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Project Summary

Control of Utility Boiler and Gas Turbine Pollutant Emissions by Combustion Modification—Phase II

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This report describes the status of an EPA-sponsored field study of NO_x emissions from coal-fired utility boilers. Previous reports (1, 2, 3,) discussed the effectiveness of combustion modification techniques to significantly reduce NO_x emissions. The simultaneous investigation of side effects (e.g., particulate emissions, boiler slagging, boiler performance) did not identify any significant problems. However, one potential side effect—fireside corrosion of the boiler waterwalls— was only partially studied. Fireside corrosion rates obtained via probes (short-term exposure) could not be correlated conclusively with actual furnace tube wastage experience. Therefore, a long-term corrosion test was undertaken to obtain representative furnace tube corrosion rate data. Also information is included on a field test using additives to suppress slag formation in a 330-MW pulverized-coal-fired utility boiler.

This Project Summary was developed by EPA's Industrial Environmental Research Laboratory, Research Triangle Park, NC, to announce key findings of the research project that is fully documented in a separate report of the same title (see Project Report ordering information at back).

Introduction

Exxon Research and Engineering Company (ER&E) under contract to EPA has been conducting field studies since 1970 on combustion modification techniques to control NO_x and other pollutant emissions from utility boilers. In early studies significant reductions of NO_x were achieved in gas- and oil-fired boilers under EPA contract CPA 70-90 (1) without optimizing the technology. In a follow-up investigation, emphasis shifted to the more difficult task of controlling NO_x emissions in pulverized-coal-fired boilers and the assessment of potential side effects. Twelve coal-fired boilers were tested under EPA Contract 68-02-0227 (2) in cooperation with boiler owner-operators and boiler manufacturers. In this study reductions in NO_x emissions averaging 39 percent (ranging from 12 to 59 percent) were achieved with no apparent adverse side effects. In addition to the optimization of NO_x emissions, the study included particulate and unburned combustible measurements, furnace corrosion rate probing, determination of boiler efficiency, and observations on changes in boiler operability; e.g., slagging, fouling, flame impingement, or instability.

In the current program, co-sponsored by EPA (Contract 68-02-1415) and the Electric Power Research Institute (EPRI

Project No. 200), five coal-fired and two mixed-fuel-fired (coal/oil, coal/gas) boilers were tested in the Phase I program (3). Four coal-fired boilers, two gas turbines, and one oil-fired boiler were tested in the Phase II program. The scope of the program was broadened under these contracts to explore the effectiveness of equipment modifications designed for NO_x control; e.g., boilers constructed with overfire air ports and use of low-NO_x improved-burner designs. NO_x emissions in the coal-fired boilers tested were reduced by 34 percent in the Phase I program and by 38 percent in Phase II. Potentially adverse combustion-modification side effects (e.g., increased particulate mass and reduced size distribution, poorer boiler performance and operability, increased furnace tube corrosion) received increased emphasis and were studied in more detail than in previous studies. Since combustion modifications for NO_x control potentially may increase slagging in boilers, as part of this program tests were conducted with promising results using additives to suppress slag formation in a coal-fired boiler.

Furnace tube corrosion, which may be aggravated by low-NO_x operation, is a potential major side effect. Data developed in past programs with corrosion probes, however, could not be conclusively related to actual furnace tube corrosion. The importance of this problem dictated a major effort to specifically address this question. An extensive long-term corrosion study was undertaken to obtain corrosion rates on actual furnace tubes.

Test Program Update

Details of test program designs, gaseous sampling and analysis, particulate, SO_x, corrosion rate, and boiler performance measurements and calculations have been covered in prior reports (1, 2, 3, 4). This report updates work performed under EPA Contract 68-02-1415 and Electric Power Research Institute Project No. 200. Field tests conducted under this program were carried out in Phases I and II. Phase II, covered by this report, updates the program covering field tests on four coal-fired and one oil-fired boiler with special emphasis on the long-term corrosion test conducted on Gulf Power Company's Crist Station boiler No. 7.

Nitrogen Oxide Emissions

Field tests conducted in the Phase I program are summarized in Table 1 for record and comparison purposes. Included in the table are details concerning the boiler manufacturer, the type of firing, kind of fuel burned, number of burners, test variables, number of tests run, and emission data for baseline and optimum low NO_x operation on each boiler tested. Table 1 shows that uncontrolled (baseline) emissions ranged from 341 to 1383 ppm with only four out of the seven boilers tested meeting the New Source Performance Standard (NSPS) of 0.7 lb $NO_x/10^6$ Btu. Three of these, Barry No. 2, Navajo No. 2, and Comanche No. 1 were equipped with overfire air ports; the fourth, Gaston No. 1, had been retrofitted with B&W's dual-register low-NO_x burners. Note that application of combustion modification techniques successfully reduced emissions below the revised NSPS of 0.6 lb $NO_x/10^6$ Btu in all cases but two (Mercer No. 1 and Widows Creek No. 5), and even Widows Creek No. 5 could meet the original standard. NO_x reductions ranged from 22 to 45 percent, averaging 34 percent commensurate with reductions achieved in prior programs (1, 2).

Results of Phase-II field tests are given in Table 2. Table 2 shows that baseline emissions in the four coal-fired boilers tested, ranging from 533 to 827 ppm, did not meet the original NSPS of 0.7 lb $NO_x/10^6$ Btu. Under low NO_x firing conditions, however, two coal-fired boilers (Cooper No. 2 and Comanche No. 2) met the new NSPS of 0.6 lb $NO_x/10^6$ Btu. There is little doubt, however, that Mill Creek No. 1 boiler could have met both NSPS requirements, but low NO_x firing was not applied to the unit during the additive tests due to a lack of time. Average NO_x reductions were 38 percent in the coal-fired boilers tested, ranging from 22 to 62 percent. This is consistent with NO_x reductions achieved in Phase I and earlier programs (1, 2, 3).

Emissions reductions obtained in boilers representative of the utility boiler population and in various current design configurations complying with recent low-NO_x requirements or guarantees have been discussed and published elsewhere (1, 2, 3, 4). NO_x emission reduction and optimization achieved on the boiler No 7 at Gulf Power Company's Crist Station, which was selected for long-term corrosion testing, is presented here to illustrate slightl different applications of combusti techniques.

Crist Station Boiler No. 7 is a hori zontally opposed fired, dry-bottom single-furnace Foster Wheeler boile rated at 500 MW capacity. This unit wa selected for testing because it is a large pulverized-coal-burning unit of moder design capable of operation wit burners out of service for staged com bustion. It also appeared to have th necessary operating flexibility an management support so that it was good candidate for the Phase IV, long term corrosion test program. Th furnace is 52 ft 5 in. wide and 40 ft deep Six pulverizers feed 24 burners arrange in three rows of four burners each in th front and rear walls of the furnace.

The operating variables found to hav a statistically significant influence o NO_x emission levels were load, exces air level, and firing patterns. Figure indicates the most important relation ships found in analyzing the test data The numbers in the symbols indicat the run numbers, while the symbol indicate the various firing patterns tested The lines in Figure 1 are least-square linear-regression lines for ppm NO vs.% oxygen calculated for each firin pattern.

The strong influence of excess ai level on NO_x emission levels for all firing patterns is indicated by the steep slope of the lines in Figure 1. Very clos agreement was found in the calculate regression coefficients (change in ppm NO_x for a 1 percent change in oxygen for the various firing patterns; i.e., 69 80, 81, 59, and 76 for firing patterns S_1 S_2, S_3, S_6, and S_7, respectively. Sinc excess air levels could be reduced by a much as 5 percent from normal t achieve low excess air operation, with out violating the 200 ppm CO maximum emission level guideline or increasin stack plume opacity, this represents a important operating variable for NO emission control. Thus, under full loa baseline operation (480-510 MW) NO emissions were reduced by 16 percen by changing from a baseline operatio (4 percent O_2) of 827 ppm NO_x to 69 ppm NO_x under low excess air (2.1 percent O_2) operation.

Reducing load by 62 percent from the 480 to 510 MW range to 190 MW unde normal excess air firing operatio lowered NO_x emissions by about 3 percent. Staged firing generally resulte in reduced loads as well as reduced NO

Table 1. *Summary of Coal- and Mixed-Fuel-Fired Boilers Tested During Phase I*

Boiler Operator	Station and Boiler No.	Boiler Mfr.(a)	Type of Firing(b)	Fuel(c) Burned	MCR (MWe)	No of Burners	Test Variables	No. of Test Runs	NO_x Emissions (i) Baseline ppm (lb/10^6 Btu)	Low NO_x ppm (lb/10^6 Btu)	% NO_x(h) Reduction
Tennessee Valley Authority	Widows Creek - 5	B&W	RW	C	125	16	4	31(d)	597 (0.81)	468 (0 64)	22
Southern Electric Generating Company	E.C. Gaston - 1	B&W	HO (e)	C	270	18	5	37(d)	389 (0.53)	278 (0.38)	29
Alabama Power Company	Barry - 2	CE	T (f)	CG	130	16	6	38	341 (0.46)	189 (0.26)	45
Potomac Electric Power Company	Morgantown - 1	CE	T	CO	575	40	5	27	552 (0 75)	403 (0.55)	27
Salt River Project	Navajo - 2	CE	T (f)	C	800	56	4	36(d)	492 (0.67)	282 (0.38)	43
Public Service Company of Colorado	Comanche - 1	CE	T (f)	C	350	20	4	30(d)	417 (0 57)	261 (0 35)	37
Public Service Electric and Gas Company	Mercer - 1	FW	FW (g)	C	270	24	4	33(d)	1383 (1 88)	876 (1 19)	37
Average of Coal Fired Boilers								33	656 (0 89)	433 (0 59)	34

(a) B&W - Babcock and Wilcox, CE - Combustion Engineering, FW - Foster Wheeler
(b) RW - rear wall, HO - horizontally opposed, T - tangential, FW - front wall
(c) C - coal, C-G - coal-gas mixed, C-O - coal-oil mixed
(d) Particulate and corrosion probe tests performed on these boilers
(e) Special low NO_x emission burners
(f) Overfire air ports
(g) Wet bottom furnace
(h) % NO_x reduction at full or near full load
(i) PPM NO_x - 3% O_2, dry basis

Table 2. *Summary of Utility Units Tested During Phase II*

Boiler Operator	Station and Mfr (a)	Boiler Mfr. (a)	Type of Firing (b)	Fuel Burned	MCR (MWe)	No. of Burners	Test Variables	No. of Test Runs	NO_x Emissions Baseline ppm (lb/10^6 Btu)	Low NO_x ppm (lb/10^6 Btu)	% NO_x(g) Reduction
East Kentucky Power Cooperative, Inc.	Cooper - 2	B&W	FW	Coal	220	18	4	101 (c)(d)	(h) 557 (0.76)	(h) 433 (0.59)	22
ublic Service Company Colorado	Comanche - 2	B&W	HO(e)	Coal	350	32	3 (c)	18	726 (1.00)	278 (0.38)	62
Public Service Electric and Gas Company	Sewaren - 5	B&W	HO	Oil	330	24	5	24	311 (0.40)	211 (0.27)	32
Houston Lighting and Power Company	Wharton - 43 (Gas Turbine)	GE	(f)	Gas	50	—	2	16	212 (0.29)	34 (0 044)	84
Houston Lighting and Power Company	Wharton - 42 (Gas Turbine)	GE	(f)	Oil	50	—	2	13	382 (0.45)	40 (0.048)	90
Louisville Gas and Electric Company	Mill Creek - 1	CE	T	Coal	330	20		(c)	533 (0 71)	(i)	
Gulf Power Company	Crist - 7	FW	HO	Coal	300	24	4	158 (c)(d)	827 (1 1)	570 (0.76)	31
Average of Coal Fired Boilers								92	661 (0.88)	427 (0.58)	38

(a) B&W - Babcock and Wilcox, GE - General Electric, Combustion Engineering, FW - Foster Wheeler
(b) FW - Front Wall, HO - Horizontally Opposed, T - Tangential
(c) Particulate tests performed on these boilers
(d) Corrosion probe tests performed on this boiler
(e) Overfire air ports
(f) Water injection
(g) % NO_x reduction of full or near full load
(h) PPM NO_x - 3% O_2, dry basis
(i) Additive test at baseline conditions only

emission levels. Separating the effect of staged firing on NO_x emission levels from the load effect indicated the following. Staged firing operation, S_2, top burners fired lean (by reduced coal flow to top row of burners) and normal excess air (4 percent O_2) resulted in a 12 percent reduction in NO_x emissions (827 ppm to 728 ppm) with about 5 percent due to load reduction (496 to 451 MW average) and the remaining 7 percent due to staged firing. Staged firing operation, S_3, (1 top mill on air only) resulted in a 39 percent reduction in NO_x emissions (to 509 ppm from 827 ppm) with about 12 percent due to load reduction and 27 percent due to staged firing. Finally, S_6, staged firing with both top mills on air only, produced a 72 percent NO_x emission reduction with about 32 percent due to reduced load (230 MW vs. 495 MW). Part of the load reduction experienced during the test period, however, was due to abnormal operating difficulties such as partial air heater plugging.

The combined effect of low excess air and staged firing operation resulted in further NO_x emissions reductions, as would be expected. Thus, the ppm NO_x levels (and percent NO_x reduction from the 827 ppm measured under baseline operation) were 451 (-31 percent), 400

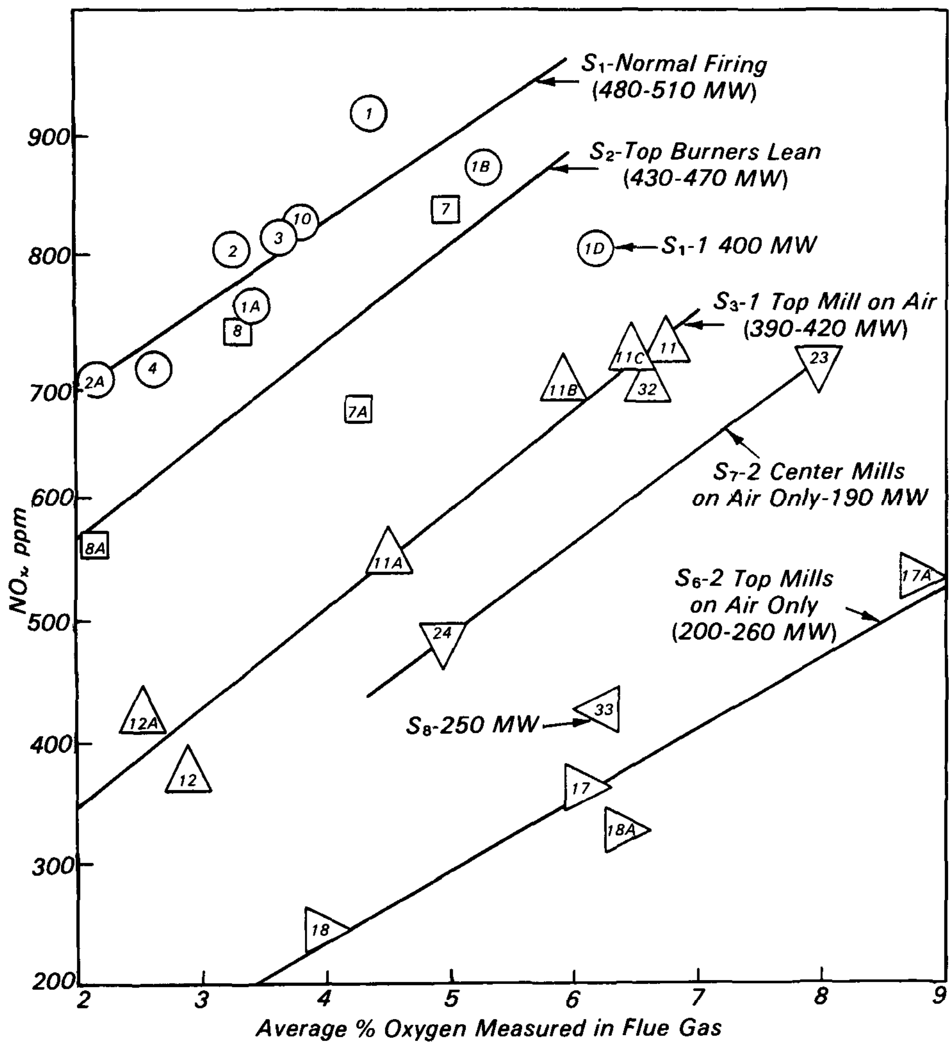

Figure 1. *PPM NO_x vs. % oxygen in flue gas [Crist No. 7 Unit].*

(-52 percent) and 244 (-70 percent) for S_2, S_3, and S_6 staged firing patterns, respectively. These results indicate that this boiler has an excellent NO_x reduction capability through modified combustion operation.

Particulate Emissions and Boiler Performance

Low-NO_x combustion modification techniques, especially staging the firing pattern in combination with low excess air firing, result in less intense combustion conditions than conventional firing methods. A tendency toward increased burnout problems, therefore, may occur which, potentially, could increase particulate mass loading as a consequence of increased carbon in the fly ash. In addition, these effects could also result in changes in particle size distribution. Changes in particulate mass loading and particle size distribution could adversely affect collection efficiency in electrostatic precipitators or in other collection devices, while an increase in unburned combustibles could have a corresponding adverse effect on boiler efficiency. A further potential adverse side effect of low NO_x operation could be a change in fly ash resistivity which might have a similar adverse effect on precipitator collection efficiency. Measurements of resistivity, however, were beyond the scope of this program.

Low-NO_x combustion modification effects on dust loading were investigated using an EPA method 5 type sampling train incorporating a Brink cascade impactor for particle size distribution. Total mass loading and particle size distribution were measured under baseline and optimized low-NO_x operating conditions upstream of the electrostatic precipitators. In the latter phase of the contract, dust loading was measured with EPA's Source Assessment Sampling System (SASS) train.

SASS train samples from East Kentucky Power Cooperative, Inc. and Public Service of Colorado power plants were analyzed for metals, PNA's, and anions. The analytical results showed that the low NO_x operating conditions at the Colorado plant did not significantly reduce all metallic emissions.

PNA concentrations were all below the requested 2 $\mu g/m^3$ levels. However, low amounts of PNA's were present (0.1-0.8 $\mu g/m^3$) on the particulate samples from the Kentucky plant. Poor PNA extractability precluded accurate analysis of the 10 μm cyclone samples. At the P.S. Company of Colorado plant, lower anion concentrations were obtained from particulate samples while higher values were detected on the condensate samples for the low-NO_x operation than during baseline operation.

Particulate emissions and particle size distribution for boilers tested in the Phase II program are summarized in Tables 3, 4, and 5. Comparing particulate mass loading data in Table 3 for baseline against low NO_x operation, shows that mass emissions under low-NO_x firing conditions, for the tests in the Phase II program, are essentially the same as for baseline operation, requiring little or no change in electrostatic precipitator collection efficiency. Tables 4 and 5 show that low-NO_x operation has very little, if any, effect on particle size distribution. Aside from potential changes in resistivity, therefore, these data indicate, as in Phase I and prior programs, that there are no significant differences in particulate mass loading or particle size distribution under now NO_x combustion conditions.

Increases in percent carbon on particulate are noted for low-NO_x firing conditions in Table 3 which do not seem to have a corresponding direct effect on mass emissions. Furthermore, the expected decrease in boiler efficiency (Table 6) not only failed to materialize, but (for the low-NO_x conditions efficiency), if anything, is even greater by a small margin, indicating that low-NO_x firing has only insignificant effects on boiler performance.

Table 3. *Particulate Emission Test Results*

Utility	Date	Test No.	Firing Condition	Load, MW	Emissions mg/m^3	gr/scf	ng/J	lb/10^6 Btu	Req. Eff. To Meet 0.1 lb/10^6 Btu	% Carbon On Particulate	Coal Ash Wt. %	HHV. Wet, Cal/g Btu/lb
East Kentucky	3/9/77	41	Base*	178	1.06	4.65	3280	7.63	98.7	1.48	12 78	11,742
Power Cooperative, Inc., Cooper	3/11/77	43	Base*	155	0.72	3.12	2361	5.49	98.2	0 94	12 48	12,217
Station, Boiler No. 2	3/25/77	59	Low NO_x*	123	0.78	3 41	2520	5.86	98.3	1 81	11.30	12,312
	3/28/77	60	Low NO_x*	123	0.87	3.82	3130	7.28	98.7	1.87	10.47	12,291
Public Service Electric & Gas												
Company	9/17/76	4D	Base**	288	0.0059	0.026	17.2	0.04	—	—	—	—
Sewaren Station Boiler No. 5	9/17/76	6C	Low NO_x**	280	0.0063	0.0274	17.2	0.04	—	—	—	—
	6/20/78	150	Base*	436	0.686	3.00	2301	5.35	98.1	—	—	—
Gulf Power Company, Crist	6/21/78	151	Low NO_x*	432	0.874	3.82	1926	4.48	97.8	2.98	12.45	11,263
Station, Boiler No. 7	6/22/78	152	Base*	417	0.864	3.78	2881	6.70	98.5	0.87	16.48	10,782
	6/23/78	153	Low NO_x*	434	0.909	3.97	2468	5.74	98.3	1.71	14.32	11,033

*Pulverized coal firing.
**Oil firing.

Table 4. *Particle Size Distribution, Wt% East Kentucky Power Cooperative Cooper Station - Boiler No. 2 Pulverized Coal Firing*

	Baseline Firing			Low NO_x Firing		
Size Range, µm	Test No. 41	Test No. 43	Average	Test No. 59	Test No. 60	Average
>2.5	98.86	92.68	95.8	95.65	91.75	93.7
2.5	2.04	3.71	2.9	3.28	5.34	4.3
1.5	0.50	1.24	0.9	0.78	1.32	1.1
1.0	0.41	0.95	0.7	0.61	1.07	0.8
0.5	0.63	1.13	0.9	1.04	1.65	1.4
<0.5	0.36	0.62	0.5	0.67	1.11	0.9

Table 5. *Particle Size Distribution, Wt% Gulf Power Company Crist Station - Boiler No. 7 Pulverized Coal Firing*

	Baseline Firing			Low NO_x Firing		
Size Range, µm	Test No. 150	Test No. 152	Average	Test No. 151	Test No. 153	Average
>2.5	93.10	94.00	93.6	92.50	89.80	91.2
2.5	2.15	3.48	2.8	3.15	3.68	3.4
1.5	0.90	0.72	0.8	1.12	1.94	1.5
1.0	0.83	0.84	0.8	0.83	1.43	1.1
0.5	1.24	1.20	1.2	1.16	1.84	1.5
<0.5	1.80	0.72	1.3	1.24	1.33	1.3

Anti-Slagging Additive Tests

Low-NO_x combustion modifications, especially staged firing in combination with low excess air operation, can result in lower net reducing atmospheres in the bottom of the furnace, often accompanied by higher temperatures. Under reducing atmosphere, coal ash fusion temperatures generally are about 200°F lower than for oxidizing conditions. This fact, coupled with higher furnace temperatures, can affect the character of the slag formation, making them more fluid and sticky with potentially greater slagging difficulties. For boilers operating near incipient slagging conditions, the application of NO_x reduction techniques could increase slagging.

Part of the Phase II program was devoted to investigating ways to control increased slagging if this problem occurred when applying NO_x control modifications. The potential use of additives gave promise of being the most cost effective solution to control or ameliorate slagging conditions in coal-fired boilers. Accordingly, arrangements were made with Basic Chemicals and the Louisville Gas and Electric Company

Table 6. *Summary of Boiler Performance Calculations*

	Boiler No.	Firing Mode	Test No.	Load MW	% O_2	NO_x Emissions, (3% O_2) PPM	lb/10^6 Btu	ng/J	Coal Ash, % (Wet Basis)	% Carbon on Particulate	Boiler Efficiency, %
East Kentucky	2	Baseline	41	178	4.2	612	0.82	351	12.37	1.48	89.82
Power Cooperative	2	Baseline	43	155	5.4	574	0.77	329	12.76	0.94	90.12
Inc. Cooper	2	Low NO_x	59	123	5.0	381	0.51	218	11.30	1.81	90.44
Station	2	Low NO_x	60	123	6.6	490	0.65	281	10.41	1.87	90.36
Gulf Power	7	Low NO_x	151	432	3.1	508	0.68	291	12.45	2.98	88.92
Company,	7	Baseline	152	417	5.5	848	1.13	486	16.48	0.87	88.86
Crist Station	7	Low NO_x	153	430	1.9	456	0.61	261	14.32	1.71	89.27

to conduct cooperative tests on LG&E's Mill Creek Station boiler No. 1. Rated output of boiler No. 1 is 325 MW, but LG&E had arbitrarily derated the unit to 300 MW in order to keep slagging conditions within manageable bounds.

Eight tests were run in June 1979: four without additive injection to develop "baseline" operating information, and four while injecting Basic Chemicals UltraMag additive, an ultra fine (<2μm) dispersion of MgO in heating oil. Additive was injected at three different rates at each of the four corners of the furnace at two different slag blower elevations immediately above the top burners. Boiler loads of 325-330 MW were maintained during the tests, sufficient to promote slagging. The effectiveness of the additive was judged by the length of time that the load could be maintained at this level before operating parameters became critical forcing a cutback in load.

Results of the anti-slagging additive trials are summarized in Table 7. Table 7 shows that tests 200, 201, and 203 (baseline - no additive) achieved 12 hours operation at full load, rated conditions (325-330 MW) before superheat and reheat steam temperatures bordered on uncontrollability. Note test 202 (no additive), however, where the boiler was slagged to the point of being out of control in 4-1/2 hours, a very short period. The reasons for this drastic performance were not readily apparent but may possibly be attributed to the fact that furnace cleanup prior to the test may not have been as effective as before or that a change to a higher slagging coal may have occurred for that day.

In tests 204 and 205 additive was injected continuously at the rate of 15 gph. Table 7 shows that full load capability of the boiler could be maintained under these conditions for 15 and 17 hours, respectively, or 3 and 5 hours longer than without additive injection. These results testify to the technical feasibility and effectiveness of the use of additives at low injection rates with pulverized-coal firing. Other potential benefits, which were beyond the scope of these investigations, may also accrue from additive usage; e.g., easier cleanup of the boiler during nightly reduced-load periods; e.g., it may not be necessary to reduce load as much and the clean-up period may possibly be shortened to achieve the same degree of cleanliness. Load-carrying capabilities, which are of special importance in tight load-demand situations, therefore could be improved.

Table 7. *Summary of Anti-Slagging Additive Test Results*

Test No.	*Date*	*Time*		*Hours @ Full Load (325-330 MW)*	*O_2, %*	*NO_x ppm ($3\%\ O_2$)*	*Test Condition*
200	6/11/79	07:27	Start				Baseline
		13:53		12	5.0	584	(No Additive)
		16:16			5.3	599	
		19:27	End				
201	6/13/79	10:00	Start				Baseline
		11:06		12	4.7	512	(No Additive)
		15:36			5.2	566	
		22:00	End				
202	6/14/79	10:00	Start				
		13:18		4.5	5.0	557	Baseline
		*14:30	End				(No Additive)
		16:15	Load Cut Back				
203	6/18/79	07:00	Start				Baseline
		08:16			4.8	448	(No Additive)
		13:45		12	4.8	479	
		15.58			4.9	517	
		19:00	End				
204	6/20/79	07:10	Start				Additive
		09:26			4.5	447	(15 gph)
		13:35		15	4.6	473	
		16:00			4.6	572	
		22:20	End				
205	6/21/79	08:15	Start				Additive
		09:38			5.3	514	(15 gph)
		13:00		17	5.3	534	
		15:35			5.7	581	
		01:15	End				
206	6/25/79	09:00	Start	12	—	—	Additive
		21:00	End				(7.5 gph)
207		09:30	Start	14	—	—	Additive
		23:10	End				(15 gph Slugs)

**Superheat/reheat sprays max. @ 14:30.*

Tests 206 and 207 were run in an attempt to optimize the additive injection rate and to test the effectiveness of other injection methods. Neither result, however, was quite as effective as injecting the additive continuously at 15 gph.

These tests indicate that anti-slagging additives may be effective in controlling or ameliorating slagging problems in pulverized-coal-fired utility boilers, especially when low-NO_x combustion modifications may be employed. The degree of slag reduction, the benefits of increased load-carrying capability, the optimum rate, and the most effective injection method, however, need to be defined in more extensive testing to shed more light on the economics and technical feasibility of additive usage for this purpose.

Corrosion Probe Investigations

Corrosion probes with exposed coupons provide a relatively simple, quick, and economical means for determining corrosion rates. Even though corrosion rate data developed in these and previous programs could not readily be related to actual furnace tube experience, relative comparisons could be made. This type of measurement was continued in the long-term corrosion investigations with the objective of eventual correlation with rates developed by ultrasonic measurement of actual furnace tubes and from exposure of furnace tube test panels.

Corrosion probe testing on Gulf Power Company's Crist Station boiler No. 7 was amplified extensively in order to obtain more data and information on the effect of corrosion with time. Conditions of exposure were maintained the same as in prior testing, simulating actual furnace tube environment. However, coupon exposure was varied from 30 to 1000 hours under both baseline and low-NO_x conditions to determine initial, intermediate, and longer term corrosion effects. In previous tests, coupons were normally exposed for 300 hours. In addition, special ports were installed in the furnace for the installation of the probes in the most desirable areas. Two of these ports were in the middle of the sidewalls, the burner zone (elevation 129.8 ft), in the most corrosion-prone area; two others were in the middle of the sidewalls, but in the upper furnace area (elevation 157.8 ft), outside of the expected corrosion area, in order to provide control data.

A comparison of corrosion rate data developed using boiler No. 7 is best illustrated in Figure 2, showing a plot of corrosion rate vs. exposure time for probes exposed to both baseline and low-NO_x firing conditions. Figure 2 shows that coupon corrosion rates decrease with exposure time asymotically up to a 1000-hour exposure. Initial corrosion rates developed at 24 to 30 hours exposure are high with considerable scatter in the data. At 250 to 300 hours exposure, corrosion rates are much lower and more consistent in range. Above 450 to 500 hours exposure, corrosion rates level out to an average rate of 10 to 12 mils/year with very little scatter in the range of the data. These rates, however, are still much higher than the 1 to 3 mil/year wastage expected in actual furnace wall tubes.

These corrosion probe investigations indicate that:

- There are no major differences in corrosion rates for probes exposed to low-NO_x vs. baseline firing conditions, especially for exposure exceeding 450 hours.
- Corrosion rates developed via corrosion probes decrease with exposure time through 1000 hours approaching an asymtote above 450 hours exposure.

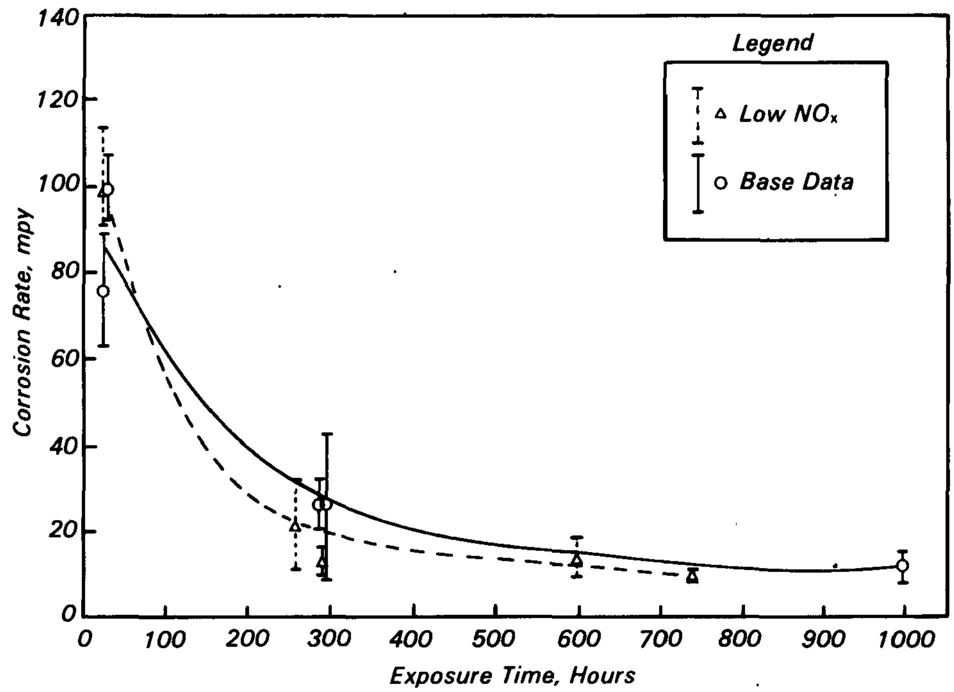

Figure 2. *Comparison of corrosion rates Gulf Power Company, Crist Station, Boiler No. 7, pulverized coal firing.*

- Corrosion probes exposed for short terms (up to 30 hours) within the burner areas in the furnace sidewalls experience significantly greater corrosion rates than probes exposed outside the burner levels under low-NO_x firing conditions. A similar trend is indicated for baseline operating conditions, but more data is needed to reach firm conclusions.
- Probes exposed for periods of 300 to 1000 hours experienced no significant differences in corrosion rates due to furnace location (burner vs. nonburner area) or furnace operating mode (baseline vs. low-NO_x firing).
- Effective correlation of actual long-term furnace tube corrosion rates requires corrosion probe exposure of a minimum of 450 hours.

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The complete report, entitled "Control of Utility Boiler and Gas Turbine Pollutant Emissions by Combustion Modification--Phase II," (Order No. PB 81-222 267; Cost: $15.50, subject to change) will be available only from:
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