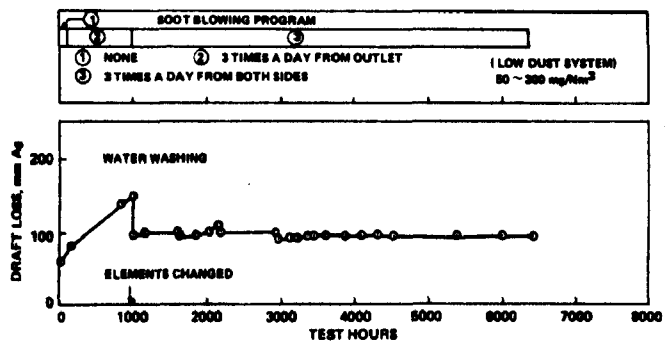③ 3 TIMES A DAY FROM BOTH SIDES   50 ~ 300 mg/Nm³

Fig. 12:   Results of air heater air side draft loss versus soot
blowing at TTJM

433
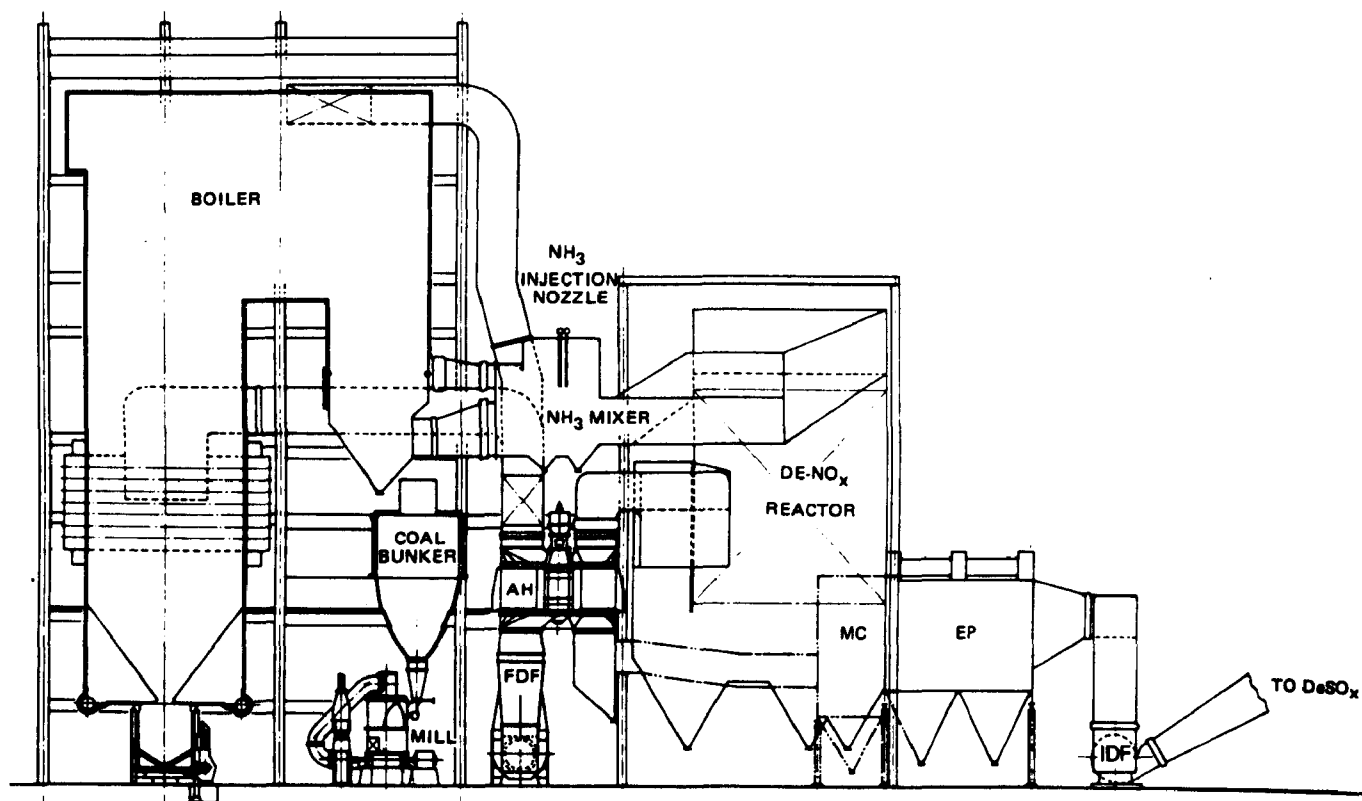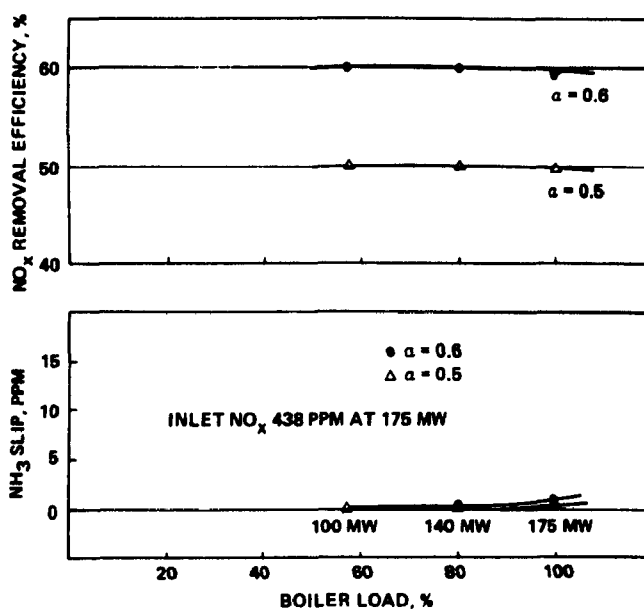
Fig. 13: General arrangement at Shimonoseki No. 1 boiler

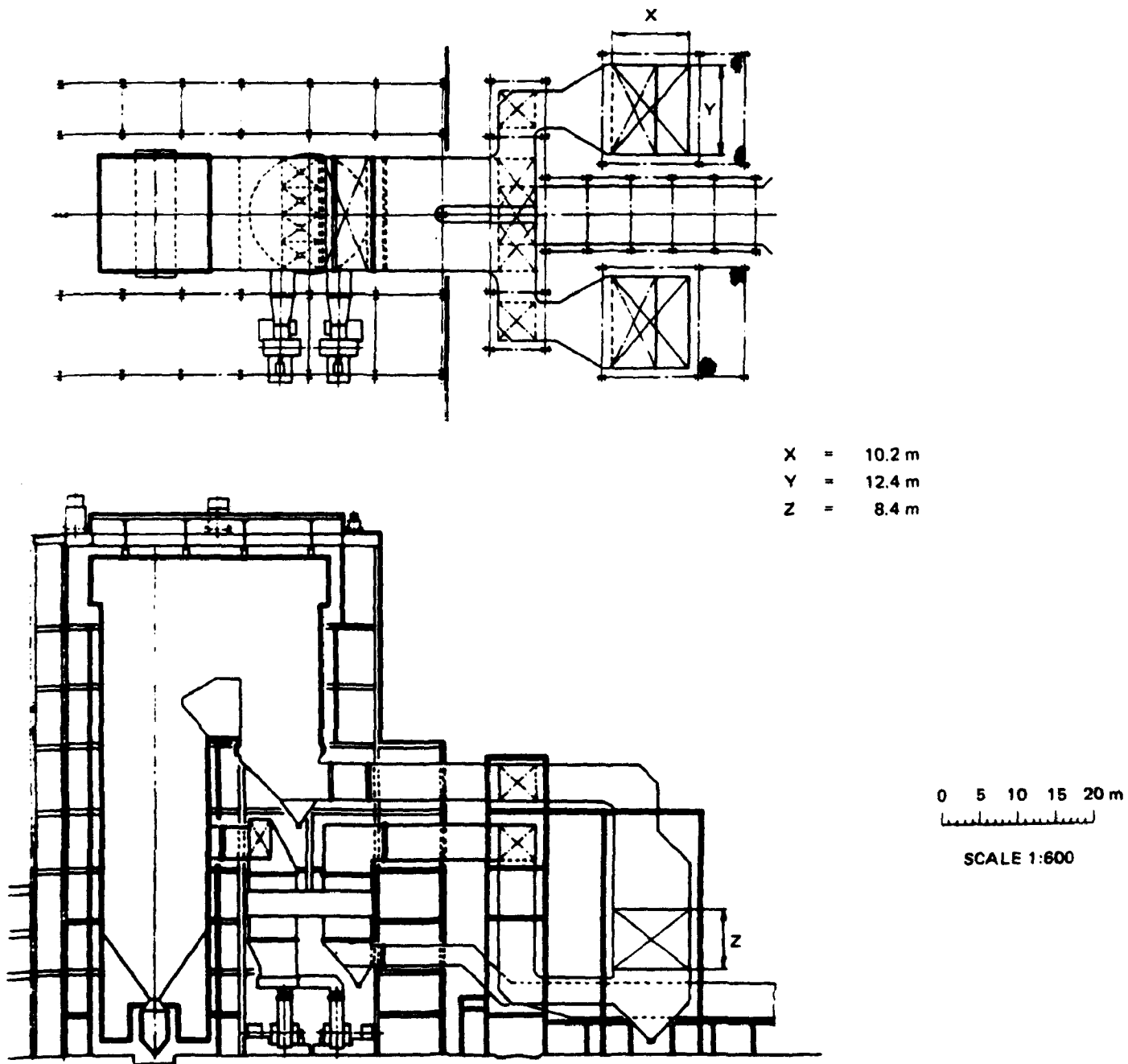Fig. 14: Initial performance test results at Shimonoseki No. 1 unit

X = 10.2 m
Y = 12.4 m
Z = 8.4 m

0 5 10 15 20 m

SCALE 1:600

Fig. 15: General arrangement of 500 MW coal-fired boiler
          with SCR system (Case I)

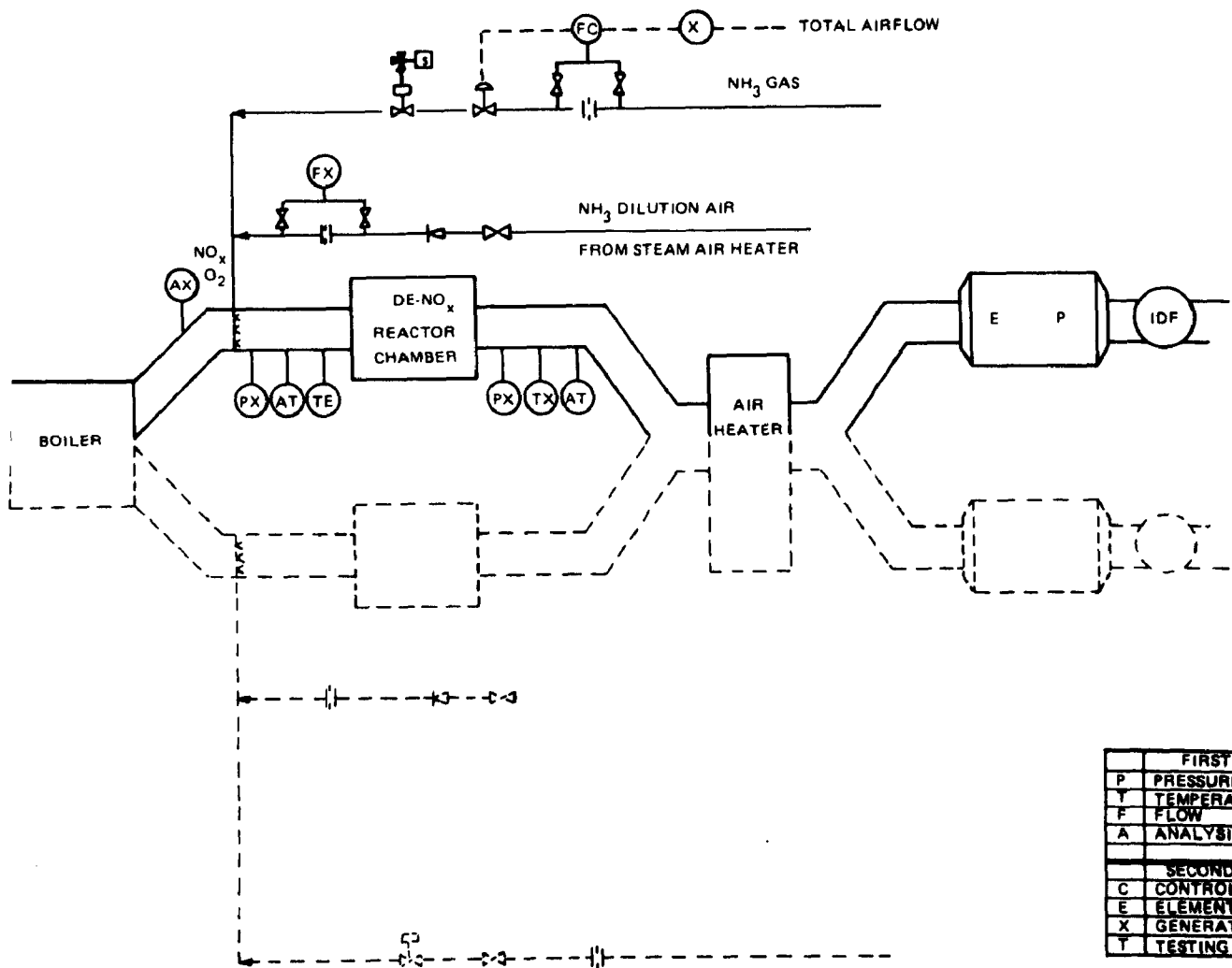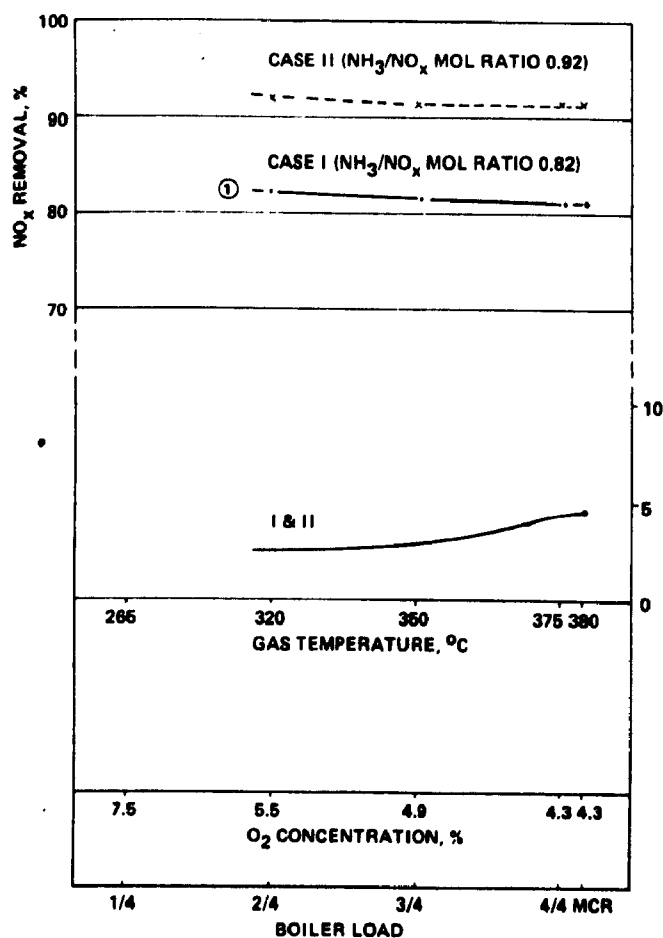|	FIRST
P	PRESSURE
T	TEMPERATURE
F	FLOW
A	ANALYSIS
	SECOND
C	CONTROLLER
E	ELEMENT
X	GENERATOR
T	TESTING

Fig. 16: P & I diagram of the SCR system

Fig. 17: Predicted NOx removal
performance versus boiler
load
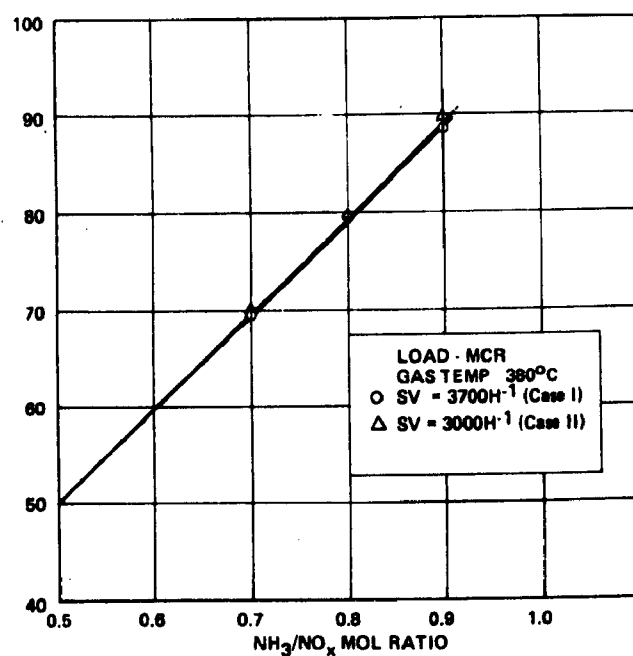
Fig. 18: Predicted NOx
efficiency vs
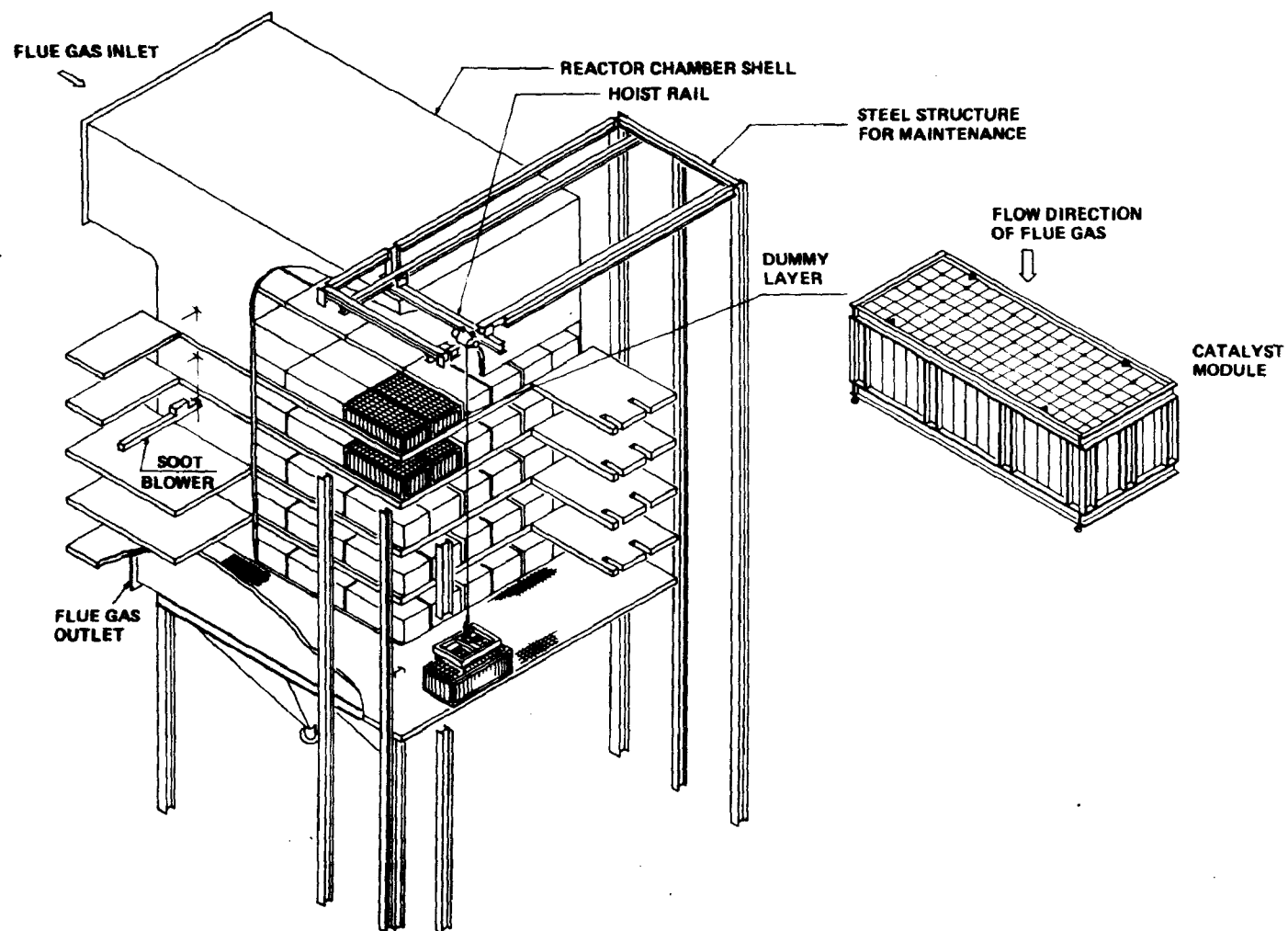NH$_3$/NOx mol ratio

437

FLUE GAS INLET

REACTOR CHAMBER SHELL

HOIST RAIL

STEEL STRUCTURE
FOR MAINTENANCE

FLOW DIRECTION
OF FLUE GAS

DUMMY
LAYER

CATALYST
MODULE

SOOT
BLOWER

FLUE GAS
OUTLET

438

Fig. 19: Cutaway view of Reactor Chamber

TABLE I
SUPPLY LIST OF MHI SCR SYSTEM

Fuel	Plant Site	Boiler Capacity	Type of Catalyst	N/R	Time of Delivery
LNG	Kyushu Electric, Shinkokura 3	600 MW	Pellet	N	6, 1978
	Kyushu Electric, Shinkokura 4	600 MW	Pellet	N	6, 1979
	Osaka Gas Co., Senpoku Plant	20 t/h	Pellet	N	12, 1976
	Osaka Gas Co., Senpoku Plant	20 t/h	Pellet	N	12, 1976
	Aito Co., Chita Factory	30 t/h	Pellet	N	5, 1978
	Aito Co., Chita Factory	30 t/h	Pellet	N	5, 1978
	Aito Co., Chita Factory	30 t/h	Pellet	N	5, 1978
	Dainippon Ink Co., Sakai Factory	30 t/h	Pellet	N	2, 1980
	TK Plant (LNG & BFG)	395 MW	Grid	R	5, 1981
Oil	Sumitomo Chemical Co., Sodegaura	370 t/h	Pellet	R	1, 1976
	Fuji Oil Co., Sodegaura Refinery	160 t/h	Grid	N	12, 1977
	Tokyo Electric, Yokosuka 4	350 MW	Grid	R	2, 1978
	Kansai Electric, Osaka 1	156 MW	Grid	R	6, 1978
	Chubu Electric, Chita 4	700 MW	Grid	R	11, 1979
	Kansai Electric, Osaka 3	156 MW	Grid	R	7, 1980
	Kansai Electric, Osaka 4	156 MW	Grid	R	12, 1979
	Kansai Electric, Sakaiko 1	250 MW	Grid	R	7, 1980
	Kansai Electric, Sakaiko 6	250 MW	Grid	R	12, 1979
	Chugoku Electric, Iwakuni 2	350 MW	Grid	R	12, 1980
	Chugoku Electric, Iwakuni 3	500 MW	Grid	N	4, 1981
	Chubu Electric, Atsumi 3	700 MW	Grid	N	12, 1980
	Chubu Electric, Atsumi 4	700 MW	Grid	N	2, 1981
	Chubu Electric, Shinnagoya 3	220 MW	Grid	R	7, 1980
	Kansai Electric, Osaka 2	156 MW	Grid	R	7, 1981
	Kansai Electric, Tanagawa 3	156 MW	Grid	R	8, 1981
	Kansai Electric, Tanagawa 4	156 MW	Grid	R	3, 1981
	Kansai Electric, Sakaiko 2	250 MW	Grid	R	9, 1981
	Kansai Electric, Sakaiko 4	250 MW	Grid	R	2, 1981
	Kansai Electric, Sakaiko 7	250 MW	Grid	R	9, 1981
	KK Plant	600 MW	Grid	R	7, 1982
Coal	Chugoku Electric, Shimonoseki 1	175 MW	Grid	R	4, 1980
	Joban Electric, Nakoso 8	700 MW	Grid	N	12, 1982
	Chugoku Electric, Shinube 1	75 MW	Grid	R	8, 1982
	Chugoku Electric, Shinube 2	75 MW	Grid	R	7, 1982
	Chugoku Electric, Shinube 3	156 MW	Grid	R	6, 1982
	KM Plant	156 MW	Grid	R	3, 1983

Remarks: N/R   N: New unit
R: Retrofit

TABLE II
DESIGN CONDITIONS—SHIMONOSEKI NO. 1 SCR SYSTEM

Boiler

Type	Mitsubishi—C-E Controlled Circulation® boiler-CCRR
Evaporation	540 t/h
Fuel	Australian bituminous coal and oil
Unit capacity	175 MW

NO_x Removal System

Type	Selective Catalytic Reduction
Gas flow	550,000 Nm³/h
Reactor	Vertical down-flow fixed bed
Catalyst	Grid type—10 mm pitch
S_V nominal	3000 H⁻¹
Inlet NO_x concentration	500 ppm
NO_x removal efficiency	51%
Ammonia slip (target)	5 ppm max.
Dust concentration	about 20 g/Nm³

TABLE III
DESIGN CONDITION OF AN SCR SYSTEM FOR A 500-MW COAL-FIRED BOILER

	Case I	Case II
NO_x value at system inlet	500 ppm	500 ppm
NO_x value at system outlet	100 ppm	50 ppm
NO_x removal efficiency	80%	90%
Ammonia slip	less than 5 ppm	less than 5 ppm
Catalyst life (target)	24 months	24 months
Mole ratio (NH_3/NO_x)	0.81	0.91

Gas conditions leaving the boiler

Gas flow rate	1,553,000 Nm³/H
Gas temperature	380 °C
Oxygen	4.3%
Sulfur dioxide	1,350 ppm
Sulfur trioxide	14 ppm
Particulate	15 g/Nm³

TABLE IV
SCR SYSTEM REACTOR CHAMBER SPECIFICATION FOR A 500-MW COAL-FIRED BOILER

		Case I	Case II
Type		Fixed bed	Fixed bed
Number		Two	Two
Direction of gas flow		Vertical down	Vertical down
Size	Width	12.4 m	12.4 m
	Height	8.4 m	11.0 m
	Length	10.2 m	10.2 m
Catalyst volume		404 m³	480 m³
Catalyst shape		Grid— 7 mm pitch	Grid— 7 mm pitch
Number of layers		Three	Four
Superficial gas velocity		5.5 m/s	5.5 m/sec
Draft loss thru reactor		less than 75 mm H₂O	less than 90 mm H₂O

APPLICABILITY OF THERMAL DeNO$_x$
TO LARGE INDUSTRIAL BOILERS

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ABSTRACT

Exxon Research and Engineering Company has developed and successfully applied a process called Thermal DeNO$_x$ for removing oxides of nitrogen (NO$_x$) from flue gas in stationary combustion sources. This non-catalytic process is based on a gas phase homogeneous reaction. The technology involves injection of ammonia (NH$_3$) and hydrogen (H$_2$) into the hot flue gas within a prescribed temperature range.

Thermal DeNO$_x$ has been commercially demonstrated in gas and oil-fired steam boilers, utility boilers and process furnaces. Successful tests have also been conducted on a municipal incinerator and an oil field steam generator. Tests on flue gas generated by coal combustion have demonstrated the applicability of the process to coal-fired boilers.

Cost effectiveness of the process is superior to other competing flue gas treatment processes in most applications. Also, Thermal DeNO$_x$ is not as capital intensive as competing processes and can be applied with similar cost and performance effectiveness for either grass roots or retrofit applications.

APPLICABILITY OF THERMAL DeNO$_x$
TO LARGE INDUSTRIAL BOILERS

INTRODUCTION

Exxon Research and Engineering Company has developed and successfully applied a process (3) called Thermal DeNO$_x$ for removing oxides of nitrogen (NO$_x$) from flue gas in stationary combustion sources. This non-catalytic process is based on a gas phase homogeneous reaction (2, 5). The technology involves injection of ammonia (NH$_3$) into the hot flue gas within a narrow and critical temperature range. This temperature range can be significantly expanded through the additional injection of hydrogen. The NO$_x$ reduction is essentially independent of the concentration of oxides of sulfur or particulate matter in the flue gas.

Thermal DeNO$_x$ has been commercially demonstrated in gas and oil-fired steam boilers, utility boilers and process furnaces. Successful tests have also been conducted on a municipal incinerator and an oil field steam generator. Tests on flue gas generated by coal combustion have demonstrated the applicability of the process to coal-fired utility boilers, but there is no commercial experience to date. In full-scale retrofit commercial demonstrations conducted by Toa Nenryo Kogyo K.K. and Tonen Sekiyu Kagaku K.K. at their Kawasaki, Japan, plants, NO$_x$ reductions exceeding 60% were achieved (see Figure 9).

Cost effectiveness of the process is superior to other competing flue gas treatment processes in most applications. Also, Thermal DeNO$_x$ is not as capital intensive as competing processes and can be applied with similar cost and performance effectiveness for either grass roots or retrofit applications. Therefore, Thermal DeNO$_x$ offers a practical alternative in the field of NO$_x$ pollution control.

443

In general, Thermal DeNO$_x$ can effect reductions in NO$_x$ emissions of up to 70% compared to the 90% reduction achievable in other processes. The specific level of DeNO$_x$ is dependent upon a number of factors, including the design or type of fired equipment, operating mode, and initial NO$_x$ level. R&D work is continuing on this process to improve its DeNO$_x$ performance and overall process design.

Thermal DeNO$_x$ may be applied to boilers for additional NO$_x$ reduction after combustion modifications have been made. Alternatively, in the event combustion modifications result in unacceptable losses in load capacity, Thermal DeNO$_x$ may be applied without these modifications.

PROCESS CHEMISTRY REVIEWED

The process chemistry relies on the selective reaction between NH$_3$ and NO$_x$ to produce nitrogen and water. This reaction proceeds in the presence of excess oxygen within a prescribed temperature range. The overall NO$_x$ reduction and production reactions are summarized in equations (1) and (2), respectively.

$$NO + NH_3 + O_2 + (H_2) = N_2 + H_2O \qquad (1)$$

$$NH_3 + O_2 = NO + H_2O \qquad (2)$$
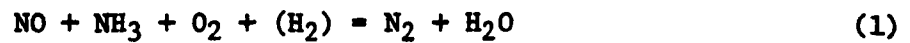
In typical flue gas environments, the NO reduction shown as equation (1) dominates at temperatures around 1740°F (950°C). At higher temperatures, the NO production reaction shown as equation (2) becomes significant, and above 2000°F (1090°C), the injection of NH$_3$ is contraproductive, causing increased NO. As temperatures are reduced below 1600°F (850°C), the rate of both reactions becomes extremely low, the NO reduction falls off drastically, and the NH$_3$ flows through unreacted.

These very rapid changes of NO reduction with temperature are shown most clearly in Exxon's published laboratory data (4). The data shown in Figure 1 is typical of laboratory results.

Exxon's technology also includes means of altering the usable temperature range. The addition of hydrogen (H$_2$) extends the temperature window over a wide temperature range as shown by the laboratory data in Figure 2. At H$_2$/NH$_3$ ratios on the order of 2:1, the NO$_x$ reduction can be forced to proceed rapidly

at 1290°F (700°C). By judiciously selecting the H_2/NH_3 injection ratio, $DeNO_x$ performance can be optimized at any intermediate temperature such that the overall temperature window is as shown in Figure 3. This temperature flexibility provides load following capability on boilers and industrial heaters.

TEMPERATURE "WINDOWS" IN INDUSTRIAL BOILERS

A typical window location for industrial boilers is usually found either within the superheater tube bank or between the superheater tube bank and the steam generator tube bank. Figures 4 and 5 illustrate an injection location for a package type boiler having two symmetrical generating tube banks situated on each side of the combustion chamber. Three injectors are located interbank on each side to provide complete coverage.

The injectors for a typical field erected, cross drum design boiler are shown in Figure 6. In this boiler the injectors are located within a superheater cavity such as might be supplied for sootblowers. Support guides for the injectors are provided from attachments to the superheater tubes.

MAJOR FACTORS AFFECTING PERFORMANCE

The major factors affecting Thermal $DeNO_x$ performance are shown in Table 1. In addition to temperature and the use of NH_3 and H_2 these include:

- Residence time at temperature
- Temperature profile
- Initial NO_x
- NH_3/NO_x ratio
- Mixing

Maximizing residence time at temperature tends to enhance $DeNO_x$ performance. Typical ranges of residence time are from less than 0.1 second to greater than 1 second. In order to achieve high performance without sacrificing significant space in the boiler, residence times of 0.2 to 0.3 seconds are preferred. The most common method of providing residence time at temperature is by injecting NH_3 at the upstream side of a cavity in the tube bank as shown in Figures 4, 5, and 6.

445

Flue gas temperature profile at the injection plane is important in Thermal DeNO$_x$ performance since wide variations in temperature may result in a lowering of overall performance. Variations of $\pm 100°F$ (56°C) can usually be accommodated without effecting performance. Larger variations may require hydrogen injection in the lower temperature zone(s) of the injection plane in order to maintain acceptable performance.

In order to accommodate temperature changes in the post-combustion zone of a boiler resulting from changes in boiler load, more than one ammonia injection grid may be required in order to maintain satisfactory DeNO$_x$ performance. For example, as load is reduced from full to 50%, the temperature for optimum Thermal DeNO$_x$ will shift toward the fire box. Temperature shifts can also occur in coal fired boilers due to slagging, type of coal, changes in excess O$_2$ and other operational variations. In addition, the use of hydrogen with its ability to widen the effective DeNO$_x$ temperature window increases the capability to deal with a wide range of boiler operating conditions. Selection of grid locations can be accomplished by temperature measurement in the case of existing boilers or in conjunction with boiler vendor performance predictions in the case of grass roots designs.

The process is also sensitive to initial NO$_x$ and NH$_3$ concentrations. The NH$_3$ injection rate is generally expressed as a mole ratio relative to the initial NO$_x$ concentration. NH$_3$/NO$_x$ ratios of 1.5 are common for initial NO$_x$ levels of 200 vppm and less. As initial NO$_x$ concentration increases, the ratio is reduced toward 1.0. Ammonia breakthrough levels are generally below 50 vppm.

NEW MIXING TECHNOLOGY BOOSTS PERFORMANCE

Recent innovations in mixing techniques have led to substantially increased performance capability with the Thermal DeNO$_x$ process. This is especially true in short residence time situations normally encountered in utility and industrial boiler applications.

For comparison purposes, three NH$_3$ injection/mixing techniques are shown on Figure 7. You will note that substantial improvements in performance have been achieved through development of an improved NH$_3$ injection technique. These data have been taken in our 30 MBtu/hr (8.8 MW) pilot plant test furnace.

In addition, pilot plant testing has shown that staged injection of hydrogen utilizing two grids in succession results in further increases in performance. These technological advances will result in performance predictions in the range of 70% or more for grass roots utility boiler applications and 60% to 70% for retrofit applications.

The impact of these advances in technology are illustrated in Figure 8. This figure shows performance predictions for a retrofit utility boiler application for three different conditions:

- single grid, no H_2
- single grid, zoned H_2
- two grids with staged H_2

A maximum performance improvement at 100% load of 24 DeNO$_x$ percentage points (from 41% to 65%) is possible here through utilization of the new technology.

PROVEN PERFORMANCE

Thermal DeNO$_x$ has been successfully demonstrated in gas and oil-fired utility boilers, package and field erected industrial boilers, process furnaces and oil field steamers as summarized in Table 2. Actual performance often represents a compromise between the technical limits of the process chemistry and cost effectiveness. In many situations, performance is maximized at full load operation, and smaller NO$_x$ reductions accepted at reduced loads with the lower reaction zone temperatures. In such installations, total NO$_x$ emissions are generally at target levels over the full spectrum of operating conditions because of the reduced NO$_x$ production rate at lower loads. Results from seven demonstrations are shown over their range of operating conditions as a function of flue gas temperature in Figure 9. Please note that these units incorporate earlier mixing technology and thus performance shown is generally lower than would be achieved with updated technology.

Alternative designs are available to suit the load demands of the particular boiler or furnace. Of the units installed to date, some have been designed for base load operation, while others accommodate all operating conditions from 50-100% of design capacity. As another example, one boiler in which Thermal DeNO$_x$ was installed operates between 35 and 50% of design, and the process was designed for these load conditions.

Applicability and effectiveness will vary from one unit to the next depending on local flue gas conditions and on the configuration of the high temperature zones. Preliminary estimates of performance expected to be achieved for retrofitting Thermal DeNO$_x$ into existing units can be made on the basis of engineering drawings and design specifications. Exxon can also provide recommendations for designing new boilers and furnaces and for modifying existing designs so as to maximize the efficiency of the process.

Most of the development of the Thermal DeNO$_x$ process has taken place on oil-fired sources, essentially free of fly ash. Fly ash from coal firing may deposit on injector grids, change gas flow patterns and temperature profiles and foul or erode injection nozzles. The extent to which reliable performance can be provided under these conditions remains to be proven. We do not feel significant or insuperable problems will arise. However, we would propose a demonstration test be performed to evaluate these factors on an existing boiler. Details of this demonstration test can be provided upon request.

WHAT ABOUT REACTIONS WITH SULFUR?

Detailed laboratory experiments have shown there are no reactions between the Thermal DeNO$_x$ process and sulfur compounds in the high temperature flue gas regions. That is, sulfur or its oxides do not interfere with the NH_3-NO_x-O_2-H_2 chemistry. Additionally, ammonia injection has been shown to cause neither additional homogenous nor additional heterogeneous oxidation of SO_2 to SO_3.

To the extent that the thermal reduction of NO_x leaves some NH_3 unreacted, and as the combustion gases cool, NH_3 reacts with SO_3 and H_2O to form ammonium sulfate ((NH_4)$_2SO_4$) and/or ammonium bisulfate (NH_4HSO_4). Ammonium sulfate is a dry solid which forms directly from the gaseous reactants without passing through the liquid state. It is not corrosive or appreciably hygroscopic. When the sulfate is formed in flue gas the resulting particles are on the order of 1-3 microns. Thus the sulfate should pass through the air preheater with very little deposition. When heated, ammonium sulfate decomposes to ammonium bisulfate and gaseous ammonia.

Ammonium bisulfate is a sticky liquid at air preheater temperatures. The melting point of pure ammonium bisulfate is 297°F (147°C), which is below the temperature of the flue gas leaving most air preheaters, but is above the metal

temperature. However, the presence of H_2SO_4 or small amounts of ammonium sulfate depress the melting point to about 266°F (130°C). So ammonium bisulfate deposits should be liquid throughout most of the air preheater, with solid deposits only at the extreme cold end. The sticky liquid is corrosive and tends to trap ash and soot particles, accelerating the rate of deposit build-up.

Ammonium bisulfate formation can be minimized by either of three principal means:

- Limiting NH_3 breakthrough to 5 vppm or less.
- Maintaining flue gas temperature at the preheater outlet above 400°F (204°C).
- Maintaining an $NH_3:SO_3$ molar ratio above 2.0 and providing sufficient residence time for the reactants to form ammonium sulfate rather than bisulfate.

In most cases the last method is the most practical for application with the Thermal DeNO$_x$ process, since typical NH_3 breakthrough levels (approximately 50 vppm) are usually twice that of SO_3. Also, maintaining a high flue gas outlet temperature is impractical since this represents a 2-3% loss in thermal efficiency for many boilers. A summary of the fouling/corrosion potential of ammonium sulfates as a function of NH_3 and SO_3 concentrations in flue gas is presented in Figure 10.

Based on laboratory and commercial tests with oil firing, these sulfates when in combination in ash deposits do not create either severe corrosion or unacceptable air preheater fouling problems when Thermal DeNO$_x$ is used in accordance with its design specifications. However, we would expect both fouling and corrosion to increase if bisulfate formation is not curtailed. In addition, long term tests conducted in two oil-fired boilers by Tonen Sekiyu Kagaku K.K. in Kawasaki, Japan, revealed sulfate/bisulfate deposits could easily be removed by waterwashing the air preheaters at reasonable intervals.

ENGINEERING CONSIDERATIONS

Although the chemistry is straightforward, certain difficulties must be overcome when applying the process to commercial equipment. Performance is generally limited by the access to the required flue gas temperature range of the reaction, and the dependence of the reaction on the local concentrations

449

of reactants, NH_3, NO_x, O_2, and H_2. Exxon's technology provides a means of adapting the chemistry requirements to industrial equipment environments, and significant NO_x reductions can be achieved by the use of Thermal $DeNO_x$ technology in existing boilers. Application to new, grass-roots designs is usually easier because the internal configuration of the cavity at the required temperature can be readily adjusted to complement the process demands.

Accommodating flue gas temperature variations is important if high $DeNO_x$ rates are to be achieved. Not only does the system have to accommodate flue gas temperature changes caused by normal load and operating variations, but it also must allow for fluctuations across the reaction zone caused by non-uniformities in flow and heat transfer. It follows, therefore, that a case-by-case evaluation of flue gas temperatures and local conditions is required for the application of Thermal $DeNO_x$ for each installation considered.

Initially, ammonia was injected only into boiler cavities, boiler regions between tube banks, which can be considered to be isothermal to a first approximation. Subsequent experimentation by Exxon Research has shown the feasibility of injecting ammonia into boiler tube bank regions as well. Thus, satisfactory NO reduction performance can be obtained by locating the injector grid in either the boiler convection pass cavities or tube bank. The ability to inject ammonia at virtually any post-combustion boiler location where temperatures range from 1292 to 1994°F (700 to 1090°C) has substantially increased the flexibility of the Exxon Thermal $DeNO_x$ Process.

SUPERIOR COST EFFECTIVENESS

The Thermal $DeNO_x$ process offers one of the most practical approaches to significant NO_x reduction from stationary fired equipment of any post-combustion NO_x removal process currently on the market. This is due to the fact that the process is far less capital intensive and achieves superior cost effectiveness even though NO_x reduction levels are somewhat lower than other processes.

In order to demonstrate cost effectiveness of the process, a 200,000 lb/hr (91 t/hr) industrial boiler has been chosen for illustration purposes. A Thermal $DeNO_x$ equipment sizing basis is presented in Table 3 and a simplified flow diagram is shown on Figure 11. It is assumed that the boiler is oil or gas

fired and has an uncontrolled NO_x level of 200 vppm corrected to 3% O_2 dry. The boiler is to be equipped with a single grid capable of injecting both NH_3 and H_2 via a steam carrier. A one month NH_3 storage capacity has been provided, and H_2 is supplied through an ammonia dissociator.

The total erected capital investment for these facilities is estimated to be $472,000 as outlined in Table 4. Direct costs include the material and labor for equipment outlined in Table 3 plus interconnecting piping. Indirect costs include field labor overheads, construction superivision and equipment, labor wage taxes, erection fee, engineering costs, and licensing fee. Contingency is based on 30% of direct, plus indirect cost less licensing fee. Costs are expressed at 1Q81 southern California level. Excluded from these costs are such items as land and owners charges.

Cost effectiveness for the sample boiler installation is also shown in Table 4 for three different bases. Annualized costs are obtained by assuming a five year payout on investment plus annual operating costs. On a heat fired basis, cost effectiveness of the process is $0.13 per M Btu (.04 mill/kWh). The cost effectiveness based on NO_x removed is $1.51 k/US ton NO_2 ($1.66 k/t NO_2) for a $DeNO_x$ efficiency of 60% and $1.29 k/US ton NO_2 ($1.42 k/t NO_2) for 70% $DeNO_x$. This cost compares favorably with some combustion modification techniques such as burners out of service and flue gas recirculation, and is substantially lower than selective catalytic reduction.

Annual operating costs are shown in Table 5. These costs are based on a 65% annual load factor and include values for NH_3, power and steam consumption and maintenance material and labor.

SUMMARY

In summary, Thermal $DeNO_x$ represents one of the most practical and cost effective means of flue gas treatment for NO_x control currently available in the market place. As the requirement for control of NO_x emissions becomes more stringent and more widespread, application of NO_x control technology will become necessary in many areas of the U.S.A. Recent technological advances have resulted in significant increases in Thermal $DeNO_x$ performance with negligible increase in investment thus further improving its cost effectiveness. No

technological difficulties are foreseen in applying Thermal DeNO$_x$ to all types of industrial boilers including coal fired, but a test in a coal fired boiler is needed to demonstrate the applicability of the technology and optimize engineering design considerations.

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FIGURE 1

TEMPERATURE "WINDOW" FOR THERMAL DENOx
REACTION-NH3 ONLY

NH_3/NO_i = 1.7

O_2 = 2.0%

RESIDENCE TIME
(@ 1900°F) = 0.1 sec

$H_2/NH_3 = 0$

EFFLUENT NO_X, VPPM

AVERAGE FLUE GAS TEMPERATURE, °C

455
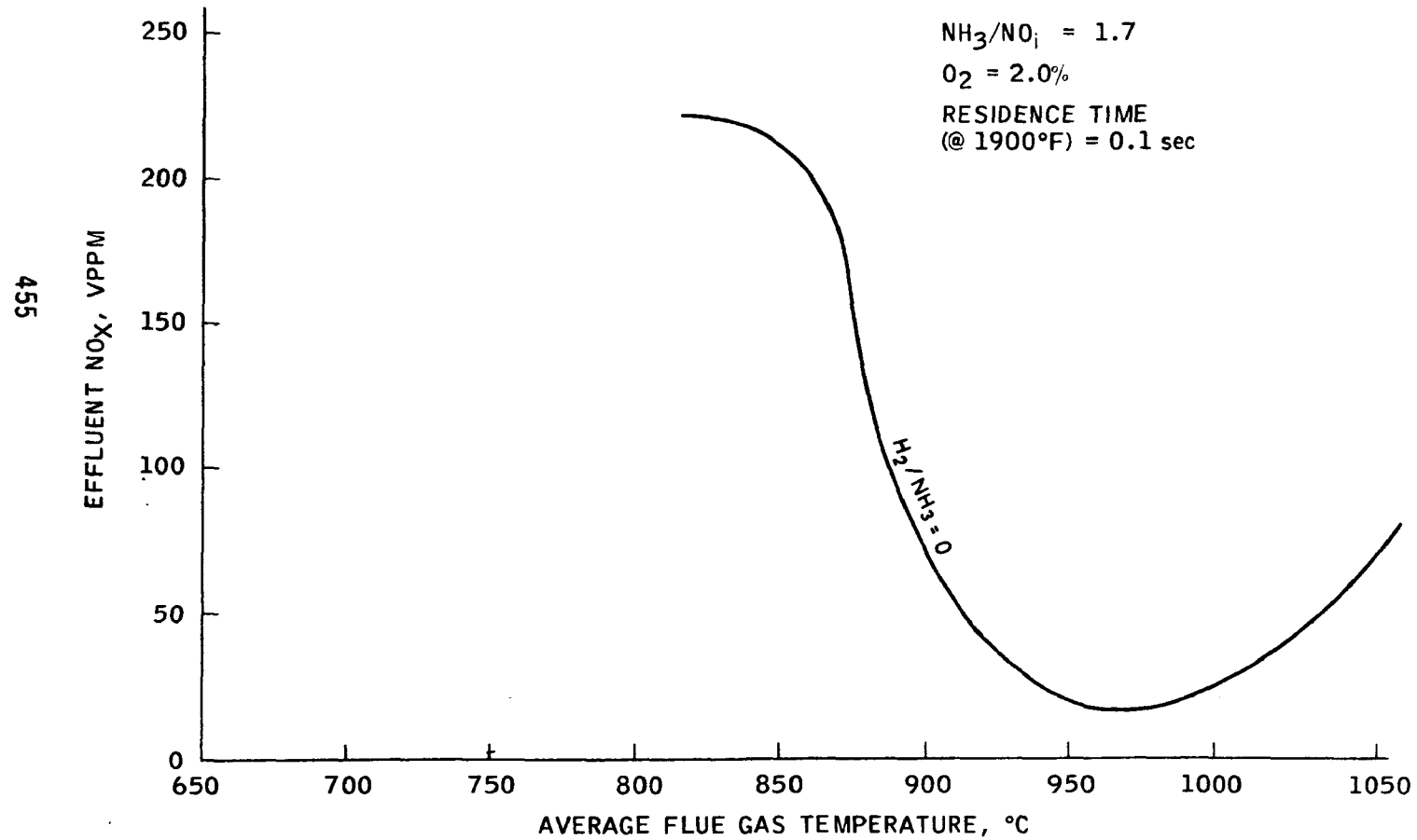
FIGURE 2

TEMPERATURE "WINDOW" FOR THERMAL DENOx REACTION-H2+NH3

$NH_3/NO_i = 1.7$

$O_2 = 2.0\%$

RESIDENCE TIME
(@ 1900°F) = 0.1 sec

EFFLUENT NO_x, VPPM

$H_2/NH_3 = 2.4$

$H_2/NH_3 = 1.3$

$H_2/NH_3 = 0.5$

$H_2/NH_3 = 0.13$

$H_2/NH_3 = 0$

AVERAGE FLUE GAS TEMPERATURE, °C
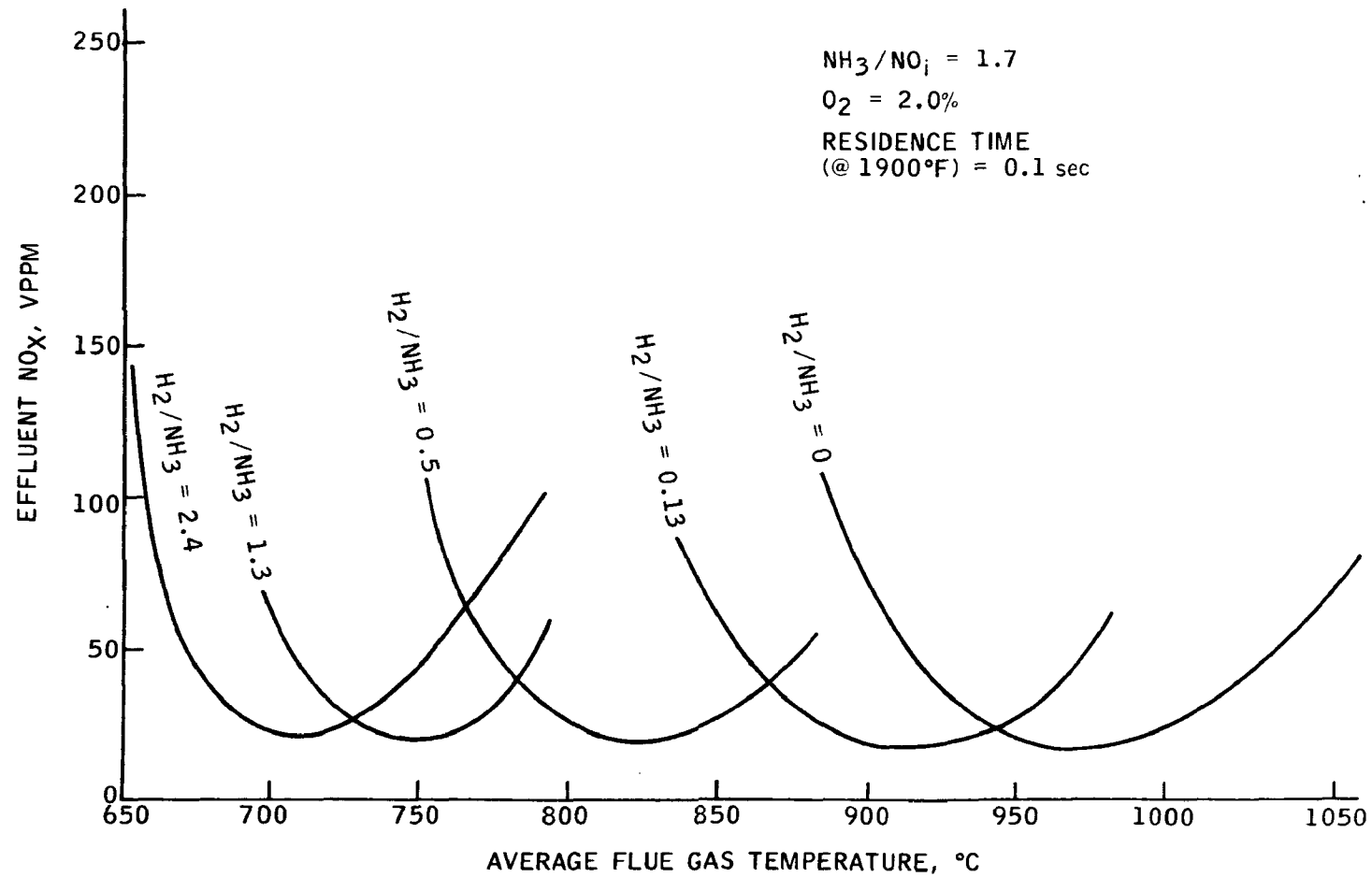
FIGURE 3

TEMPERATURE "WINDOW" FOR THERMAL DENOx REACTION

$NH_3/NO_i = 1.7$

$O_2 = 2.0\%$

RESIDENCE TIME

(@ 1900° F) = 0.1 sec

EFFLUENT NO_X, VPPM

$H_2/NH_3 = 2.4$

$H_2/NH_3 = 0.0$

AVERAGE FLUE GAS TEMPERATURE, °C
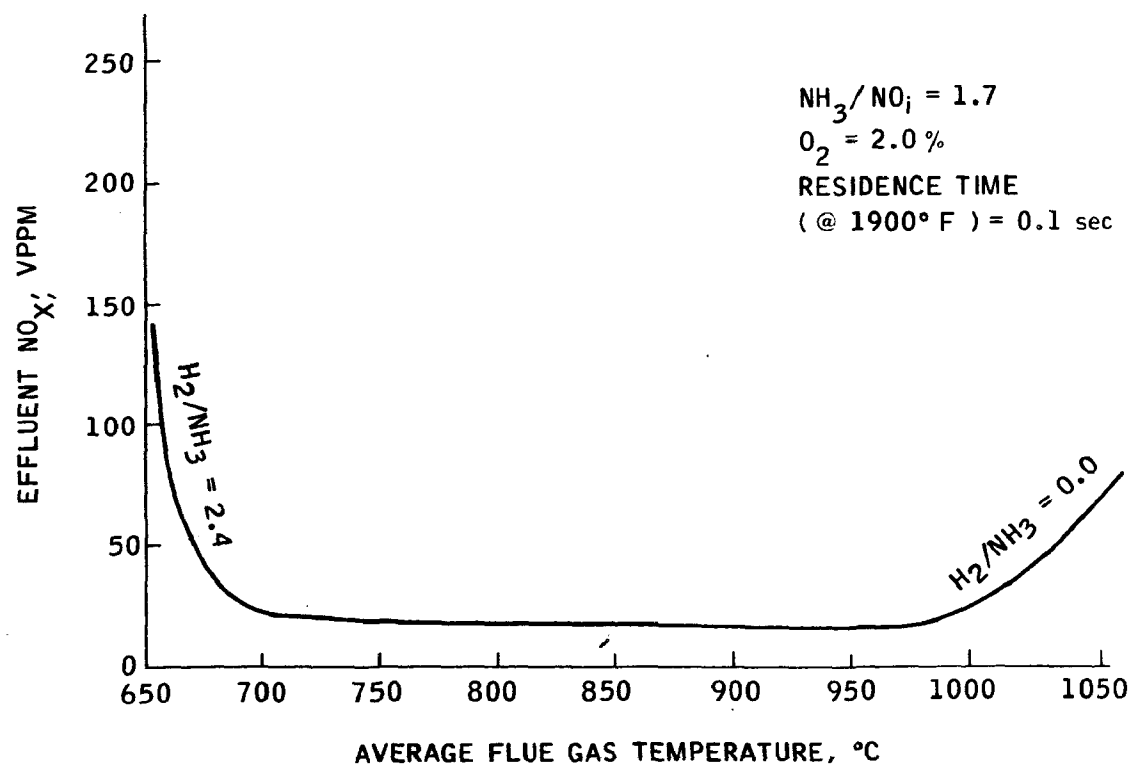
FIGURE 4

TYPICAL PACKAGE BOILER THERMAL DENOx INJECTOR DESIGN
(Rear View)

Steam Drum

Flue Gas Passage

Vertical Injector (TYP)

Horizontal Injector (TYP)

458
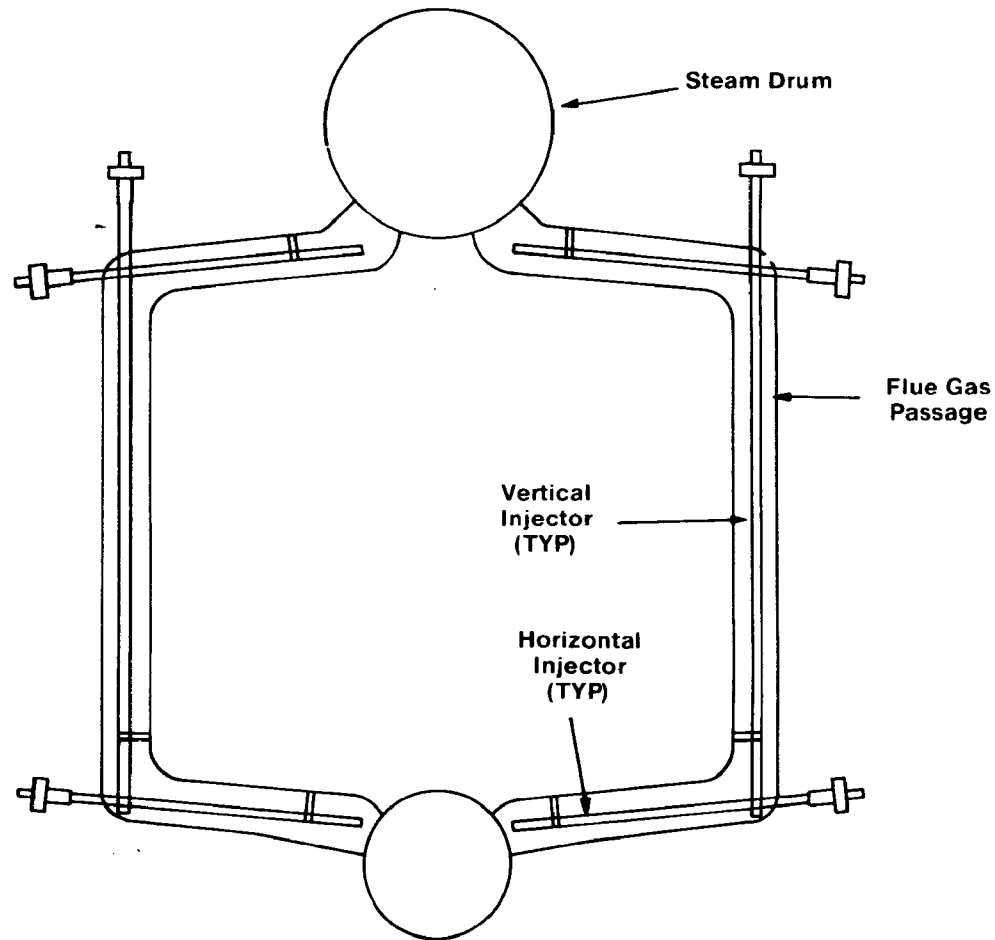
FIGURE 5

TYPICAL PACKAGE BOILER THERMAL DENOx
INJECTOR DESIGN
(Plan View)
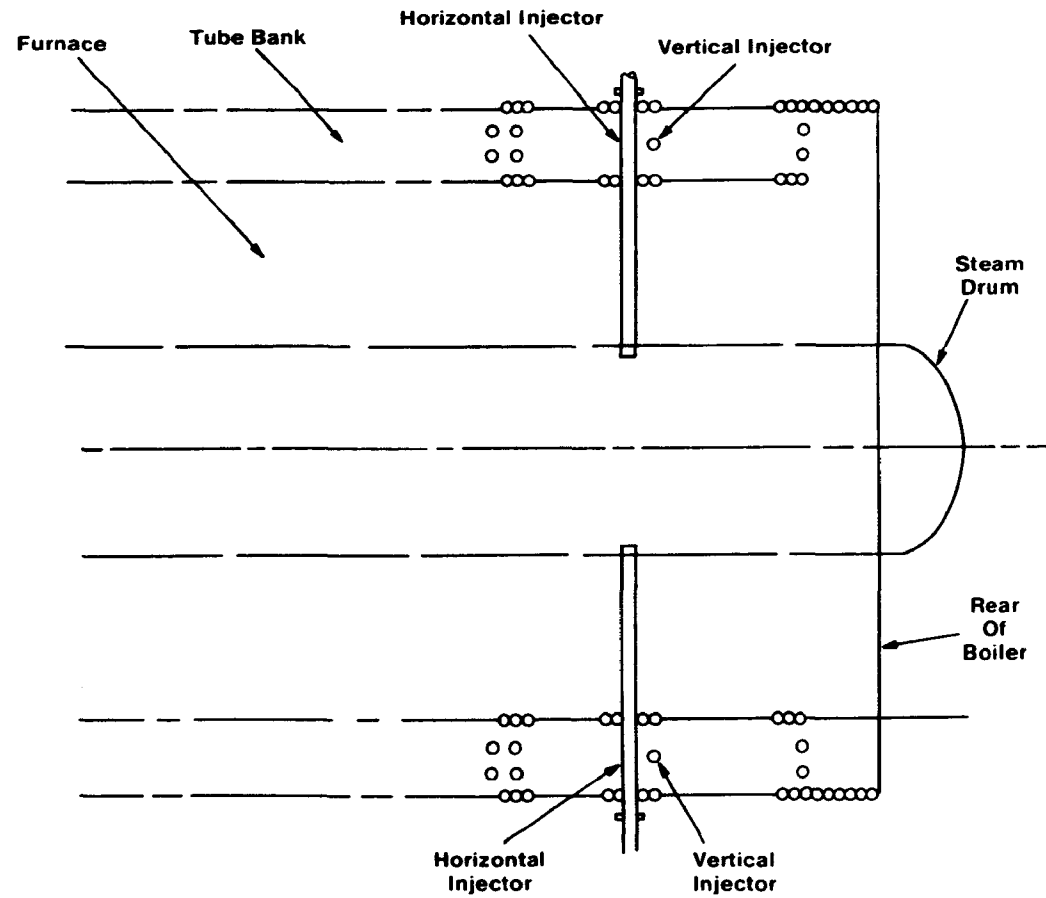
FIGURE 6

TYPICAL CROSS DRUM BOILER THERMAL DENOx INJECTOR DESIGN

460
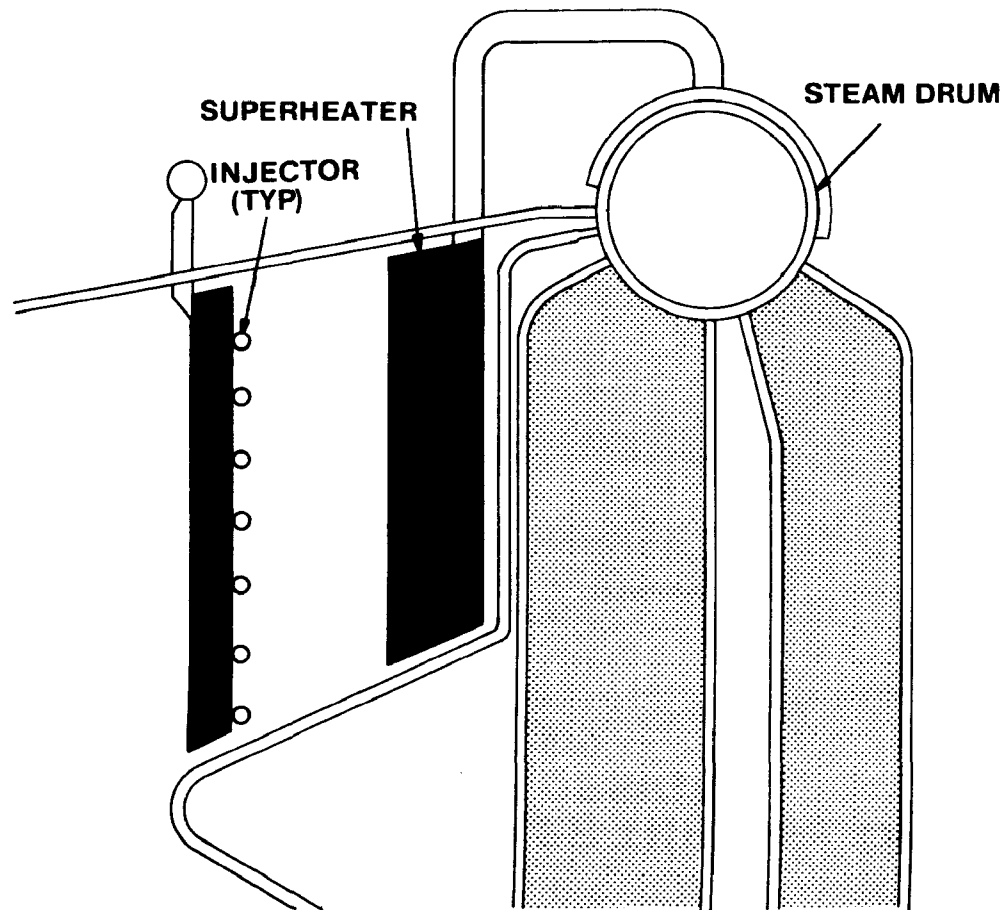
FIGURE 7

DENOx PERFORMANCE IN PILOT PLANT TESTS USING VARIOUS MIXING TECHNIQUES
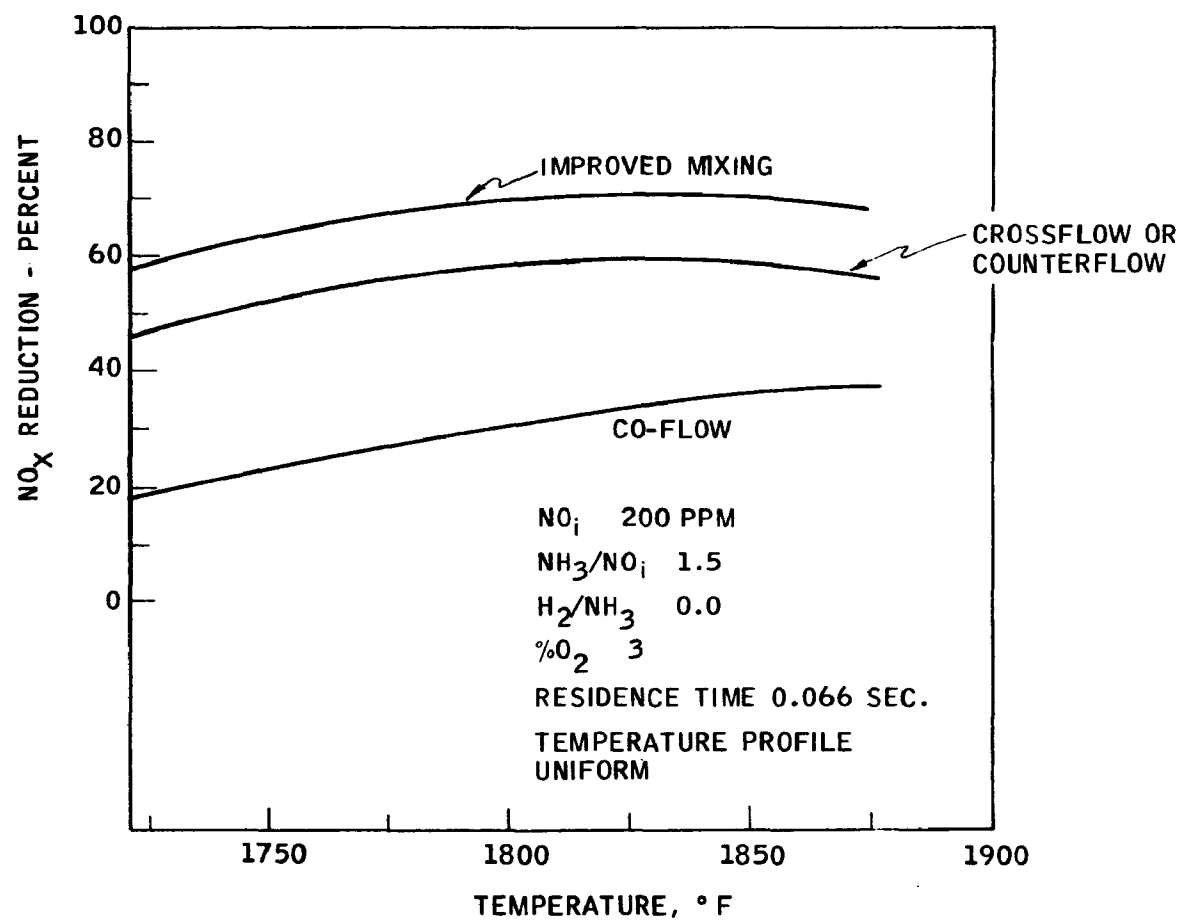
FIGURE 8

UTILITY BOILER PERFORMANCE PREDICTIONS
EFFECTS OF IMPROVED MIXING AND HYDROGEN ADDITION
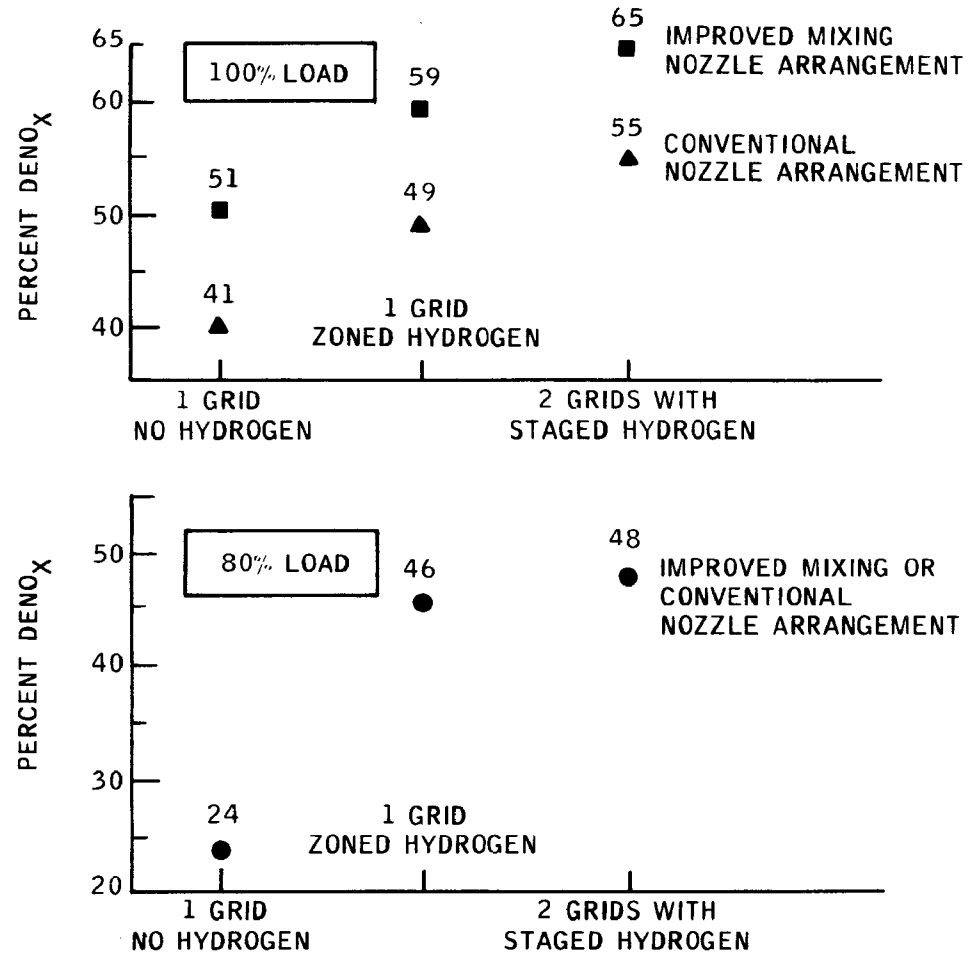
FIGURE 9

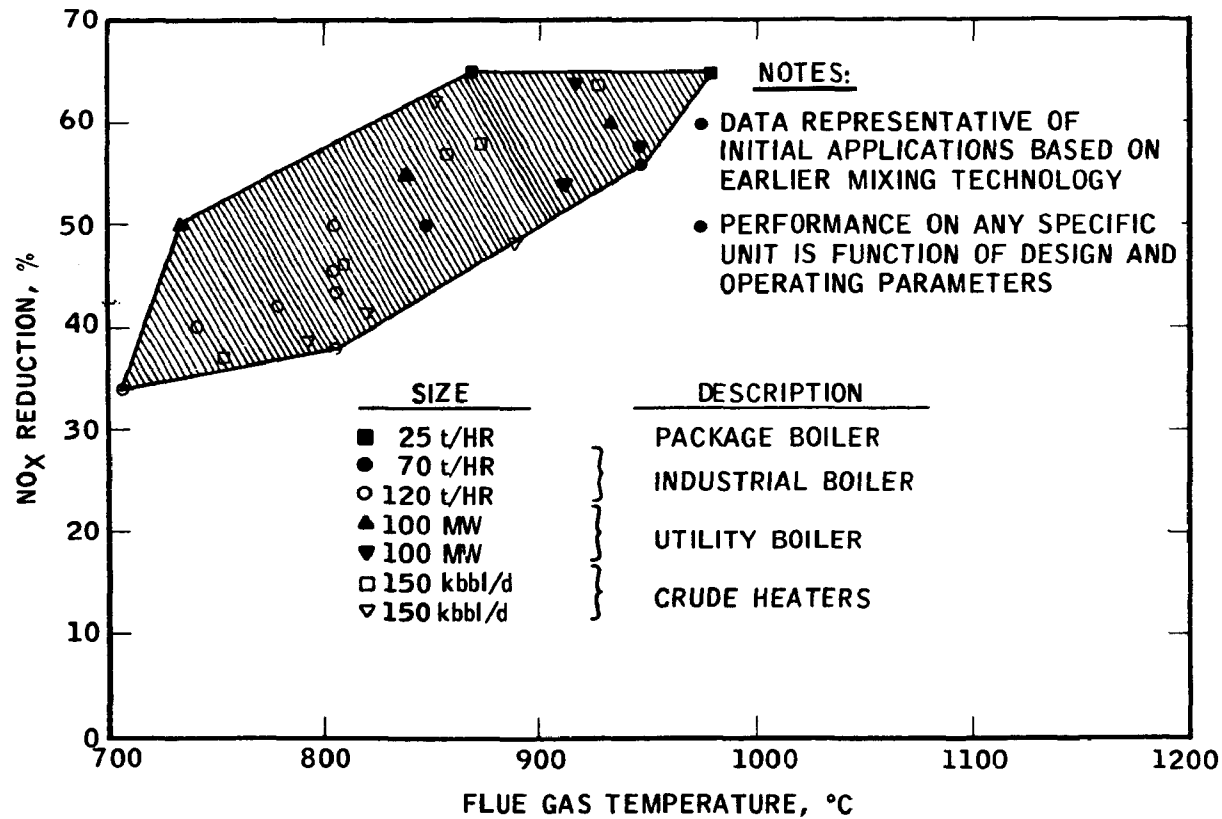# PERFORMANCE OF THERMAL DENOx
SYSTEMS IN COMMERCIAL APPLICATIONS

NOTES:

- DATA REPRESENTATIVE OF INITIAL APPLICATIONS BASED ON EARLIER MIXING TECHNOLOGY

- PERFORMANCE ON ANY SPECIFIC UNIT IS FUNCTION OF DESIGN AND OPERATING PARAMETERS

SIZE		DESCRIPTION
■ 25 t/HR		PACKAGE BOILER
● 70 t/HR	}	INDUSTRIAL BOILER
○ 120 t/HR		
▲ 100 MW	}	UTILITY BOILER
▼ 100 MW		
□ 150 kbbl/d	}	CRUDE HEATERS
▽ 150 kbbl/d		

NOx REDUCTION, %

FLUE GAS TEMPERATURE, °C

FIGURE 10

FOULING POTENTIAL OF AMMONIUM SULFATES
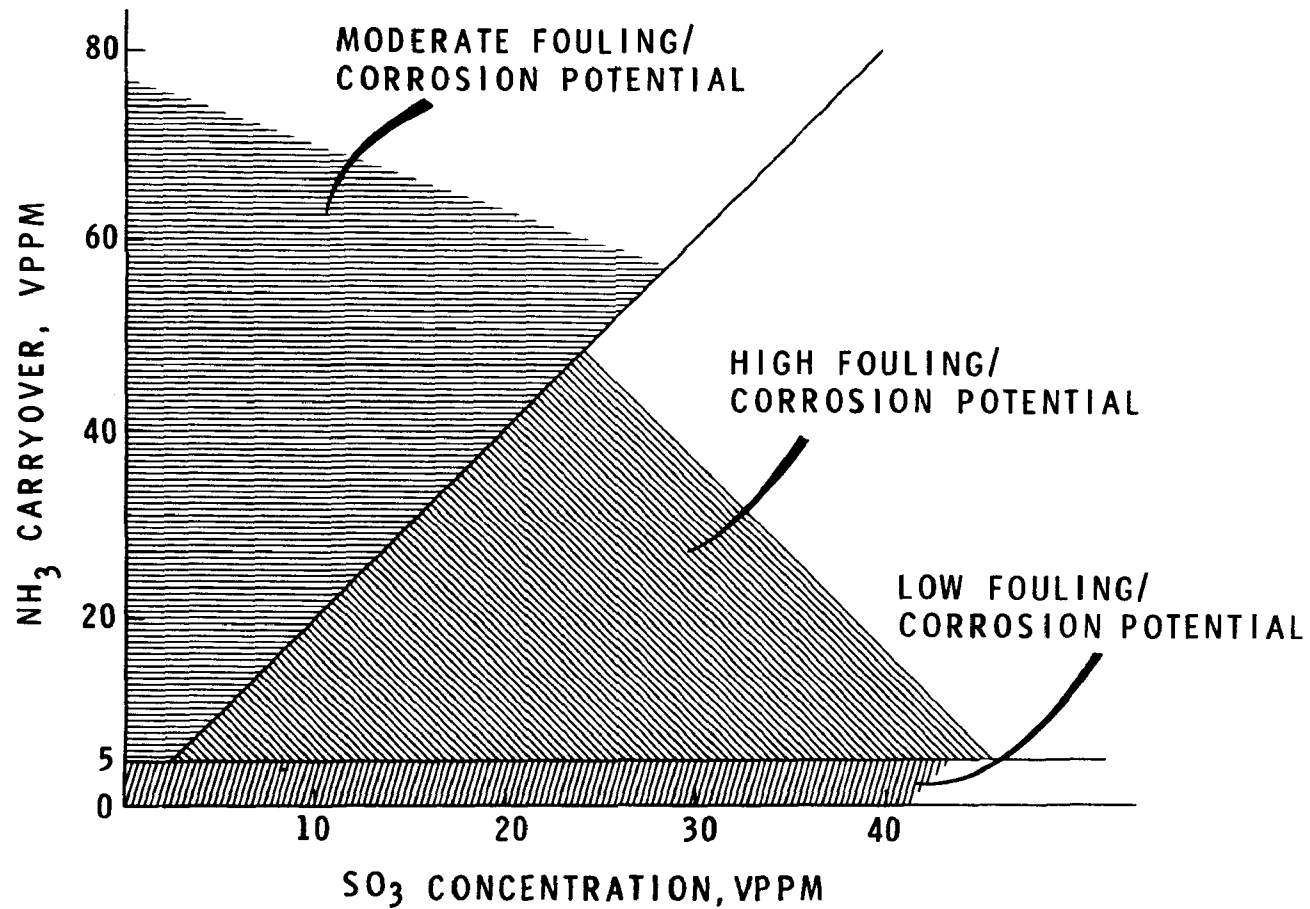
FIGURE 11

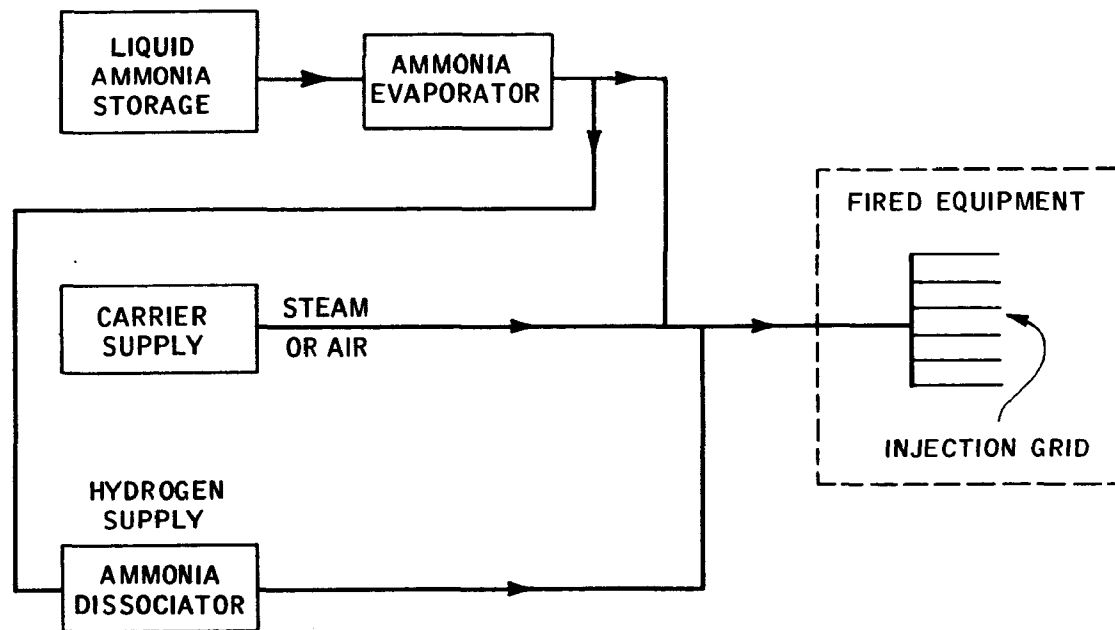# SIMPLIFIED THERMAL DENOx SUPPLY SYSTEM FLOW DIAGRAM

TABLE I

MAJOR FACTORS IN THERMAL DENOx PERFORMANCE

- FLUE GAS TEMPERATURE -

  + WITH OR WITHOUT H_2

- RESIDENCE TIME AT TEMPERATURE

- TEMPERATURE PROFILE

- INITIAL NO_X

- NH_3/NO_X RATIO

- MIXING

TABLE II

THERMAL DENOx EXPERIENCE SUMMARY
(OIL AND GAS FIRED UNITS)

	OPERATIONAL	CONSTRUCTION PHASE	DESIGN PHASE
JAPANESE INDUSTRIAL BOILERS	3		
JAPANESE UTILITY BOILERS	5		
JAPANESE PETROLEUM HEATERS	4		
CALIFORNIA OIL FIELD STEAMER (DEMONSTRATION)	1		
CALIFORNIA FLAT GLASS MELTING FURNACE (DEMONSTRATION)	1		
CALIFORNIA PETROLEUM HEATERS	2	19	5
CALIFORNIA UTILITY BOILER		1	
CALIFORNIA INDUSTRIAL BOILERS		3	
CALIFORNIA INCINERATORS			2

467

TABLE III

EQUIPMENT SIZING BASIS FOR PERMANENT THERMAL DENOx FACILITIES FOR SAMPLE INDUSTRIAL BOILER

BOILER DESIGN CONDITIONS	200,000 LB/HR, 615 PSIG, 700 F
FUEL	OIL OR GAS
INITIAL NO_x	200 PPM
NH_3/NO_x	1.5
H_2/NH_3	0.5
CARRIER REQUIREMENT	STEAM, 1500 LB/HR, 15 PSIG (MINIMUM)
NH_3 STORAGE TANK	30 DAY STORAGE CAPACITY (8000 GALLONS)
NH_3 VAPORIZER	(1) ELECTRIC ELEMENT, DIRECT CONTACT
NH_3 DISSOCIATOR	(1) 750 SCFH
INJECTION GRID	SINGLE LOCATION
INSTRUMENTATION	AS REQUIRED

TABLE IV

THERMAL DENOx INVESTMENT COST AND COST EFFECTIVENESS FOR SAMPLE INDUSTRIAL BOILER

CAPITAL INVESTMENT[1]

MATERIAL AND LABOR[2]	$168 K
INDIRECT COSTS[3]	$215 K
CONTINGENCY[4]	$ 89 K
	$472 K

COST EFFECTIVENESS

$/M BTU FIRED	0.13
K$/TON NO_x REMOVED @ 60% $DeNO_x$	1.51
K$/TON NO_x REMOVED @ 70% $DeNO_x$	1.29

NOTES: (1) INVESTMENT COSTS ARE EXPRESSED AT IQ81 SOUTHERN CALIFORNIA LEVEL

(2) INCLUDES EQUIPMENT ITEMS LISTED IN TABLE III PLUS INTERCONNECTING PIPING

(3) INCLUDES FIELD LABOR OVERHEADS, CONSTRUCTION SUPERVISION AND EQUIPMENT, LABOR WAGE TAXES, ERECTION FEE, CONTRACTOR ENGINEERING, EXXON RESEARCH AND ENGINEERING CO. CHARGES, AND LICENSING FEE. EXCLUDED ARE SUCH ITEMS AS LAND AND OWNERS CHARGES.

(4) CONTINGENCY IS BASED ON 30% OF DIRECT COSTS PLUS INDIRECT COSTS MINUS LICENSING FEE.

TABLE V

THERMAL DENOx ANNUAL OPERATING COST FOR SAMPLE INDUSTRIAL BOILER

ITEM	ANNUAL CONSUMPTION[1]	UNIT GAS	ANNUAL COST
AMMONIA[2]	165 TONS	$170/TON	$27,965
ELECTRIC POWER[3]	136 MWH	$50/MWH	6,800
STEAM[4]	4290 TONS	$12/TON	51,480
MAINTENANCE MATERIAL AND LABOR[5]			11,760
		TOTAL	$98,005

NOTES:

(1) ASSUMES 65% LOAD FACTOR

(2) INCLUDES AMMONIA FOR DIRECT INJECTION PLUS HYDROGEN PRODUCTION

(3) INCLUDES POWER REQUIREMENT FOR AMMONIA VAPORIZER AND DISSOCIATOR

(4) LOW PRESSURE STEAM (15 PSIG MINIMUM) FOR CARRIER

(5) ASSUMED TO BE 7% OF DIRECT INVESTMENT COST

UTILITY BOILER ENVIRONMENTAL ASSESSMENT -- THE EPRI APPROACH

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ABSTRACT

EPRI's environmental assessment program for air emissions comprises
physical and chemical characterization, ecological and human health research
and an integrated analysis of costs, benefits and risks associated with vari-
ous generating technology and emission control approaches. Physical and
chemical characterization is approached from both a regional and localized
aspect and includes primary and secondary pollutants. Regional transport
research began with the Sulfate Regional Experiment (SURE) in the Northeastern
U.S. and continues with visibility and acid deposition research in the East
and West.

Localized plume distribution is being studied on a site-specific basis
beginning with simple and continuing with more complex terrain. Both efforts
include extensive field measurement programs designed to evaluate or develop
modeling techniques for predicting utility contributions to ground-level
concentrations or deposition.

Ecological research currently emphasizes the potential effects of acid
deposition and includes watershed, aquatic, forest, crop, and grassland
research. Current studies focus on biogeochemical processes which influence
resultant soil and water acidity and nutrient balance.

Health effects research concentrates on determining human health effects
of airborne utility emissions using animal studies, human clinical studies and
epidemiology.

The ultimate objective of these research efforts is the evaluation of
relative risk of generation mixes and emission control strategies.

472

UTILITY BOILER ENVIRONMENTAL ASSESSMENT - THE EPRI APPROACH

INTRODUCTION

The purpose of my presentation is to describe NO_x research results, research in progress and research planned by the Environmental Assessment Department of EPRI.

The Environmental Assessment Department is part of the Energy Analysis and Environment Division, one of six technical divisions at EPRI.

The primary objectives of the EAD are to identify, measure and determine the relative importance of emissions from electricity generation transmission and use. The Department comprises four program areas: Environmental Physics and Chemistry, Ecological Studies, Environmental and Occupational Health, and Environmental Risk and Issues Analysis. The research I will discuss today is planned and executed under the auspices of one or more of these programs. It is apparent that we are organized along disciplinary lines, and you will see from my discussion that research projects tend to fall within one of these four categories.

My objectives in this presentation are:

1) to illustrate through examples of research results, research in progress and research planned what we see as the most important areas of study with reference to NO_x,

2) to open our research program to investigators involved in similar or allied pursuits in hopes of encouraging an exchange among our staffs, and

3) to invite your comments on the directions we have established and the questions we are asking through research.

473

My presentation is divided into six major areas: NO_x emissions, transformation and transport, human health effects, ecological effects, materials damage and visibility degradation (see Figure 1). Discussion under each of these headings will be organized, with minor variations, as follows: results to date, research in progress, and planned research.

NO_x EMISSIONS

Results to Date

Our first NO_x emissions project began in 1975 prompted by published reports of elevated ozone concentrations in power plant plumes. The objectives of this initial research were to determine whether ozone was generated in power plant plumes and to develop a qualitative understanding of dominant influences on the potential for such ozone generation. Investigative methodology included reactive plume modeling and measurements of plumes at four southwestern and western power plants representing gas- and coal-fired boilers in dry or humid climates (1,2,3).

Subsequently, interest turned to the potential of NO_x to contribute to the formation of NO_2 and nitrates on a regional scale. This regional research will be discussed under transformation and transport.

The next area of interest was the formation of nitrates and nitric acid as potential contributors to visibility degradation and acidic precipitation. A modeling approach was obviously required to evaluate the impact of an individual or group of power plants on air quality at some distance from the source. In order to accurately model NO_x reactions, we needed to develop an understanding of key reactions and reaction rates. Chamber research was begun in 1978 in this pursuit and continues to date.

Plume measurements have shown ozone formation in the West and Southwest under the conditions studied to be a rare occurrence. The chamber studies indicated that oxidation of NO_x to HNO_3 and NO_3 in gas phase reactions depends on the presence of hydrocarbons.

On-going Research

Current research related to NO_x emissions includes validation of the chamber studies by aircraft sampling in a power plant plume and a more general plume model validation project (4). In this project, oxides of nitrogen are of major importance. Ground level pollutant characteristics predicted by plume models are being investigated in addition to chemical and physical transformations which will require validation of reactive plume models. We plan eventually to include a moderately complex and a complex site in addition to these current studies at a flat terrain site.

TRANSFORMATION & TRANSPORT

Results to Date

As mentioned above, EPRI's attention turned early to regional considerations with the Sulfate Regional Experiment (SURE). I have nothing to report now on results because final reports are in preparation. However, I will summarize the objectives and approach of the SURE (5).

SURE began in 1977 with the primary objective of defining the relationship between emitted primary pollutants (e.g., SO_2) and regional, ambient concentrations of secondary pollutants (e.g., sulfates). Subobjectives included:

o   the establishment of a regional air quality data base through measurements made at ground level and aloft, and

o   the determination of the location and magnitude of emissions during air quality measurement periods.

It was hoped that with this approach it would be possible to derive quantitative methodology for relating emissions from power plants to regional air quality as measured by SO_2 and particulate sulfate. In addition to measuring SO_2 and sulfates, nine ground-based stations measured continuously for nineteen months NO/NO_x, O_3, temperature, dewpoint and suspended particles. Aircraft which operated six days during the central month during each season (seven "intensives" during the nineteen month field program) measured SO_2, O_3,

475

NO/NO_x, b_{scat} and condensation nuclei. SURE field sampling is now complete and the final report is being written.

In early 1978, the SURE program was supplemented with a precipitation chemistry component consisting of nine stations sited in close proximity to the nine SURE continuous monitors. The primary objective of this research was to relate rain pH to air quality or emission parameters already included in the SURE.

Also in 1978, outdoor air quality studies were supplemented with characterization of the indoor environment as a function of outdoor pollution levels, structure type, geographic locality and other variables including presence of smokers and type of heating and cooking fuel (6).

Planned Research

We are currently in a major planning exercise regarding regional air quality studies. This process consists of a "Delphi-type" survey of industry representatives, academicians and agency personnel which asks for a ranking of research areas, forcing functions and research aspects. SO_x and NO_x rank high in importance and have been combined for planning purposes. The primary forcing functions or motivating factors for research are the potential for oxides of nitrogen to contribute to human health, ecological or esthetic effects and materials damage. The most important research aspects are chemical transformation, regional transport, wet and dry deposition, synthesizing models and atmospheric dilution.

A workshop was held in April 1978 to review effects of trace nitrogen compounds on human health and welfare, identify mechanisms of nitrogen compound formation and transport, assess the present state of knowledge of these phenomena and recommend and prioritize critical areas of research (7). Participants agreed research was needed in all aspects and most importantly in removal (from atmosphere) mechanisms, transformation in plumes and ammonia flux.

476

HUMAN HEALTH EFFECTS

Identified Research Needs

A planning study accomplished in 1978 (8) evaluated existing information on the health effects of nitrogen oxides, identified the need for better methodology and the existence of gaps in knowledge and recommended a research program appropriate for EPRI and responsive to the need for information. At the top of the list of needed research was the development of more precise and accurate methods for monitoring NO_2/NO_3^-, peroxacyl nitrates (PAN) and N-nitrosamines. Additional research needs include:

o   characterization of NO_2/NO_3^- in respirable suspended particles,

o   animal inhalation toxicology of
   - NO_2/NO_3^- aerosols
   - N-nitrosamines
   - PAN

o   human clinical studies for threshold limit values and respiratory function response for
   - PAN
   - NO_2/NO_3^- aerosols, and

o   human epidemiology for
   - NO/NO_2
   - NO_2/NO_3^-
   - PAN
   - N-nitrosamines.

Results to Date

In response to the need for better monitoring methodology, research was begun to determine the rates and amounts of artifact nitrate formation on standard fiberglass filter media; to devise, if possible, correction factors which might be applied to historical nitrate concentrations; to test other media; and, to recommend best available sampling and analysis techniques.

The research clearly demonstrated large and erratic artifact formation on untreated glass fiber filters (9). Anywhere from 10 to 100 percent of the

477

reported nitrate was attributed to on-filter reactions, with a most likely value of about 20 percent. Unfortunately, it is not likely that historical records can be corrected because although artifact formation varied according to experimental conditions, it also varied strongly and in an unpredictable way on the filter handling procedures used prior to exposure.

Most health-related NO_x research is still underway, so results are limited but do not indicate that exposure to ambient outdoor levels of NO_2 and nitrate is harmful to health. There is some evidence that elevated NO_2 indoors may be linked to increased respiratory disease in children.

On-going Research

Current research in animal inhalation toxicology involves an increased range and duration of exposure concentrations and interactions of NO_2 with SO_2, O_3 and SO_2 and O_3 together.

Planned Research

The five-year plan includes animal inhalation toxicology studies of chronic and acute exposures to mixed gases, human clinical studies of acute effects of NO_2 alone and epidemiological studies of chronic effects of indoor and outdoor exposures to ambient concentrations.

ECOLOGICAL STUDIES

Results to Date

EPRI's ecological research on effects of oxides of nitrogen focuses primarily on the contribution of nitrate through dry and wet deposition. The majority of research underway in this area has begun recently. One study from which there are interim results is the Integrated Lake/Watershed Study (ILWAS) which is being conducted at three Adirondack (New York) Lakes. In this project, water chemistry is determined from the incoming rainfall above the canopy and as the water passes through the watershed/lake system.

Rainfall chemistry analysis has shown:

o NO_3^- to vary less than sulfate over the year,

o NO_3^- concentration is about one-fourth that of SO_4^- in the summer and
     about equal in winter, and

o   a relatively low SO_4^-/NO_3^- ratio for snow when compared to rain.

On-going Studies

The field program for the Integrated Lake/Watershed study is scheduled to
end in December 1981 and will be followed by a year of data analysis and model
development and refinement. An interim report will be published in the fall
of 1980.

Other on-going research falls under four categories: forests and surface
waters, agricultural crops, aquatic biota and economic assessment. Current
research in forests is focused on a microcosm approach to identifying key
parameters in forests sensitive to acidic precipitation.

Research on effects on agricultural crops and aquatic biota has only
recently begun. Crop research consists primarily of experimental field stud-
ies with some use of laboratory microcosms. In aquatic studies, research will
focus on the effects of acidification and potentially resultant toxic metal
concentrations on decomposition processes.

Planned Research

Future research in the lake/watershed approach will focus on application
and validation (and additional development, if necessary) of the ILWAS model
using watersheds located in other geographic locations and exhibiting other
geological, climatological and biotic regimes.

In forest studies, it is hoped that expansion of microcosm research to
field studies will increase our understanding of acidification processes and
forest ecosystem responses.

Interest in grasslands is fostered primarily by concern about possible
effects of sulfur deposition, primarily in the form of SO_2. Although NO_2 is
not considered a regional problem, the deposition of secondary products,
nitrates, must be considered in the overall investigation of the impact of
power plant emissions. The approach will be to look at nutrient cycling,
yield and productivity.

479

EPRI's crop effects research will focus on acid rain rather than gaseous pollutants as has most previous research. Emphasis will be on ecological processes leading to changes in fertility, yield and quality of agricultural soils and plant species. The ultimate objective is to develop mitigation and management methodology where the need is shown by research.

For aquatic systems, the on-going research on effects of acidification of decomposition mentioned above will be expanded to include effects on other processes hopefully leading to predictive capability and results which will refine some aspects of the lake/watershed modeling. Studies of effects on specific species or communities will be carefully chosen to complement research being conducted by EPA, universities and federal and state resource management agencies. Mitigative strategies (e.g., liming and fertilization) will be investigated.

MATERIALS DAMAGE

The approach to date has been to refine damage estimates for various surfaces and their distribution throughout the U.S. The primary pollutant of interest has been SO_2 rather than NO_x. Urban Boston was used as a prototypical site. Results should be published within the next year. Currently, no additional work is underway. In the future, such estimates would be used in overall risk/cost/benefit analyses of alternative generation and emission control technologies.

VISIBILITY

On-going Research

EPRI's visibility research has taken three fundamental approaches:

o   development and intercomparison of quantitative instrumental methods for measuring visibility

o   development of regional data bases on visibility variability, causes of visibility impairment, and the development of reliable regional visibility models, and

o   the assessment of social and economic costs generated by visibility impairment and the remedial costs at various levels of protection.

480

EPRI's first step was to establish one visibility station in the Southwest and one in the Northeast to serve the first purpose mentioned above, i.e., methodology intercomparison and, through fine particle measurements, begin building a base of information for understanding the relationship between ambient air quality and visibility.

Following these initial tests, additional measurement stations were established (two in the Northeast and five in the Southwest) to acquire accurate and reliable information on the regional distribution and variability of visibility impairment.

Concurrently, EPRI has funded the development and testing of an automated multi-wavelength telephotometer which is now in the field testing stage (10).

The third fundamental approach mentioned above was the development of social and economic benefit/cost comparisons. Among the important objectives are:

o   evaluation and development of methodology for estimating air pollution damage

o   determination of the degree to which anthropogenic sources, particularly power plants, are associated with visibility impairment

o   estimation of costs associated with reducing power plant emissions, and

o   identifying and quantifying economic and social benefits from improved visibility.

Planned Research

EPRI plans to expand the Western visibility network during 1981. Data from these regional networks will provide data initially for setting baselines and for empirical studies of the causes of visibility impairment. Eventually, such data will be used in the development of regional models which could be used to examine the potential for specific sources to impact visibility in defined geographic areas.

481

Social and economic assessments will hopefully lead to a better under-
standing of source relationships, social costs and benefits of visibility
impairment and improvement and the impact of emission controls on visibility
in specific geographic areas.

SUMMARY

I have discussed the EPRI Environmental Assessment Department's program
of NO_x research. This program includes six major areas: NO_x emissions,
transformation and transport, human health effects, ecological effects, mater-
ials damage and visibility degradation. My primary objective was to open
channels of exchange between our staff and contractors and other researchers
doing similar or complementary research. We believe it is very important to
coordinate such research activities to best utilize limited resources whatever
their source. We invite your comments and contacts and hope that you might
share with us your results, current research and plans for the future.

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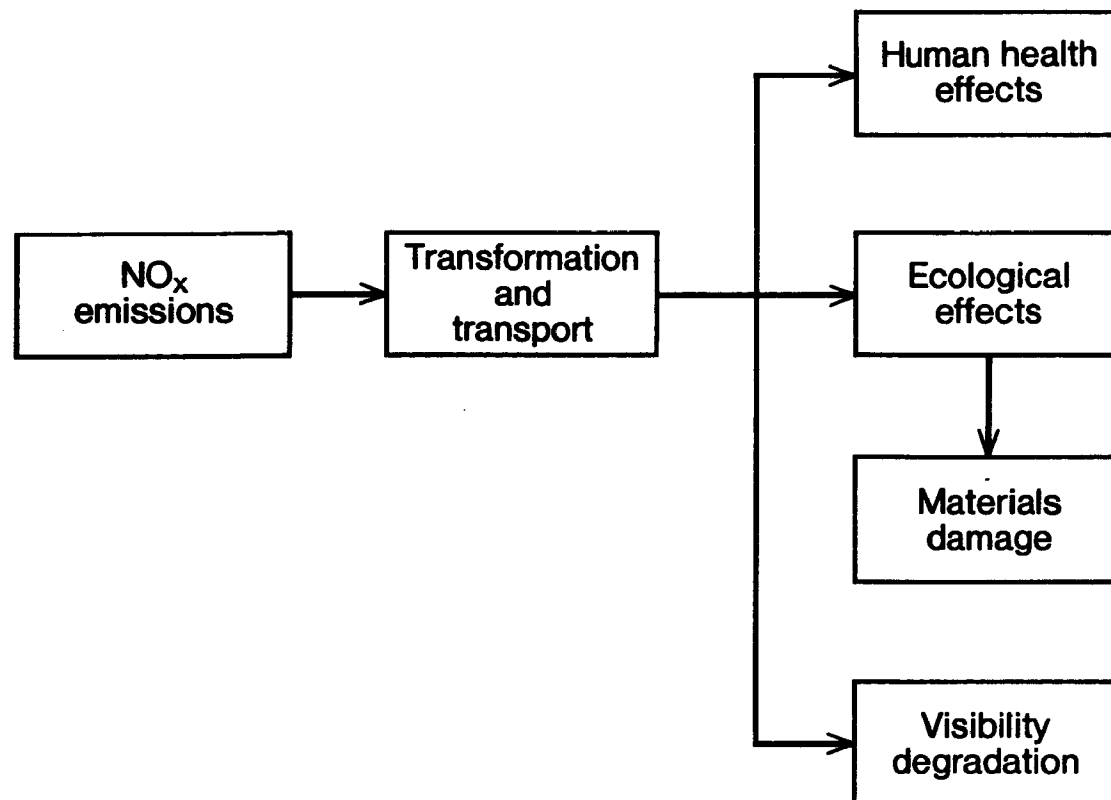
Figure 1.   NO$_x$ Major Issues

SINGLE-CYLINDER TESTS OF EMISSION CONTROL
METHODS FOR LARGE-BORE STATIONARY ENGINES

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486

ABSTRACT

The research work presented herein was undertaken in order to develop combustion modifications which substantially reduce NO_x emissions of large-bore engines, without significantly increasing fuel consumption of carbonaceous emissions. The scope of the project covers NO_x control technology for diesel and spark ignition engines, bore sizes ranging from 8 to 20", and both 2 and 4 cycle charging methods. The current status of the project permits us to report the results of 40% of the Phase III experimental tests. In Phases I and II, a compendium of 3ℓ emission control methods was prepared, and an evaluation procedure was used to screen down the list to the 12 methods which are now being tested in Phase III.

Cooper Energy Services utilized a 20" bore, 330 rpm single cylinder engine to test the effect of unmixedness (modified fuel gas injection) and conventional "tuning" methods (timing, equivalence ratio, spark location, gas valve location, and piston shape). The principal finding was that NO_x emissions are more sensitive to air-fuel ratio than any other variable, giving a factor of five reduction as the equivalence ratio was leaned out from $\phi \simeq .76$ to $\phi \simeq .62$. The practical implication is that spark gas engine emissions are limited primarily by turbocharger efficiency and the combustion lean limit. Rate of heat release analysis confirmed that a reduction in fuel-air ratio produces longer ignition delay and lower flame speed. Gas valve modifications degraded NO_x; piston shape had more effect on NO_x than either gas valve or spark plug location.

Fairbanks Morse conducted tests of pilot injection and increased rate of injection on an 11" bore model PA-6 engine at 1,000 rpm. At 9 g/bhp-hr the baseline NO_x is characteristic of this class of engines. Retarded timing increases BSFC 1.1% and decreases NO_x 4% per degree crank angle. Exhaust temperature was found to limit the NO_x reduction achievable with either pilot injection or injection rate at full load; however, at part load NO_x reductions of 20% were found for both methods with some BSFC improvement. Analysis of derived heat release profiles show that the "spike" observed for high speed diesels does not appear for the PA-6 engine.

ACKNOWLEDGEMENTS

SECTION 1

INTRODUCTION

Large-bore stationary engines are a significant source of NO_x emissions in the United States. Primarily used in pipeline transmission and compression of natural gas, oil drilling, and electric power generation, this class of engines accounts for 1.5% of U. S. fuel usage, as shown in Table I. Covering a power range from 100 to 750 hp per cylinder, and a speed range from 300 to 1200 rpm, this engine class includes both diesel and spark ignition types. Most large-bore engines are turbocharged in order to reduce fuel consumption.

Emissions control efforts for large-bore engines are limited to NO_x, since the emissions of carbon-containing species (CO, HC, soot) are relatively low and the conventional engine fuels nearly sulfur-free. As shown in Table II, the NO_x emission rate of these engines is significantly higher than any other major combustion device for a given amount of fuel, and is almost a factor of six greater than the coal-fired utility boiler (which is the stationary source of greatest concern). This remarkably high NO_x emission rate is caused by four factors:

- Compression preheating to 800°K increases flame temperature;

- Low heat loss during combustion maintains high flame temperature;

- Air-fuel ratio in the 18-20 range which maximizes NO_x; and

- Low rpm results in 10-20 msec at peak temperature.

In certain portions of the combustion chamber, the flame temperature is so high that the NO_x level reaches equilibrium (8,000-12,000 ppm) and then begins to decrease by the reverse of the Zeldovich mechanism as the gas cools by expansion.

The outlook for emission standards for large-bore engines is uncertain at this writing because of fast-changing control technology. In July 1979, the EPA proposed NO_x emission ceilings corresponding to 40% reduction from the typical level, as shown by Figure 1. These standards as proposed would come into effect in 1982. However, while these standards were being formulated and reviewed, examples of new control technology (e.g., torch-ignition for spark gas engines and catalyzed reduction of NO_x by ammonia) began to be investigated by several engine manufacturers. Recently, the California Air Resources Board issued a model rule based on catalyst technology which calls for a 90% NO_x reduction by as early as 1983, contingent on the successful demonstration of control technology. Apart from the question of emission standards, engine manufacturers are experiencing incentives for low NO_x emissions due to PSD requirements. As shown in Figure 2, the installation of a 5,000-hp engine station will require an NO_x emission rate of 5 g/hp-hr (which is equivalent to about a 60% reduction from uncontrolled levels) in order to avoid a lengthy PSD review process.

The promise of recent developments reflects two basic premises concerning the NO_x level of large-bore engines:

(1) There is substantial potential for NO_x reduction.

(2) The actual levels of NO_x which are feasible can only emerge after extensive experimental and field test work.

The EPA program described below is aimed at this experimental test work.

SECTION 2

PROGRAM DESCRIPTION

The objective of the present program is to develop a technical foundation for substantial reduction of NO_x emissions of representative large bore engines, without degradation of fuel economy. As the program has evolved, it now appears reasonable to target for 50-60% NO_x reduction with less than 3% penalty in fuel consumption. Table III shows the four major phases of work, starting with the identification of various emission-control methods and ending with field tests on full scale engines. Currently, Phase III is about 40% complete, and the results of the first four methods of NO_x control are reported herein:

<u>Spark</u>

- Piston shape, gas valve, and spark location

- Altered gas valve

<u>Diesel</u>

- Pilot injection

- High injection

The NO_x control methods which are being tested for spark-ignition engines fall into four categories, as follows:

(1) Reduced temperature

(2) Leaner combustion

(3) Stratified combustion

(4) Exhaust gas treatment

Figure 3 illustrates the mechanisms by which NO_x production is altered in Categories (1)-(3) above. The contours labelled 1, 10, 100, and 1000 ppm/msec define a steep surface of increasing NO_x production rate. Normally, a hot gas element follows the path labelled "conventional," starting at about 2400°K flame temperature and increasing to 2600°K or more due to compression. This produces NO_x at a rate well above

492

1000 ppm per millisecond as illustrated by the contours on Figure 3. The "reduced temperature" methods simply shift this path to the left (about 100°K lower) where the NO_x production rate is much lower. The "lean combustion" methods force the combustion to begin and proceed at lower fuel-air ratio ($\phi \simeq 0.7$) where the NO_x production rate is reduced. The "stratified combustion" method creates a lean and rich zone, thereby avoiding the $\phi = 0.8-0.9$ regime (where NO_x production is at a maximum). This brief discussion provides some background on the methods which are being tested in Phase III for spark gas engines.

For diesel-engine NO_x control, the approach which has guided our Phase III plans is to retard the fuel injection process and compensate for the delayed burning by:

- Reduced ignition delay, and/or
- Increased mixing rate.

Normally, retarded timing causes unacceptable penalties in fuel consumption, and often results in excessive exhaust temperature and soot levels. Therefore, it is essential for NO_x control to make the latter stages of the combustion process more vigorous in order to allow the early stages to be retarded and less intense.

Table IV presents the 12 NO_x-control methods which were selected for testing in Phase III. The process of selection was based on the projected NO_x reduction, the projected cost of control (per horsepower), and the feasibility. The relative ranking of the concepts by two of these criteria is illustrated in Figure 4, in which the threshold for Phase III selection is shown as a dashed line starting at 20% NO_x reduction, and requiring greater NO_x reductions above \$30/hp ten-year cost impact.

SECTION 3

SPARK IGNITION ENGINE TESTS

A. EXPERIMENTAL ARRANGEMENTS

The tests were conducted using a Cooper Model Z330 single-cylinder, two-stroke engine of 20" bore and 20" stroke dimensions, 681-hp rated power at 130 bmep and 330 rpm. Gas fuel is injected directly into the cylinder during the compression stroke, and the resulting mixture is ignited by two spark plugs nominally firing at 7° before top center. Figure 5 shows the air and fuel supply piping and controls in schematic; the air manifold pressure and temperature could be controlled independently. Figure 6 is a photograph illustrating the general layout of the experimental facility. The large cylinder is the plenum in the air supply used to dampen air pressure fluctuations.

Emissions samples were taken from the following three points, as shown in Figure 7:

    (1)   Exhaust stack (diluted with scavenging air);

    (2)   Exhaust port (undiluted--see Figure 8); and

    (3)   Cylinder contents during combustion ("Cox valve").

Samples were analyzed for NO/NO_x, THC, CO, CO_2, and O_2 by conventional methods (chemiluminescent, FID, NDIR, and paramagnetic analyzers, respectively). The fuel-air ratio of the trapped gas is essentially unknown for a scavenged 2-stroke engine. This problem was solved by mounting a poppet valve at the exhaust port as shown in Figure 8. The valve was actuated by the flow of high pressure exhaust gas (undiluted by scavenging air).

494

Natural gas was used throughout the experiments; the composition varied slightly as shown in Table V.

In order to provide additional diagnostic information about the combustion process, the cylinder pressure traces were averaged for several hundred consecutive cycles. The time-resolved rate of heat release in the cylinder was calculated from each averaged pressure trace by a thermodynamic computer program.

B. BASELINE DATA AND THE EFFECT OF FUEL-AIR RATIO

The NO_x emissions of the engine in its normal configuration were obtained for several spark timings and air-fuel ratios in order to establish a baseline or reference for further tests. All runs were made at rated power and speed (130 bmep and 330 rpm). The results, presented in Figure 3, show that the air-fuel ratio affects NO_x markedly, reducing NO_x a factor of five (from 25 to 5 g/bhp-hr) as the mixture is leaned out from a fuel-air equivalence ratio of 0.76 to 0.62. Retarded spark timing also reduces NO_x, giving about a 25% NO_x change for a timing shift of 4° crank angle (6% per degree).

The steepness of the NO_x vs ϕ graph, which is characteristic of all premixed combustion systems, suggests that the most fruitful approach for low NO_x is to lean out the mixture. Several limits are encountered, however, as the mixture is shifted to lower fuel/air ratio:

- Misfire Limit: Positive, reproducible ignition becomes more difficult to achieve very lean mixtures. The flame may begin to propagate away from the spark plug, but falter or travel at low flame speed. The first sign of misfire is increased variation in peak cylinder pressure. Instrumentation on the Z330 single-cylinder engine automatically calculates the standard deviation in peak pressure (σ), which is normally in the 60-90 psi range for satisfactory ignition. In the 90-120 psi range, some misfire is first noticed but engine operation may be

495

marginally feasible. Above about 120-130 psi, misfire
is definitely unacceptable. For the baseline engine,
Figure 9 shows $\sigma = 90$ psi reached at about $\phi = 0.62$ to
0.66.

- **Late or Incomplete Combustion**: Flame propagation is
  slower for very lean mixtures. This leads to penalties
  in fuel consumption and CO/HC emissions due to pockets
  of mixture which are partially unburned. Notice in
  Figure 9 that the bsfc increases as the fuel-air equiva-
  lence ratio is extended below about $\phi = 0.65$.

- **Turbocharger Capacity Limit**: In any shift to higher air-
  fuel ratio, in order to maintain power, the fuel flow
  cannot be reduced. Instead, the air pressure must be
  increased; but the ability of the engine to supply itself
  with high pressure air is limited. For a typical spark
  gas engine, turbocharger efficiency is limited to about
  64%, which ultimately limits the fuel-air ratio.

The emphasis of the EPA experimental program is on finding means to
overcome the misfire limit.

C. EFFECT OF PISTON SHAPE, GAS VALVE LOCATION, AND SPARK PLUG LOCATION

Prior to the tests of specific NO_x control methods, an attempt was
made to find out if the baseline engine configuration was optimum with
respect to the choice of piston and the location of gas valve and spark
plugs. Manufacturers often vary these components in order to "tune"
an engine for best fuel consumption and emissions. The matrix for
these "conventional" techniques is given in Table VI, which shows
systematic timing variations for each combination tested.

Three piston shapes (shown in Figure 10) were tested, and the
results are given in Figure 11. Apparently, substitution of the
"tee-pee" piston increased fuel consumption from 6,750 to 6,950 Btu/
bhp-hr (a 3% penalty). The "Mexican Hat" piston and the flat top

(baseline) piston give almost identical performance, except that the Mexican Hat piston may allow slightly leaner operation without misfire (see Figure 11, top set of curves). If 110-psi pressure variation were to be taken as the misfire limit, the baseline piston would be limited to about 8 g/bhp-hr NO_x at $\phi = 0.66$ compared to the Mexican Hat at 6 g/bhp-hr NO_x at $\phi = 0.63$.

The locations of the spark plug pairs and the gas valve are shown in Figure 12. Variations in the location of these components made very little difference in NO_x or bsfc with proper timing adjustments, as shown in Figure 13. The center spark (open symbols in Figure 13) allowed leaner operation without misfire (σ below 120 psi).

In summary, the baseline engine configuration with flat top piston, center spark plugs, and center gas valve appears to be relatively well "tuned" with respect to NO_x and bsfc. This configuration was used as the baseline standard for the remainder of the tests.

D. EFFECT OF GAS VALVE DESIGN

In a gas-injected engine, the mixture at the time of ignition may contain incompletely mixed pockets. The number, size, and composition of these pockets depends in part on the initial fuel gas dispersion achieved by the gas valve. The standard gas injector is an outward opening pintle valve of 1-1/8 in throat diameter (.405 sq-in annular throat area). This design was altered, as shown in Figure 14, in order to explore the effect of fuel gas dispersion (local stratification) on NO_x emissions and fuel consumption.

The results are shown in Figure 15. It is interesting to note the change in slope of the NO_x vs ϕ curves as the gas valve throat diameter increases from 1.13" (o, •, ▲) to 1.31" (•) and then to 2.13" (□). The flatter curves for a larger gas valve can be explained in terms of differences in the extent of mixing at the time of combustion: It is known that poorly-mixed fuel-air mixtures produce a constant amount of NO_x per unit fuel, no matter how much extra air is present. This is because the extra air does not mix with isolated fuel pockets and

therefore does not affect the flame temperature. In Figure 15 the very large gas valve presumably resulted in this type of fuel-pocket combustion and a flat NO_x vs ϕ curve. By contrast, the well-mixed combustion produced by a small gas valve is very responsive to any additional air (lower ϕ) because the additional air lowers the flame temperature.

As a result, the NO_x level can be increased but not decreased by changing the gas valve design on the Z330 engine. The existing gas valve appears to be nearly optimized in that it produces a very homogeneous mixture. Reducing the gas valve area from the baseline (.405 sq. in) may slightly reduce misfire (see the top set of curves in Figure 15) and thereby extend the lean limit of operation.

E.   ANALYSIS OF THE RATE OF HEAT RELEASE

For each run, the rate of heat release in the cylinder was calculated from a smoothed pressure trace. The rate of heat release is determined by and therefore gives information about the ignition delay, the rate of flame area growth in the early stages of combustion, and the rate of burning in the critical late stage of combustion as residual pockets of flammable mixture are reached by the flame and consumed. Figure 16 illustrates typical rate-of-heat-release curves for two runs made at 5° and 9° spark timing. Note that the two curves have essentially the same triangular shape, but are shifted by about 4° (as expected). The combustion duration is just under 40° crank angle. The rate of heat release is sharply peaked, with the maximum heat release occurring at the point of greatest flame area and rate of flame travel. This probably occurs just as the flame (visualized as an irregular hemisphere propagating toward the piston) first reaches the wall. The front of the triangle is steep, the slope proportional to the average flame speed. The back of the triangle is dependent on the chamber geometry, which affects the flame area reduction. The "tail" represents the consumption of residual unburned gas and is critical to the fuel consumption performance.

Recall that the fuel-air ratio, ϕ, has a marked effect on the NO_x emission. The rate of heat release analysis provides insight on how the combustion process is affected by changes in ϕ. As seen in Figure 17, successive reductions in ϕ cause four changes:

- Triangle starts later (longer ignition delay);
- More gradual front side of the triangle and peak reached later (slower flame speed);
- Lower peak (lower maximum burning rate); and
- Longer "tail" (longer combustion duration)

Further analysis of the shape of the rate of heat release is being conducted. Apparently the NO_x level can be correlated with the slope of the front side of the triangle (flame speed). As further data becomes available, we will attempt to construct a function $f(\alpha,\beta)$ of the same form as the rate of heat release and correlate the parameters α, β with operating conditions of the engine.

F. FORTHCOMING SPARK IGNITION TESTS

In the forthcoming tests, lean-burn methods such as torch-ignition and multiple spark will be tested. These methods show promise of up to 70% NO_x reduction, not only based on the baseline data on the Z330 single-cylinder engine, but also based on data presented by Helmich (1979) and Chrisman (1980), as shown in Table VII. The research needs for torch ignition which will be addressed by the EPA project include the following:

- Methods of metering the amount of fuel in the torch chamber in order to optimize torch fuel-air ratio.

- Systematic study of the effects of torch shape and direction, by changing nozzle diameter, nozzle shape, nozzle length, and orientation of the axis.

In addition ammonia/catalyst systems for exhaust gas treatment will be tested. The research needs for these systems include the following items:

- Control systems for catalyst temperature

- NH_3 carryover detection

- Platinum vs base metal

- Catalyst life (extended tests)

- Optimum space velocity

- Corrosion from sulfates (which form from the reaction of SO_3 traces with NH_3

SECTION 4

DIESEL ENGINE TESTS

A. EXPERIMENTAL ARRANGEMENTS

The tests of diesel engine methods were carried out on an 11" bore four-stroke turbocharged single-cylinder engine, the Model PA-6 of S.E.M.T. design. The characteristics of this engine are as follows:

- Displacement, 1090 in^3

- Compression ratio, 11.8/1

- Rated power, 350 hp[*] at 1000 RPM

- Brake mean effective pressure, 270 psi

- Injection: 20-mm plunger, 8 x .50 mm holes

- Piston shape: Mexican hat

- Standard timing: 23.5 btdc

Figure 18 gives a cutaway view of the entine. Manifold air temperature and pressure can be controlled independently as in the Cooper facility described above. The emissions and cylinder pressure instrumentation is also comparable, with the exception that only exhaust sampling is done for the diesel tests.

B. BASELINE CHARACTERISTICS AND THE EFFECT OF TIMING

The NO_x emissions and fuel consumption of the PA-6 are strongly influenced by the timing of the start of fuel injection, as shown in Figure 19. The NO_x can be reduced from 9 to about 6 g/bhp-hr by retarding injection from 18 to 11° btdc (4.5% per degree). However, exhaust temperature is excessive and there is a substantial fuel penalty. Attendant to the NO_x reduction is a fuel penalty of about 1.1% per degree of retardation on the average.

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[*]Equivalent to 400 hp on multicylinder engine.

501

These characteristics are representative of large-bore diesel engines and the engine seems to be appropriate as a test facility. The scatter in NO_x data for replicate runs is ± 0.5 g/bhp-hr or about $\pm 5\%$.

C. PILOT INJECTION

Pilot injection was tested in an attempt to compensate for the undesirable side effects of retarded timing. The pilot quantity was varied from 4 to 12% of the total fuel per cycle, and four pilot advances were tested (40, 60, 80, and 120° btdc). Figures 20 and 21 show the results for full load and part load, respectively. The solid line represents the baseline (no pilot) case. At full load, pilot injection did not improve the BSFC-NO_x characteristics. Retarded timing beyond 19.5° btdc was not possible because of exhaust temperature limitations.

However, at part load, certain configurations of pilot injection improved BSFC by up to 6% at fixed timing. Apparently pilot quantity should be minimized unless timing is retarded. With retarded timing at part load (Figure 21), NO_x may be reduced by about 20%. Results were inconsistent, however.

In summary, pilot injection did not give significant NO_x reductions except in special cases. The pilot system was not matched to the injector and this may have limited its potential NO_x effect.

D. INCREASED INJECTION RATE

The intent of increased injection rate, like pilot injection, is to allow retarded timing without undesirable side effects such as smoke excessive fuel consumption, or high exhaust temperature. Figure 22 illustrates the difference in fuel injection schedule between the standard injector (20 mm plunger, 8 x .50 mm nozzle) and a high-rate injector (24 mm plunger, 9 x .55 nozzle). The larger injector has a higher average fuel pressure and a shorter injection duration. Eight combinations of plunger and nozzle were tested, as shown in Table VIII.

The results for full load (350 hp) and part load (234 hp) are presented in Figures 23 and 24, respectively. It is clear that unless timing

is retarded, the increased injection rate acts to increase NO_x instead of reducing it. With retarded timing, increased injection rate is beneficial but the NO_x response is mixed:

(a)   Full load - no improvement in NO_x-bsfc.

(b)   Part load - up to 20% NO_x reduction at fixed bsfc; and 30% NO_x reduction if a bsfc penalty of 3% is permissible.

The best injection system appeared to be the combination of the 24 mm plunger and 8 x 0.6 mm nozzle.

REFERENCES

1.   Helmich, M. J., "Clean Burn Engine," paper presented at the AGA Transmission Conference, New Orleans, Louisiana, May 1979.

2.   Chrisman, B., "Exhaust Emissions Regulations and Control Technology," paper presented at the 27th Annual Meeting of the Gas Compressor Institute, Liberal, Kansas, April 1980.

Relative
NO$_x$ Emission
Levels

Advanced
Low-NO$_x$ →
Engines
(Torch, Catalyst)

Proposed
EPA NSPS
(40% Reduction)

California
Model Rule
(90% Reduction)

Phases	Phase III	Phase
I & II	R&D	IV
		Field
Concepts		Tests

1.25

1.00

.75

.50

.25

0

1977   1978   1979   1980   1981   1982   1983   1984   1985   1986

EPA Program
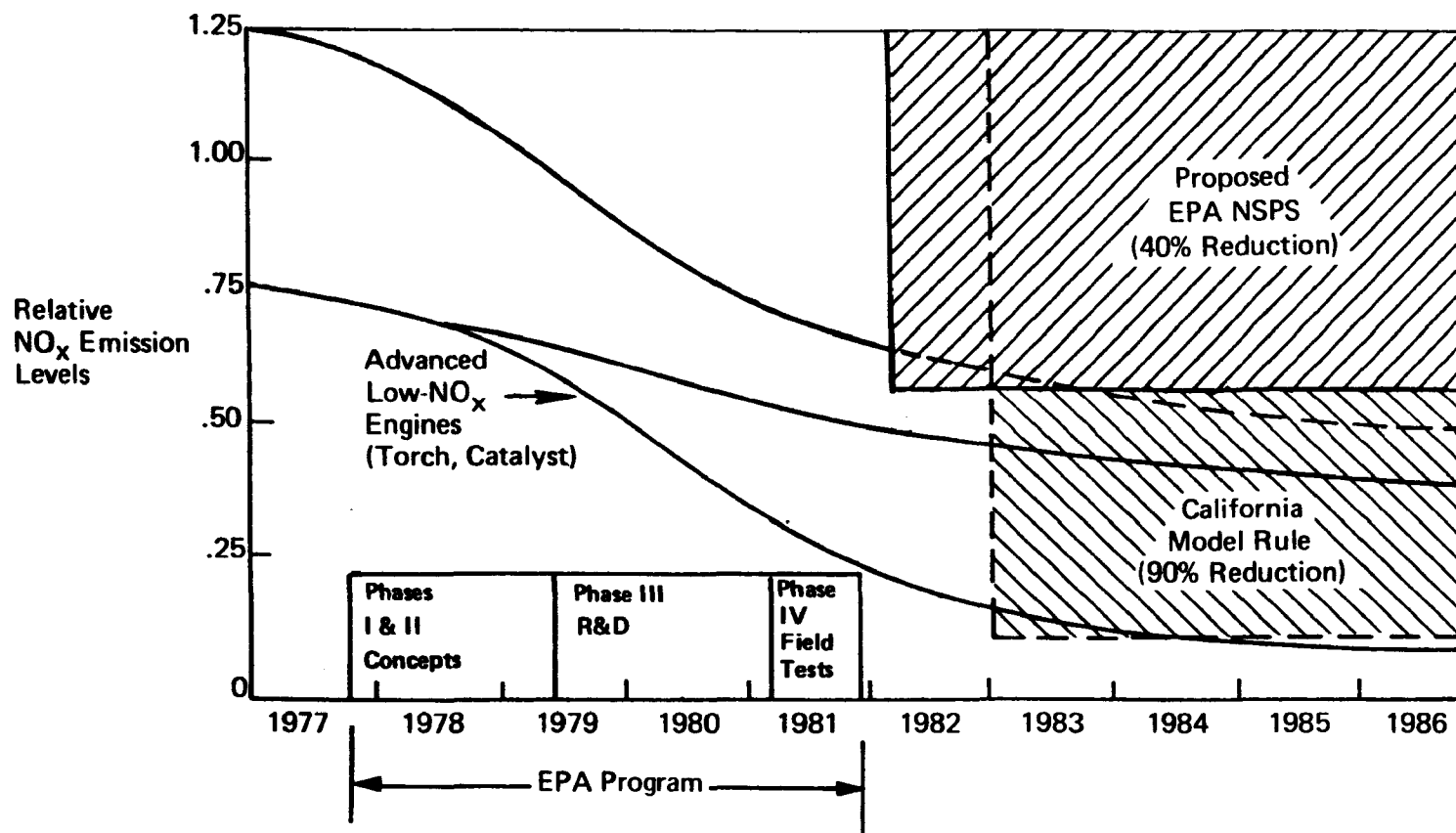
Figure 1.   Scenario of the development of
large-bore engine emissions.
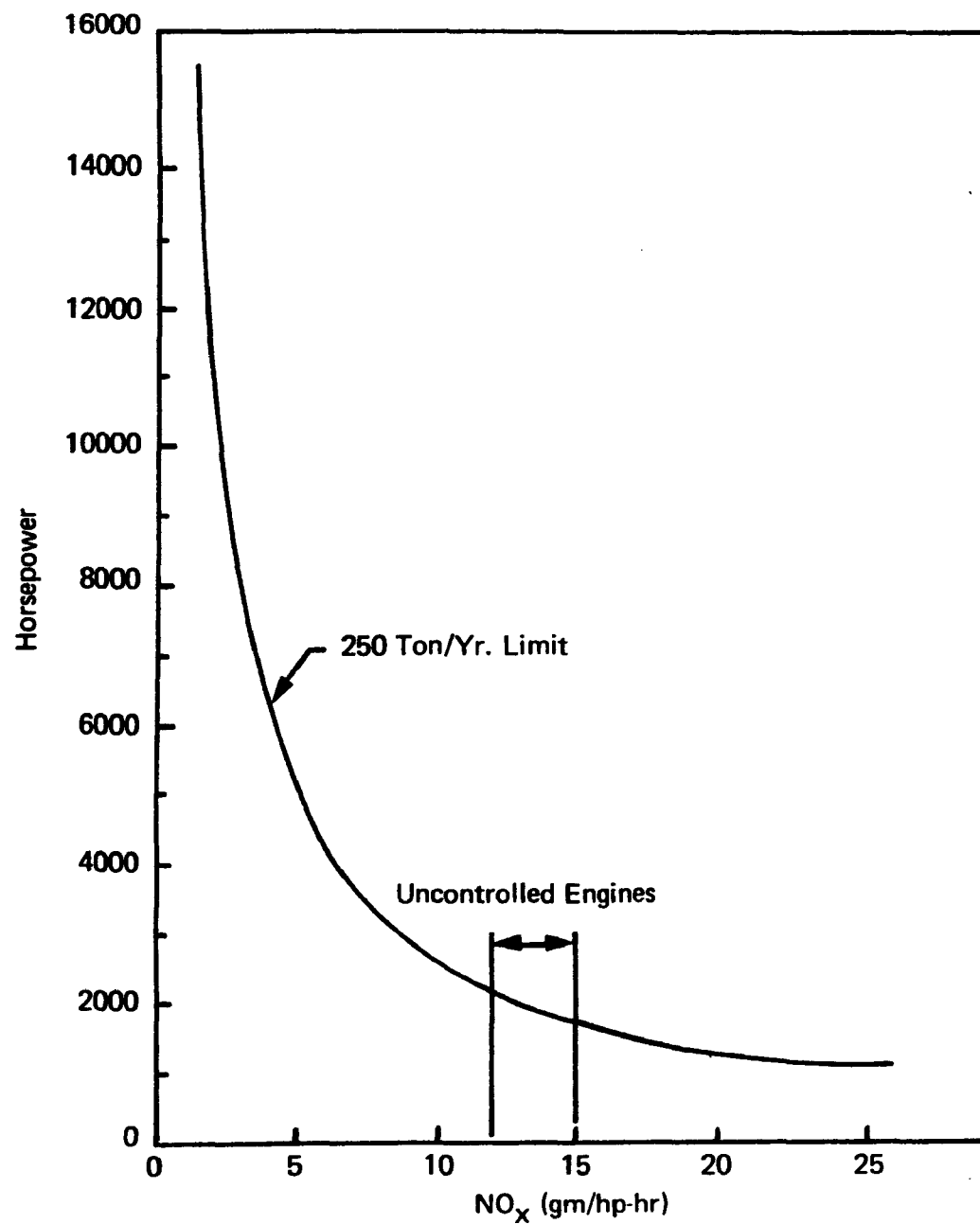
Figure 2. Low NO$_x$ allows larger engine installation
without PSD review process.
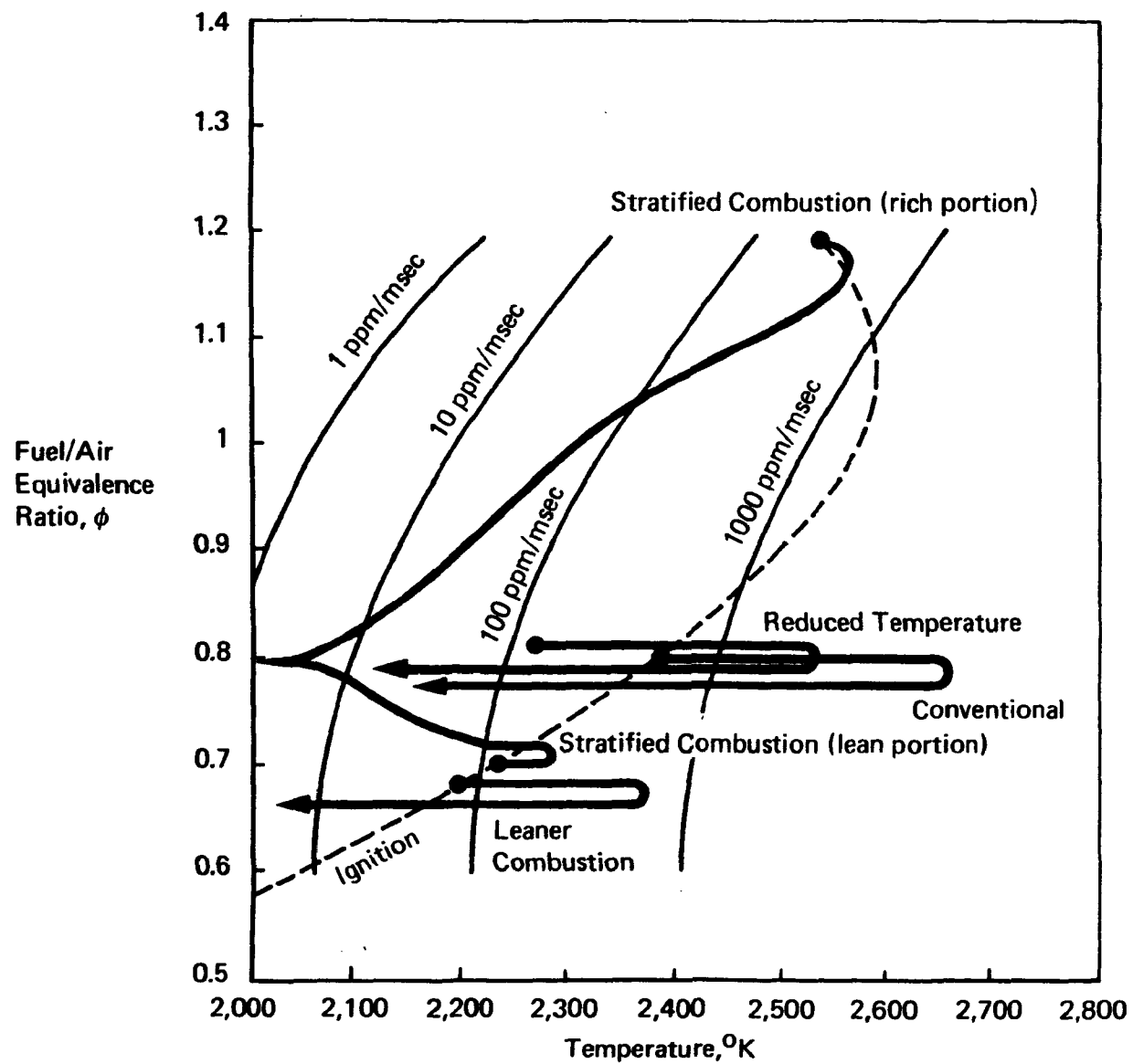
Figure 3. Basic categories of Nitric-Oxide suppression for spark ignition engines.
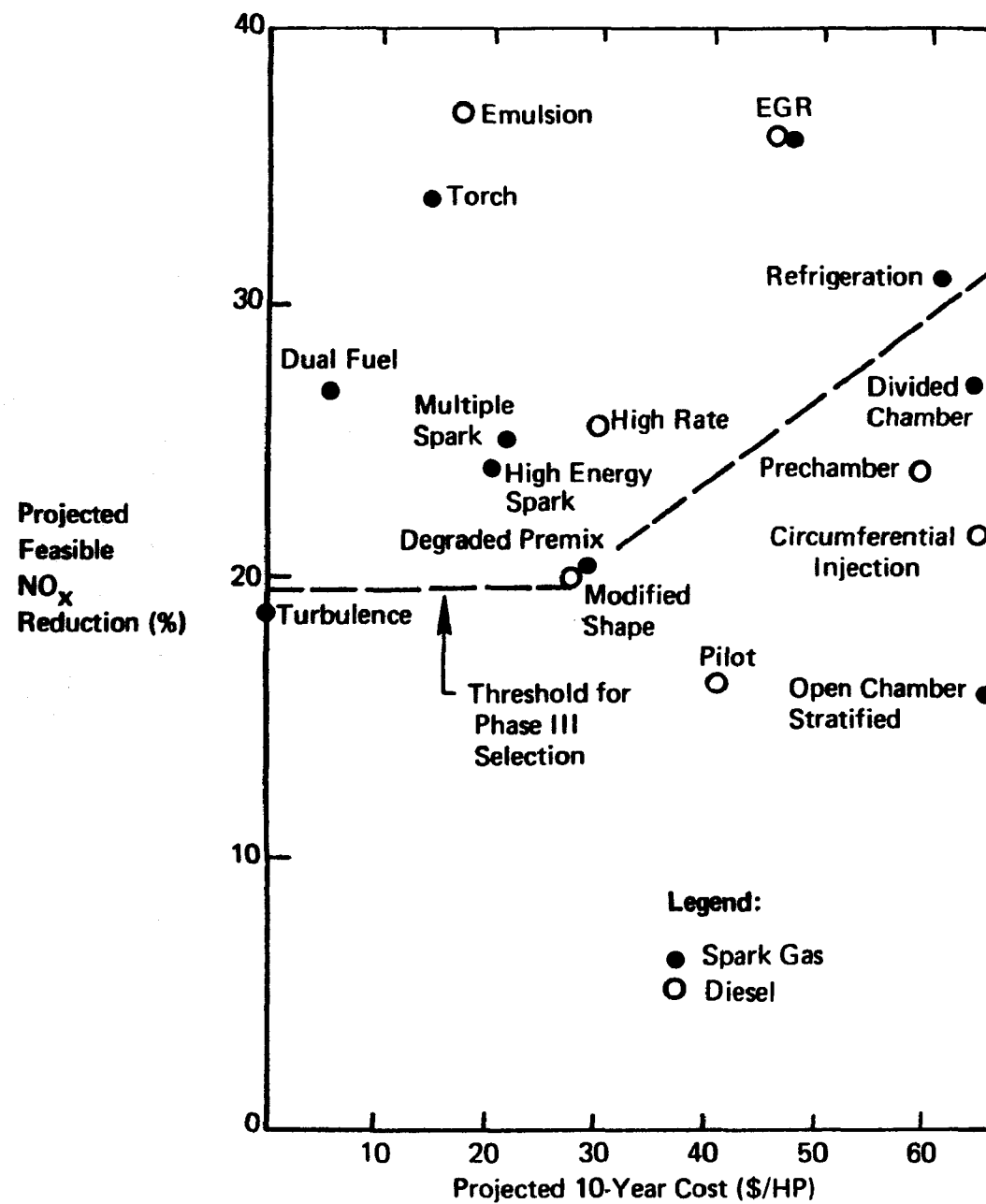
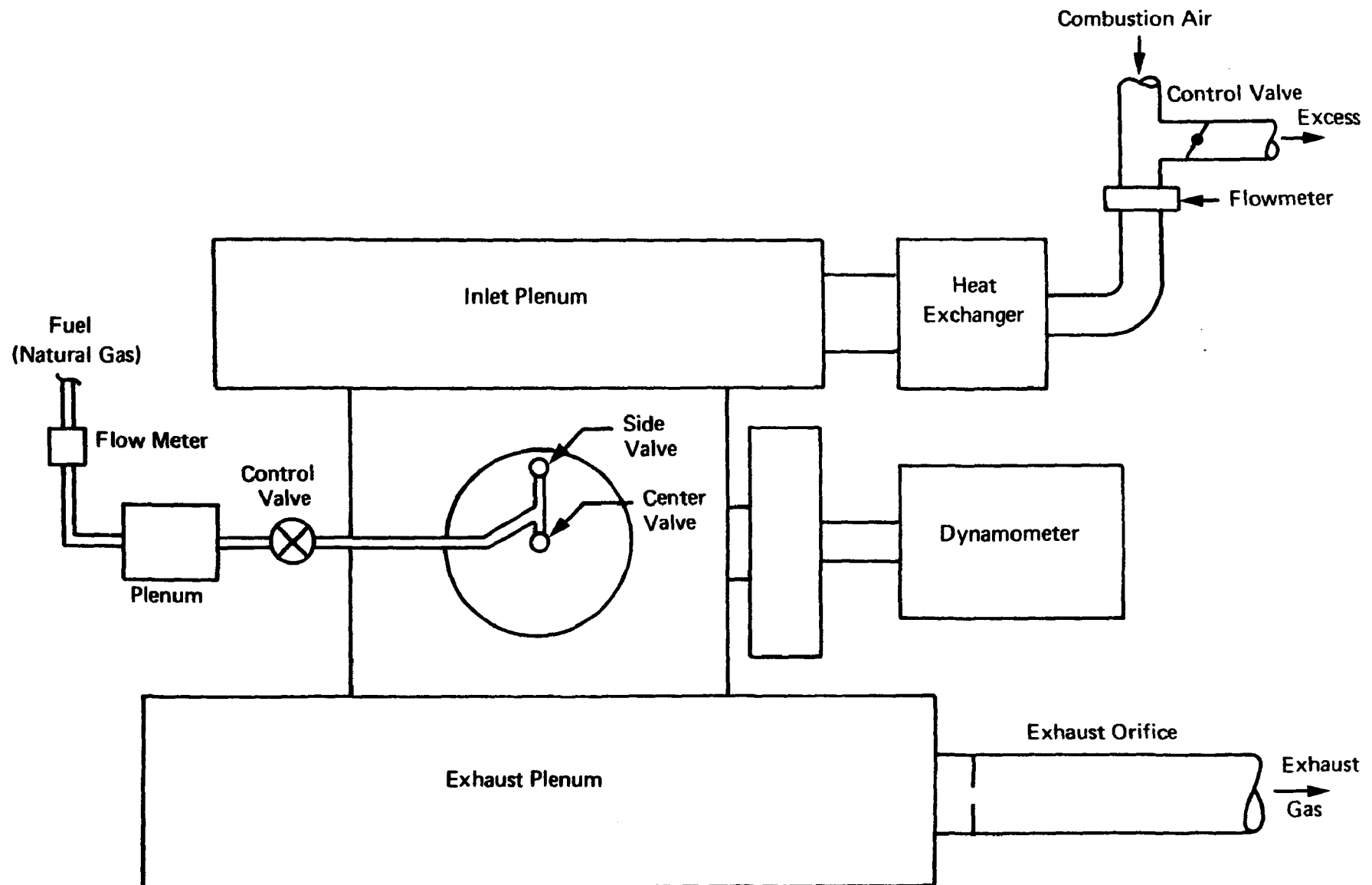Figure 4. Cost effectiveness of emission control methods

Figure 5. Plan view schematic laboratory single-cylinder engine Model
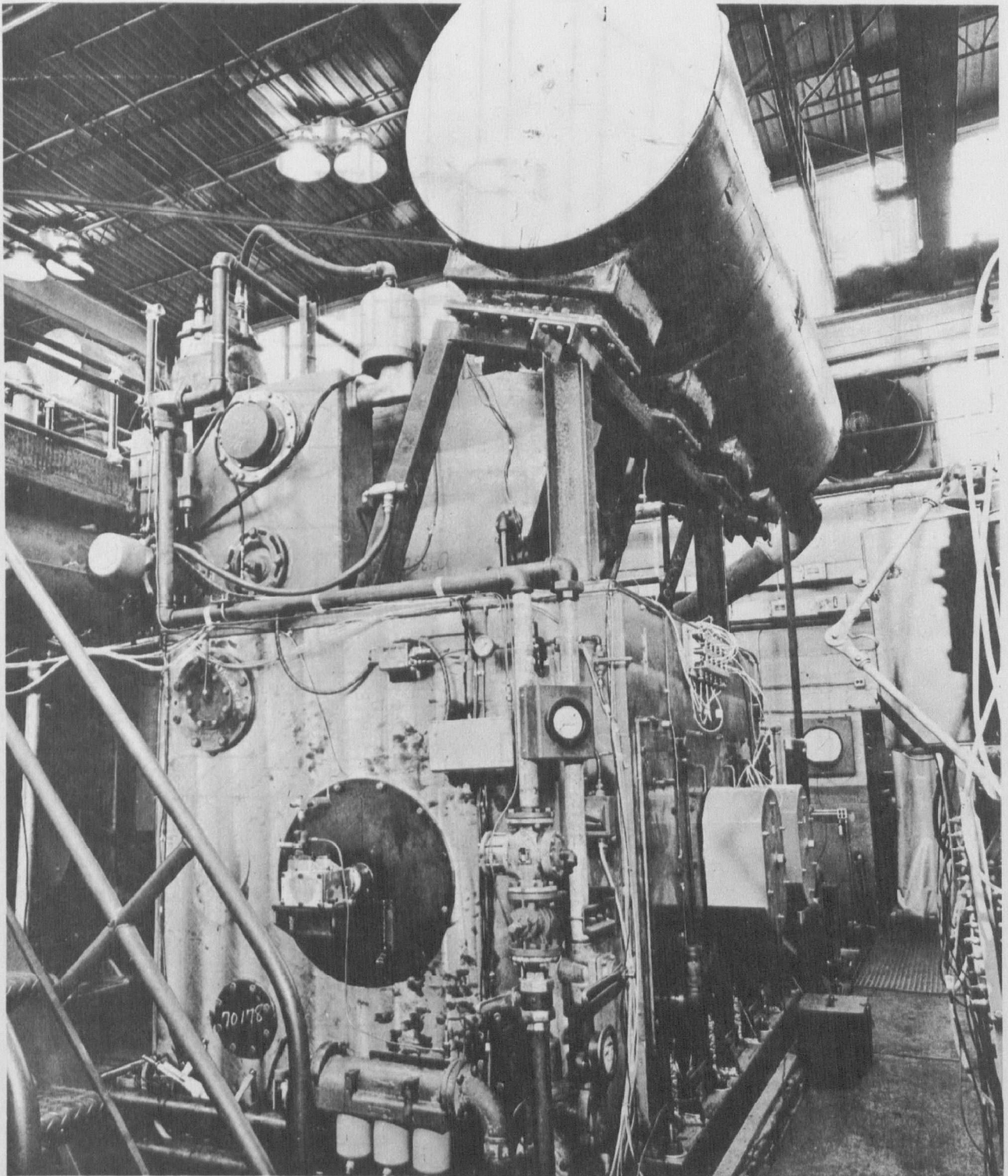Z330 (20" bore x 20" stroke).

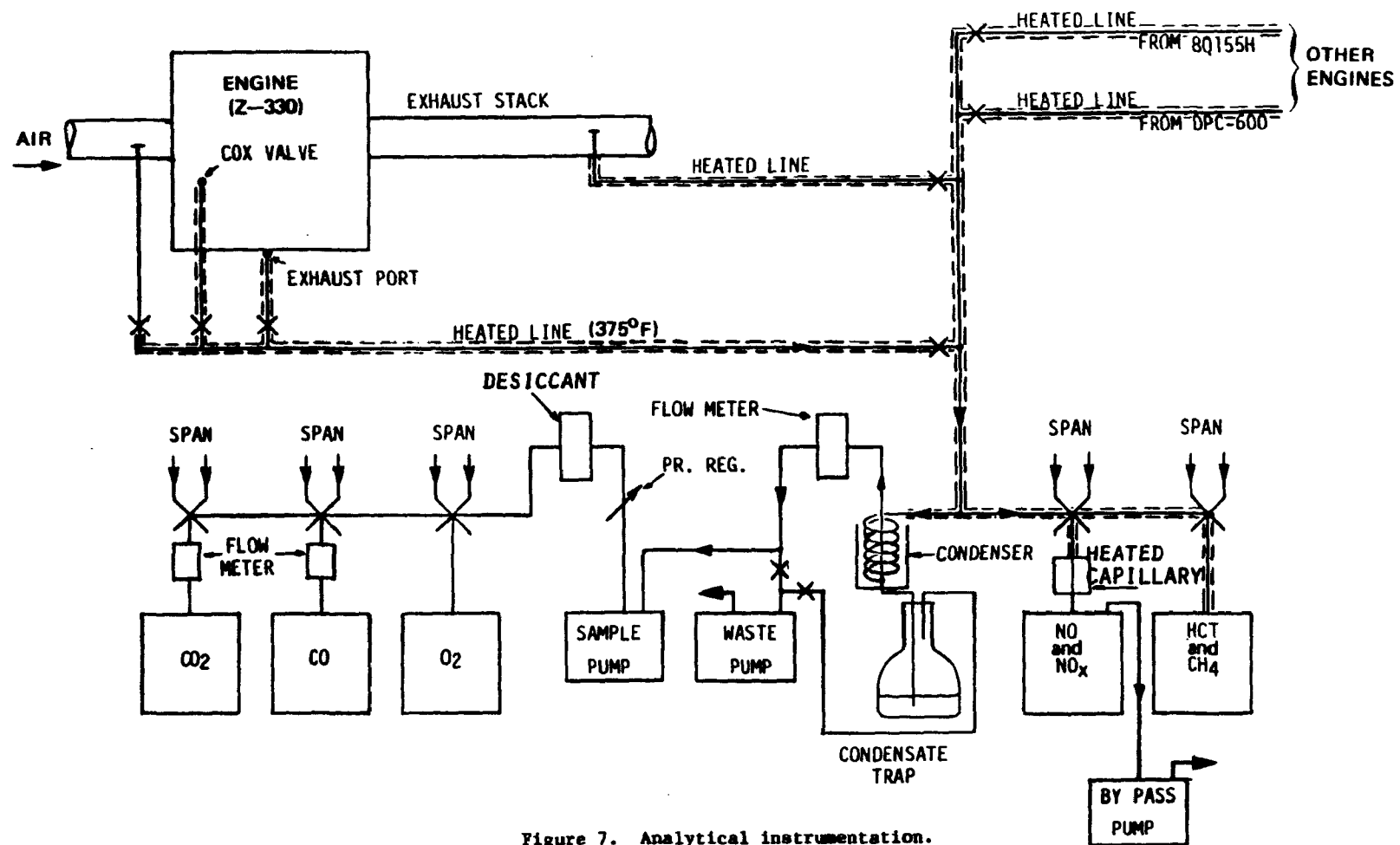Figure 6.   General arrangement of Z330 single cylinder engine.

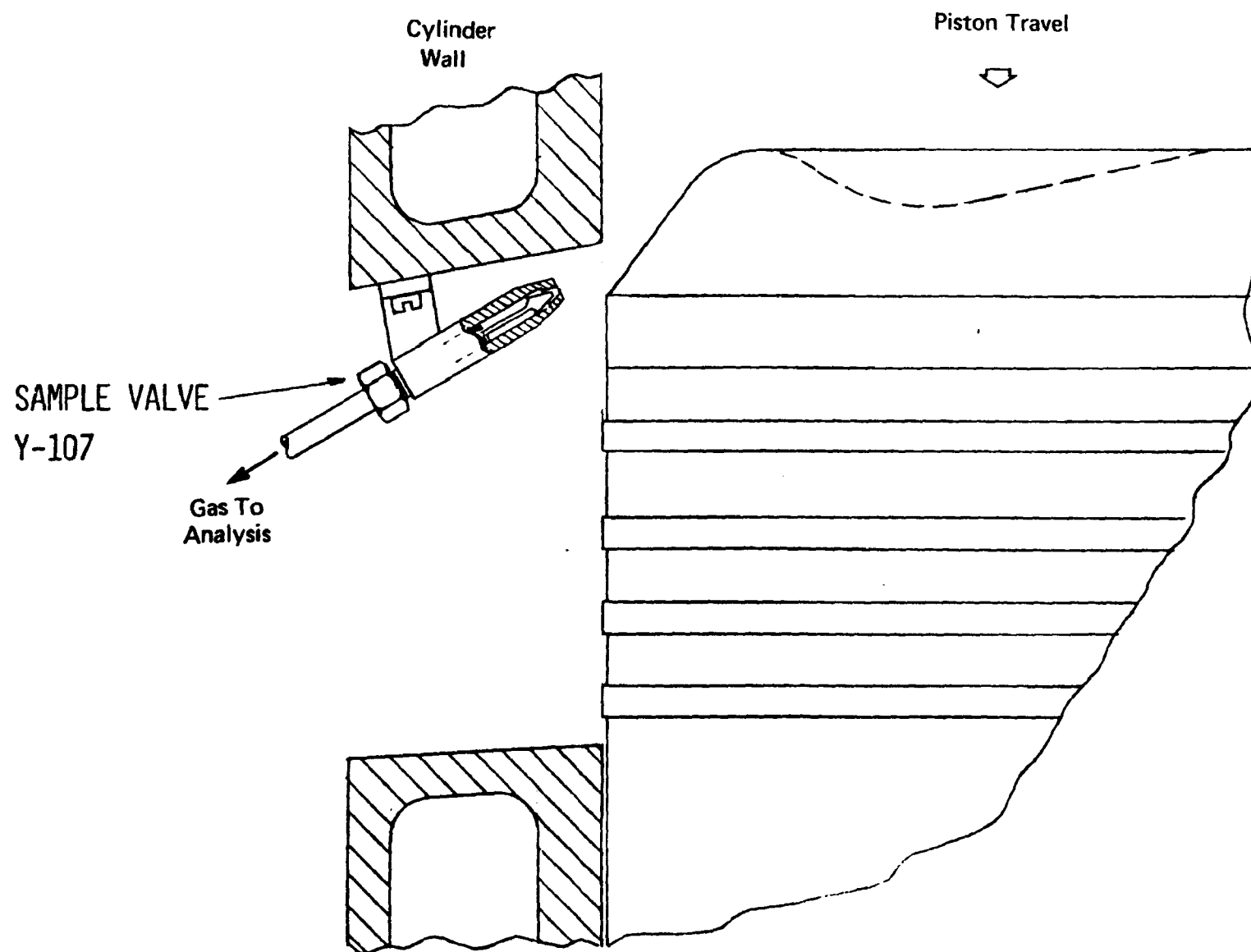Figure 7. Analytical instrumentation.

Cylinder
Wall

Piston Travel

SAMPLE VALVE
Y-107

Gas To
Analysis

Figure 8. Sample valve for extracting cylinder blowdown
constituents from exhaust port.
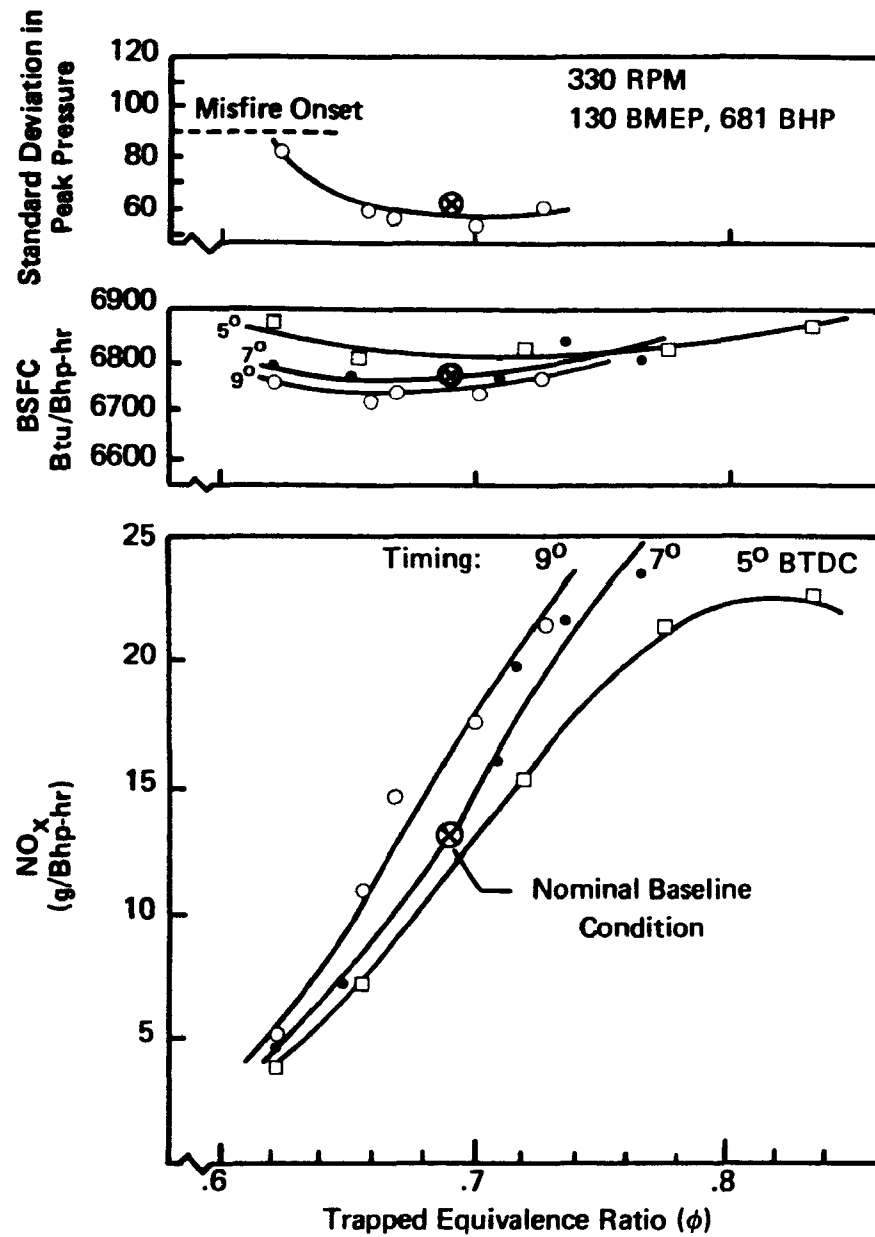
Figure 9. Baseline characteristics Cooper Z330 engine.
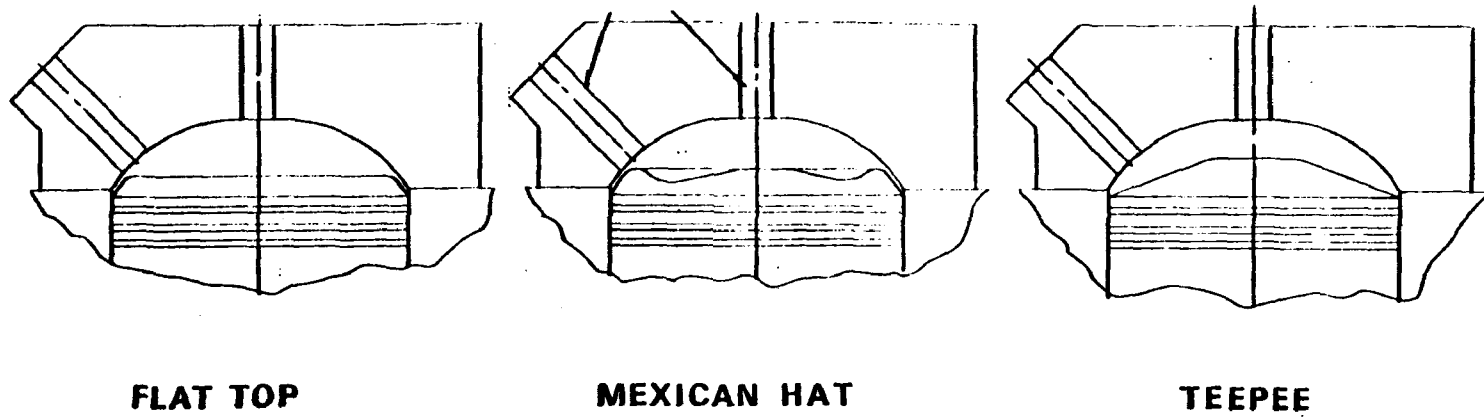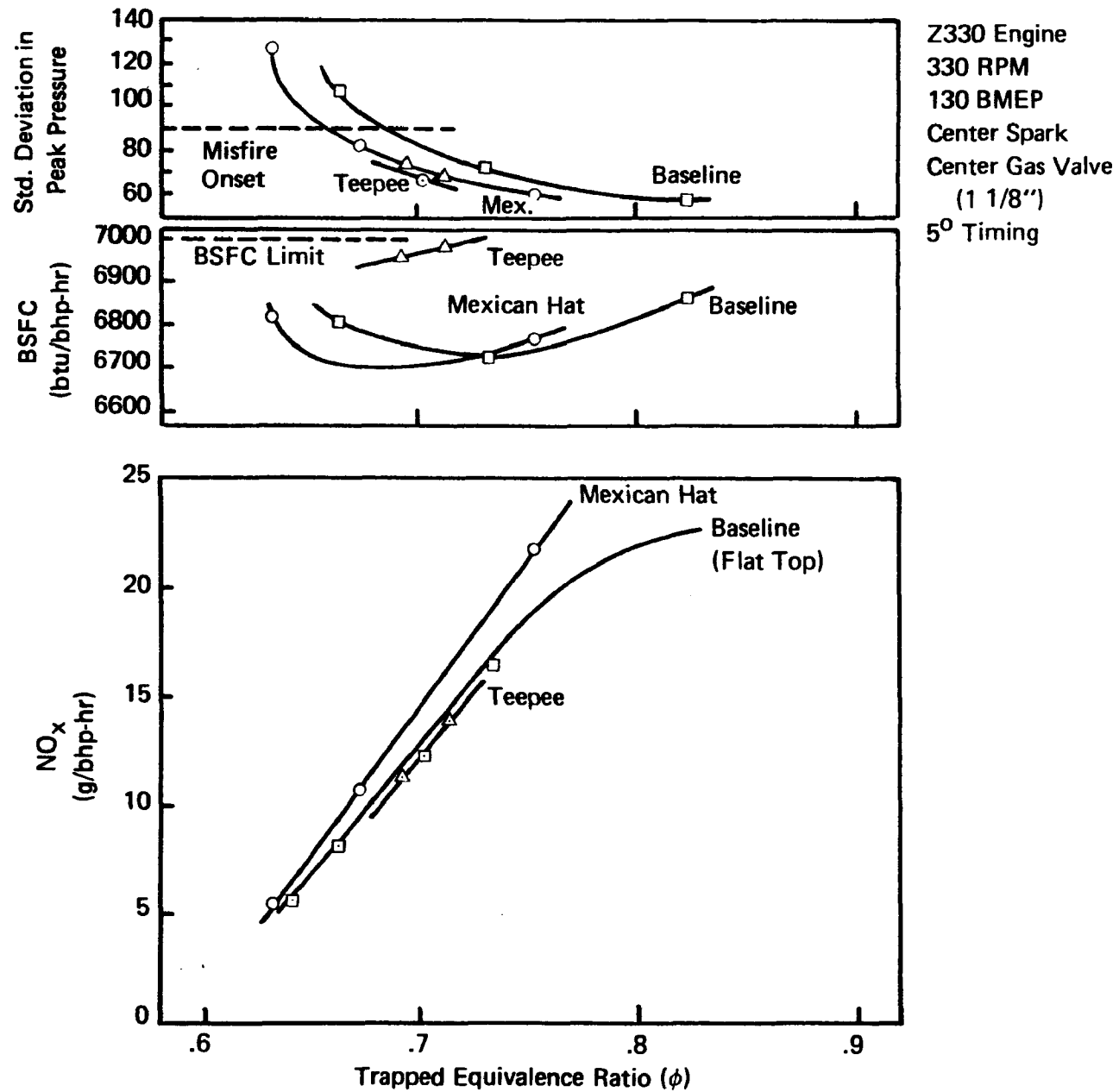
FLAT TOP   **MEXICAN HAT**   **TEEPEE**

Figure 10. Piston crown shapes.

Std. Deviation in Peak Pressure

140
120
100
80
60

Misfire
Onset

Teepee

Mex.

Baseline

Z330 Engine
330 RPM
130 BMEP
Center Spark
Center Gas Valve
(1 1/8")
5° Timing

BSFC
(btu/bhp-hr)

7000
6900
6800
6700
6600

BSFC Limit

Teepee

Mexican Hat

Baseline

514

NO_x
(g/bhp-hr)

25

20

15

10

5

0

Mexican Hat

Baseline
(Flat Top)

Teepee

.6   .7   .8   .9

Trapped Equivalence Ratio (ϕ)
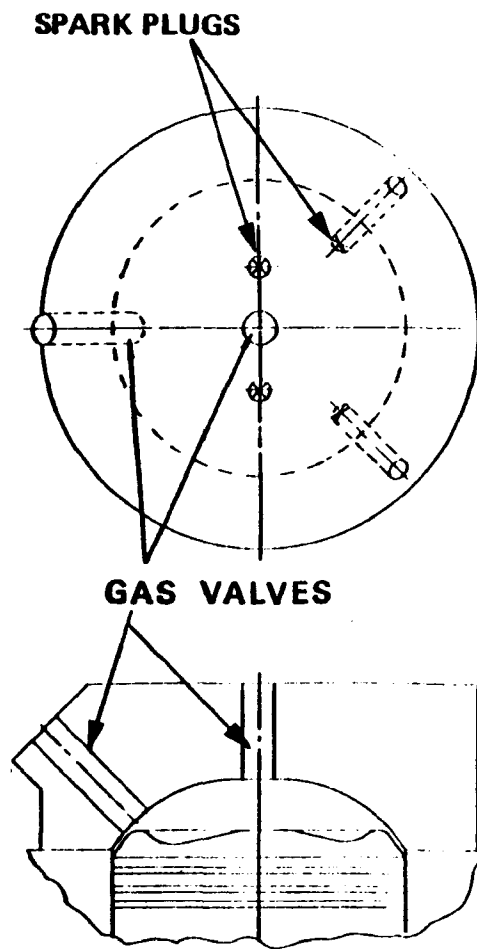
Figure 11.   Effect of piston shape.

SPARK PLUGS

GAS VALVES

Figure 12. Spark plug and gas valve locations.
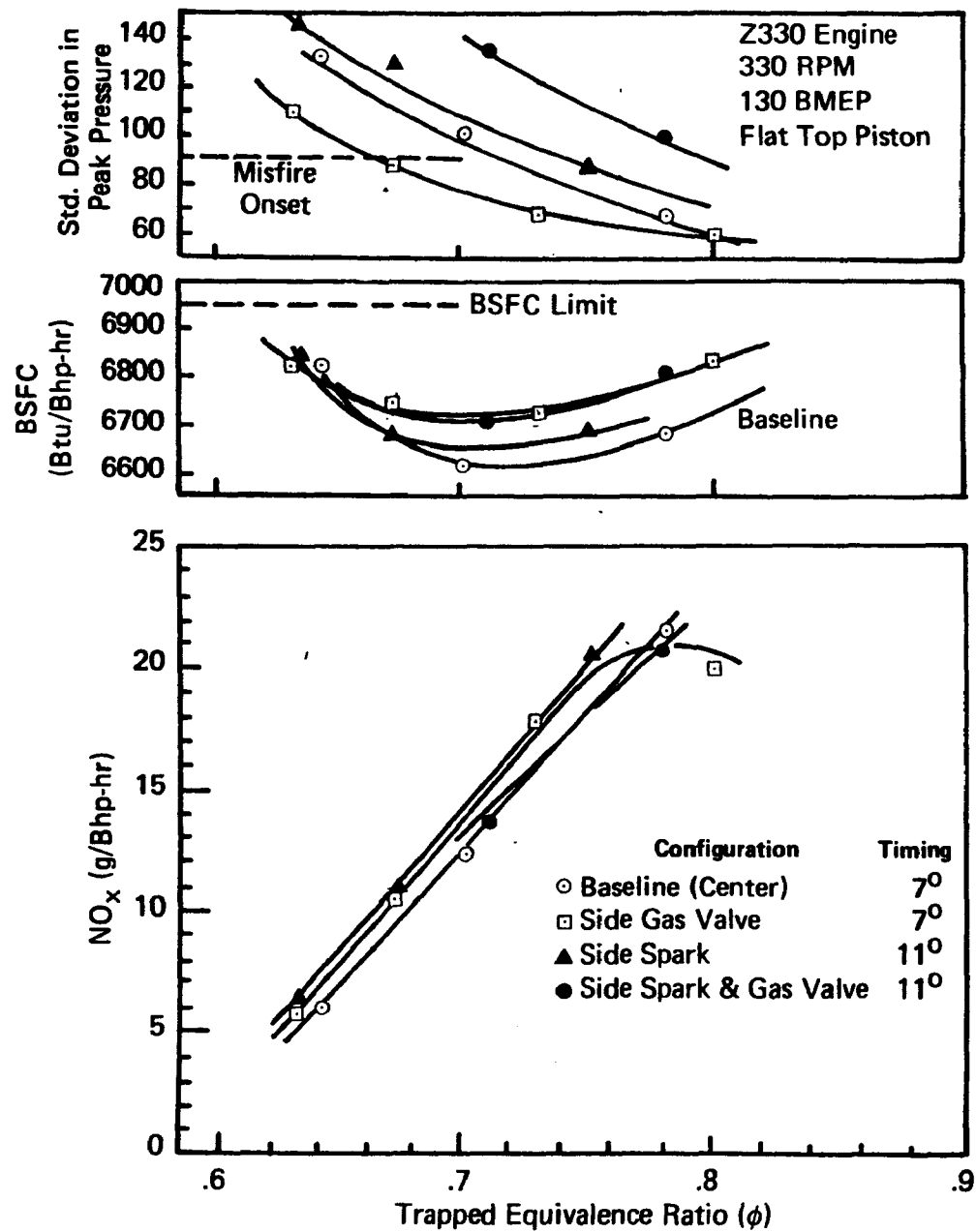
Figure 13. Effect of gas valve and spark location.

$1\frac{1}{8}$ REDUCED AREA

(.336-in.^{2} throat)

$1\frac{1}{8}$ STD.

(.405-in.^{2} throat)

$1\frac{5}{16}$ Increased Area
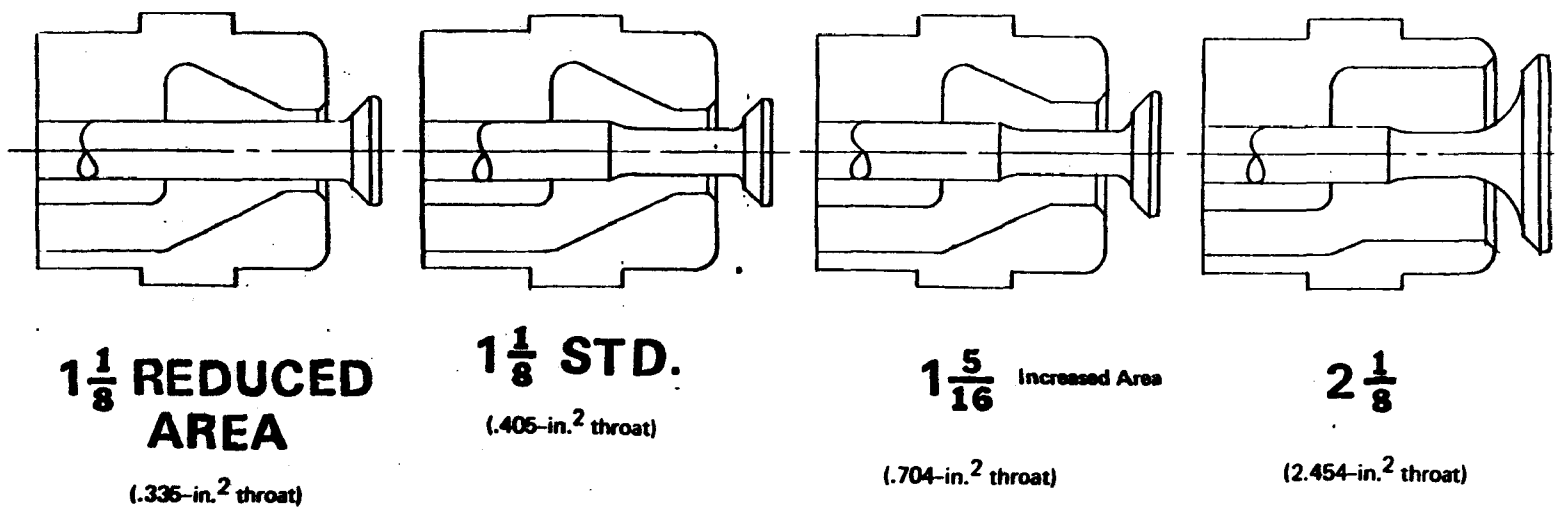
(.704-in.^{2} throat)

$2\frac{1}{8}$

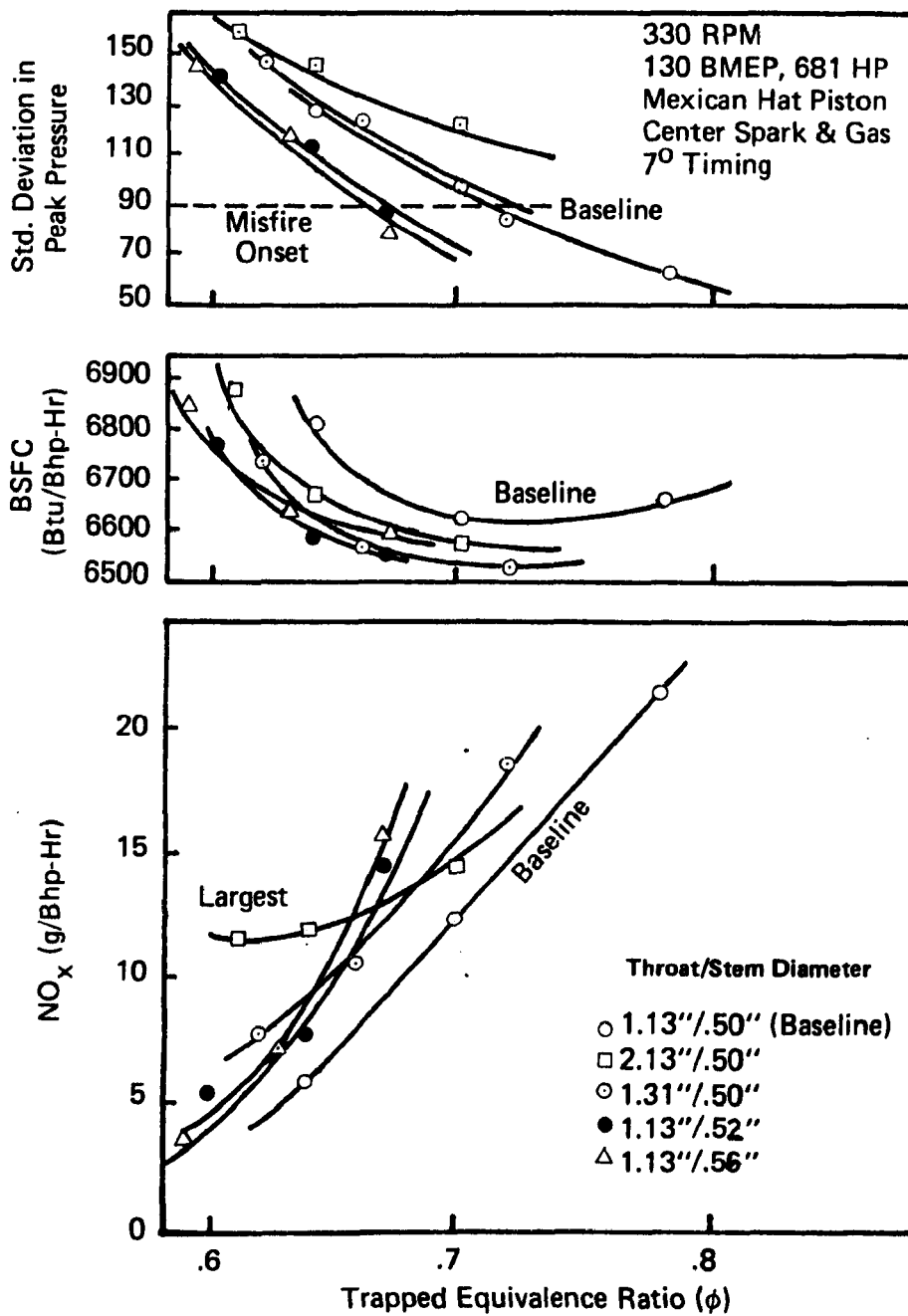(2.454-in.^{2} throat)

Figure 14. Gas valves.

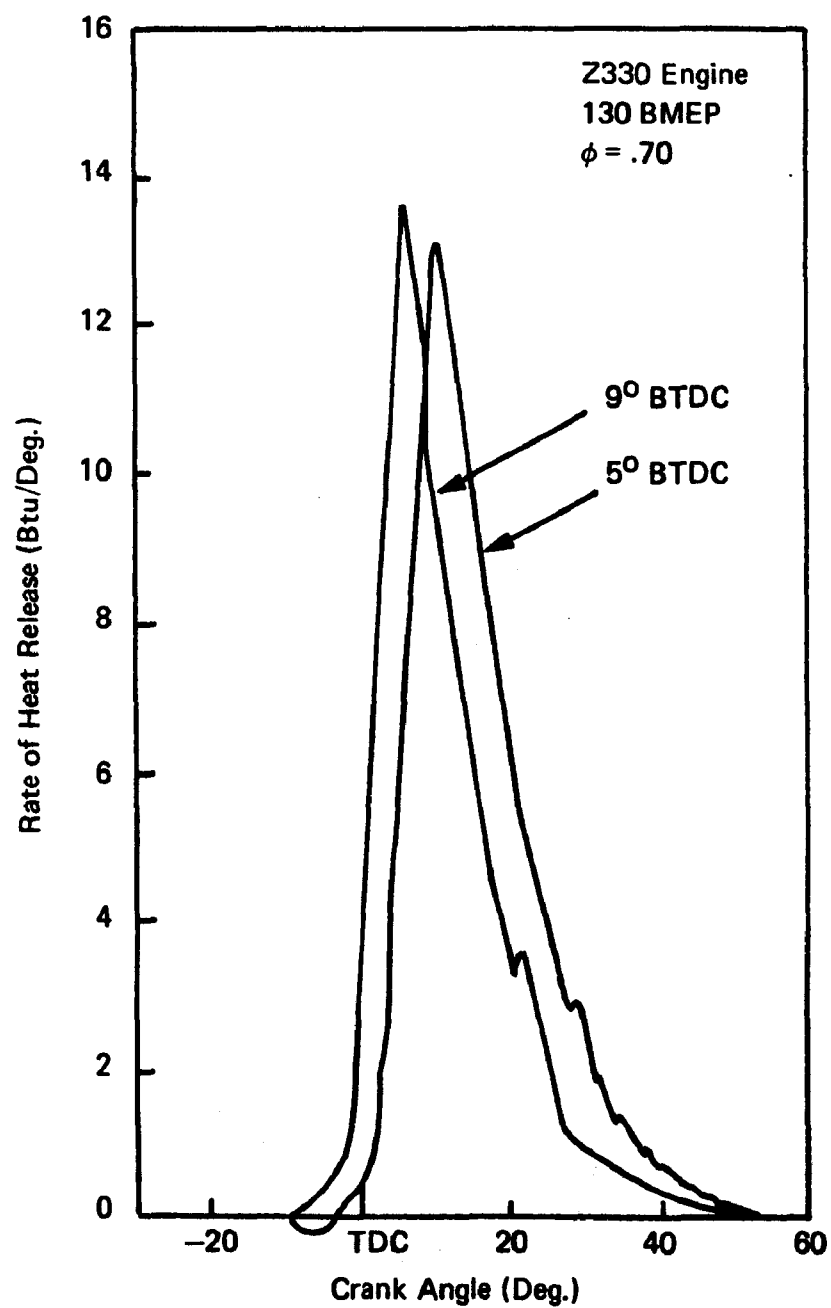Figure 15. Effect of gas valve modifications.

Figure 16. Effect of Timing
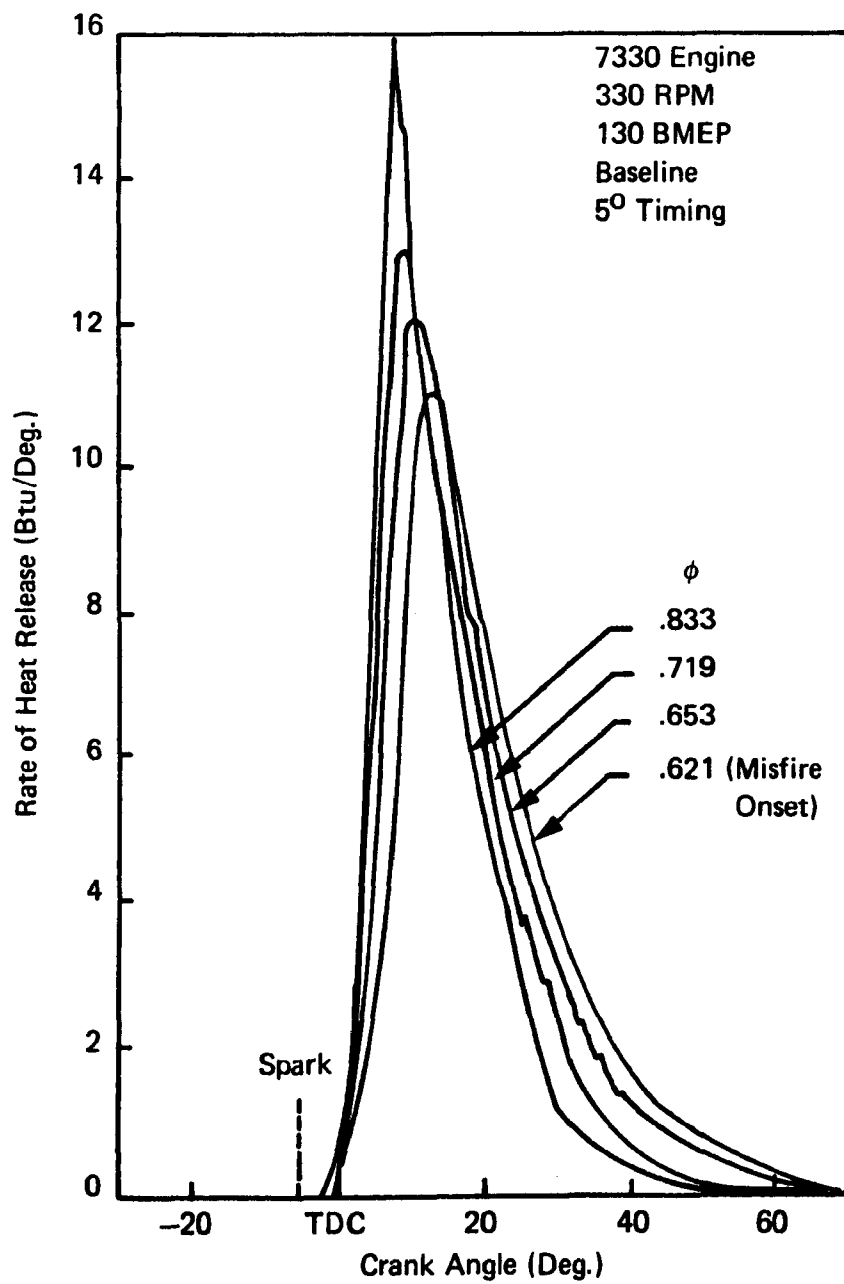
Figure 17. Effect of Fuel-Air Ratio
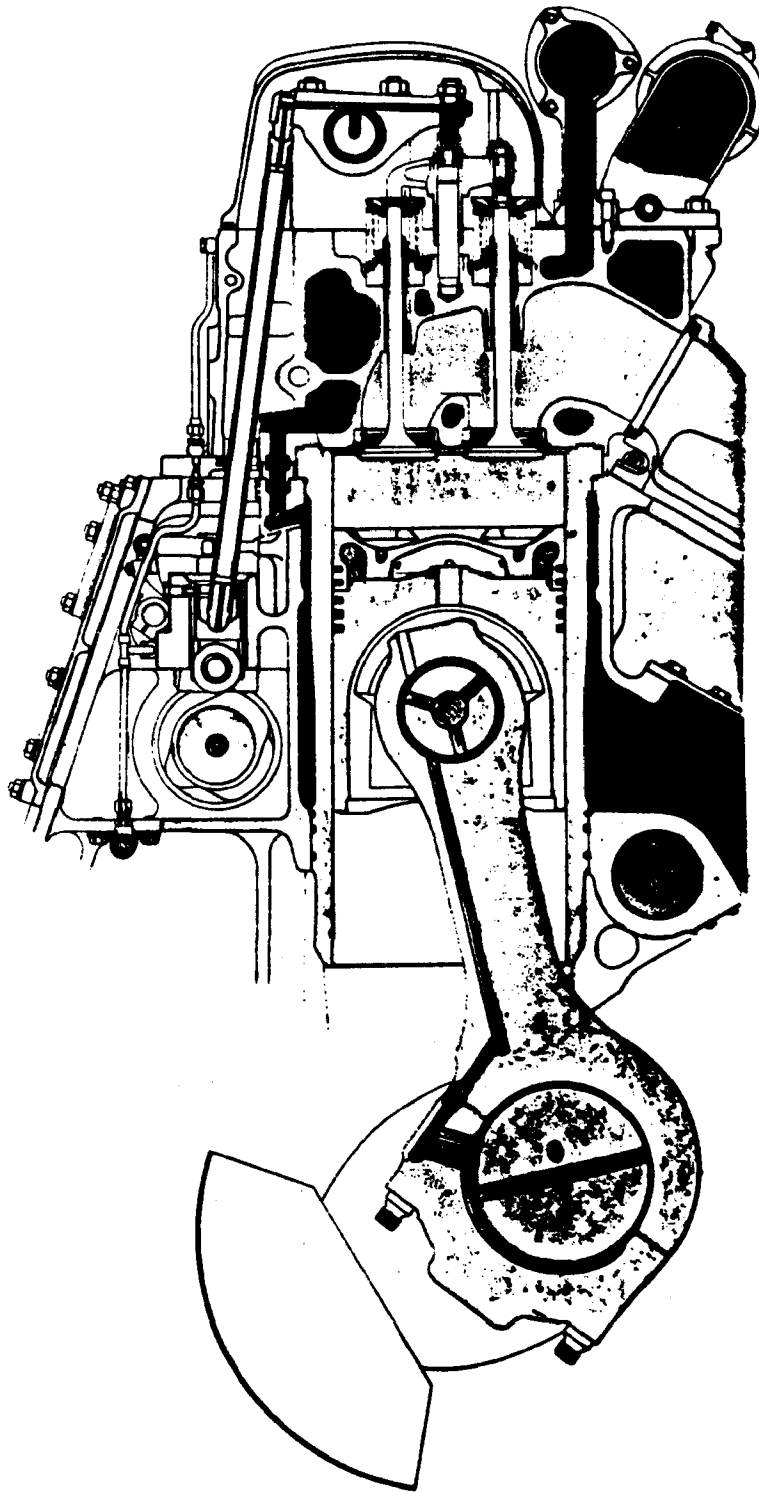
Figure 18. Section across a cylinder of the PA-6 engine

521
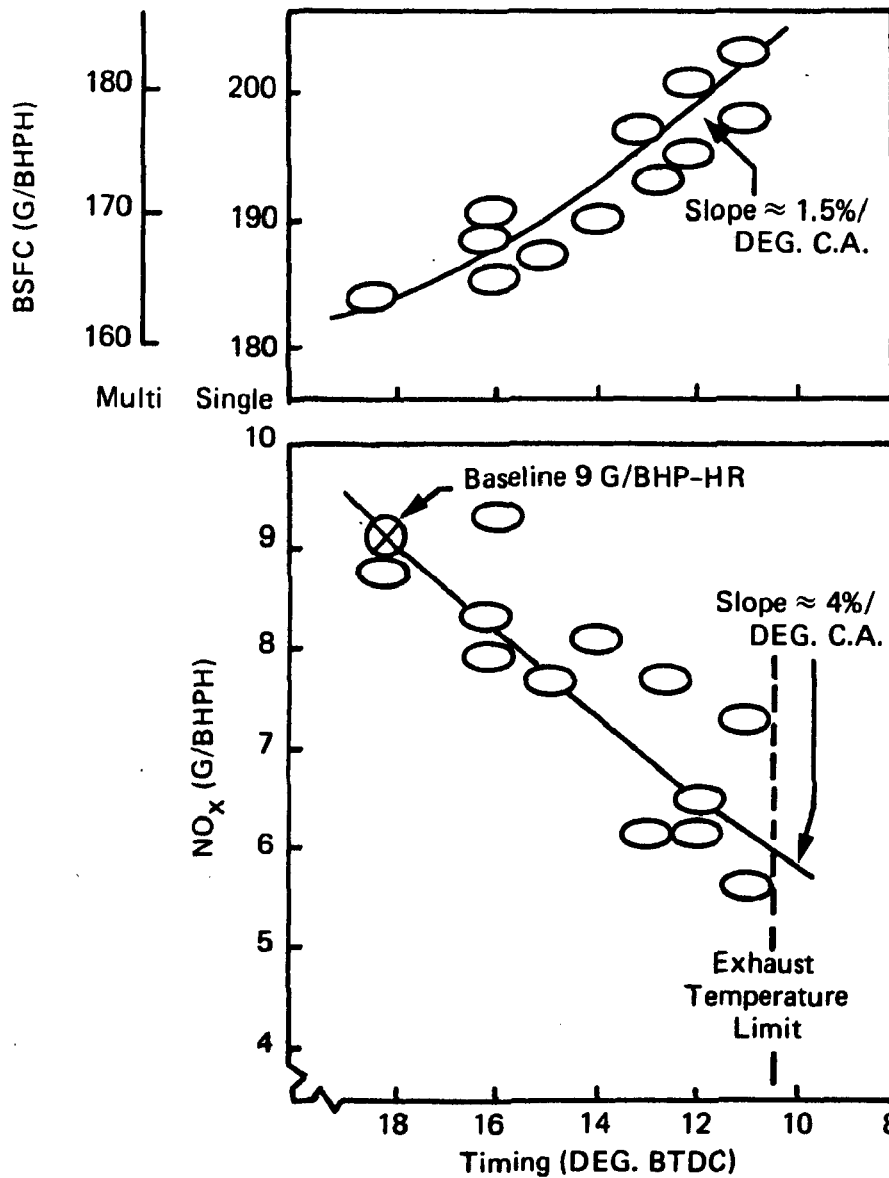
Figure 19. Diesel Baseline Characteristics
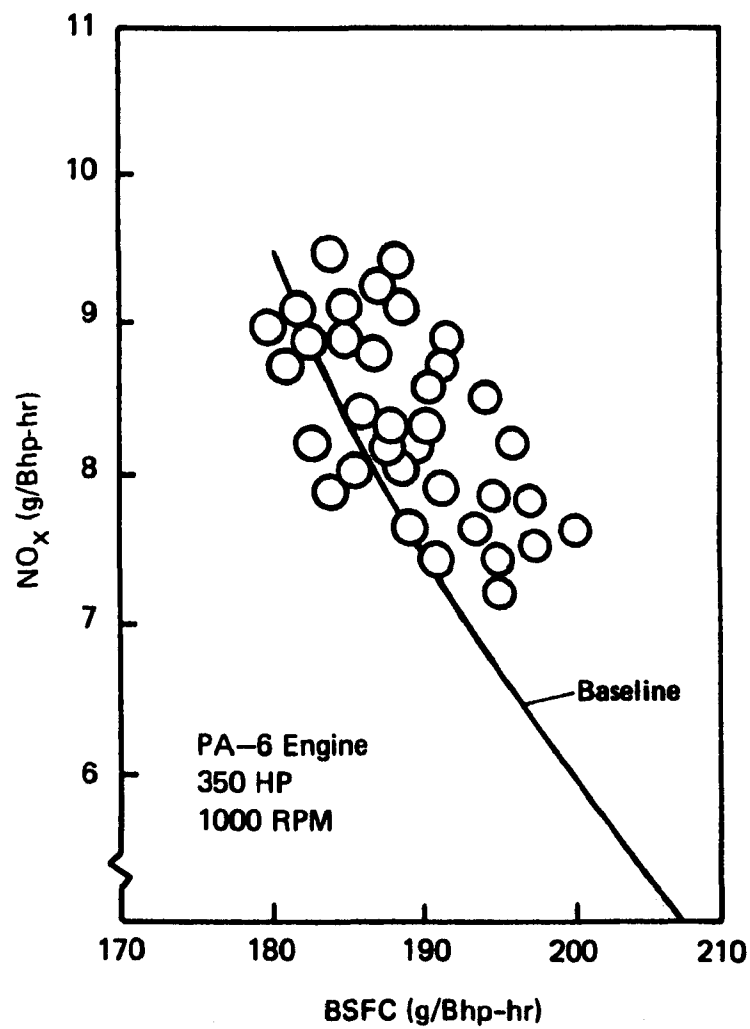
Figure 20.   Effect of Pilot Injection
(Full Load)
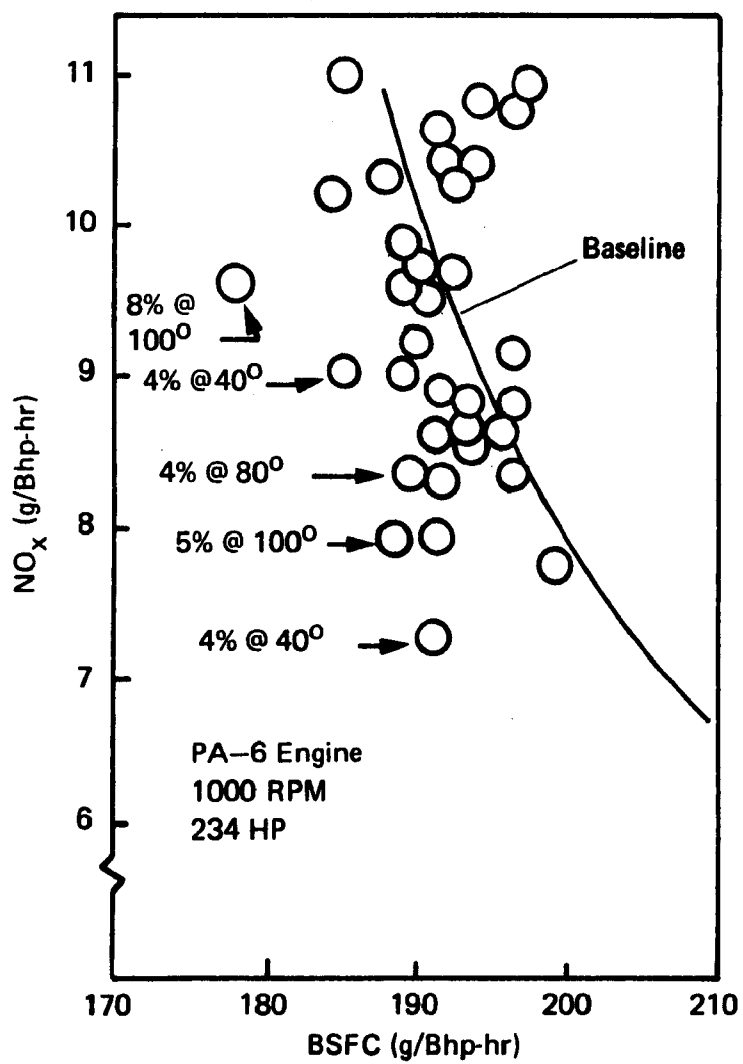
Figure 21. Effect of Pilot Injection
(2/3 Load)

524

NEEDLE LIFT

FUEL PRESSURE

24 mm PLUNGER
9 x .55 mm NOZZLE

20 mm PLUNGER
8 x .50 mm NOZZLE (BASELINE)

-20   TDC   +20

525
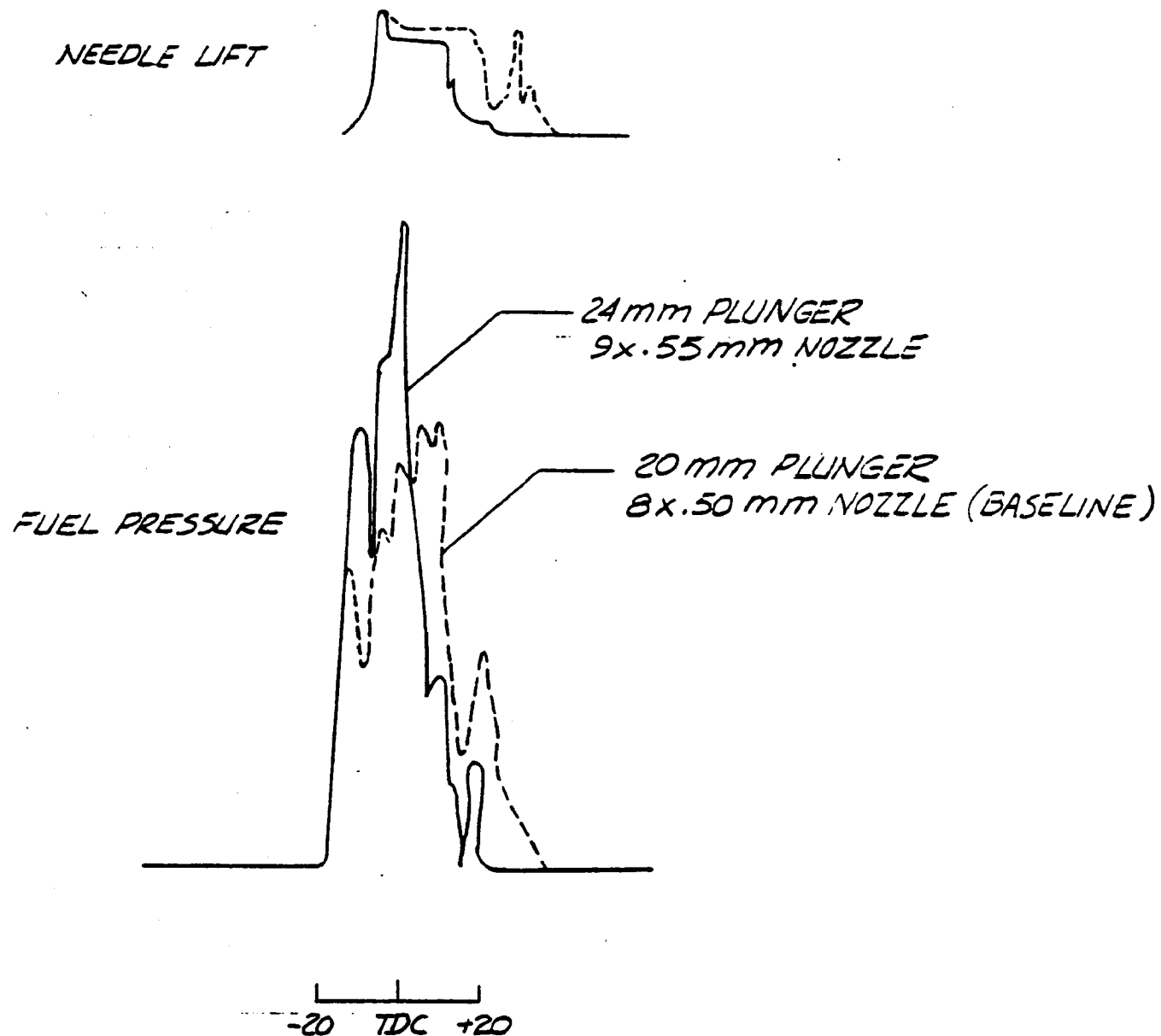
Figure 22.   Effect of Plunger/Nozzle on Injection Rate
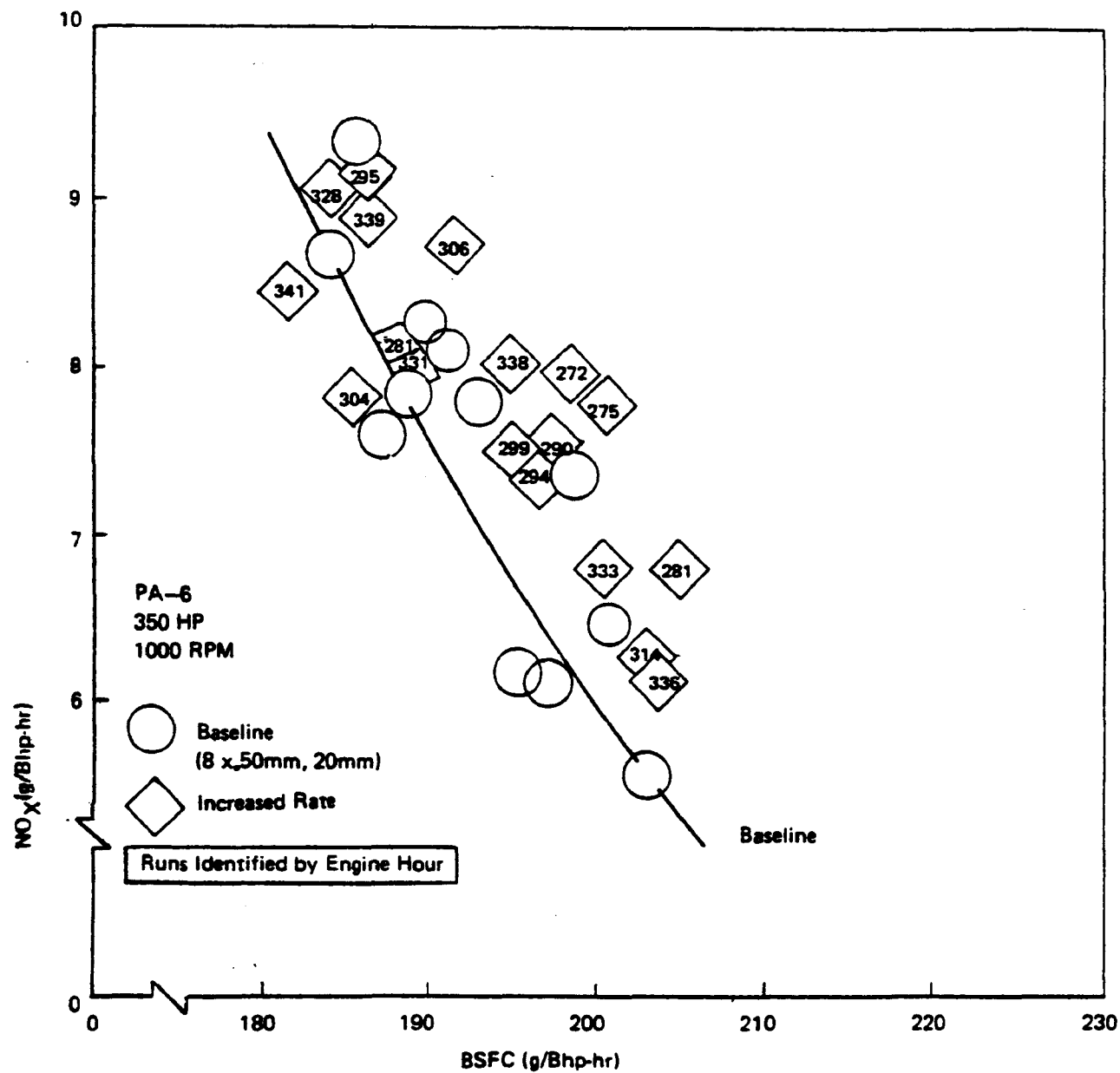
Figure 23.   Effect of Rate of Injection

527
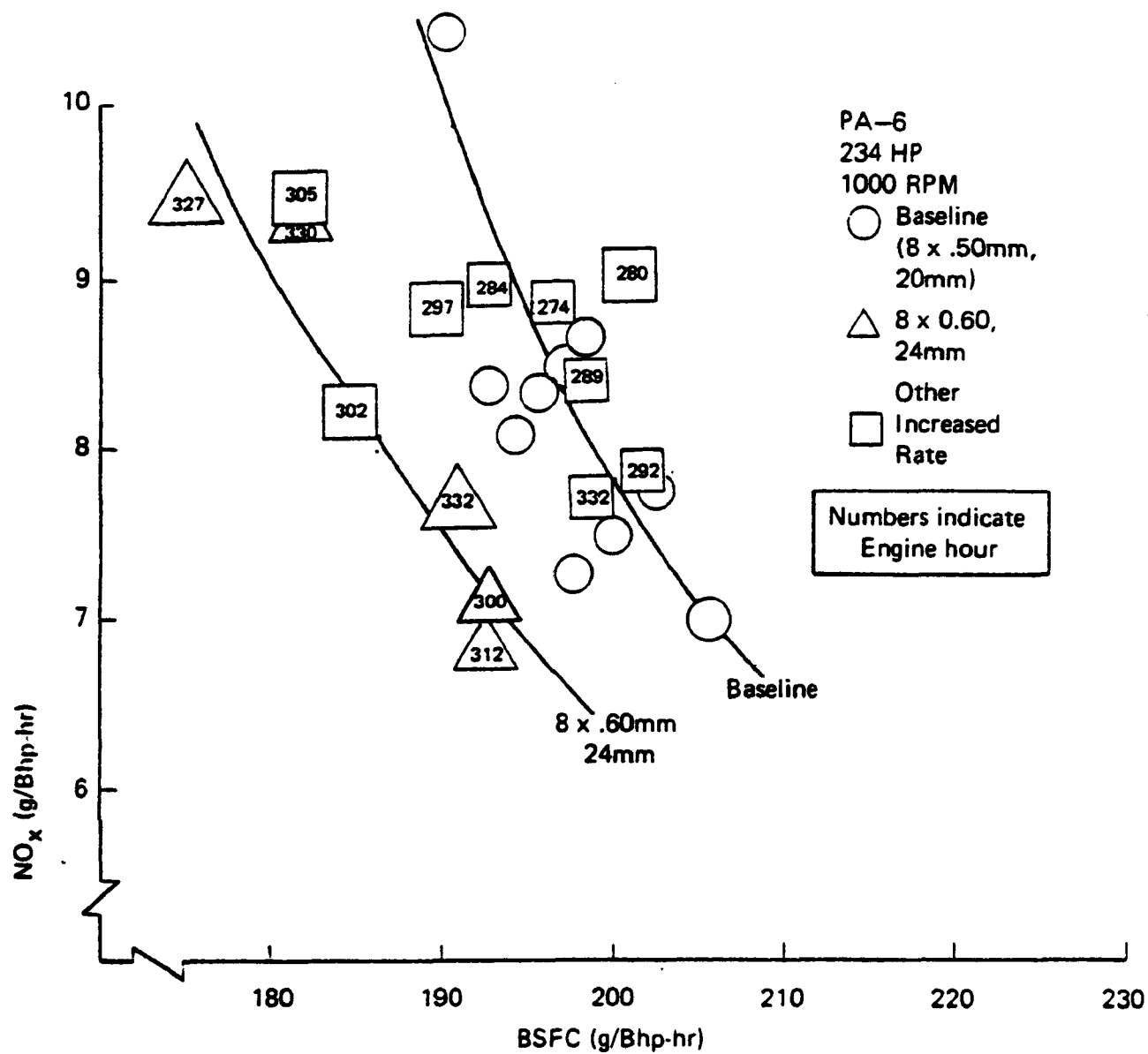
Figure 24. Effect of Rate of Injection

TABLE I: STATIONARY LARGE BORE ENGINE POPULATION

Engine Type	Application	Estimated Annual Fuel Use (10^{14} Btu)
Spark	Gas Pipeline Transmission	3.4
	Gas Gathering, recompression and storage	1.7
Diesel	Deep oil well drilling rigs and oil transport	3.0
	Baseload electricity generators for municipal utilities	1.7
	Standby generating sets for nuclear and hospitals	0.7
	Industrial power and water/sewage pumping	0.6
	TOTAL	11.0
		(1.5% of U. S. Fuel Use)

TABLE II: NO_x EMISSION RATE OF LARGE BORE ENGINES
COMPARED TO OTHER COMBUSTION DEVICES

Device	Typical NO_x Emission (lb/MM Btu)
Large Bore Engines	4.0
Automotive SI Engines	2.0
Coal Fired Utility Boilers	0.7
Industrial & Commercial Boilers (Oil Fired)	0.4
Industrial Furnaces (Gas Fired)	0.3
Residential Furance and Water Heater	0.1

TABLE III: MAJOR PHASES OF WORK

		Share of Project Resources
PHASE I (4 months)	Identify emission-control methods (34 identified)	3%
PHASE II (11 months)	Evaluate the methods to select the 12 most promising based on: • predicted NO_x reduction • retrofit feasibility • BSFC effect • cost	14%
PHASE III (24 months)	Operate single-cylinder 20"-bore spark and 11"-bore diesel engines to test the 12 promising emission control methods	66%
PHASE IV (9 months)	Field tests on multicylinder engines	17%

TABLE IV: PHASE III TESTING

SPARK IGNITION	Conventional	Spark Location Gas Valve Location Piston Shape
	Lean Burn	Multiple Spark Torch Ignition High Energy Spark Feedback Control
	Stratified Charge	Degraded Premix
	External	Charge Refrigeration NH_3/Catalyst
DIESEL	Retarded Timing	Emulsion High Injection Rate Pilot Injection
	External	EGR NH_3/Catalyst

TABLE V: FUEL COMPOSITION
(NATURAL GAS)

	March 1979	July 1979	October 1979	January 1980
Methane	95.70%	96.00%	97.96%	95.07%
Ethane	3.20	3.00	1.07	1.82
Propane	.17	.14	.21	.27
Butanes	.03	.04	.08	.12
C_5 and up	.03	.04	.06	.08
Nitrigen	.35	.37	.20	2.18
Carbon Dioxide	.47	.40	.42	.45
Heating Value (Btu/scf)$_{dry}$	1016	1033	1024	1011

TABLE VI: TEST MATRIX FOR CONVENTIONAL TECHNIQUES

	CENTER SPARK		SIDE SPARK	
	Center Gas	Side Gas	Center Gas	Side Gas
Timing	9 7 5 3°	9 7 5 3°	13 11 9 7°	13 11 9 7°
Mexican Hat Piston	– ● ● –	– ● ● ●	– ● ● –	– ● ● –
Teepee Piston	● ● ● ●	● ● ● –	● ● – –	● ● ● –
Flat Top Piston	– ● ● –	– ● ● –	– ● ● –	– ● ● ●

Each dot represents 3 to 5 runs, varying F/A.

TABLE VII

PRELIMINARY DATA ON LEAN-BURN ENGINES

Source	Engine	Configuration	NO_x (g/bhp-hr)	Fuel Penalty
Cooper Bessemer (EPA Program)	Z330 20" Bore 1-Cylinder	Increased Air Pressure* (ϕ = .72 → .62)	16.2 → 4.9 (70%)	1–2%
Cooper Bessemer (Helmich, 1979)	GMVH 14" Bore 12-Cylinder	● Jet-Cell ● Modified TC ● Retarded Timing	10.2 → 3.0 (70%)	2.6%
Cooper Superior (Chrisman, 1980)	SGT 10" Bore 2-Cylinder	● Pre-Chamber ● Retarded Timing ● ϕ = .67 → .54	13.0 → 4.0 (70%)	Unspec.

*No Turbocharger Limitation

ABSTRACT

This paper is based upon work sponsored by EPA to evaluate combustion modification technology applied to industrial process equipment. The test program described herein was aimed at the development of combustion modifications for reducing NO_x emissions from process heaters. In particular, staged combustion air and lowered excess air were applied separately and in combination to a natural draft vertical cylindrical crude heater and the effects on heater efficiency and NO_x emissions were studied.

At a crude throughput of approximately 59 percent of the heater capacity, reductions in NO_x emissions of over 50 percent from baseline emission levels were observed when firing refinery gas fuel and using the combined modifications of staged combustion air and lowered excess air. Burner and heater performance actually improved slightly with the application of these modifications. An increase in heater efficiency of over two percent was observed for low-NO_x-firing as compared to baseline conditions.

The same modifications were tried firing residual oil simultaneously with the gas fuel. Some reduction in NO_x emission was achieved, however the magnitude of the reduction was smaller than that obtained for gas fuel only.

The cost effectiveness in dollars per unit mass of NO_x removed is calculated and the feasibility of the staged air/low excess air modification for retrofit application to natural draft process heaters is discussed.

537

SECTION 1

INTRODUCTION

At the Third EPA Stationary Source Combustion Symposium, KVB reported on subscale process heater combustion modification tests. The report summarized the effects on NO_x emissions of several types of modifications, including staged combustion air, flue gas recirculation, lowered excess air, altered injection geometry, and low NO_x burner installation. The work showed that staged combustion air appears to be the most cost effective combustion modification for process heaters. Both staged air and flue gas recirculation produced NO_x emission reductions in excess of 60 percent below baseline emission levels.

COMBUSTION MODIFICATIONS TO A FULL SCALE PROCESS HEATER

The present report summarizes the testing of a full scale natural draft refinery process heater firing natural gas, refinery gas, and No. 6 oil fuels. A staged air injection system was designed by KVB and installed by the refinery for these tests. The system is capable of supplying up to 50 percent of the stoichiometric air requirement. The staged air is injected by means of lances inserted through the heater floor as it was in one of the subscale test configurations. The process heater was tested with and without the staged air modification and over a range of loads and stack excess oxygen concentrations. Stack gas emissions and heater efficiencies were measured for all conditions.

Lowered excess air and staged combustion air modifications were applied separately and in combination. NO_x emission reductions of up to 52 percent below baseline levels were achieved when firing gas fuel with no short term

538

ill effects on the heater. Heater efficiency was increased at the low NO_x conditions due to the lowering of excess air. Staging the combustion air did not appear to significantly alter efficiency; the same level of lowered excess air was attainable both with and without staging.

In the most favorable situations the combination of staged air and lowered excess air costs $64/Mg NO_x reduction. Staged combustion air applied separately is expected to be considerably more expensive-approximately $2600-$3000 per Mg NO_x reduction.

OBJECTIVE AND SCOPE

The objective of the program is to develop advanced combustion modification concepts requiring minor hardware modifications that could be used by operators and/or manufacturers of selected industrial process equipment to control emissions. The development is aimed at equipment on which the modifications will be most widely applicable and of the most significance in mitigating the impact of stationary source emissions on the environment. The program involves investigation not only of emissions but also multimedia impacts and control cost effectiveness.

The program includes both subscale and full-scale testing. Subscale testing is a necessary part of development of new hardware to ensure acceptable performance, which is a vital aspect of emissions control. Full-scale testing is also necessary on more than one process design configuration (e.g., forced draft and natural draft) before equipment manufacturers and the process industry can employ a given emission control technology.

At the conclusion of the study, a final engineering report will be prepared summarizing the accomplishments of the subscale and full-scale demonstration tests. A series of guideline manuals will be prepared to acquaint equipment manufacturers with the most promising emission control methods that have been demonstrated and to offer technical guidance that can be directly applied in their process equipment design.

SECTION 2

TEST HEATER AND EMISSIONS SAMPLING

TEST UNIT DESCRIPTION

The test unit was a natural draft, vertical cylindrical crude oil process heater which is used to supply a partially vaporized charge to a crude oil distillation column. A maximum load of 108 m^3/h (16,250 bbl/d) may be sent through the heater in two passes. A sketch of this crude oil heater is presented in Figure 1.

The maximum firing rate of the heater is 16.1 Mw thermal input (55 x 10^6 Btu/hr). It is fired by six John Zink DBA-22* natural draft burners. The burners are combination gas/oil burners rated at a maximum of 2.68 Mw (9.14 x 10^6 Btu/hr) each with a turndown ratio of 3:1. Although combination gas/oil burners are used, some gas must always be fired because the unit is base loaded at constant oil firing rate and an automatic temperature controller adjusts the gas fuel flow to maintain crude oil outlet temperature.

Three parameters may be controlled in the heater: excess oxygen, (by furnace draft), firing rate, and load. The stack damper is the main control for the pressure drop across the furnace. The pressure drop may also be controlled by opening or closing the secondary air registers which are in the base of the heater. Each burner has a set of primary and secondary registers

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*Mention of trade names does not constitute endorsement by the Environmental Protection Agency.

which can be adjusted independently of the other burners. The stack damper and register adjustments establish the excess oxygen. The load is controlled by pumps and valves on the inlet and outlet of the heater.

STAGED AIR SYSTEM DESCRIPTION

This application of staged combustion utilizes air lances in the firebox to supply air to the flame zone a given distance above the base of the flame. Figure 2 presents a schematic of this system.

The system consists of twenty-four vertical 316 stainless steel pipes 3.18 cm (1-1/4 in.) diameter arranged four per burner at 90° apart. A 45° elbow is placed on each pipe to provide better mixing across the flame. A fan supplies air to the lances through a manifold and flexible tubing. The lances may be varied in height up to 1.2 m (four feet) from the base of the burners. Extensions for the lances allowed staging heights up to 2.4 m (eight feet) for oil firing tests.

EMISSIONS SAMPLING INSTRUMENTATION

Monitoring of the required gaseous and particulate emissions was performed with an EPA furnished mobile laboratory. The laboratory's monitoring capabilities are presented in Table 1. A schematic of the continuous monitoring system is presented in Figure 3. A detailed description of a similar mobile emissions laboratory has been presented in a previous report (Ref. 1).

Continuous gaseous emissions analyzers provide the capability for measurement of O_2, CO_2, CO, SO_2, NO, NO_x, and HC (as methane) in the flue gas. Particulate total mass and sizing as well as SO_3 measurements are non-continuous. SO_3 measurement is by a controlled condensation technique using a Goksoyr-Ross type coil.

1. Hunter, S.C., et al. "Application of Combustion Modifications to Industrial Combustion Equipment," EPA Report 600/7-79-015a, NTIS Order No. PB 294214, January, 1979.

The O_2, CO_2, and CO concentrations are measured on a dry basis. SO_2, HC, and NO_2 measurements are made through a heat-traced sample line and are determined on a wet basis. NO may be sampled either wet or dry.

SECTION 3

DISCUSSION OF RESULTS

LOAD AND EXCESS OXYGEN VARIATIONS

A series of tests was conducted to evaluate the performance of the process heater with regard to NO_x emission and efficiency over varying load and excess oxygen conditions. These tests were first made while firing a gaseous fuel mixture consisting of natural gas and refinery fuel gas and then while firing residual oil simultaneously with the gas mixture.

The NO emissions as a function of excess oxygen are shown in Figures 4 and 5. The highest NO emission generally occurred at the intermediate load condition, 70% of rated capacity. NO_x emission increased with increasing excess oxygen up to approximately 4-6 percent O_2 for all fuel combinations. In the 4-6 percent O_2 range, NO emission was relatively insensitive to excess O_2 level and, at higher excess O_2, NO emissions decreased.

The nitrogen content of the gaseous fuels was negligible whereas the nitrogen content of the oil fuel was 0.8 percent by weight, hence, the difference in absolute NO emission between Figures 4 and 5. Several ratios of oil/gas are reported in Figure 5. These ratios indicate the approximate fuel split by percentage of total heat input. Changes in the fuel split occurred because a) gas fuel composition and heating value could change in a short time period and b) total heat input required to maintain the load could change due to changes in the composition of the crude charge to the heater.

At the intermediate load, the baseline excess oxygen was 4 percent which was regarded by the plant as a normal operating level. The excess oxygen variation tests indicated that continuous operation of the heater at 2 percent

excess O_2 was possible without additional operator supervision. Below this level the heater draft tended to become unstable. Fluctuations in the draft caused occasional smoking of the unit and resulted in positive stack or convection section pressures which are dangerous in a natural draft heater because they can cause flashback. Flashback occurs when a flame encounters a back pressure which forces it downward and out the bottom of the heater through the air registers.

STAGED COMBUSTION AIR TESTING

The next phase of testing at the process heater site involved the evaluation of the staged combustion air system. This evaluation included the variation of three important parameters: 1) burner equivalence ratio, ϕ_B, 2) excess oxygen level, and 3) staged air insertion height.

For the staged combustion air tests, due to changes in plant operation, it was necessary to fire a different refinery gas from that used in load and excess oxygen variations. This gas, called "adsorber gas," contained a greater percentage of higher hydrocarbons than did the "fuel gas" or natural gas and, therefore, a higher heating value. Baseline NO emission with adsorber gas was about 8 percent higher (8 ppm) compared with fuel gas.

The NO emission is graphed as a function of burner equivalence ratio, $\phi_B = \dfrac{(A/F)_{Burner}}{(A/F)_{Stoichiometric}}$. The staging height for this test series was 1.2 m (4 ft.) and the load was $64 m^3/h$ (9600 bbl/d), 60 percent of rated capacity. At each overall excess O_2 level ϕ_B was decreased in steps to its minimum value which was determined by the limitations of the staged combustion air fan. Figure 6 shows that at 4 percent O_2 the minimum ϕ_B (maximum staging) obtained was 0.74 which decreased NO emissions 35 percent below the baseline of 105 ppm, dry at 3 percent O_2. At 2 percent O_2 and minimum ϕ_B of 0.65 the NO concentration dropped to 51 ppm, dry, corrected to 3 percent O_2. This represented a reduction of 51 percent below the 4 percent O_2 baseline condition and a 43 percent below the 2 percent O_2 (non-staged) level. Table 2 summarizes the NO_x

reductions and efficiency changes for the various combustion modifications to the process heater while firing adsorber gas.

Figure 7 shows similar trends in NO emissions for varying Φ_B and excess O_2 at a higher load. The same degree of staging could not be achieved at the intermediate load because of fan capacity limitations, however, the curves in Figure 7 indicate that roughly the same NO_x reductions would have been obtained had the minimum Φ_B values of Figure 6 been reached.

The results of another test series in which overall excess oxygen and burner equivalence ratio were kept constant while varying staged air insertion height are shown in Figure 8. (The staged air height is defined as the height above the heater floor at which the staged combustion air is injected. This is approximately equal to the height above the burner gas tips and oil gun.) There was little, if any, effect of staging height on NO emissions. Since the burner tile top was about 0.23 m (0.75 ft) above the floor of the furnace and since the staged air pipes were located on a diameter outside that of the burner tile injection heights of less than about one foot above the heater floor resulted in impingement of the staged air on the burner tile. Thus, the minimum staging height was approximately 0.3 m (one foot).

The results of staging the combustion air while firing the No. 6 oil/adsorber gas mixture at intermediate load are shown in Figure 9 and 10. While lowering the excess air reduced NO_x by a percentage similar to that obtained firing gas fuel only, the use of staged combustion when firing oil with gas did not produce as large a percentage decrease in NO_x emissions as it did when firing adsorber gas only. The absolute amount of NO_x reduction, however, was about the same for combined fuel firing as it was for gas alone. For example, for the case of staged combustion air combined with lowered excess air firing oil and gas, Figure 9 shows that the NO level dropped from a baseline of 219 ppm, dry corrected to 3 percent O_2, to 166 ppm, dry at 3 percent O_2 for a drop of 53 ppm. For the same conditions firing adsorber gas only at the intermediate load the drop was 46 ppm.

This behavior indicates that fuel nitrogen conversion to NO_x was reponsible for a large fraction of the observed emissions when firing the oil/gas mixture. It appears then that approximately half of the baseline NO_x

emission firing oil with gas is due to fuel nitrogen and half is due to thermal NO_x since NO emissions firing this mixture were about twice those observed firing a nitrogen-free refinery gas. The estimated fuel nitrogen conversion efficiency, based on the ratio of oil to gas in the fuel and the oil fuel nitrogen content (~0.8%), is approximately 19 percent.

Figure 10 shows that NO_x emission decreased slightly as staging height increased firing oil with gas. Very little decrease was observed at heights greater than 1.2 m (4 feet).

During all testing with the staged combustion system operating, careful observation of the flame and furnace draft was made. There did not appear to be any problems with coking of the process tubes and at no time was there any emission of carbon monoxide or unburned hydrocarbons even at 2 percent stack excess oxygen. There were certain instances in which the draft in the convection became slightly positive at the low O_2 condition with maximum staging, however, flashback was never observed. The long term effect of this change in furnace draft in terms of maintenance or operational costs is not yet known.

COMPARISON OF PRESENT RESULTS WITH SUBSCALE RESULTS

Table 3 summarizes the NO_x reductions obtained at the present full scale process heater with the emission reductions observed at the subscale test site. For gaseous fuels the trends are the same for both subscale and full scale tests except that the percentages are somewhat lower in the present data. For tests with oil fuels lowered excess air alone was more effective in reducing NO_x emission than was staged combustion alone - unlike the trend observed in the subscale test where staging the combustion gave a significantly greater NO_x reduction than low excess air. Also, the percentages are much lower for the full scale heater than they were for the subscale heater firing No. 6 oil alone.

The reasons for the lower percentage NO_x reductions firing gas fuel only in the full scale heater are not altogether clear. Furnace bulk gas and wall temperatures were much lower in the full scale heater than they were in the subscale unit (~700°F vs. 1700°F). Residence times, however, were probably longer in the full scale heater. The baseline NO emission with the same

burner type in the subscale heater firing natural gas was 131 ppm, dry, corrected to 3 percent O_2 compared with the present 105 ppm, which is reasonable in light of the temperature differences mentioned. There may be a decrease in the effectiveness of combustion modifications in reducing thermal NO_x as temperatures are decreased. The mixing of the combustion air and fuel may have been different enough to cause the changes in NO_x reductions from subscale to full scale. The precise location, angle of injection, and spray angle associated with the staged air system are probably also important parameters in the NO_x reduction process.

Unfortunately, direct comparisons of the oil-firing results are not valid since the full scale unit was firing a considerable amount of gas along with the residual oil. In the subscale tests no gas was fired with the oil. Although the fuel nitrogen in the subscale tests was much lower (~0.3%) than it was in the full scale tests, the apparent fuel nitrogen conversion in the former tests was about twice that of the latter. The fractions of thermal and fuel NO_x are thought to be about the same in either case-about 50-50. Further work is planned to determine whether or not the performance of these combustion modifications can be improved for oil-firing applications.

SECTION 4

COST ANALYSIS

In this paper we will concentrate on the cost analysis of lowered excess
air and staged combustion air applied separately and in combination to a
process heater with a thermal input capacity of 16.1 MW (55 x 10^6 Btu/h). We
will consider only the gaseous fuel application. Costs for oil-fired units
will be determined pending the results of further experimentation.

INITIAL CAPITAL COSTS

There is no initial capital cost associated with the lowered excess air
(LEA) modification at the levels of O_2 used in the present tests. Such costs
would be incurred if operation at stack oxygen contents of less than 2 percent
were desired since an automatic oxygen control and analyzer would then be
required.

The initial capital costs of a staged air system such as that of Figure 2
are given in Table 4. The installed costs include direct labor and overhead
charges at contract labor rates. Required equipment and materials include a
high pressure blower, a damper, piping, fittings, valves, stainless steel
lances for insertion into the firebox, and temperature and flow measurement
probes. Shipping costs are also included.

The annual operating costs for combustion modifications to a full scale
heater are given in Table 5. The fuel savings were based on the efficiency
increases for the various modifications shown in Table 2 and a market price of
natural gas of $2.50/$10^6$ Btu. (The latter assumption may not be valid in a

548

case where the refinery uses an off-gas which is not readily marketable and would otherwise be flared. In that case, there would be no cost savings associated with the increased efficiency).

In determining the total annualized costs of combustion modifications several assumptions regarding state and federal taxes, insurance, depreciation method, and financing constraints have been made. These are listed in Table 6 and the total annualized costs for the process heater modifications are given in Table 7.

Note that there are two columns for the staged combustion air (SCA) modification only. The one labelled "4% O_2" applies to the SCA modification at a normal operating condition which results in 4 percent O_2 at the stack. The fuel savings and annualized costs are calculated relative to those of a heater having a 4 percent O_2 condition without staging. For the column labelled "2% O_2" the fuel savings and annualized costs are calculated relative to those of a heater having a normal operating condition of 2 percent O_2 at the stack with no staging. For those refinery heaters which normally operate at ~2% O_2 the column "SCA Only-2% O_2" applies. For those which normally operate at ~4% O_2 the column "SCA Only-4% O_2" applied. The "SCA + LEA" column shows fuel savings and annualized costs relative to a 4 percent O_2 normal operating condition without staging.

One may ask why all process heaters do not operate at 2 percent O_2 rather than 4 percent O_2 since it appears to be cost effective to do so. Refinery gas varies significantly in composition and thus requires a varying amount of combustion air. To avoid the possibility of air deficiency and to minimize the need for continuous operator attention, many process heaters are operated at a higher excess oxygen than would be necessary with a more consistent fuel. With the current need to conserve energy, this practice is being revised by installing oxygen controllers and increasing operator attention.

Table 8 gives the annual NO_x emission reductions and cost effectiveness of each combustion modification. The annual NO_x emission reduction is calculated using the values given in Table 2 for percent NO_x reduction and assuming continual operation at 70 percent capacity for 80 percent of the year. The

549

cost effectiveness is simply the total annualized costs divided by the annual NO_x reduction capability.

Table 8 shows that for a gas-fired heater which normally operates at 4 percent excess oxygen the combination of staged combustion air and lowered excess air is an economically and environmentally attractive modification. Lowered excess air alone is very economical but is only 1/3 to 1/4 as effective in reducing NO_x. For a heater which normally operates at 2 percent O_2 the costs of staged combustion air would not be greatly different from those arising from the use of SCA alone at 4 percent O_2. This cost is, however, much greater than the cost of SCA + LEA.

The question of which modification is most cost effective in a given instance will depend on each individual plant situation and each individual heater. Each plant must determine the following:

1) the credit, if any, it should allow for fuel savings,

2) the normal excess oxygen in the heater, and

3) whether or not a lower excess oxygen can be obtained without additional cost.

SECTION 5

SUMMARY

Combustion modifications proved effective on a natural draft process heater rated at 108 m^3/h (16,250 barrels/day) of crude capacity when firing refinery gas. In addition, heater performance was measured for other fuel mixtures including natural gas and No. 6 oil.

While firing refinery gas a maximum NO_x emission reduction of 51 percent was observed, below a baseline emission concentration of 105 ppm, dry corrected to 3 percent O_2. An increase in efficiency of 2.37 percent was observed for this condition and, in general, efficiency was improved by the application of combustion modifications.

Staged combustion air gave a significant NO_x reduction when firing refinery gas regardless of excess oxygen level. Staging height did not have a major effect on NO_x emissions over the range of 0.3 to 2.4 meters.

The NO_x emissions occurring for the various modification techniques followed the trends observed at the subscale level, however, the percentage reductions were slightly less. In absolute magnitude, the NO_x emission reductions occurring for gas-firing were approximately equal to those occurring when No. 6 oil was included in the fuel. The percentage reductions were less, however, for oil apparently because of the fuel nitrogen conversion.

A cost analysis covering initial capital and annual operating costs, total annualized costs, and cost effectiveness of each of the combustion modifications was made. The results indicate that staged combustion air may be an economically and environmentally desirable modification, however, the cost effectiveness for any single application will ultimately depend upon several factors unique to that situation.

STACK
4'-6" O.D. (1.4m)

CONVECTION SECTION

NOT TO SCALE

RADIANT SECTION
16'-9½" O.D. (5.1m)
15'-9½" I.D. (4.8m)

AIR PLENUM AND SOUND
SUPPRESSION BOX

55'-0" 16.8m

4'-0" 1.2m

12'-3½" 3.7m

119'-4" 36.4m

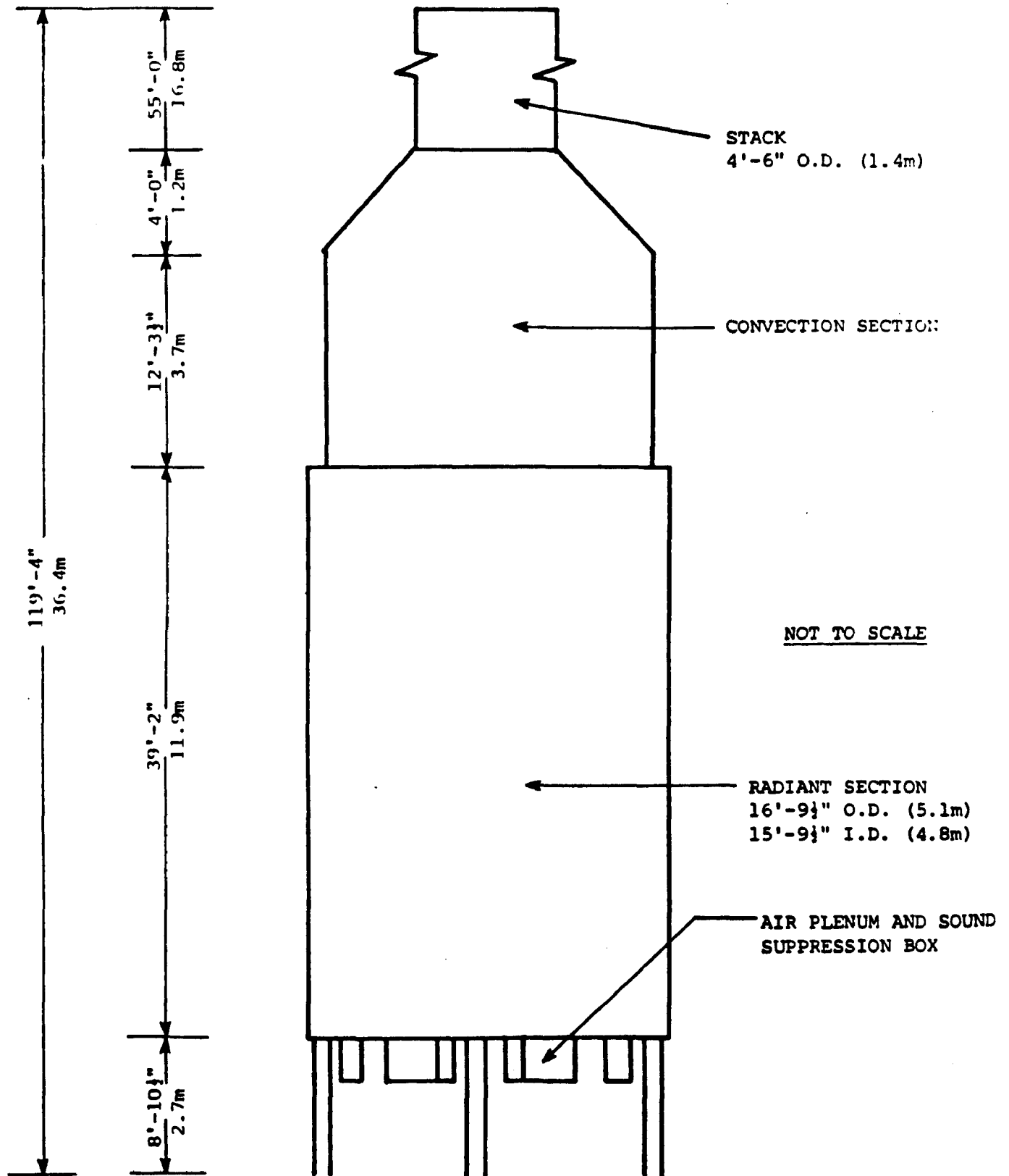39'-2" 11.9m

8'-10½" 2.7m

Figure 1.   Sketch of the process heater at Location 7.
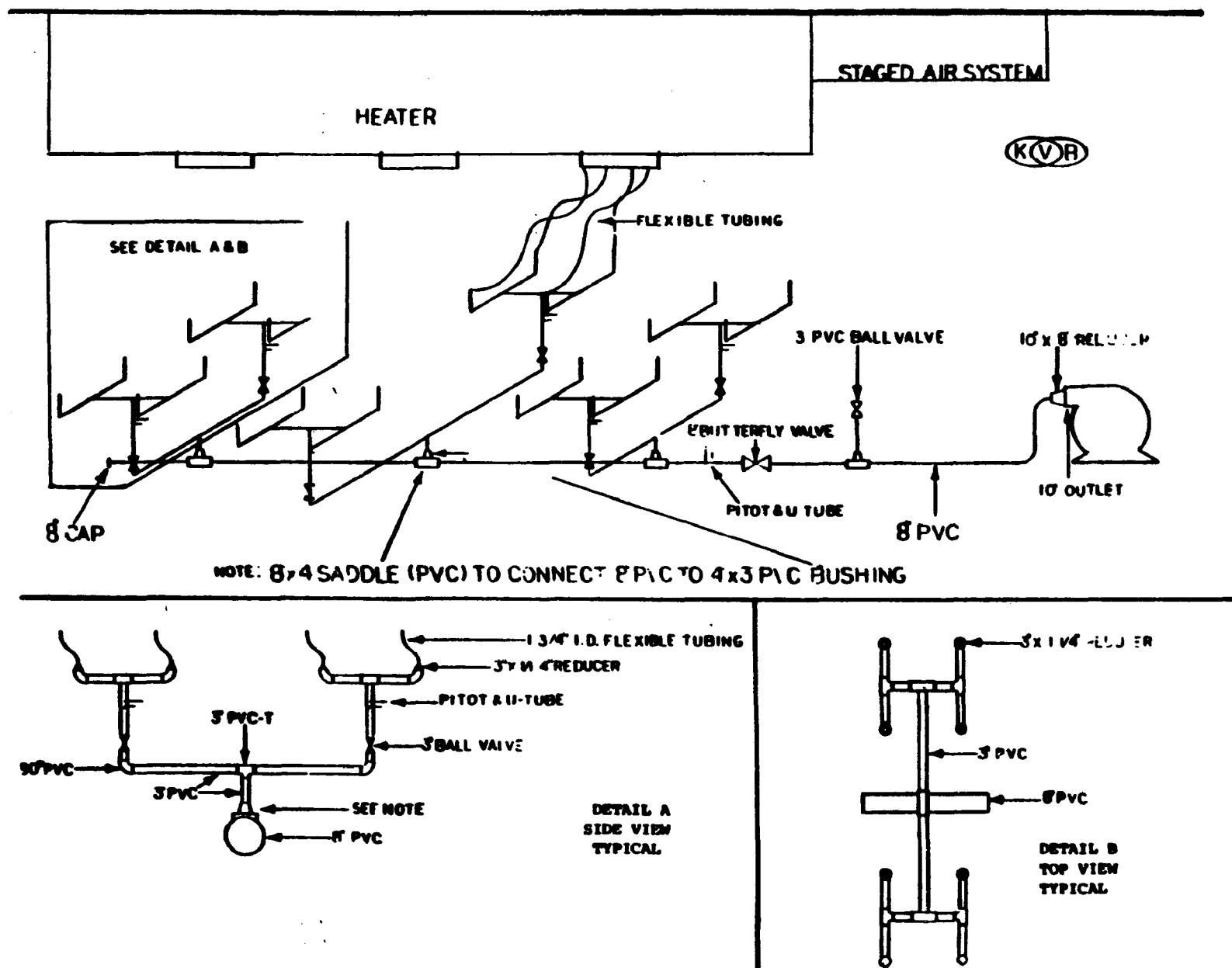
Figure 2. Flow Schematic of Staged Combustion Air System for a Natural Draft Process Heater.
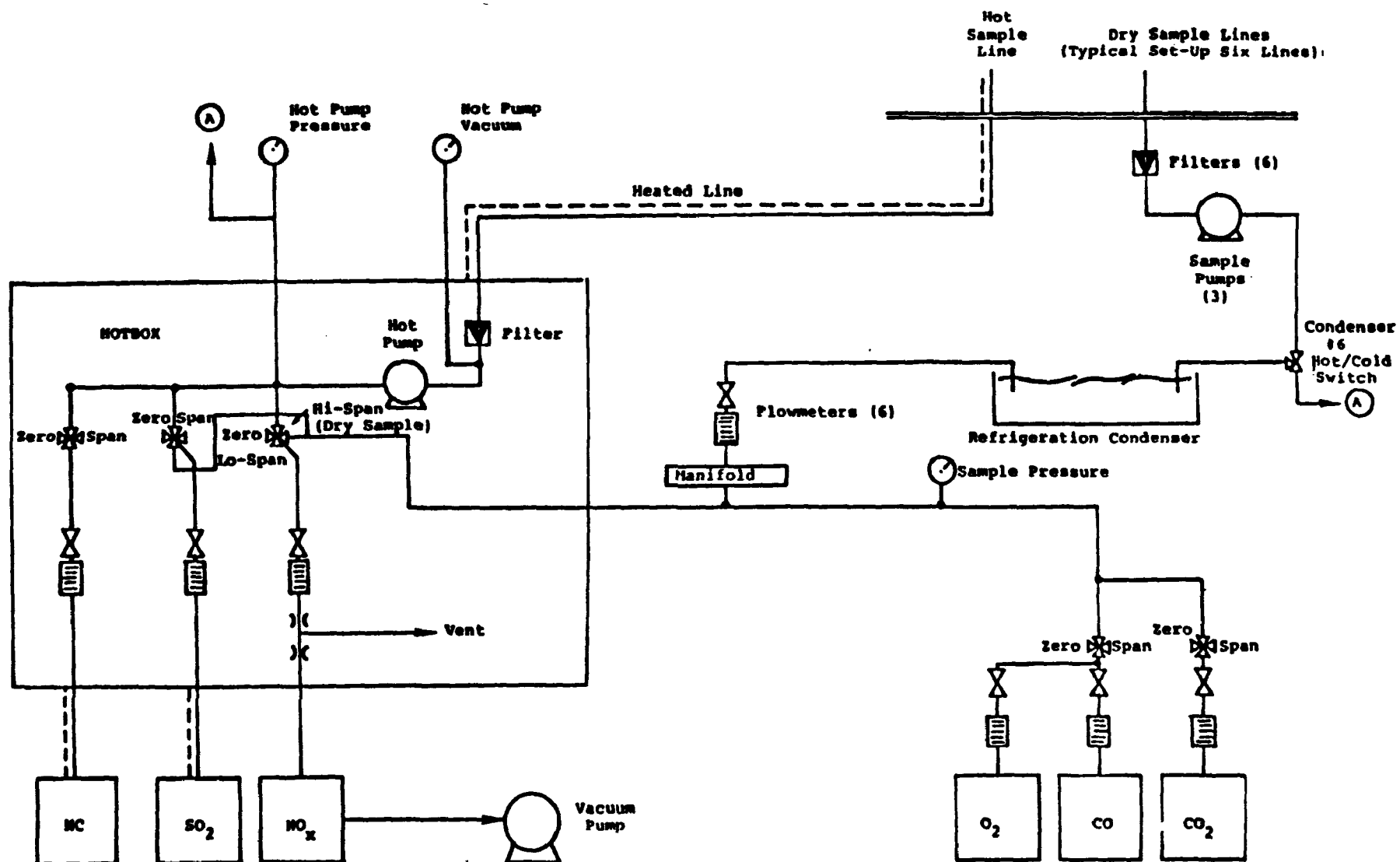
Figure 3. Flue gas sampling and analyzing system.

NO emissions at three different loads as a function of stack excess oxygen for a natural draft process heater firing a natural gas/refinery gas mixture.
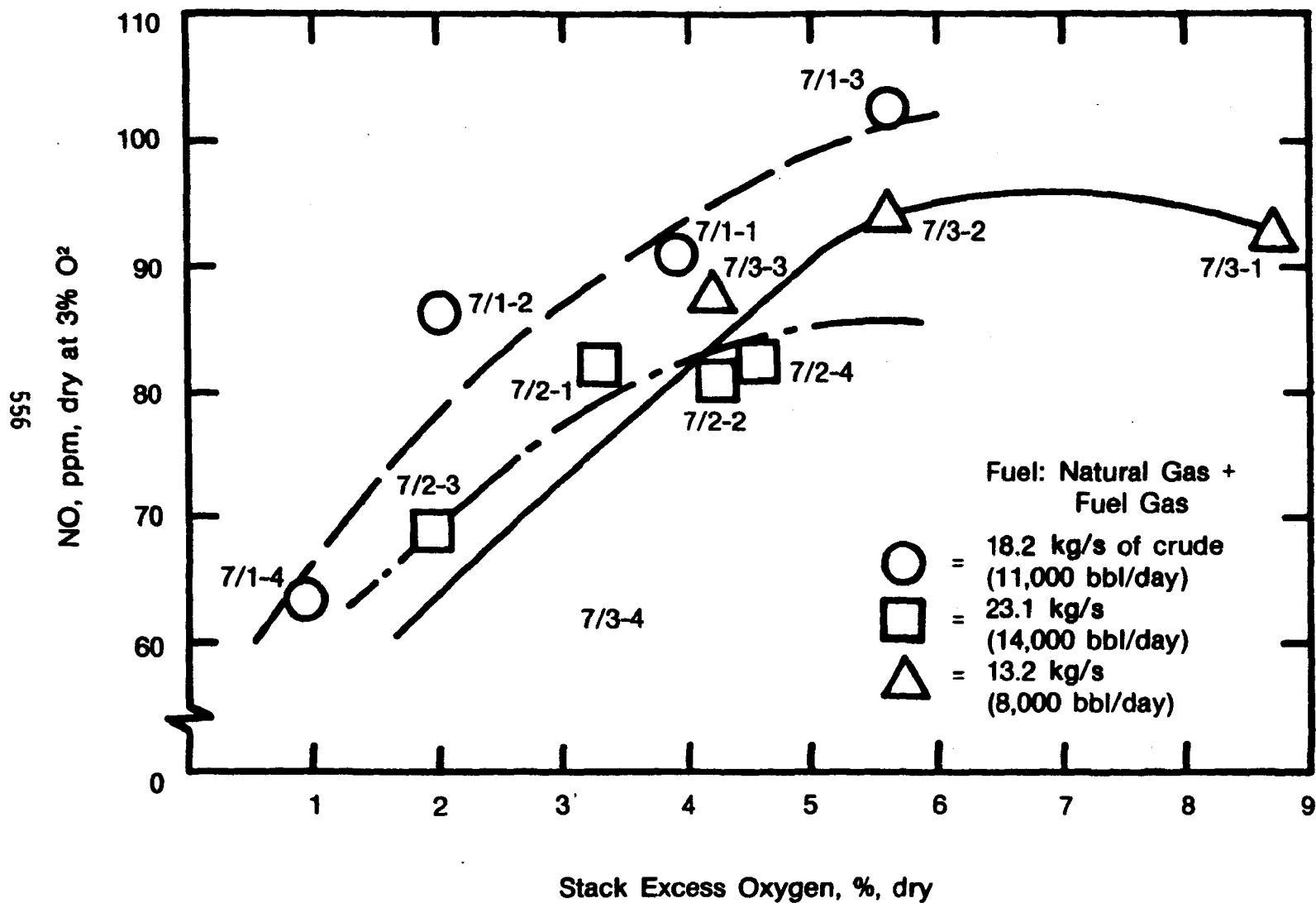
Figure 4.

NO emissions at three different loads as a function of stack excess oxygen for a natural draft process heater.
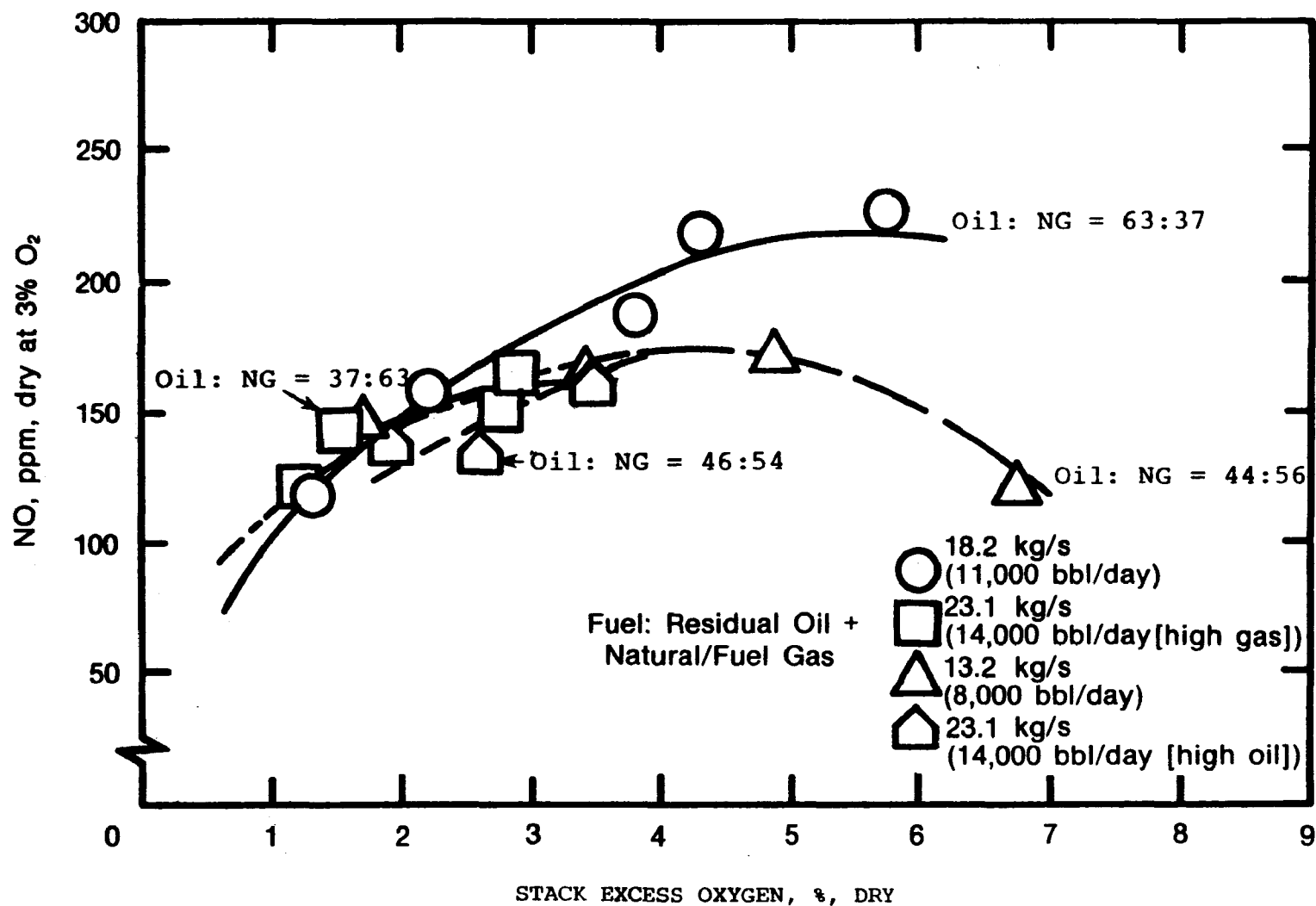
Figure 5.

No emissions as a function of burner equivalence ratio at two excess oxygen levels with constant staged air insertion height.

Fuel: Adsorber Gas
Staging Height: 4′ (1.2m)
Load: 9600 bbl/d (15.9 kg/s)

○ 4% O_2
□ 2% O_2

$\overline{\Phi}_B$ = (A/F) ACT/(A/F) STOIC.
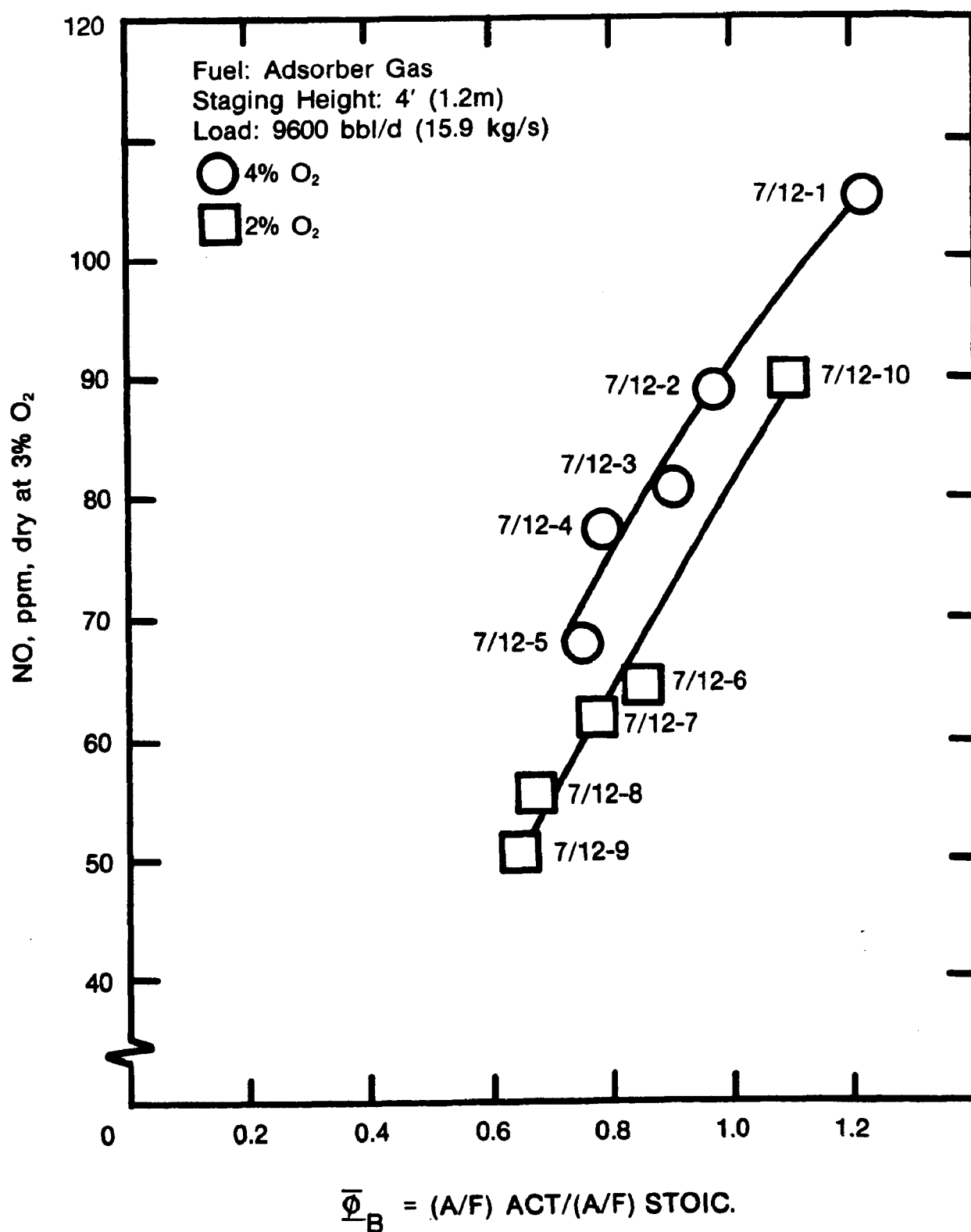
Figure 6.

NOemissions as a function of burner equivalence ratio at two excess oxygen levels with constant staged air insertion height.
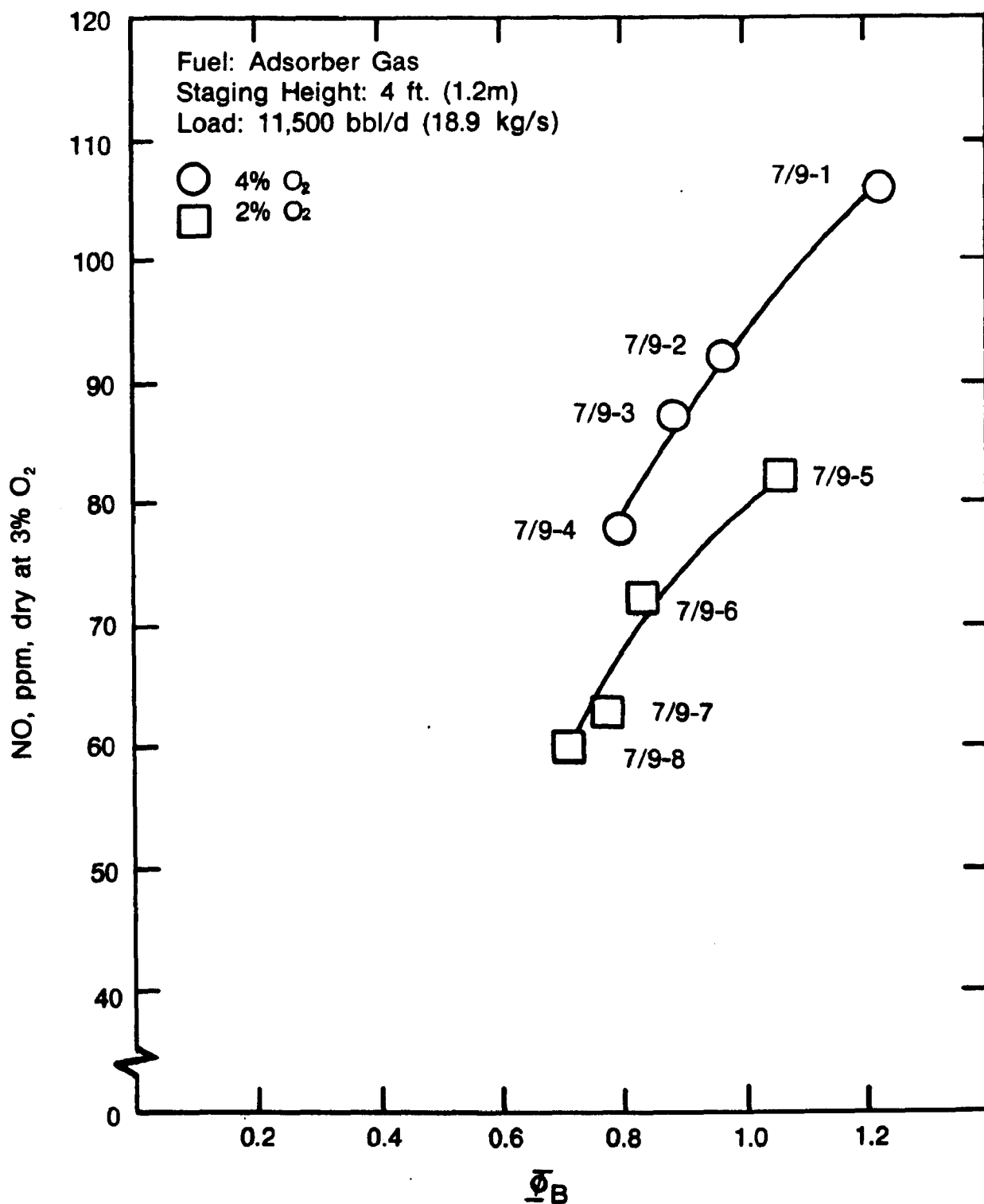
Figure 7.

NO emissions as a function of staging height at constant excess oxygen and $\overline{\phi}_B$.
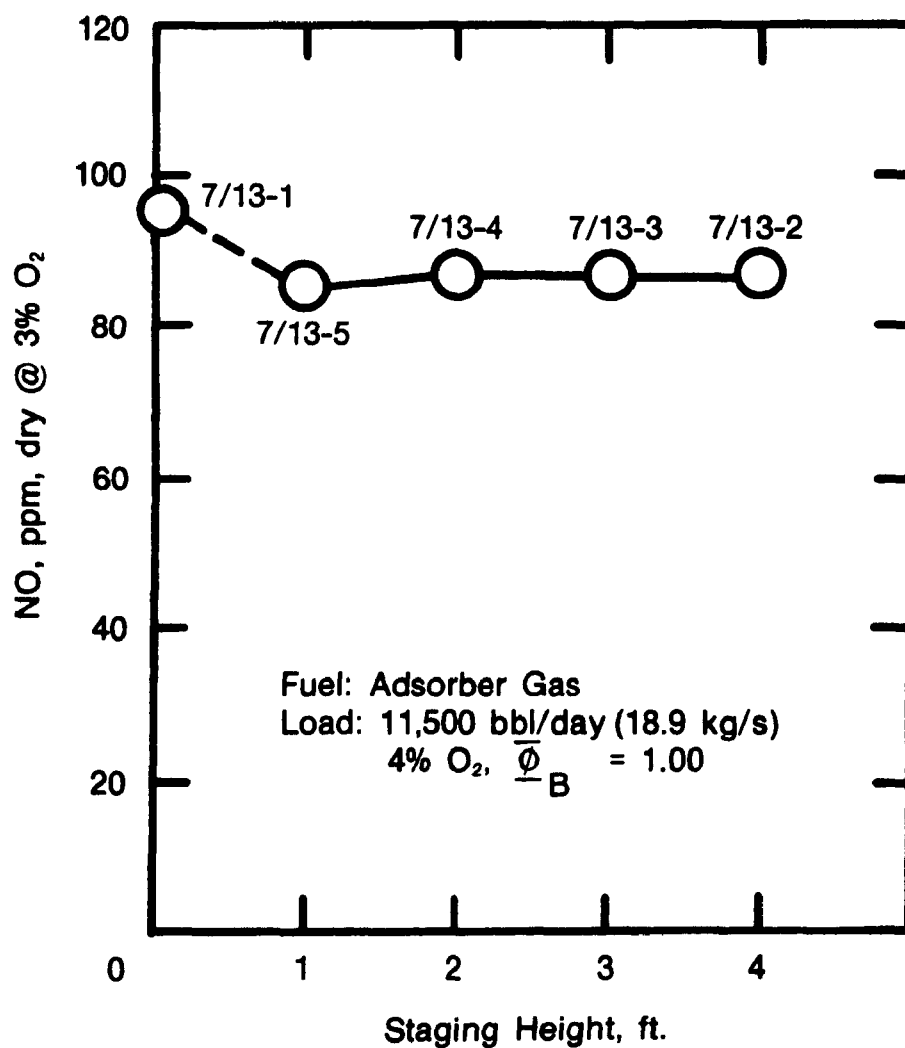
Figure 8.

NO emissions as a function of burner equivalence ratio for a gas-oil fuel mixture.

Load: 11,500 bbl/d (19.0 kg/s)
Excess O_2: 2%
Staging Height: 4 ft (1.2m)
Fuel: 47% Adsorber Gas +
      53% No. 6 Oil

O_2 = 4%
7/18-8
Baseline

7/18-7
(No staging)

7/18-4

7/18-5

7/18-6

NO, ppm, dry at 3% O^2

$\overline{\Phi}_B$

Figure 9.

NO emission as a function of staging height for gas-oil fuel mixture.
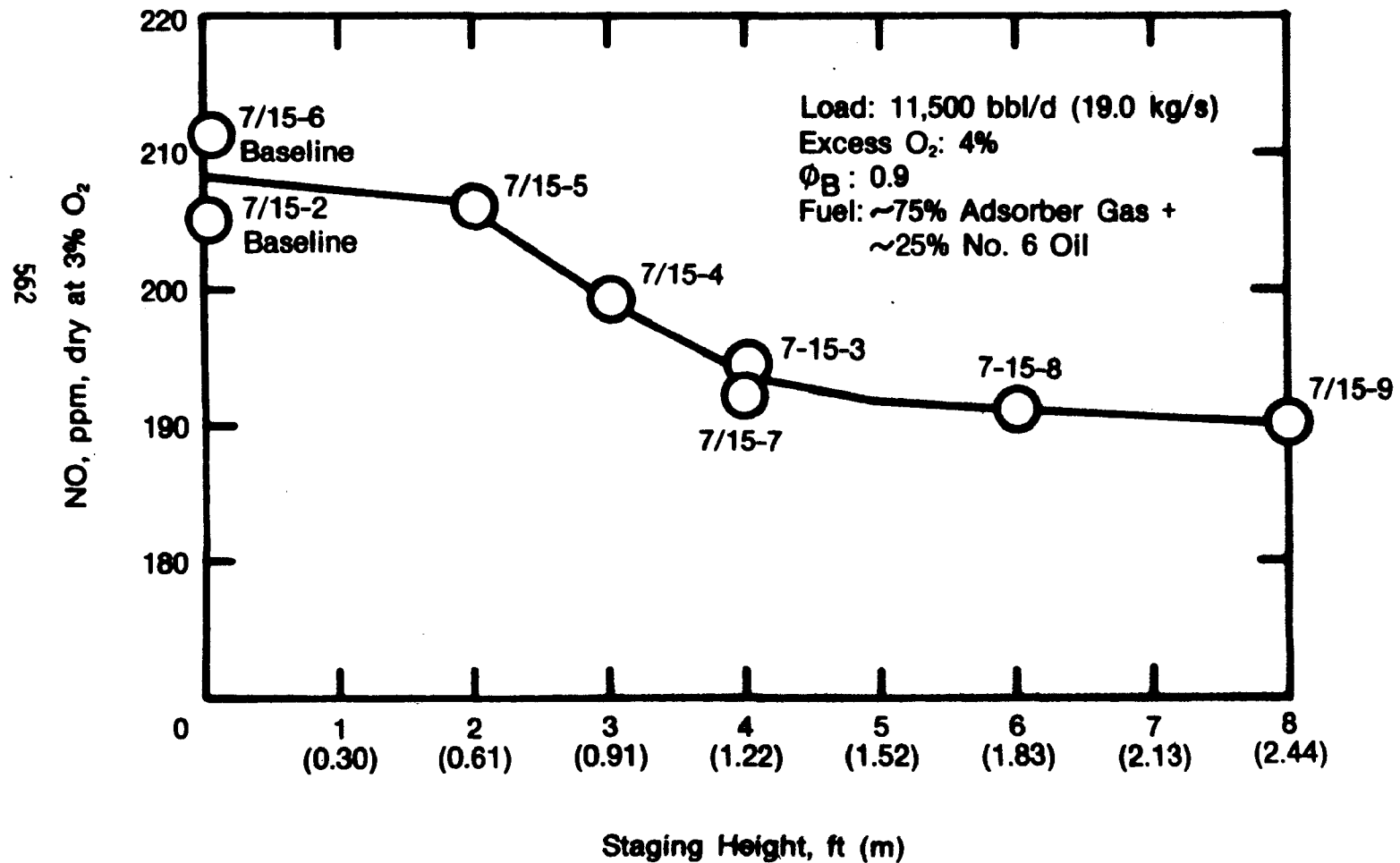
Figure 10.

ADDENDUM

SUBSCALE TESTS OF COMBUSTION MODIFICATION
FOR STEEL FURNACES

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COST CALCULATIONS FOR FLUE GAS RECIRCULATION
APPLIED TO STEEL FURNACES - CASE II

If one may assume complete recovery of the flue gas energy in the
recirculated flue gas such that the only losses in the steel furnace system
are the stack losses, then there will be no fuel penalty associated with the
FGR modification. In this instance, the annual operating costs of 20 percent
FGR in a steel furnace will consist of only the fan electrical and system
maintenance cost elements. The annual operating costs for three heater sizes
assuming full recovery of the heat of the recirculated flue gas is shown in
Table I.

TABLE I. ANNUAL OPERATING COSTS FOR A STEEL
FURNACE HAVING 20 PERCENT FGR (1980 $)

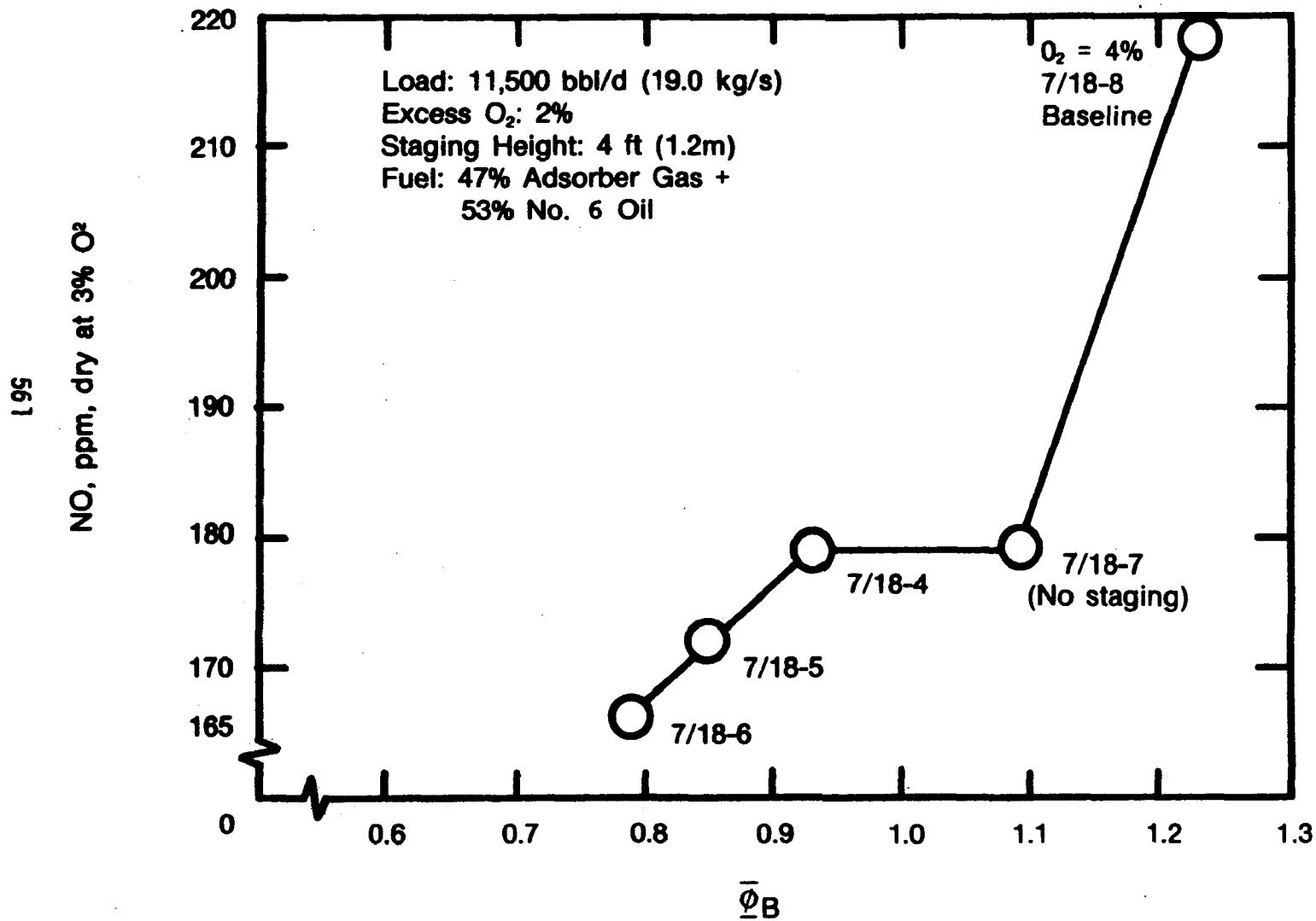| Heater Size	2.9 MW	73.3 MW	147 MW
Fan Electricity	$ 400	$3,600	$7,700
Maintenance	1,850	5,400	9,400
Total	$2,250	$9,000	$17,100

The revised total annualized costs of FGR on steel furnaces are shown in
Table II.

TABLE II. TOTAL ANNUALIZED COSTS OF 20 PERCENT FGR ON
A STEEL FURNACE WITH WASTE HEAT RECOVERY (1980 $)

2.9 MW	73.3 MW	147 MW
$9,516	$30,186	$53,979

The annual NO_x reduction capability of the FGR modification and the cost
effectiveness (equal to the total annualized cost divided by the annual NO_x
reduction) are given in Table III.

564

TABLE III. ANNUAL NO$_x$ EMISSION REDUCTION AND COST
EFFECTIVENESS OF FGR (1980 $)

Heater Size	2.9 MW		73.3 MW		147 MW	
	No. 2 Oil	NG	No. 2 Oil	NG	No. 2 Oil	NG
Annual NO$_x$ Emission Reduction Capability (Mg/y)	8.7	7.5	218	186	437	374
Cost Effectiveness ($/Mg)	1094	1269	138	162	124	144

Note that if the assumption of total waste heat recovery from the recirculated flue gas is valid (as could be the case if the flue gas for FGR comes from the outlet of a waste heat boiler or a regenerative heat exchanger), then flue gas recirculation becomes more attractive than either the steam or water injection modifications for larger heater sizes (73.3 MW and up). For small heaters, however, it is not as cost effective as steam injection with either No. 2 oil or natural gas fuels nor is it as cost effective as water injection firing natural gas fuel.

The original Tables VII, VIII, and X in this report have been recently revised and the updated versions are shown below. The cost effectiveness of flue gas recirculation with full heat recovery may be compared to the cost effectiveness calculations in the revised Table X.

When the cost effectiveness values in Table X (Rev.) and Table III are plotted on log-log paper against heater size, one finds that for No. 2 oil fuel FGR with heat recovery capability has the lowest cost per Mg NO$_x$ reduction for heaters larger than 13.5 MW (46 x 10^6 Btu/h). For natural gas fuel, FGR with heat recovery becomes cheaper than water injection for heater sizes greater than 8.5 MW (29 x 10^6 Btu/h) and it is cheaper than steam injection at heater sizes in excess of 60 MW (205 x 10^6 Btu/h).

TABLE VII (REV.)   TOTAL ANNUALIZED COSTS OF WATER OR STEAM INJECTION

Annual Operating Cost (No. 2/Natural Gas)	$3,100/1,600	$81,000/39,300	$159,500/83,000
State and Federal Taxes (11% of IFC)	385	2,090	3,520
Insurance (0.5% of IFC)	18	95	160
Total Annual Expenses (No. 2)	$3,503	$83,185	$163,180
Total Annual Expenses (Natural Gas)	$2,003	$41,485	$86,680
INITIAL FIXED COSTS (IFC)	3,500	19,000	32,000

(WATER OR STEAM)
ROR=i=15%,n=12
Capital Recovery
   Factor=.1845=CR
Annual Income
   Tax Rate=50%
Investment Tax
   Credit=10%=i_c
   (1st year only)

Total Annual
   Capital Factor*
   (ACF)=.2773

Annual Capital Charge (=IFCxACF)	971	5,269	8,875

TOTAL ANNUALIZED COSTS
(1980 DOLLARS)

No. 2 Oil	4,474	88,454	172,055
Natural Gas	2,974	46,754	95,555

$$*ACF = CR + T\left(CR - \frac{1}{n}\right) - \frac{i_c}{n}$$

$$\text{where } CR = \text{capital recovery factor} = \frac{i}{1-(1+i)^{-n}}$$

and T = 1.0 (for debt/equity ratio of 0)

TABLE VIII (REV.) TOTAL ANNUALIZED COSTS OF FGR

Annual Operating Costs (No. 2/Natural Gas)	37,630/19,350	894,000/437,000	1,787,100/873,100
State and Federal Taxes (11% of IFC)	2,035	5,940	10,340
Insurance (0.5% of IFC)	100	270	470
Total Annual Expenses (No. 2)	$39,765	$900,210	$1,797,910
Total Annual Expenses (Natural Gas)	$21,485	$443,210	$883,910
INITIAL FIXED COSTS	18,500	54,000	94,000

ROR=i=15%,n=12
Capital Recovery
  Factor=.1845
Annual Income Tax
  Rate=t=50%
Investment Tax
  Credit=i_c=10%
  (1st year only)

Total Annual
  Capital Factor
  =.2773

Annual Capital Charge	5,131	14,976	26,069

TOTAL ANNUALIZED COSTS
(1980 DOLLARS)

No. 2 Oil	44,896	915,186	1,823,979
Natural Gas	26,616	458,186	909,979

TABLE X (REV.) COST EFFECTIVENESS OF COMBUSTION MODIFICATIONS
ON A STEEL FURNACE ($/$10^3$ Kg OF NO_x REDUCTION)
INCLUDING ANNUAL INCREMENTAL FUEL COSTS

		Furnace Heat Input	
Modification	2.9 MW ($10x10^6$ Btu/hr)	73.3 MW ($250x10^6$ Btu/hr)	147 MW ($500x10^6$ Btu/hr)
STEAM INJECTION			
No. 2 Oil	443	351	340
NG	294	186	189
WATER INJECTION			
No. 2 Oil	1,119	893	860
NG	744	472	478
FLUE GAS RECIRCULATION			
No. 2 Oil	5,160	4,198	4,174
NG	3,549	2,463	2,433

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16. ABSTRACT The proceedings document the approximately 50 presentations made during the symposium, October 6-9, 1980, in Denver, CO. The symposium was sponsored by the Combustion Research Branch of EPA's Industrial Environmental Research Laboratory, Research Triangle Park, NC, and the Electric Power Research Institute (EPRI), Palo Alto, CA. Main topics included utility boiler field tests; NOx flue gas treatment; advanced combustion processes; environmental assessments; industrial, commercial, and residential combustion sources; and fundamental combustion research. This volume contains papers that were not received in time for inclusion in the four volumes distributed during the symposium.

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