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AP-42
Section 1.3
#11

Controlling NOx Emissions From Steam Generators

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The information presented is directed to those individuals concerned with reducing nitrogen oxides (NO_x) emissions from gas, oil, or coal fired utility steam generators. First, this paper presents NO_x emission data obtained in the testing of tangentially fired utility boilers; second, it relates these data to the general body of information developed by other investigators in the areas of theoretical analysis and bench scale and full scale testing; and finally, it discusses current design practice in relation to NO_x emission control and the continuing R&D effort required to assure acceptable control technology.

In recent years, concern for environmental quality and enactment of legislation to limit emissions of air pollutants from stationary sources has placed an additional responsibility on the designers of fuel burning equipment.

The desire for high combustion efficiency to utilize completely the available energy in the fuel has always been foremost. Through development efforts, the emissions of solid combustibles, CO, and hydrocarbons have been virtually eliminated in large stationary steam generating units. However, when the problem of NO_x emissions is examined, it becomes apparent that some substantial changes in design and operation of combustion equipment will be required to produce the desired reduction without increasing the emissions of other pollutants or jeopardizing the safety and operating flexibility presently realized.

Considerable success has been achieved by various investigators in reducing NO_x emissions through modification of the combustion process. In addition, a gratifying unanimity exists as to the mechanism of NO_x formation and means for control. Where apparent differences exist in results, they are principally attributable to the design of the combustor.

The objectives of this paper are threefold: first, to present the NO_x emissions data that have been acquired by Combustion Engineering; second, to relate this information to generally accepted theory and the results of other investigators; and finally, to describe the modified combustion systems currently being offered and future R&D required to assure acceptable control technology applicable to tangential firing.

Nitrogen Oxide Formation

In all high-temperature combustion processes using air as the oxidant, the combination of atmospheric nitrogen and oxygen results in the formation of nitric oxide (NO). Although NO is thermodynamically unstable at lower temperatures, the decomposition rate is so slow that once formed, the concentration remains essentially constant as heat is removed from the combustion gases. Reaction kinetics indicate increased NO formation with increased excess air, flame temperature, and time at temperature.[1,2] A small amount of NO is further oxidized to NO_2 as the combustion gases cool. The emission is the sum of these two species and is referred to as NO_x.

A number of investigators have found evidence that conversion of chemically combined nitrogen in the fuel to NO_x is responsible for a significant part of the total NO_x emitted from stationary sources.[3,4] The conversion of fuel nitrogen to NO_x can occur at a much lower

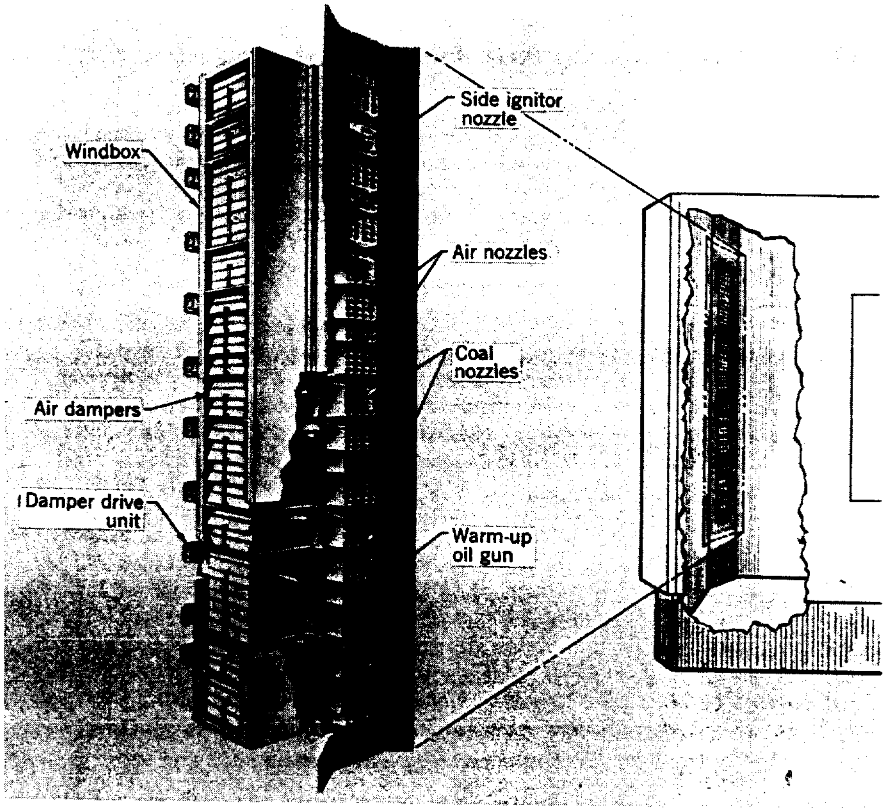

Figure 1. Tangential firing system.

Figure 2. Tangential flame pattern viewed from top of furnace. Oil firing.

flame temperature than the conversion of atmospheric nitrogen, but can be controlled by reducing the available oxygen in the primary flame zone.

Since this paper deals exclusively with results from tangentially fired furnaces, it is appropriate to discuss the concepts involved in tangential firing as they relate to NO_x formation.

Tangential Firing

The first tangentially fired furnace was designed in 1927. Since then, over 700 tangentially fired units have been placed in operation, and they account for approximately 40% of the installed fossil fuel fired utility generating capacity in the United States.

As illustrated in Figure 1, the fuel is admitted at the corners of the combustion chamber through alternate compartments. Distribution dampers proportion the air to the individual fuel and air compartments. Thus, it is possible to vary the distribution of the air over the height of the windbox, vary the velocity of the air stream, and change the rate of mixing of the fuel and air. Fuel and air nozzles tilt in unison to raise or lower the flame in the furnace to control furnace heat absorption in the superheater and reheater sections. The fuel and air streams from each corner of the furnace are aimed tangent to the circumference of a circle in the center of the furnace. In operation, a large swirl is created in the furnace as illustrated in Figure 2.

The impingement of each stream on the adjacent stream provides a source of ignition energy and promotes bulk gas mixing. Since the entire furnace acts as a burner, precise proportioning of fuel and air at each of the individual fuel admission points is not required. Locally fuel-rich or air-rich streams are blended in passing through the furnace, resulting in complete combustion of the fuel. A large amount of internal recirculation of bulk gas coupled with slower mixing of fuel and air provides a combustion system which is inherently low in NO_x production for all fuel types.

NO_x Emission Testing

As the result of NO_x emission measurements by Sensenbaugh and Jonakin[5] in the late 1950's, it was considered that any NO_x regulations then anticipated could be met by the application of tangential firing. In 1969, in recognition of growing public concern and pending national legislation, NO_x testing activities were accelerated. Through the cooperation of 25 utility companies, data have been collected on 45 tangentially fired units as part of a continuing program to develop analytical methods based on reaction kinetics and furnace heat transfer characteristics for prediction and reduction of NO_x emissions. The data represent a nearly equal number of gas, oil, and coal-fired units covering the entire utility size range, i.e., from the small older units to the most recent large units.

Over 700 individual test runs have been made. Generally, O_2 and NO_x measurements were taken at the gas inlet to the air preheaters using a probe grid with a minimum of 12 points. Equal individual samples were blended, and O_2 was continuously monitored using a paramagnetic analyzer. Replicate NO_x samples were analyzed by the phenoldisulfonic acid method (ASTM D-1608), and a continuous electrochemical analyzer was used for trending NO_x on certain series. Complete fuel analyses were performed, usually on daily samples, with particular attention being given to fuel nitrogen. Flyash samples were collected from the gas duct to the air preheaters on certain of the coal-fired units to determine the influence of combustion modifications on solid combustible emissions. Operating data were taken to establish fuel firing rate and air flow distribution and to study changes in heat transfer performance resulting from combustion modifications. Observations were made of furnace conditions and stack appearance. Inspections to determine the condition of windbox compartment dampers and fuel nozzles were made when outages could be scheduled.

For discussion purposes, the results are grouped by fuel type. Some of the units have divided furnaces with two separate tangential firing systems. In the figures that follow, these units have been represented as a single furnace cell.

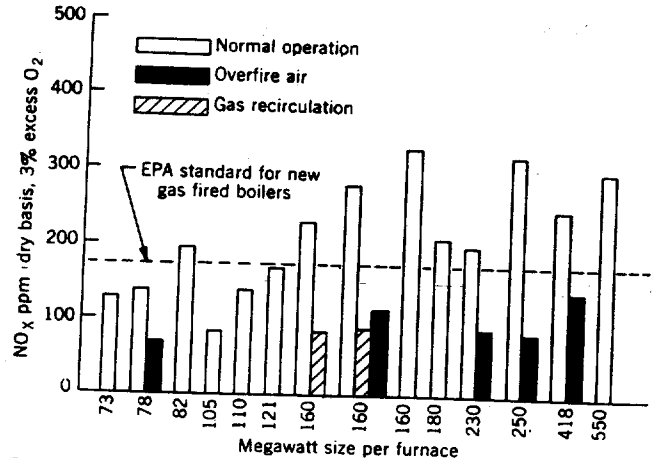

Figure 3. NO_x emissions from tangentially fired furnaces firing natural gas.

Natural Gas Firing

NO_x emissions under normal operating conditions of 10% excess air are presented in order of increasing megawatt generation in Figure 3. All data were collected by C-E except for that on the 160-Mw size. These are actually duplicate 320-Mw, divided furnace units in the Southern California Edison (SCE) system and have been extensively tested as reported in Ref. 6.

The SCE data have been included in this paper for two reasons. The first is to illustrate the spread in emission level that can be obtained from essentially "duplicate" units. In this instance, there appear to be valid reasons for the variation from 230 to 330 ppm NO_x measured on these units. The unit with the 330-ppm emission level had been burning oil prior to the tests on natural gas and considerable deposits were left on the furnace walls which would tend to decrease the rate of heat removal from the flame, resulting in higher flame temperature and higher emissions. The unit with the 230-ppm emission level was equipped with gas nozzles which differ from the nozzles supplied on the other two units. This points out that seemingly subtle differences in design or operation can make substantial differences in emission levels.

The second reason for including the SCE data is that these boilers are unique in having flue gas recirculation through the windbox. Flue gas recirculation is mixed only with the air entering the air compartments. The air entering through the fuel compartments does not contain any flue gas recirculation. This system was designed in the late 1950's and installed as original equipment to provide for full steam temperature when firing oil. Tests in a tangentially fired laboratory boiler prior to designing the system showed better flame stability at high flue gas recirculation rates when the recirculated gas was restricted to the air compartments. While mixing of recirculated gas with the entire air supply might be more effective in NO_x emission control, excessive recirculation at partial loads could result in loss of ignition, creating an operating hazard.

The units tested range from 73 to 550 Mw in a single furnace cell. There is a trend toward higher emissions in larger units. The scale-up in generation was achieved by increasing the furnace cross-sectional area and increasing the Btu fired per square foot of cross-sectional area. The newer, larger furnaces are obviously operating at higher temperatures than the older smaller units and producing higher NO_x emissions.

Of the 14 units tested, only 5 meet the EPA NO_x emission standards for new gas fired sources (0.2 lb of NO_2/million Btu fired or 175-ppm dry at 3% excess O_2) as normally operated. By shutting off fuel to the upper level of fuel compartments while continuing to supply air through the upper fuel and air compartments, the NO_x emissions were reduced below the EPA limit on all units tested under these conditions. We have chosen to call this type of operation "overfire air simulation" rather than off-stoichiometric combustion or two-stage combustion as used by others. Flue gas recirculation was also demonstrated as an effective means of controlling NO_x emissions with gas firing by Southern California Edison.[6]

Tests were conducted on one 250-Mw unit to establish the effects of air preheat and water injection on NO_x emissions.[7]

Eliminating air preheat by stopping the rotation of the Ljungstrom air heater at 75% load reduced the NO_x emission level from 200 to 100 ppm as air temperatures decreased from 490° to 81°F. Stack gas temperature increased from 225° to 540°F, which decreased boiler efficiency 8.3%. The load limitation was imposed to avoid overheating the air heater outlet duct and stack.

Water injection tests using existing oil guns as atomizers reduced NO_x emission level from 330 to 110 ppm at full load. Boiler efficiency decreased 5% at the maximum water injection rate of 45 lb/million Btu fired.

Overfire air simulation with low excess air reduced NO_x emission to 65 ppm at 75% load and to 90 ppm at full load. A greater reduction was obtained with overfire air simulation than with either water injection or elimination of air preheat without a sacrifice in boiler efficiency.

Residual Oil Firing

NO_x emissions under normal operating conditions are presented in order of increasing megawatt generation in Figure 4. Southern California Edison data[6] for the three 160-Mw furnaces were included to illustrate the effects of flue gas recirculation to the windbox (as previously described under gas firing) and also the influence of chemically combined nitrogen in the fuel. The 160-Mw unit with an emission rate of 600 ppm was fired with California residual oil containing 1% nitrogen. The oil was also high in sulfur and ash. The duplicate units were fired with an Indonesian oil having only 0.3% nitrogen and low in sulfur and ash. While the furnace burning California residual oil may have been dirtier as a result of the higher sulfur and ash, the major fraction of the increased NO_x emissions is attributed to the higher fuel nitrogen content. Gas recirculation through the windbox is normally used when operating on oil. The tests without recirculation were conducted to establish the benefit of flue gas recirculation in controlling NO_x emissions.

Of the 16 oil-fired units reported, 9 would meet EPA NO_x emission standards for new oil-fired sources without modification (0.3 lb of NO_2/million Btu fired or 230 ppm dry at 3% excess oxygen). Of these 9, 7 are coal-fired designs. Two are peaking units with low preheated air temperatures. With the exception of the one unit with 600-ppm NO_x emission, fuel nitrogen ranged from 0.2 to 0.5%.

Combustion modifications such as overfire air, gas recirculation through the windbox, and low excess air operation were effective in reducing NO_x emissions. High nitrogen fuel oils will present difficult emission control problems; however, fuel nitrogen contents above 0.5% are found only in California residual oils which provide about 10% of the present U. S. utility fuel oil supply.

There is no discernible trend showing increased NO_x emissions with larger units as was observed with natural gas firing. It appears that with tangential firing of oil, NO_x is produced primarily by conversion of fuel nitrogen. For most units tested, the NO_x formation from atmospheric nitrogen is believed to be less than 100 ppm. The indicated conversion of fuel nitrogen to NO_x ranges from 43% for 0.2% nitrogen oils to 30% for 1% nitrogen oils, when operating normally at approximately 3% oxygen.

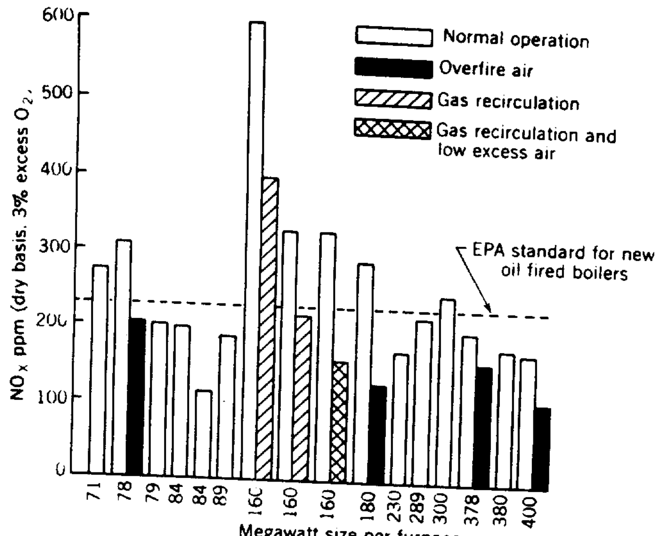

Figure 4. NO_x emissions from tangentially fired furnaces firing residual fuel oil.

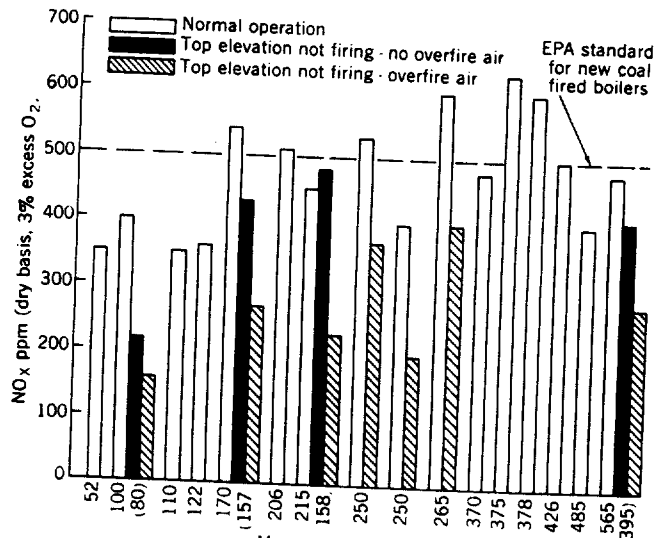

Figure 5. NO_x emissions from tangentially fired furnaces firing coal.

Coal Firing

NO_x emissions under normal operating conditions are presented in Figure 5 in order of increasing megawatt generation.

Of the 16 coal-fired units reported, 10 would meet EPA NO_x emission standards for new coal-fired sources under normal operation (0.7 lb of NO_2/million Btu fired or ~500 ppm dry at 3% excess oxygen).

Overfire air simulation by taking the coal pulverizer supplying the upper elevation of fuel nozzles out of service was effective in reducing NO_x on all units tested under these conditions. On a given unit, the amount of NO_x reduction is primarily dependent on the reduction in air supplied to the fuel ignition zone. On a number of units not designed to operate at full load with one pulverizer out of service, it was necessary to reduce load to the megawatt rating indicated in parentheses. Overfire air simulation on the 565-Mw unit at the extreme right of Figure 5 was conducted with the upper two coal nozzles out of service (4 of 6 pulverizers operating), which required a load reduction to 395 Mw.

Fuel types represented by the data are lignite and western, midwestern, and eastern bituminous coals. It would be very misleading to draw any generalizations from this sample of units as to the relationship between fuel type and level of NO_x emissions. The slagging tendencies of the individual coals coupled with furnace heat release rates appear to be more closely related to NO_x emission levels than general coal type.

Fuel nitrogen ranged from 1.0 to 1.7 in the coals tested. The complex relationships existing among the operating variables in coal-fired furnaces preclude establishing any trend of NO_x emission with increasing fuel nitrogen from the data presently available.

Combustion Engineering participated with Esso Research and Engineering Company in extensive testing of one 500-Mw, twin furnace, tangentially coal-fired unit as part of a program sponsored by EPA.[8] The NO_x emissions were 380–450 ppm under normal operation and 200–250 ppm with overfire air simulation. The significant reduction obtained was achieved without affecting steam temperature characteristics, furnace slagging, or unit efficiency. Solid combustible and CO emissions were virtually unaffected by overfire air operation. The flyash content averaged

0.5% combustibles and CO emissions averaged 50 ppm.

Reduced load tests were performed with various fuel nozzle combinations. The particular three levels in service did not significantly affect NO_x emissions under normal operation. The maximum overfire air effect was obtained with the three lower elevations in service.

This furnace has a low heat release rate (75% of current design practice) and burns a good grade of coal from a slagging standpoint. It was possible to operate with as low as 2.2% O_2 leaving the furnace without slagging the furnace walls under normal operation or when simulating overfire air.

Observations on Test Variables

The following observations may be made regarding the effects of change in operating or design variables on NO_x emission for tangentially fired units.

Excess Air. NO_x emissions increase as excess air is increased with all fuels. Considerations for establishing minimum acceptable operating levels in a given application are emissions of CO, smoke, or solid combustibles and flame stability. Furnace slagging is an additional consideration for coal-fired units. Operating at 10% higher excess air than the established minimum will normally increase NO_x emission by 20% for all fuels.

Nozzle Tilt. The fuel and air nozzle tips can be tilted from the horizontal position by ±30 degrees. Minimum NO_x emissions were generally obtained at horizontal tilt position.

Air Flow Distribution. Increasing the percentage of air flow through the fuel compartments increases the rate of fuel-air mixing and increased NO_x formation by 20% on oil firing. This same change on coal firing resulted in only 10% increased NO_x emissions. A 20% increase in NO_x emissions was observed with gas firing with a high percentage of air flow through either the fuel or air compartments. Intermediate settings produced the lowest NO_x emissions with gas firing.

Load Reduction. A decrease in load reduced NO_x emissions with all fuels. The NO_x reduction was 50% on gas-fired units and 25% on coal and oil-fired units for a 25% reduction in load. The higher reductions observed on gas-fired units would be expected since the NO_x formation is exclusively from atmospheric nitrogen.

Flue Gas Recirculation. To be effective in NO_x emission control, flue gas recirculation must be introduced in the primary flame zone. Introduction through the furnace bottom did not have any effect on 5 units tested (2 coal, 2 oil, and 1 gas). Flue gas recirculation mixed with a portion of the combustion air has been tested only on one design with oil and gas firing.[6] Reductions in NO_x emissions of 35% on oil and 60% on gas firing were achieved with 30% gas recirculation. There are no tangentially coal-fired designs with gas recirculation through the windbox.

Overfire Air Simulation. NO_x emissions decrease as overfire air is increased. Because of variations in compartment flow areas for overfire air admission from unit to unit and variations in damper setting, the same percentage of stoichiometric air to the fuel admission zone was not obtained on every unit. For coal and oil firing, the reduction in NO_x emissions averaged 38%. For natural gas firing, the reduction in NO_x emission averaged 50%.

Fuel Nitrogen. Fuel nitrogen is a consideration only with oil and coal firing. There are definite indications that NO_x emissions are a function of percent fuel nitrogen with oil firing. Trends in NO_x emission with the percentage of nitrogen in coal cannot be established from the data presently available.

Furnace Slagging. Coal-fired furnace wall deposits would be expected to influence NO_x emissions since higher furnace gas temperatures would occur as the effectiveness of the heat transfer surface is decreased. Changes in furnace wall conditions have been observed to produce 100 ppm differences in NO_x emission on a given coal-fired unit. A coal ash with increased slagging tendencies could indirectly influence NO_x emissions by requiring operation at 1 or 2% higher O_2 to control furnace wall deposits.

The quantity or character of wall deposits was not changed when simulating overfire air in 24-hr test runs on 2 units. Shorter tests on other units did not indicate any adverse effects from overfire air simulation. Longer-term tests are required to fully explore potential wall corrosion, slagging, and other operating considerations.

Low Air Preheat. Lowering air preheat has been demonstrated to be a factor in controlling NO_x emissions when firing natural gas. However, in view of the penalties in plant efficiency and other disadvantages, there are more preferable means to lower NO_x emissions. Reduced air preheat would not be expected to be as significant with oil or coal firing where a substantial fraction of the NO_x is formed from fuel nitrogen. Elimination of air preheat might be expected to increase particulate emissions when firing oil or coal. Preheated air is required for pulverizer operation on coal-fired units. The higher exit gas temperatures resulting from elimination of preheat would require additional water spray if a scrubber system is to be incorporated in the design. Electrostatic precipitators or induced-draft fans, if required, would become larger and more expensive.

Water Injection. Water injection has been demonstrated to be effective in reducing NO_x emissions on 1 gas-fired unit. However, the large quantities of water required and the loss in plant efficiency detract from the desirability of using this method for NO_x emission control. This method would be expected to be less effective in NO_x emission control with coal or oil since it acts primarily to reduce emissions from fixation of atmospheric nitrogen.

Equipment Design

National standards for NO_x emissions from stationary sources firing over 250 million Btu/hr became law on Dec. 23, 1971, and apply to all units contracted for after Aug. 17, 1971. The various air quality control regions are permitted to adopt more stringent emission standards if required to attain the national ambient air quality standard.

In the period following the introduction of clean air legislation in 1969, up to the finalizing of emission standards in Dec. 1971, the degree of NO_x emission control required could only be speculated upon. Additionally, the effectiveness and operational acceptability of various control methods were known for only a few units. Many tangentially fired coal, oil, and gas units contracted for during this period were designed with overfire air systems. Gas recirculation through the windbox was also included on a number of gas and oil-fired designs.

Tangentially fired units are currently being designed to meet EPA NO_x emission standards based on the test information presented earlier and the analysis of information published by other investigators. On oil and gas-fired units, larger furnaces and both gas recirculation through the windbox and overfire air systems are used to insure meeting EPA standards in day-to-day operation. Coal-fired units are being designed with overfire air systems to meet current EPA NO_x emission standards.

In the recirculated gas and air duct system for oil or gas-fired units, recirculated gas is mixed with air in the 2 outer channels of the duct from the air preheaters to the windbox. The center channel contains air only, which goes to the fuel and overfire air compartments. The device is installed in the ductwork to insure thorough mixing of the recirculated gas and air to prevent stratification. Each windbox has fuel compartments alternating with the compartments containing the mixed air and recirculated gas. Air admitted to the fuel compartments is not mixed with any recirculated gas. The overfire air system on a gas or oil unit consists of 2 air compartments per corner with manually tilting nozzles installed 5 to 8 ft above the top fuel compartments. The overfire air system is nominally designed for 15% of the total air requirement and is supplied only with air.

Overfire air is provided to reduce NO_x emissions on coal-fired units by adding 2 air compartments at the top of the windbox in each corner of the furnace which lengthens the windbox by approximately 5 ft. These compartments are normally sized for 15% of the windbox air flow and have manual dampers for air flow control and manual nozzle tilt control. The position of the overfire air dampers and tilt will be optimized after initial operation to give the lowest NO_x emissions consistent with satisfactory furnace performance.

The application of our test results to coal-fired units may not be as simple as the data would indicate. Tests have been run for relatively short duration, and overall effects on furnace slagging have not been completely evaluated. Burning certain coals at low excess air or with overfire air, which reduces the air in the primary combustion zone, may result in excessive slag accumulations on the furnace walls.

Certain low-ash, high fusion, nonslagging coals may lend themselves more readily to this type of operation. However, as of now we do not have enough experience with overfire air on large furnaces burning a wide variety of coals to predict ash deposits on walls, carbon loss, etc. Operational procedures using overfire air systems in coal firing will have to be worked out on each unit after start-up.

Continuing R & D Effort

Data will not be obtainable from units incorporating design modifications described in the preceding section for 1–4 yr because of the time required to design, fabricate, and erect this type of equipment. Efforts will be continued to develop analytical prediction models based on reaction kinetics and furnace heat transfer characteristics to predict NO_x emissions from tangentially fired units. Additional data will also be acquired on operating units. Some of the areas currently under investigation are:

1. Combination firing of oil and coal.
2. Type of oil atomization.
3. Slagging and corrosion potential with overfire air simulation firing coal.
4. Changes in furnace heat absorption patterns with combustion modifications for NO_x control.
5. NO_x production by electrostatic precipitators. (Present C-E data indicate an increase of 70 ppm on 2 of 4 units tested. Establishing the contribution of NO_x emissions, if any, from electrostatic precipitators is extremely important since this contribution cannot be controlled by combustion modification and may have a bearing on the type of particulate removal system selected for new units.)
6. Pilot plant testing. Plans are being developed for modifying a small tangentially coal-fired utility unit to study the control of NO_x formation. A variety of combustion modification techniques such as overfire air, flue gas recirculation, low air preheat, and steam or water injection would be tested singly or in combination using a variety of admission points. Operating variables such as coal type, escess air, and load would also be explored. This program would provide accurate and detailed information on many systems and modes of operation that could not be economically designed and tested on a large new unit.

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