OAR Box 1478

Prepped by Ollie Stewart

Document Number:

23) II-C-2

Docket Number:

A-95-28

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, DC 20460

Docket No. A-95-28
Item No. II-C-2

OFFICE OF
AIR AND RADIATION

RECEIVED
SEP - 5 1995
EPA AIR DOCKET

June 6, 1995

Blair A. Folsom, Ph.D.
Senior Vice President
Energy and Environmental Research Corporation
18 Mason
Irvine, CA 92718

Dear Dr. Folsom:

It was a pleasure to see you again at the recent NOx Symposium in Kansas City. Attached is a UARG technical paper that was recently presented to EPA. This paper raises some issues related to the application of reburning (gas and coal) on Group 2 Boilers. Your comments and insights, regarding the extent of the concerns discussed in this paper, would greatly benefit our evaluation of reburning applicability to Group 2 boilers. Therefore, I request you to provide us your comments on the UARG paper as soon as possible. If you have any questions, please feel free to either call me at (202) 233-9093 or send me a fax at (202)233-9595. Your cooperation in this regard will be appreciated.

Please mail your comments to:

Ravi K. Srivastava
U.S. Environmental Protection Agency
Acid Rain Division
Mail Code 6204J
401 M Street, SW
Washington, D.C. 20460

Sincerely,

Ravi K. Srivastava

Discussion Of Factors Relevant To Section 407 NOx Emissions Standards For Group 2 Utility Boilers

Prepared for the UARG Control Technologies Committee

by

J. E. Cichanowicz

May 1995

Discussion Of Factors Relevant To Section 407 NOx Emissions Standards For Group 2 Utility Boilers

TABLE OF CONTENTS

Executive Summary

This document summarizes background material relevant to NOx rulemaking for Group 2 boilers, as required under Section 407 of the 1990 Clean Air Act Amendments. At present, there are a total of 235 operating utility boilers over 25 MW generating capacity that can be characterized as Group 2 units. Results from the UARG-maintained database describing Group 2 boilers suggest that cyclone, 2-burner cell-fired, and slag tap (wet-bottom) wall-fired boilers comprise approximately 90% of the Group 2 boiler capacity. In contrast, the cumulative generating capacity from 3-burner cell-fired, slag tap (wet-bottom) turbo-fired, roof-fired, arch-fired, stoker-fired, and fluidized bed units comprise approximately 10% of the Group 2 boiler capacity.

A total of 15 demonstrations or early applications of various NOx control technologies on Group 2 boilers have either been completed, are presently being conducted, or are planned. These demonstrations provide results describing NOx removal and boiler impacts, and can be used to derive the levelized cost per ton of NOx removed. For any particular boiler category, NOx control cost is highly dependent on site specific variables and assumptions; accordingly costs reported in this document are conducted for identical assumptions. As a consequence, NOx control cost per ton as calculated for the demonstration sites in this report may be different from the cost as calculated by other organizations, including the host utility. However, the general range of cost is similar, and representative of technology application to the boiler category on a national basis.

The results and range of estimated cost for selected Group 2 boiler demonstrations are summarized as follows:

<u>2-Burner Cell-fired Boilers.</u> Demonstration tests or commercial applications are in progress or complete at the following stations: Dayton Power & Light/Stuart, Allegheny Power/Hatfield, Detroit Edison/Monroe, and American Electric Power/Muskingum River. NOx reductions achieved with combustion controls range from 44-50%, and provide NOx control for approximately $125-275/ton. Significantly, these demonstrations are being conducted at generating capacities of approximately 600 MW, a scale that reflects challenges anticipated for commercial deployment. Accordingly, the

demonstrations and early applications serve to minimize (but not completely eliminate) additional risk for broad application.

Cyclone Boilers. Reburn (gas and coal) and selective non-catalytic reduction (SNCR) have each been demonstrated on this Group 2 category at approximately 100 MW. These demonstration results have shown 40 and 50% NOx reduction is possible with gas and coal reburn (at the Ohio Edison Niles and Wisconsin Power & Light Nelson Dewey Station, respectively). NOx reduction is compromised at low load, and in fact significant operation at low load can limit long-term NOx reduction to as low as 10%. Results with SNCR from the Atlantic Electric B.L. Englund Station suggest 35% NOx reduction is achievable.

For the specific conditions defined by these demonstrations, NOx control costs of $1075-1300/ton were derived for reburn, and $900-1350/ton for SNCR. These demonstrations were conducted at a scale (~100 MW) that is not representative of the cyclone boiler inventory, thus considerable risk is anticipated in scale-up to other commercial units.

Slag Tap (Wet-bottom) Wall-fired Boilers. SNCR and SCR have been demonstrated at the Public Service Electric & Gas Mercer Station; and an advanced 2-stage OFA technology is planned for demonstration at the Ohio Valley Electric Corporation Kyger Creek Station. Mercer results (equivalent to 160 MW) show SNCR delivers 35% NOx reduction, at a cost of $886/ton. For SCR, greater than 80% NOx reduction was achieved at an estimated cost of $1400-1700/ton, depending on reagent consumption and catalyst life. Results are not yet available for the Kyger Creek 2-stage OFA demonstration.

The results of these 15 demonstrations, early applications, and commercial-hardware test programs suggest 2-burner cell-fired boilers will receive the most pressure to provide significant (e.g. 50%) NOx reduction, due to modest cost and availability of control technology. Cyclone boilers could also receive pressure for NOx reductions of 40-50%, even though the control cost per ton exceeds the control cost for Group 1 boilers. Slag tap (wet-bottom) boilers may also receive pressure for NOx reductions of 35%, equivalent to that provided by the Mercer SNCR process and the combustion modifications planned for Kyger Creek.

TECHNICAL FEASIBILITY AND COST EVALUATION OF NOx CONTROL TECHNOLOGIES FOR GROUP 2 BOILERS

Section 1

INTRODUCTION

This document presents background information regarding NOx control technologies as required by Section 407 of the 1990 Clean Air Act Amendments (CAAA), for Group 2 coal-fired boilers. This paper will not address in detail the candidate control technologies, which have been deliberated at length in numerous position papers prepared by both UARG and regulatory agencies (EPA, 1994; STAPPA/ALAPCo, 1994; UARG, 1993a; UARG 1993b). Rather, the key NOx control technology demonstration tests conducted on Group 2 boilers will be discussed, focusing on the results describing control capabilities and cost.

Group 2 boilers are comprised of a wide variety of steam boiler designs that (with the exception of fluidized bed units) are no longer constructed for utility application, having yielded to the more popular and commercially proven pulverized coal-fired wall and tangential designs[1]. There are approximately 235 coal-fired Group 2 boilers that exceed 25 MW capacity. Including fluidized bed units, a total of nine boiler categories can be distinguished based upon design features.[2]

This position paper focuses on the Group 2 boiler categories that are most significant in terms of generating capacity, suggests consolidating categories where appropriate, and identifies those categories of minimal importance due to limited capacity factor and remaining boiler lifetime. Most Group 2 boiler designs were predicated on concepts that at the time (1950-60s) were chosen to maximize boiler thermal efficiency while minimizing size and cost. These designs were developed and promoted by the boiler vendors, and were

---

[1] Section 407 defines the Group 2 boilers as ...."*(A) wet bottom wall-fired boilers, (B) cyclones, (C) units applying cell burner technology, and (D) all other types of utility boilers*". Regarding category A, to avoid confusion between true wet-bottom boilers and boilers that employ wet bottom ash sluicing, this discussion will refer to category A as slag tap (wet-bottom) boilers, employing either wall- or turbo-firing. Category D is broadly interpreted to include roof-fired, arch-fired, stoker-fired, and fluidized bed boilers.

[2] In the most broad definition, Group 2 units can include cyclone, 2-burner cell and 3-burner cell-fired, slag tap (wet-bottom) wall-fired, slag tap (wet-bottom) turbo-fired, roof-fired, arch-fired, stoker-fired, and fluidized bed boilers.

popular with the utility industry because they were successful in providing low cost and reliable power. However, the same design features that promoted high efficiency and low capital cost have hindered the development of commercial acceptable and inexpensive combustion NOx control concepts.

This document describes the Group 2 boiler inventory (Section 2), summarizes results from Group 2 NOx control technology demonstration tests (Section 3), presents a cost analysis of NOx control technology based on these demonstration results (Section 4), reviews remaining technical risks for deployment of these technologies (Section 5), and summarizes control cost and key issues relevant to Section 407 rulemaking (Section 6).

Section 2

GROUP 2 BOILER INVENTORY

Table 1 summarizes UARG's provisional estimate of the Group 2 boiler inventory according to design type, describing both the number of units and total generating capacity (UARG, 1995c). Figures 1-4 present further information describing the boiler inventory for each major category, presenting the cumulative number of units as a function of generating capacity.

The major categories of Group 2 boilers are described in the following section.

2.1. Cyclone Boilers

As shown in Table 1, a total of 87 cyclone boilers comprise 24,476 MW of generating capacity, and represent one of the two largest categories of Group 2 boilers. Generally designed and constructed between 1950 and 1965 by Babcock & Wilcox, these units employ a unique high temperature "cyclone" section that transforms coal ash to slag, subsequently accumulating at the furnace bottom for removal via a slag tap. The cyclone transforms approximately 70-80% of all coal ash to slag, with only 20-30% of coal ash entrained as fly ash. The lower fly ash content of flue gas and reduced erosion allow a compact furnace and convective section, as intertube spacing can be decreased.

Cyclone boilers have not been amenable to the types of combustion modifications applied to Group 1 boilers. This is principally due to the requirement that the cyclone section maintain a minimum heat release rate (e.g. heat release per unit volume, Btu/ft^3) and temperature to insure slag is maintained at the proper temperature for removal. Also, cyclone boilers employ crushed and not pulverized coal, which is introduced into the furnace in a manner that may not be amenable to conventional techniques for delayed mixing with combustion air.

A small fraction of cyclone boilers is designed to inject ash collected by the particulate control device into the furnace. This feature improves fuel carbon utilization, increasing boiler thermal efficiency. Cyclone boilers that reinject ash do not exhibit significantly different operating characteristics; however the additional ash residence time in the furnace could affect the tolerable level of flue gas residual NH_3 content for control technologies employing ammonia as reagent.

TABLE 1

GROUP 2 BOILER POPULATION: NUMBER OF UNITS AND TOTAL GENERATING CAPACITY

Unit Type	Number of Units	Total MW(e)
Cyclone	87	24476
Cell (2-burner)	31	23342
Slag Tap (Wet Bottom) Wall	23	4712
Roof/Vertical	43	4191
Slag Tap (Wet Bottom) Turbo	5	1990
Stoker	23	1160
Cell (3-burner)	3	859
Arch	9	627

Figure 1 presents the cumulative number of cyclone boilers as a function of generating capacity. Significantly, the population of cyclone boilers is biased to relatively small units, as approximately half of the cyclone boilers are less than 200 MW in capacity, and less than 10 exceed 600 MW.

Based on boiler inventory data (UARG, 1995c) and accounting for recent capacity factors as reported to the Federal Energy Regulatory Commission (FERC), cyclone boilers as a class are estimated to produce 828 tons of NOx annually, or approximately 39% of the NOx from Group 2 boilers (UARG, 1995d)

2.2. Cell-fired Boilers

The second largest category of Group 2 units are referred to as cell-fired boilers, as they employ multiple burners arranged in compact and discrete "cells". These units, designed and constructed by Babcock & Wilcox, employ furnaces that feature either a 2-burner or 3-burner array within one cell.[3] The 2-burner array dominates the cell-fired boiler inventory, and thus is the focus of this section.

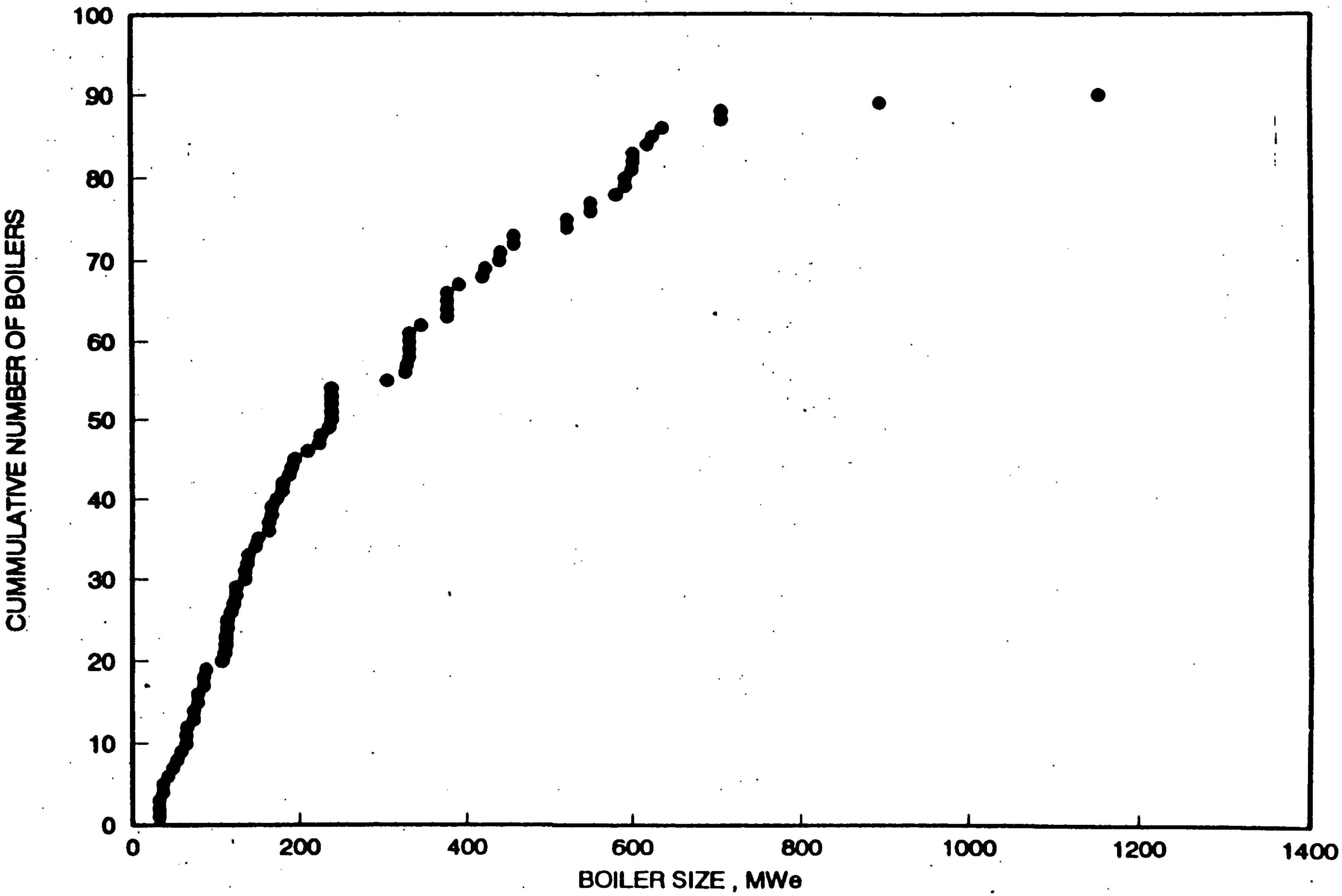
As shown in Table 1, a total of 31 cell-fired boilers employing the 2-burner array comprise 23,342 MW of generating capacity. The close proximity of burners and compact geometry establishes an intense mixing process and high heat release rate per unit volume of furnace, which promotes NOx production. Unlike cyclone boilers, cell-fired units employ pulverized fuel, and approximately 80% of coal ash is entrained in flue gas as fly ash.

Historically, conventional low NOx burners (LNBs) have been difficult to apply to these units, as the delayed fuel and air mixing patterns characteristic of LNBs create relatively long flames. These extended flames can impinge on furnace walls and promote erosion and corrosion, subsequently compromising furnace reliability, and increasing maintenance costs. Regardless of these obstacles, LNB concepts developed by Babcock & Wilcox and Riley Stoker have been recently applied to cell-fired boilers[4]. In addition,

[3] Part 76 of Section 407 defines a cell-fired boiler as a wall-fired boiler that utilizes two or three circular burners combined into a single vertically oriented assembly that results in a compact, intense flame. Any low NOx retrofit of a cell-fired boiler that reuses the existing configuration of a cell burner, with a close-coupled wall opening would not change the designation of the unit as a cell burner boiler.

[4] Although both Babcock & Wilcox and Riley Stoker provide conventional LNB for retrofit to cell-fired boilers, there is a significant difference is implementation that influences feasibility and cost. Retrofit of the B&W LNB to Ohio Edison's Sammis Station required considerable furnace modifications, that were conducted as part of a major unit upgrade. In contrast, the Riley Stoker LNB was retrofit to the AEP Muskingum River Station as a "plug-in" installation, and did not require significant furnace modification. The optimal choice for any given site

FIGURE 1
CYCLONE BOILER POPULATION:
CUMULATIVE NUMBER OF BOILERS VERSUS BOILER SIZE



one original boiler manufacturer (Babcock & Wilcox) has developed a Low NOx Cell Burner (LNCB) specifically for these units.

Figure 2 presents the cumulative number of 2-burner cell-fired boilers as a function of generating capacity. In contrast to the distribution for cyclone units, the population of cell-fired boilers is biased to relatively large units; no cell-fired units exist below 300 MW, and less than ten are below 600 MW. For these boilers, the significant majority of generating capacity is provided by units greater than 600 MW.

Based on boiler inventory data (UARG, 1995c) and accounting for recent capacity factors as reported to FERC, 2-burner cell-boilers as a category are estimated to produce 880 tons of NOx annually, or approximately 42% of the NOx from Group 2 boilers (UARG, 1995d)

Regarding the 3-burner array (not reflected in Figure 2), there are 4 units totaling 1109 MW capacity (2 at 250 MW, 1 at 220 MW, and 1 at 359 MW). No control technologies are commercially available for this design.

2.3. Slag Tap (Wet Bottom) Wall-fired

Slag tap (wet bottom) wall-fired boilers are similar to cyclone boilers in that a high heat release rate furnace generates slag from coal ash, which collects at the furnace bottom, and is ultimately removed through a slag tap[5]. These units were designed and constructed generally from 1950-1960, almost exclusively by Babcock & Wilcox and the Foster Wheeler Corporation[6]. As shown in Table 1, a total of 23 slag tap (wet bottom) wall-fired boilers provide 4,712 MW of generating capacity, comprising the third largest category of Group 2 boilers. Similar to cyclone boilers, approximately 80% of the coal ash is directed to slag, and the remaining 20% entrained in flue gas as fly ash.

No LNB concepts have yet been applied to slag tap (wet bottom) wall-fired boilers, due to restrictions similar to those encountered cell-fired boilers: the compact furnace designs are not compatible with longer, delayed mixing flames. In addition, LNB process conditions could interfere with the production and removal of slag, possibly increasing flue gas ash loading to the convective section thus inducing erosion. One utility (American Electric Power) is investigating the potential to apply overfire air to one particular

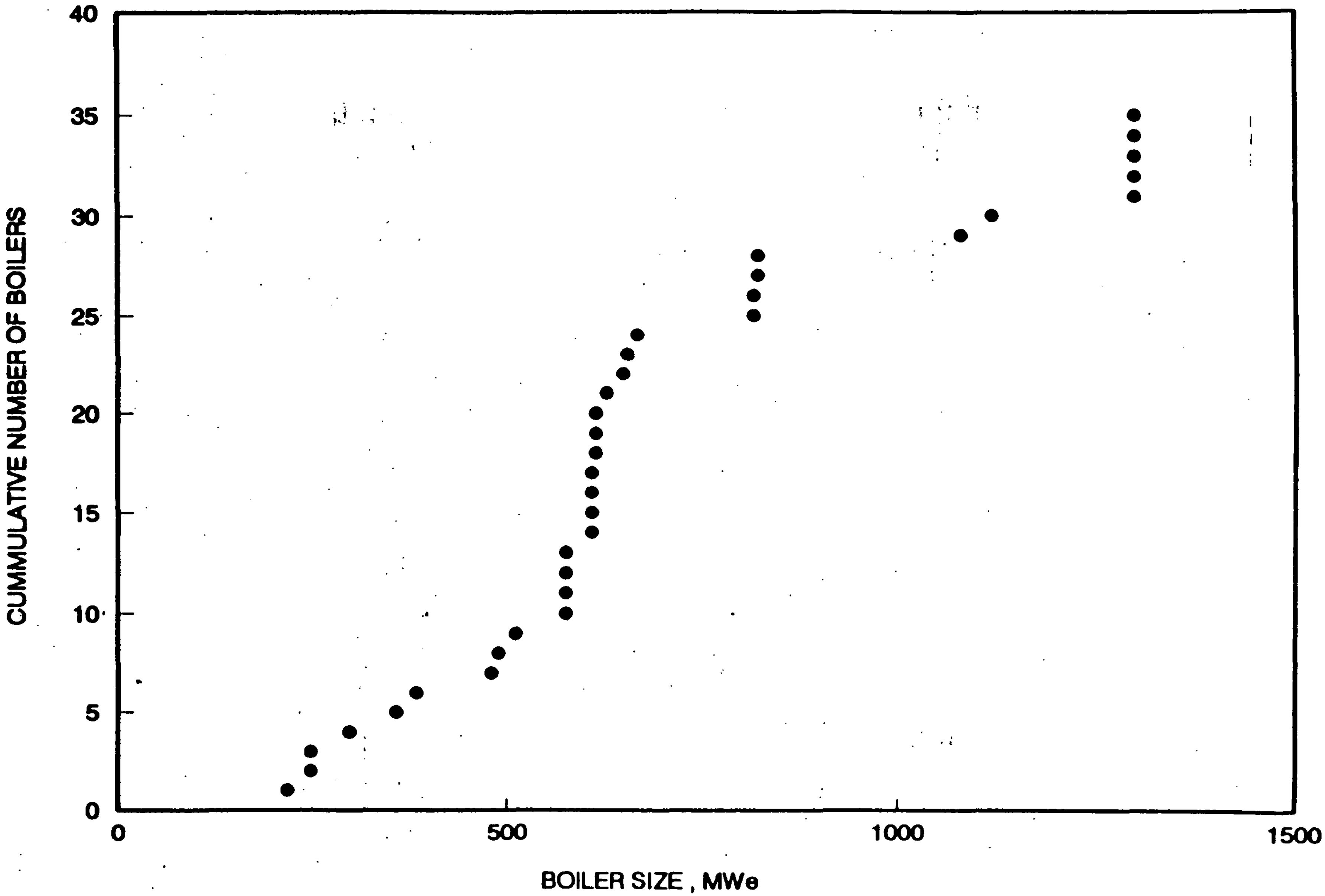
---

requires a detailed engineering assessment, including the value of furnace modifications that may improve thermal performance.

5 Wet-bottom means the boiler has a furnace bottom temperature above the ash melting point and the bottom ash is removed as a liquid.

6 Several tangential-fired units of this design were designed and constructed by Combustion Engineering (presently ABB) in the mid-50's; all but one have since been converted to natural gas firing. These units are not reflected in the boiler inventory.

FIGURE 2
TWO CELL BURNER BOILER POPULATION:
CUMULATIVE NUMBER OF BOILERS VERSUS BOILER SIZE



slag tap (wet bottom) boiler design in an exploratory effort to determine NOx control capability.

Figure 3 presents the cumulative number of slag tap (wet bottom) wall-fired boilers as a function of generating capacity. Most notable are the 13 units of identical capacity (and similar design) at nominally 220 MW capacity. The majority of generating capacity is for units of 220 MW capacity and greater.

An updated version of this boiler is the Riley Turbo-Furnace, provided by Riley Stoker from the early 1960s to the mid 1970s, and referred to here as the slag tap (wet-bottom) turbo-fired boiler (capacity not reflected in Figure 3). Only five of these units exist, but comprise 1,990 MW capacity, equal to almost 50% of the conventional slag tap (wet bottom) wall-fired boiler capacity. These units similarly employ a high heat release environment that does not allow extensive delayed fuel and air mixing without detrimental consequences.

Based on boiler inventory data (UARG, 1995c) and accounting for recent capacity factors as reported to FERC, both slag tap (wet bottom) wall-fired and turbo-fired boilers are estimated to produce 291 tons of NOx annually, or approximately 14% of the NOx from Group 2 boilers (UARG, 1995d).

2.4. Roof-fired

As shown in Table 1, a total of 43 roof-fired boilers comprise 4191 MW of generating capacity, and represent the fourth largest category of Group 2 boilers. Roof-fired boilers (predominantly provided by Babcock & Wilcox) employ vertical coal nozzles located in the boiler "roof", injecting pulverized coal with combustion air. There are a wide variety of roof-fired boiler design concepts, and depending on the specifics of fuel and air admission, the flame can be either J- or U- shaped, or entirely vertical. Design information on these units suggests the furnace residence time is inadequate to accommodate significant staging or delay of fuel and air. As a result, combustion modifications have been applied with varying degrees of success in altering the mixing patterns to lower NOx emissions.

Conventional LNB in conjunction with overfire air has been retrofit into one roof-fired boiler as part of a Dept. of Energy Clean Coal Technology demonstration (Hunt, 1994). As described in Section 3, this project also includes an evaluation of SNCR postcombustion control. The significant cost for major modifications to boiler pressure parts may limit the application of this specific LNB/OFA concept demonstrated to a broad roof-fired boiler segment.

FIGURE 3
WET-BOTTOM WALL-FIRED BOILER POPULATION:
CUMULATIVE NUMBER OF BOILERS VERSUS BOILER SIZE

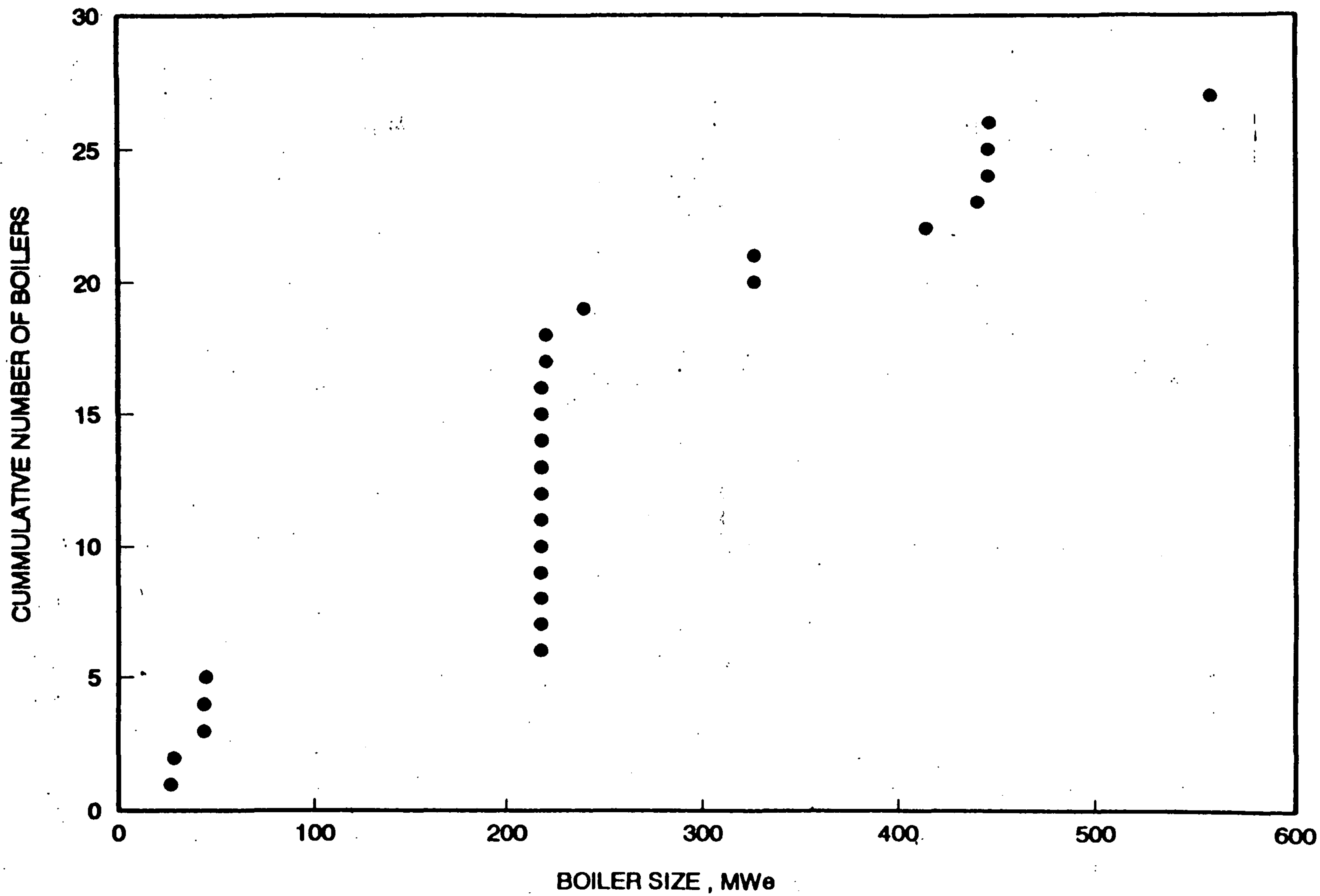


Figure 4 presents the cumulative number of roof- and vertical- fired boilers as a function of generating capacity. Most notable are that all but six of the units are below 200 MW capacity.

In addition to the roof-fired concept, an additional 6 units totaling 627 MW of capacity employ a related design referred to as arch-fired (not reflected in Figure 4). This concept similarly employs vertically-oriented burners, but admits combustion air through the adjacent wall. A selected number of these units were characterized in an EPRI test program (EPRI, 1983) to produce low NOx emissions (~0.2-0.3 lbs/MBtu). However not all arch-fired boilers employ the same design as those tested in this program and may exhibit different emission characteristics.

Based on boiler inventory data (UARG, 1995c) and accounting for recent capacity factors as reported to FERC, roof-fired boilers as a class are estimated to produce 122 tons of NOx annually, or approximately 6% of the NOx from Group 2 boilers (UARG, 1995d).

2.5. Stoker-fired

Stoker boilers are generally moving chain grate units that fire crushed coal or other solid fuels, which require significant residence time for acceptable fuel utilization. Many utilities employ stokers to fire alternate fuels as a supplement to coal (e.g. peat, shredded tires, etc.), and accordingly operate these units at a low capacity factor. Table 1 shows that 23 stoker boilers comprise a total of 1160 MW of capacity.

NOx control measures with stoker-fired boilers are confined to overfire air and flue gas recirculation; these techniques have been deployed with modest success.

Figure 5 shows all stoker boilers are less than 80 MW in generating capacity, with half the units less than 50 MW.

Based on boiler inventory data (UARG, 1995c) and accounting for recent capacity factors as reported to FERC, stoker-fired boilers as a class are estimated to produce 23 tons of NOx annually, or approximately 1% of the NOx from Group 2 boilers (UARG, 1995d).

2.6. Fluidized Bed

Fluidized bed boilers represent a design concept that within the last ten years have been significantly deployed for utility scale generation. Two different types of fluidized bed units can be applied to utility power generation: atmospheric and pressurized. These units feature extended fuel and combustion gas residence time, which promote the ability to fire low rank,

FIGURE 4
ROOF- AND VERTICAL-FIRED BOILER POPULATION:
CUMULATIVE NUMBER OF BOILERS VERSUS BOILER SIZE

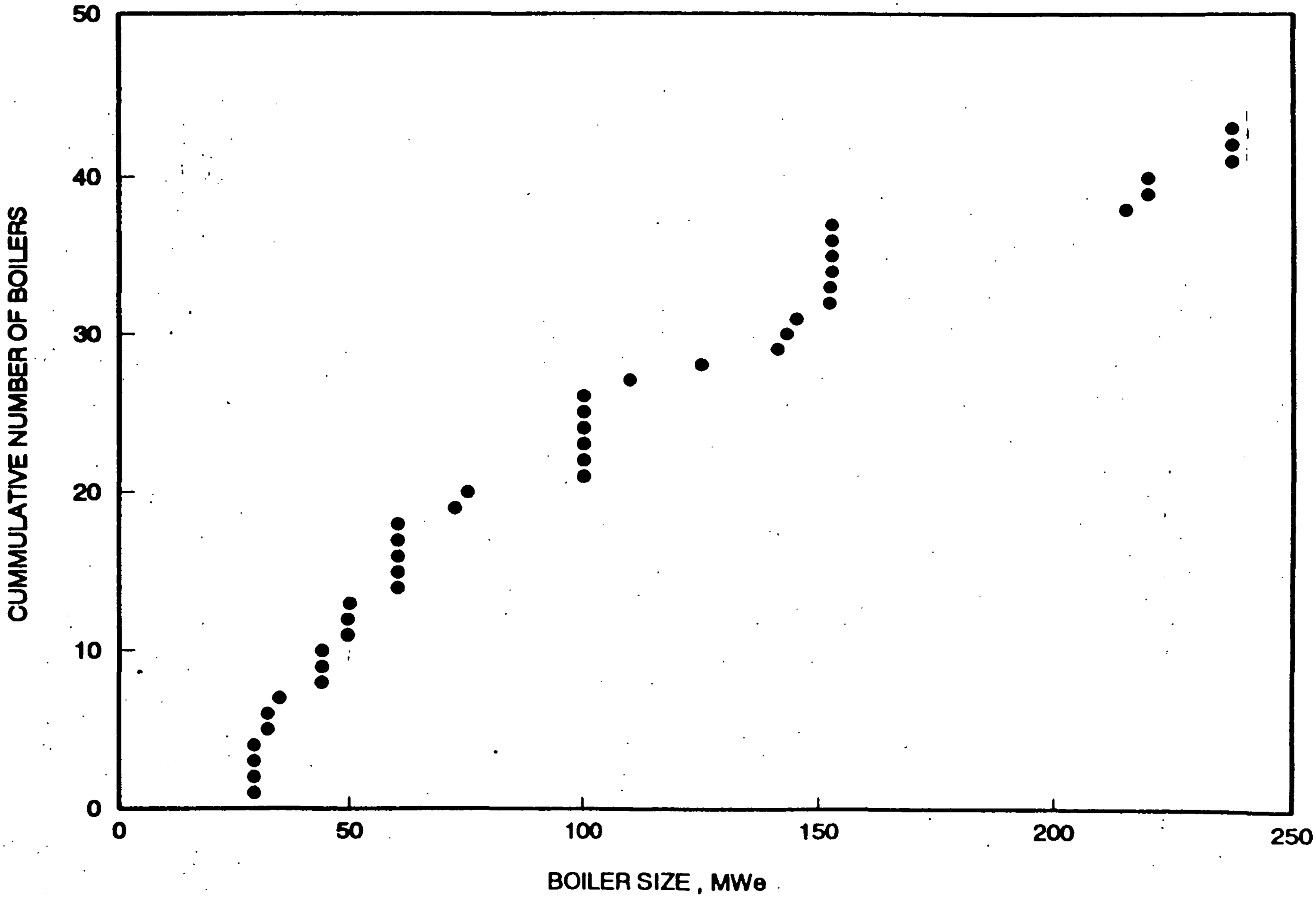
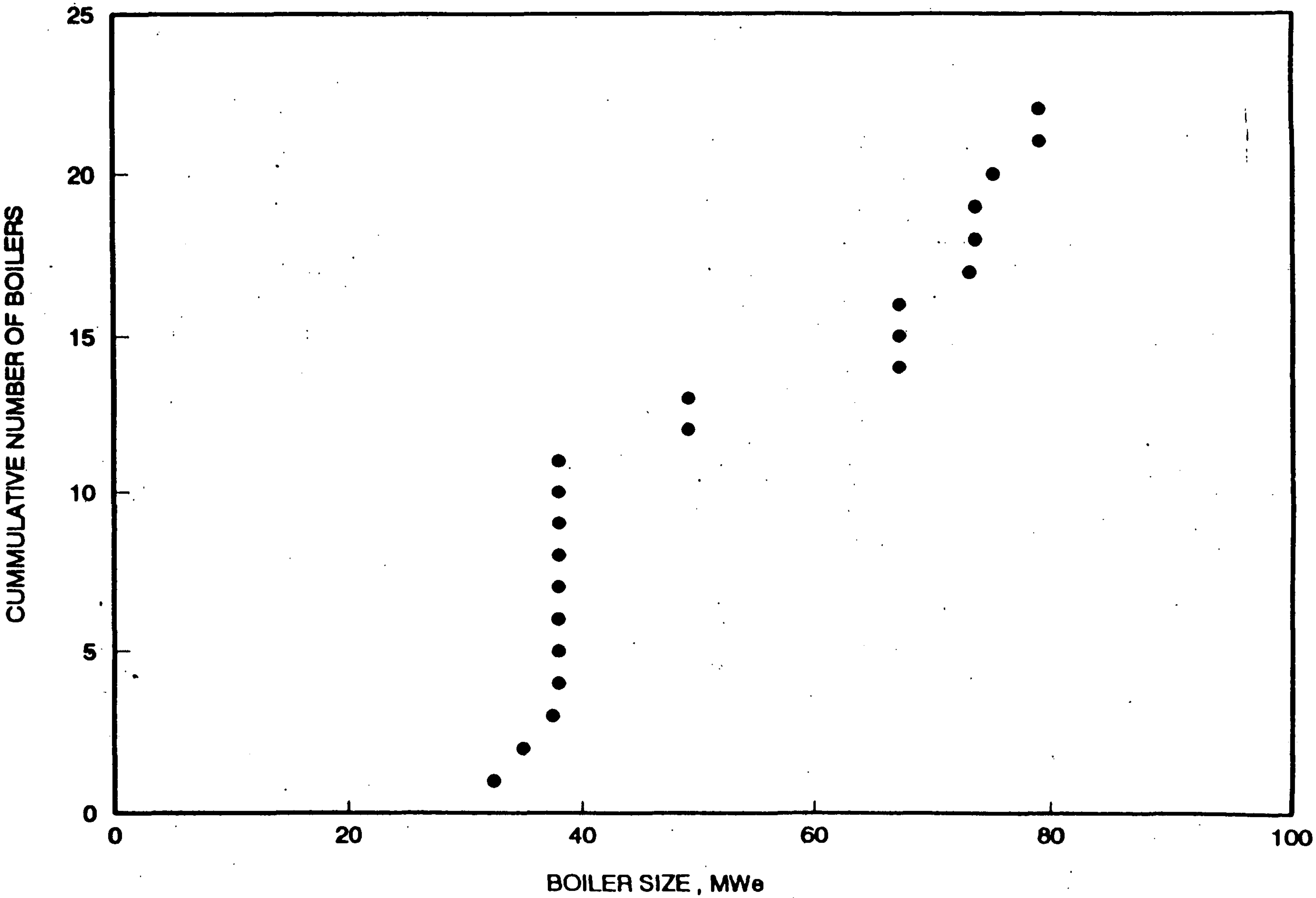


FIGURE 5
STOKER-FIRED BOILER POPULATION:
CUMULATIVE NUMBER OF BOILERS VERSUS BOILER SIZE



low volatility coals, or other types of solid fuels. The relatively low heat release rates and combustion temperatures, and the ability to maintain precise control over excess air level minimizes NOx production from these units to nominally 0.2-0.3 lbs/MBtu. The only supplemental NOx control technology that has been applied to fluidized bed boilers is SNCR.

Over 180 fluidized bed boilers representing a wide range in generating capacity are operating in North America, producing the steam equivalent of approximately 5,000 MW of electrical generating capacity. However, many are below the equivalent of 25 MW of electrical generating capacity, and due to inherent low NOx emissions produced, are insignificant in the national NOx inventory.

Section 3

DISCUSSION OF GROUP 2 DEMONSTRATION TESTS

NOx control technologies have been evaluated for Group 2 boiler applications in recent years through a series of demonstrations funded by the U.S. Dept. of Energy Clean Coal Technology Program, the U.S. Environmental Protection Agency, EPRI, and individual utilities. The principle objective of these demonstrations has been to gain experience with Group 2 boiler NOx control technologies, and develop strategies that may be broadly applicable on a national basis, or within a given utility operating system.

Tables 2A-2D summarize the significant demonstrations conducted to date, in progress, or planned in the near future. This table summarizes the short-term and (where available) long-term NOx removal, impacts on the boiler and/or plant, and key comments regarding test results or technology feasibility. The discussions presented in Table 2 are organized according to boiler type: cyclone, 2-burner cell-fired, slag tap (wet bottom) wall-fired, and roof-fired boilers. There are no other demonstrations of NOx control technologies for Group 2 boilers presently known at this time that are judged relevant to this rulemaking process. Highlights of the demonstration results are described in the following section.

3.1. Cyclone Boilers

A total of six demonstrations are either completed, in progress, or planned for NOx control technology on cyclone boilers. These demonstrations address coal and natural gas reburn, SNCR, and SCR.

<u>Reburn.</u> Three demonstrations have been conducted or are in progress for reburn technology: Wisconsin Power & Light/Nelson Dewey (coal reburn), Ohio Edison/Niles (gas reburn), and City Water Light & Power/Lakeside (gas reburn). The Nelson Dewey and Niles demonstrations, conducted at nominally 100 MW, represent the largest scale evaluations of reburn technology on cyclone boilers. The City Water Light & Power/Lakeside demonstration (33 MW) is in an early stage of operation, and only preliminary, short-term results are presently available.

Although representing a major technical contribution, the results from the Nelson Dewey and Niles demonstrations require significant extrapolation to

TABLE 2A
GROUP 2 BOILERS: DEMONSTRATIONS AND FIELD TEST SUMMARY
CYCLONE-FIRED

Host Utility/ Station	Technology	NOx Removal	Impacts	Comment
a. Wisconsin Power & Light/ Nelson Dewey (100 MW)	coal reburn	Long Term: 55-60%, at full load; 33-50% at loads down to 35% of MCR.	Minor increases in fly ash LOI inducing thermal efficiency decreases of 0.10-1.5%. Other impacts (slagging, fouling, furnace corrosion, ash collection) judged not significant. 5 yr material assessment not complete.	Full load NOx reduction (55-60%) may not be achieved at low loads, due to reburn system restriction by minimum heat flux required at the cyclone section. Also, effective reburn fuel dispersion in flue gas will be increasingly difficult at higher generating capacities than the relatively small 110 MW demo unit, limiting NOx reduction.
b. Ohio Edison/ Niles (115 MW)	gas reburn	Long-Term: 40% over a 1107 h period, at >75% full load. Reburn could not be employed at <80 MW. Full load reduction: 47%	Increase in slagging possible; reburn fuel I&C system necessary for reburn fuel management, safety. Materials assessment not completed. 0.20% thermal eff. penalty	Full load NOx reductions may overpredict commercially achievable level of control, depending on load profile. At Niles, gas reburn could not be deployed below approximately 70% full load; actual long-term NOx reduction given this constraint and historical load factors is ~10%.
c. City Water, Light & Power, Lakeside Station (33 MW)	gas reburn	Short-term: 52-77% @ >70% load, and 23% gas reburn.	<500 hrs testing, long-term observations not yet complete	Scale-up of results complicated by small capacity (33 MW) unit, which offers favorable reburn fuel mixing conditions. Relation between operating load and NOx removal will provide further insight as to commercial operation (e.g. Niles, Nelson Dewey performance).

TABLE 2A
GROUP 2 BOILERS: DEMONSTRATIONS AND FIELD TEST SUMMARY
CYCLONE-FIRED (CONT'D)

Host Utility/ Station	Technology	NOx Removal	Impacts	Comment
d. Atlantic Electric/ Englund (w/ash recycle, 138 MW, 2.6% S coal)	SNCR (urea)	Short-term: 35% reduction (from 0.9-1.23 lbs/MBtu) @<5 ppm residual NH3; 40% reduction @<10 ppm residual NH3.	Residual NH3: 10 ppm selected as maximum tolerable level. N2O Production: 3-7% of NOx reduction.	This demo produced short-term results, over a load range of 70-103% maximum capacity. Residual NH3 of 10 ppm did not promote air heater deposits over a 4 week period. Reinjection of collected fly ash appears to reduce NH3 contamination issue. Scale-up for effective reagent dispersion still presents significant engineering challenge.
e. Public Service New Hampshire/ Merrimack Unit 1 (120 MW)	SNCR (urea)	planning/design stage only; target 30%	not available	This SNCR application will be the first commercial deployment of high momentum injection lances on a coal-fired boiler.
f. Public Service New Hampshire/ Merrimack Unit 2 (w/ash recycle, 320 MW)	SCR	planning/design stage only; target 65%	not available	This demo will be operational by mid-1995 at the target 65% NOx reduction; additional catalyst can be added to the reactor in future years to increase NOx removal to ~90%.

TABLE 2B
GROUP 2 BOILERS: DEMONSTRATIONS AND FIELD TEST SUMMARY
CELL-FIRED

Host Utility/ Station	Technology	NOx Removal	Impacts	Comment
g. Dayton Power & Light/Stuart Station (605 MW)	B&W low NOx cell burner (LNCB)	Long-term: ~50% reduction from approximately 1.1 lbs/MBtu	Modest increase in fly ash LOI, most significant at 50% load. Small (0.20-0.60%) effect on boiler efficiency	50% reduction achieved in long-term operation at full load; thermal efficiency reduction due to higher LOI more than offset by separate program to improve fuel/air distribution.
h. Allegheny Power/Hatfield Unit 3 (575 MW)	B&W LNCB	Short-term: 50% from approximately 1.1 lbs/MBtu	LOI increase by 1%	not available at present
i. Detroit Edison/Monroe Station (750 MW)	B&W LNCB	Short-term: 44% from approximately 0.93 lbs/MBtu	unit operating since 11/94; impacts being defined in present test program	Monroe features a special LNCB pattern to accommodate a furnace division wall, as well as provisions to allow a range of fuel properties
j. AEP/ Muskingum River, Unit 5 (600 MW)	conventional Riley LNB	Short-term: early results suggest ~50% from 1.2 lbs/MBtu; coal type (S, Btu/lb) affects NOx control	unit operating since 5/94; impacts being defined in present test program	Muskingum River units are a "hybrid" in that a top row of conventional register burners exist in addition to cell-burners.

TABLE 2C
GROUP 2 BOILERS: DEMONSTRATIONS AND FIELD TEST SUMMARY
SLAG TAP (WET-BOTTOM) WALL-FIRED

Host Utility/ Station	Technology	NOx Removal	Impacts	Comment
k. Ohio Valley Electric/Kyger Creek (210 MW)	2-stage OFA	planning stage; no results available	n/a	Unit anticipated operational by 4Q/1995.
l. PSE&G/Mercer (325 MW, SNCR on 160 MW equivalent section)	SNCR (urea)	Short-term: 35-38% NOx removal (from 1.8 lbs/MBtu) with 5-8 ppm residual NH3	Increase in air heater Δp incurred with excursions in residual NH3 significantly above 10 ppm.	Short-term test over 2 month period on coal demonstrated 35% at maximum capacity. In general, lower load and/or switching to natural gas restricted NOx reduction to 20-30% for most cases. Commercial design selected on the basis of this demo; maximum residual NH3 slip of 5 ppm defined to protect ash resale contracts.
m. PSE&G/ Mercer (325 MW)	SCR, possibly combined w/SNCR	Short-term: preliminary results suggest >80%, with fresh catalyst	high aux power required for reagent preparation and injection	Five month test program shows approximately 4800 1/h space velocity reactor can successfully operate in horizontal configuration. Long term operation to determine catalyst deactivation essential.

TABLE 2D
GROUP 2 BOILERS: DEMONSTRATIONS AND FIELD TEST SUMMARY
VERTICAL OR ROOF-FIRED

Host Unit/Station	Technology	NOx Removal	Impacts	Comment
n. Public Service Co. of Colorado/ Arapahoe (100 MW)	vertically oriented LNB + OFA, plus SNCR	Long Term: for LNB/OFA, ~65% reduction from 1.15 lbs/MBtu; SNCR provides additional 11-45%	LNB/OFA: no significant CO, LOI change. SNCR: process operated to limit residual NH3 to 10 ppm; N2O production 20-35% of total NOx removed	Unit operational since 8/92; total NOx reduction can exceed 80%, depending on load and operating conditions. Production of N2O (greenhouse gas) in terms of total NOx could be a significant environmental consideration.
o. AEP/Tanners Creek	changes to coal injector and air introduction inducing LNB-type conditions	Long Term: target 40% reduction, from 1.1 lbs/MBtu	no major detrimental impacts anticipated	Unit anticipated to be operational by 6/95; combustion optimization complete by 9/95. Accordingly, levelized cost per ton reported in Table 3 and text is estimated, based on design targets.

be applied to 300-600 MW units[7]. Both demonstration tests exhibited NOx removal of up to nominally 60% for short-term periods, but long-term results over a broad load range suggest considerably lower NOx reduction (10-35%), due to restrictions on reburn stoichiometry at lower loads.

A key factor determining the feasibility of reburning is the availability of residence time in various regions of the furnace to accommodate reburn reactions. As will be discussed in more detail in Section 5, the strict requirement for a minimum residence time within a cyclone furnace from the upper cyclones to the furnace exit may limit the number of boilers that can successfully apply reburn. This limit was recently encountered by a midwestern utility that solicited technical proposals for reburn technology for six cyclone boilers, ranging from 150 to 500 MW. Of these six units, only one was judged by the commercial boiler supplier that offered reburn technology as capable of providing adequate residence time for reburn reactions.

Equally important, the scaling factors to extrapolate this technology from nominally 100 to 300 MW and greater are not fully understood. The key challenge is to mix an extremely small quantity of gas or solid fuel into a much larger volume of hot, reacting combustion products. This mixing must be fully accomplished within finite time periods to extract the maximum benefits in terms of NOx reduction and utilization of primary and reburn fuel. The coal reburn and gas reburn demonstrations have successfully met these mixing and dispersion challenges over physical distances of nominally 20-25 feet; deployment at 300 MW and greater capacity requires meeting these same challenges over distances of 40-50 feet. Accordingly, although in concept reburn can be applied to large capacity units, mixing of the reburn fuel may limit NOx reduction to insignificant levels, limiting commercial feasibility.

Boiler impacts in terms of fuel efficiency and reliability are measurable and must be accounted for in evaluating the cost of reburn technology. Given present information available, these penalties will increase reburn cost, but are not prohibitive. The most significant commercial consequence of reburn technology is the inability to maintain NOx control at lower loads, as diverting fuel from the cyclone section inhibits ash transformation to slag for subsequent removal. The consequence of this limit is a restriction of reburn application at less than 60-70% load.

<u>SNCR.</u> A 3 month test at Atlantic Electric's G.L. Englund Station demonstrated modest (35%) NOx removal with SNCR while maintaining acceptable residual NH_3 (5 ppm) in flue gas. The G.L. Englund boiler is not

---

[7]The City Water Light & Power/Lakeside demonstration, although anticipated to provide additional insight to the engineering design of a gas reburn process, may be of limited value in terms of extrapolation to a commercial design due to the limited generating capacity (33 MW).

typical of most cyclone units for two reasons. First, collected fly ash is recycled and reinjected into the cyclone, and is thus removed from the system only as bottom ash. As a result, conventional limits imposed by absorption of ammonia from the flue gas by fly ash do not apply, potentially allowing this unit to operate at higher normalized stoichiometric ratio than commercially practical, thus overpredicting NOx control. Second, the 100 MW unit capacity does not reflect the reagent mixing challenges posed by higher capacity units. Similar to the case described for reburn, the challenge to mix a small volume of reagent into a much larger volume of hot, reacting combustion products within the necessary residence time may limit NOx reduction, especially for units greater than 100 MW where no commercial experience exists.

Further demonstration of SNCR technology will be conducted at the Public Service of New Hampshire (PSNH) Merrimack Station on Unit 1, with startup scheduled for 1995. This 120 MW unit is designed for 30% NOx reduction and less than 5 ppm NH_3 slip, and will employ high energy reagent injection lances. Results describing control of NOx and residual NH_3 may be available in late 1995 or early 1996, and thus may be relevant to the Group 2 boiler rulemaking.

SCR. Demonstration of SCR on a low sulfur coal-fired cyclone boiler will be conducted at the PSNH Merrimack Station on Unit 2, with startup scheduled for 1995. This 320 MW unit is designed initially for 65% NOx reduction and less than 5 ppm NH_3 slip; the SCR reactor will incorporate additional volume to increase catalyst inventory and meet future NOx reduction requirements. Given the necessity to obtain at least 18 months operation to assess catalyst deactivation, results describing control of NOx and residual NH_3 on a long-term commercial basis will not be available to be relevant to the Group 2 rulemaking[8].

3.2. Cell-fired boilers.

Demonstration or commercial deployment of LNB-type technology has been or is presently being conducted at several utilities. These utilities and stations are Dayton Power & Light/Stuart, Allegheny Power/Hatfield, Detroit Edison/Monroe, and American Electric Power/Muskingum River. These demonstrations or early applications represent different LNB concepts to

[8] Several new plants incorporating SCR have received considerable publicity (Carney's Point and Keystone Generating Stations of U.S. Generating Company, both presently operational) which regulators may propose as adequate to demonstrate commercial use of SCR on Group 2 boilers. New pulverized coal-fired plant process conditions are more amenable to SCR that existing Group 2 boilers, primarily due to boiler NOx production rates and ability of balance-of-plant components to tolerate residual NH3 and byproduct SO3. Thus, although new pulverized coal-fired plant SCR applications are significant technical accomplishments, they bear little relevance to Group 2 rulemaking.

delay fuel/air mixing while retaining acceptable fuel burnout within the compact furnace geometry. Further specifics are described as follows:

B&W Low NOx Cell burner (LNCB). This NOx control technology was developed specifically for application to B&W cell-fired boilers. Long-term NOx removal of 50-60% was documented at Dayton Power & Light, accompanied by a boiler thermal efficiency penalty that was initially significant but reduced to acceptable values (0.20-0.60%) with improved fuel/air distribution. The LNCB technology has also been recently installed at Allegheny Power's Hatfield Ferry Power Station, and results similarly suggest 50% NOx reduction long-term is possible, in exchange for a 1% increase in fly ash carbon content (as LOI). A complete assessment of boiler impacts was completed only for the Dayton Power & Light demonstration, with additional testing and evaluation planned for the Allegheny Power and Detroit Edison applications. The most significant unresolved concern is potential corrosion/erosion of furnace waterwalls, requiring higher furnace O2 and thermal efficiency loss.

Conventional LNB. A conventional Riley LNB was retrofit to the American Electric Power (AEP) Muskingum River Station, which features a furnace design that is a hybrid between a cell-fired and conventional furnace, in that a top row of conventional burners is included. Preliminary results with the design coal suggest 50% NOx reduction is achievable based on short-term measurements, and no detrimental operating impacts have yet been identified. However, no long-term evaluation of NOx removal or impacts has been completed.

After 6 months of successful operation with the design fuel, the fuel source was switched to a low sulfur compliance coal. The increase in both heating value (12,400 vs. 11,500 Btu/lb) and ratio of fixed/volatile carbon (1.61 vs. 1.44) associated with the compliance coal changed the pulverized fuel delivery and possibly combustion conditions in a manner to lower NOx control efficiency from 50 to 40%. The specific cause of the compromise to NOx control has not yet been identified, and is presently being evaluated by the boiler vendor and AEP staff. It is important that low cost and effective remedial actions for the compromise in NOx reduction be identified in order for the demonstration to be judged a success, particularly as this problem was induced by a coal switch for SO2 control.

3.3. Slag Tap (Wet Bottom) Wall-fired

The Ohio Valley Electric Corporation (OVEC) Kyger Creek and Public Service Electric & Gas Corporation (PSE&G) Mercer Station are two host units for NOx technology demonstrations for slag tap (wet bottom) wall-fired boilers. These demonstrations address (a) OFA as a combustion control concept, and (b) SNCR and SCR technology, respectively, as NOx control concepts.

<u>OFA.</u> The Kyger Creek demonstration will evaluate two-stage OFA. At present this demonstration is in final planning and design stages, with results expected by fourth quarter 1995. Due to the highly uncertain nature of results, and significant potential to increase fly ash carbon content and furnace corrosion, no specific NOx control targets have been identified.

<u>SNCR, SCR.</u> In 1993 PSE&G conducted a commercial demonstration of SNCR on a 160 MW section of the 321 MW Mercer Unit 2. These results showed an approximate 35% NOx reduction was achieved with acceptable residual NH_3 (5-7 ppm) over a 3 month demonstration program. Based on these results, PSE&G purchased a commercial SNCR system for both Units 1 and 2 at the Mercer Station, designed to provide 35% NOx reduction.

In addition, PSE&G is conducting a test program to evaluate a horizontally-configured SCR process on 25% of the flue gas from Mercer Unit 2 (e.g. equivalent to 80 MW). This process employs plate-type SCR catalyst in a horizontal reactor configured to fit the site plan, with additional NOx reduction provided by a catalytic air heater. Preliminary information indicates the design targets of >80% NOx removal have been achieved; however data reflects new catalyst performance, and is not representative of long-term operation with a lower activity catalyst (Wallace, 1995). Additional details of the SCR test results will be released in mid 1995, along with results from a special 3 month test campaign to combine SNCR with SCR on this type of boiler.

3.4. Roof-Fired Boilers

Public Service Company of Colorado/Arapahoe and American Electric Power Corporation/Tanners Creek are two host units for NOx technology demonstrations for roof-fired boilers. These demonstrations address LNB/OFA and burner injector nozzle modifications as a combustion control concept.

Public Service Company of Colorado is demonstrating a conventional LNB with OFA retrofit into the boiler roof, supplemented by SNCR. This concept entails significant modifications to the boiler, including major modifications necessary to install a conventional LNB in a vertical orientation from the boiler roof. Based on long-term results, the combination of roof-mounted LNB and SNCR provides approximately 80% NOx reduction, with LNB alone responsible for 66%, and the remaining 14% (equivalent to 40% inlet conditions) removal provided by SNCR.

American Electric Power is conducting a test program to evaluate the effectiveness of modifications to coal injection nozzles to delay mixing and induce LNB-type conditions within a roof-fired design furnace. These modifications are targeted to provide 40% NOx reduction with no increase to fly ash carbon content, cr other detrimental effects on thermal efficiency.

Section 4

COST OF DEMONSTRATED TECHNOLOGIES

This section summarizes the available cost information for the Group 2 boiler demonstrations. The key components of cost incurred by a utility are addressed: capital requirement ($/kW), fixed and variable annual operating cost, and the levelized cost per ton ($/ton) of NOx removal. Where possible, cost information is provided by the host utility or project sponsors. Where it is necessary to derive costs based on design information and reported performance, assumptions are employed based on the technical literature or EPRI-published guidelines.

Table 3A-3D summarize the key technical premises that were used in deriving costs for each of the demonstration projects. The economic premises are adapted from the EPRI Technical Assessment Guide. The latter are:

- levelized capital recovery factor based on a 20 year period, and employing an levelization factor of 0.1732,
- operating cost escalation factor based on a 20 year project lifetime, and employing a levelization factor of 1.312, and
- unit capacity factor of 65%

References employed in preparing Tables 3A-3D are summarized in Appendix A.

It is important to note the levelized NOx removal cost per ton was calculated for each demonstration and control technology based on similar assumptions and premises. This approach allows comparing results between very different technologies on an equivalent basis. The assumptions and premises adapted for this paper may not be the same as employed by other organizations, such as the technology vendor or the host utility. As a result, there will likely be differences in the NOx control cost per ton reported for the same demonstration by other organizations.

4.1. Cyclone Boilers

Coal Reburn (Wisconsin Power & Light/Nelson Dewey). Table 3A reports this coal reburn demonstration required $66/kW capital (Babcock & Wilcox in the final report to the DOE estimate the capital cost for a commercial 600 MW plant at $45/kW). Annual variable operating cost is estimated by assuming a

TABLE 3A
GROUP 2 BOILER DEMONSTRATIONS: COST EVALUATION
CYCLONE-FIRED

Host Utility/ Station	Technology	Long-Term NOx Removal	Capital ($/kW)	Annual Fixed O&M	Reagent/ Process Reqmnt	Fuel Impact	levelized $/ton
a. Wisconsin Power & Light/ Nelson Dewey (100 MW)	coal reburn	50%, from 1.2 lbs/MBtu, over 35-100% of MCR.	66 (Note: B&W estimate 43 for 600 MW)	5% of capital	Δ 0.6% MW aux power for fuel pulv.	0.30% boiler eff. decrease	1072
b. Ohio Edison/ Niles (115 MW)	gas reburn	40%, from 1.2 lbs/MBtu, over 35-100% of MCR.	35	5% of capital	18% gas use; 0.1 % MW aux power	0.20% boiler eff. loss	1283
c. City Water, Light & Power, Lakeside Station (33 MW)	gas reburn	n/a	n/a	n/a	n/a	n/a	n/a

TABLE 3A
GROUP 2 BOILER DEMONSTRATIONS: COST EVALUATION
CYCLONE-FIRED (CONT'D)

Host Utility/ Station	Technology	NOx Removal	Capital ($/kW)	Annual Fixed O&M	Reagent/ Process Reqmnt	Fuel Impact	levelized $/ton
d. Atlantic Electric/ Englund (w/ash recycle, 138 MW, 2.6% S coal)	SNCR	Long-term: 35% reduction (from 0.9-1.23 lbs/MBtu, average of 1.05), based on the average for <5- 10 ppm residual NH3	15	5% of capital	NSR of 1.0 for 40% ΔNOx; 0.10% aux power	0.50% boiler efficiency penalty	1349
e. Public Service New Hampshire/ Merrimack Unit 1 (120 MW)	SNCR	Long Term: 30% planning target from 2.0 lbs/MBtu	25	5% of capital	NSR of 1.0 for 40% ΔNOx; 0.20% MW aux power	0.25% boiler efficiency penalty	1074
f. Public Service New Hampshire/ Merrimack Unit 2 (w/ash recycle, 320 MW)	SCR	Long Term: 65% planning target from 2.66 lbs/MBtu	65	.75% of capital	NH3/NOx ratio of 0.65; 0.10% MW aux power for 4 in w.g	0.50% boiler efficiency penalty	537

TABLE 3C
GROUP 2 BOILER DEMONSTRATIONS: COST EVALUATION
SLAG TAP (WET-BOTTOM) WALL-FIRED

Host Utility/ Station	Technology	NOx Removal	Capital ($/kW)	Annual Fixed O&M	Reagent/ Process Reqmnt	Fuel Impact	levelized $/ton
k. Ohio Valley Electric/Kyger Creek (217 MW)	2-stage OFA	planning info only; estimate 30-50% from 1.6 lbs/MBtu	5	5% of capital	n/a	n/a	n/a
l. PSE&G/ Mercer (325 MW)	SNCR	Long-term: 35-38% NOx removal (from 1.8 lbs/MBtu) with 5-8 ppm residual NH3	12	5% of capital	assume NSR of 1; 0.2% capacity aux power	0.3% thermal eff. penalty	886
m. PSE&G/ Mercer (325 MW)	SCR, possibly combined w/SNCR	Short-term: 85-90% at MCR from 1.8 lbs/MBtu. Long-term results n/a pending catalyst lifetime	93	0.75% of capital	NH3/NO ratio of 0.80; 0.20% capacity aux power	0.3% thermal eff. penalty	1400-1700

TABLE 3D
GROUP 2 BOILER DEMONSTRATIONS: COST EVALUATION
VERTICAL OR ROOF-FIRED

Host Unit/Station	Technology	NOx Removal	Capital ($/kW)	Annual Fixed O&M	Reagent/ Process Reqmnt	Fuel Impact	levelized $/ton
n. Public Service Co. of Colorado/ Arapahoe (100 MW)	vertically oriented LNB + OFA, plus SNCR	Long-term: LNB/OFA: 65% from 1.15 lbs/MBtu SNCR: 40% from 0.4 lbs/MBtu	LNB/ OFA: 67 SNCR: 41	equal to $48, $305/ton for LNB, SNCR	SNCR: NSR of 0.75	LNB/OFA: 0.3% thermal eff. penalty assumed SNCR: 0.54% at full load	PSCCo reports: LNB/OFA: $966; incl. 56 days downtime. SNCR: $2966, incl. 7 days downtime.
o. AEP/Tanners Creek (150 MW)	changes to coal injector and air introduction inducing LNB-type conditions	Short-term: target 40% anticipated from 1.1 lbs/MBtu	13	5% of capital	none anticipated	none anticipated	275 (estimated, actual results by 7/95)

small penalty in fuel utilization, and higher auxiliary power consumption by the pulverizers to process the reburn coal. Annual fixed operating cost is assumed ~~to be~~ 5% of capital requirement. These estimates are based on a 20% heat input from reburn fuel. These assumptions provide a levelized NOx control cost of $1072/ton, based on 50% NOx reduction from 1.2 lbs/MBtu.

Gas Reburn (Ohio Edison/Niles). Table 3A reports this natural gas reburn demonstration required $35/kW capital. An equivalent operating cost for reburn fuel is calculated by assuming a 20% heat input from reburn fuel, and assuming a natural gas price differential with coal of $0.50/MBtu. Annual fixed operating cost is assumed as 5% of capital requirement. These assumptions provide for a levelized NOx control cost of $1283/ton, based on 40% NOx reduction from 1.2 lbs/MBtu.

It is important to recognize that gas reburn cost varies significantly with the premises of the analysis, most notably (a) NOx reduction, (b) differential cost of natural gas and coal, and (c) production of SO_2 allowances. Regarding NOx reduction, proponents of gas reburning have assigned NOx reductions achieved at full load conditions, or for pulverized coal-fired boilers as typical of cyclone-fired units over a commercial load range. Accordingly, NOx reductions as high as 70% have been employed in cost calculations. Regarding the differential fuel price, the ability to purchase natural gas on a short-term basis for approximately the same cost (per MBtu) as coal has encouraged reburn proponents to assume a negligible cost premium for natural gas as a reburn fuel, which lowers calculated gas reburn control cost per ton[9]. Finally, the nominal 20% displacement of coal by natural gas and reduction in SO_2 production provides the basis for crediting gas reburn with the market value of SO_2 allowance credits. Under these and other assumptions that represent best-case conditions, reburning is estimated to cost as low as $350-650/ton (May 1994).

Contrary to these assumptions, the Niles demonstration results have shown the first premise regarding NOx control capability is not technically feasible. Second, the assumption of employing short term contract natural gas prices is not a commercially acceptable manner to purchase an essential fuel, when utilities are obligated by long-term contracts for power supply. Third, although the value of reduced consumption of SO_2 allowances cannot be

[9] The EPA document "Alternative Control Techniques - NOx Emissions From Utility Boilers" reports the cost of gas reburning can triple as the natural gas/coal price differential increases from $0.50 to $2.50 /MBtu. Specifically, the EPA analysis cited an increase in NOx control cost per ton from $543 to $1510/ton for a 300 MW cycling coal-fired cyclone boiler for the stated range of natural gas/coal price differential; this analysis assumed 55% NOx reduction and did not account for inflation and escalation (e.g. analysis in constant dollars). Accounting for a long-term NOx reduction of 40% and for inflation and escalation (e.g. analysis in current dollars), natural gas reburn NOx reduction cost ranges from approximately $1200- 3400/ton, consistent with the analysis conducted for this paper.

discounted, the evolving marketplace for SO_2 allowance transactions and the highly variable disposition of individual utilities towards the sale or preservation of SO_2 allowances limits the credit that can be applied.

SNCR (Atlantic Electric/Englund). Table 3A reports this SNCR demonstration requires $12/kW for capital, excluding one-time costs for the demonstration, such as testing. A fixed operating cost of 5% of capital is assumed. A variable operating cost of approximately $870,000 for reagent consumption is calculated (based on the reported normalized stoichiometric ratio of 1 to achieve 35% NOx reduction), and a nominal auxiliary power penalty assigned. The result of $1349/ton is calculated based on a 35% NOx reduction from 1.15 lbs/MBtu.

Detailed information regarding the SNCR application at Public Service New Hampshire/Merrimack Unit 1 has not been released; only general information reported in recent trade press articles is available. This information reports capital cost is $25/kW, reflecting the more complex equipment necessary for the high momentum injector lances. Using this capital requirement with realistic assumptions for annual fixed operating cost (5% of capital), operating normalized stoichiometric ratio, and boiler thermal efficiency penalties, NOx control cost is estimated as $1074/ton.

SCR. Similar to the Merrimack SNCR application, detailed cost for SCR deployment on Unit 2 is not available. General information reported in recent trade press articles suggests a capital cost of $65/kW; however this capital cost includes the reactor only and an initial catalyst quantity equivalent to 25% of the total inventory. This capital cost estimate does not include potential balance-of-plant modifications, such as additional flue gas handling capability, or improvements to maintain a clean air heater.

Assuming an annual fixed cost of 0.75% of capital requirement, competitive ammonia reagent supply cost ($250/ton), 0.1% of plant output for auxiliary power for additional flue gas resistance and reagent vaporization/preparation, a levelized NOx reduction cost of $537/ton is calculated for 65% NOx reduction. It is important to note this result is significantly influenced by the very high and unrepresentative baseline NOx production rate of 2.66 lbs/MBtu.

4.2. Cell-fired

B&W LNCB (Dayton Power & Light/Stuart). Retrofit of the B&W LNCB is estimated to require $8-12/kW. The Dayton Power & Light demonstration did not identify a significant decrease in fuel utilization efficiency, however a small fuel use penalty of 0.30% is assigned to account for boilers with a more compact furnace arrangement. Accordingly, based upon a 50% NOx reduction from 1.1 lbs/MBtu, capital requirement of $10/kW, annual fixed costs equivalent to 5% of capital requirement, and the 0.3% boiler thermal efficiency penalty, a levelized NOx removal cost of $173/ton is calculated.

B&W LNCB (Allegheny Power/Hatfield). Capital requirement is approximately $11/kW; early results suggest 50% NOx reduction from 1.1 lbs/MBtu are possible. Thermal efficiency impact has not yet been defined, and accordingly a 0.30% penalty is assumed.

Based on this modest boiler thermal efficiency penalty, and an annual fixed operating cost equivalent to 5% of capital requirement, a levelized NOx control cost of $204/ton is estimated.

Detroit Edison/Monroe. Capital requirement of $9.4 M for the demonstration project equates to approximately $12.5/kW. Early results suggest 44% NOx reduction from 0.93 lbs/MBtu is possible. Consistent with a modest increase in ash carbon content from 1.25 to 2.5%, a boiler thermal efficiency penalty of 0.20% is assigned.

Assuming an annual fixed operating cost equal to 5% capital requirement, a levelized NOx control cost of $275/ton is estimated.

Riley LNB Retrofit (American Electric Power/Muskingum River). Capital requirement is approximately $9/kW; early results suggest 50% NOx reduction from 1.2 lbs/MBtu is possible. No boiler thermal efficiency or operating cost penalties have been identified, and are assigned a zero cost.

Assuming an annual fixed operating cost equal to 5% capital requirement, a levelized NOx control cost of $126/ton is estimated.

4.3. Slag Tap (Wet Bottom) Wall-fired

2-stage OFA (Ohio Valley Electric Corporation/Kyger Creek). No cost information is available from this demonstration project, which is presently in planning stage. Capital cost incurred for this demonstration is approximately $1,000,000 equivalent to approximately $5/kW. Significant uncertainty remains regarding other inputs to the cost evaluation, such as long-term NOx reduction, and thermal efficiency impacts. For example, exposing the compact, high temperature furnace zone to substoichiometric conditions may induce waterwall corrosion that would require frequent tube replacement, and thus significant operating and maintenance cost penalties could be incurred. Accordingly, cost estimates will not be offered until further information is available in 4Q/1995.

SNCR (PSE&G/Mercer). The capital requirement for the SNCR process commercially procured for the Mercer Station is $12/kW. Annual reagent cost is estimated as approximately $1.8M to achieve 35% NOx reduction, based on a normalized stoichiometric ratio of 1.0. Including a 0.25% capacity loss for auxiliary power (for reagent injection), thermal efficiency penalties, and a competitive ammonia reagent supply cost of $250/ton, a levelized NOx removal cost of $886/ton is estimated.

SCR (PSE&G/Mercer). The SCR process tested at 80 MW at the PSE&G Mercer Station required $93/kW for capital. Annual fixed operating costs are presumed to be 0.75% of process capital. An annual cost of $2.6 M is estimated for (a) catalyst replacement, (b) ammonia supply, and (c) auxiliary power for flue gas pressure drop and reagent preparation. Based on these inputs, levelized NOx control cost is estimated to be $1400-1700/ton.

4.4. Roof-Fired

Public Service Company of Colorado/Arapahoe. An engineering cost study conducted as part of this Dept. of Energy Clean Coal Technology demonstration estimated capital requirement for the LNB/OFA system. In addition to the cost for process equipment obtained from the supplier, the study included the cost of extensive boiler and balance-of-plant modifications, and replacement power for 56 days of outage. A total capital requirement of $67/kW is projected. An analogous study was prepared for SNCR, including a second category of boiler and balance-of-plant modifications, and reports a capital requirement of $41/kW.

Assuming a 0.3% boiler thermal efficiency penalty for LNB/OFA, and 65% NOx reduction from 1.15 lbs/MBtu, LNB/OFA is estimated to provide NOx reduction for $966/ton. Regarding SNCR, assuming a normalized stoichiometric ratio of 0.75, and a 0.54% boiler thermal efficiency penalty, a levelized NOx removal cost of $2966/ton is estimated, based on 40% NOx reduction from 0.4 lbs/MBtu. If SNCR were deployed at the initial boiler NOx production rate of 1.15 lbs/MBtu, levelized control cost would be reduced to approximately $1200/ton, accounting for additional capital and reagent cost.

American Electric Power/Tanners Creek. Total capital requirement for this demonstration is $2 M, including a $400,000 charge for asbestos remediation that may not be required for application of this concept on similar units.

AEP staff anticipate that no thermal efficiency penalty will be incurred, and that 40% NOx reduction is a reasonable target.

Accordingly, based on solely capital recovery charges, and an annual cost of 5% of capital for fixed O&M, the levelized NOx control cost is estimated to be $275/ton.

Section 5

REMAINING TECHNICAL RISKS

The results of the demonstration projects described in this report will significantly reduce the risk to a utility of deploying NOx control technologies on Group 2 boilers. However, the site-specific nature of utility boilers is responsible for differences in design details that could be significant in terms of NOx control. Several risks will remain, that although not preventing application of a particular control technology, may limit the extent the technology can be applied to the national boiler inventory. These risks are summarized for NOx control technologies addressed in the demonstration in the following.

5.1. Cyclone Boiler Reburn: **Broad Applicability To Utility Boiler Population, Long-term Operability/NOx Removal, Scaling To Large Capacity, Furnace Material Corrosion**

• Broad Applicability To Utility Boiler Population. A key factor determining reburn feasibility is the available flue gas residence time in various regions of the furnace. Three key residence times must be provided in reburn design to provide commercially acceptable NOx removal of 50-60% at full load. Based on the results of the Wisconsin Power & Light Nelson Dewey Demonstration, a conservative estimate of necessary residence times for coal reburn are (a) 0.10 sec between the upper cyclone and reburn fuel injector, (b) 0.8 sec between the injection of reburn fuel and overfire air, and (c) 0.9 sec between overfire air injection and the furnace exit (Babcock & Wilcox, 1994). Accordingly, a total of approximately 1.8 sec of residence time must be available from the upper cyclone to the furnace exit. It should be noted these authors cited the residence time could be as low as 1.2 sec (e.g. comprised of 0.10, 0,50, and 0.60 sec respectively) depending on the assumptions inherent to their calculations, and the extent reburn fuel and overfire air are successfully mixed.

Residence time required for gas reburn, based on demonstrations conducted for both cyclone and conventional pulverized coal boilers, will be lower. The required residence time has been estimated as approximately 1.2 sec, subject to the same uncertainties as described for the coal reburn analysis.

The significance of the residence time requirement is the potential limit to the number of boilers that can apply reburn. As described in Section 2, a boiler vendor commercially providing reburn technology identified only one of six candidate cyclone boilers owned by a midwestern utility as feasible for reburn technology. *Uncertainty: the population of utility cyclone boilers that provide sufficient residence time in the upper furnace section for reburn reactions.*

• Long-Term Operability/NOx Removal. The principle remaining risk is the limit to NOx reduction achievable over a long-term period, encompassing a broad range of boiler loads and process conditions. For cyclone boilers, both the Nelson Dewey and Niles demonstrations showed that a minimum heat flux (e.g. load) must be observed within the cyclone section to maintain proper ash slagging and removal. The minimum heat flux required (and thus the minimum load at which reburn technology can operate) for the family of cyclone boilers over the utility population is unknown. Although possibly representing an extreme case, the Ohio Edison/Niles gas reburn demonstration delivered only a 10% reduction in NOx over the load range. *Uncertainty: lower load at which reburn can be successfully operated without inducing problems in slag production and removal, and long-term NOx reduction achievable.*

• Furnace Material Corrosion. Reburn technology can require the furnace to operate in substoichiometric combustion conditions, which can induce or accelerate the corrosion of furnace waterwalls. Particularly with high sulfur coal, oxygen-deficient conditions can promote formation of corrosive species. Neither the Nelson Dewey nor the Niles demonstrations identified significant corrosion as a result of reburning; however long-term observations are necessary to document this effect. The required measurements were not conducted over a long-term period in the Niles demonstration due to a lack of funding and limited success in commercially providing NOx reduction. The necessary studies are presently in progress for the Nelson Dewey demonstration. *Uncertainty: fixed operating cost for the maintenance and replacement of furnace tubes.*

• Design Scaling To Large Capacity. The ability to disperse reburn fuel, either as a solid (coal) or gaseous (natural gas) media, into high temperature reacting flue gas within the proper temperature and residence time is a significant challenge. Achieving the necessary mixing conditions, although accomplished at the nominal 100 MW generating capacities selected for demonstration, may be difficult to achieve at larger commercial scale. As noted in Section 1, approximately 50% of the cyclone boilers are 200 MW capacity or greater, representing a significant fraction of the national NOx inventory. Specifically, the 100 MW reburn demonstrations conducted on any boiler type (e.g. cyclone or pulverized coal wall, and tangential-fired) feature a maximum distance of approximately 15-20 ft within the convective section across which reburn fuel must be dispersed. In contrast, the distance over which reburn fuel must be dispersed for a 300 MW boiler could be up to 50 ft and more, which considering the restricted access for reburn injectors is a significant challenge. *Uncertainty: Commercially achievable NOx removal due to limits in uniformly dispersing reburn fuel in combustion products in the correct temperature window.*

5.2. SNCR (all Group 2 boilers): **NOx Removal/Residual NH_3 Control For Large Units (>200 MW), Impacts Of High Residual NH_3 On Balance-of-Plant Operations.**

• <u>NOx/Residual NH_3 Control At Large Capacity.</u> As described in Table 3, a potential factor limiting SNCR performance with respect to NOx and residual NH_3 may be the physical distance over which reagent must be mixed. Similar to reburn, SNCR has been demonstrated only at generating capacity considerably lower than anticipated for most commercial applications. Most long-term, coal-fired SNCR demonstrations have been limited to 100 MW, with the maximum equivalent to 160 MW. *Uncertainty: NOx removal and residual NH3 achievable due to limits in mixing SNCR reagent at higher generating capacities.*

• <u>Impact of High Residual NH_3 On Balance-of-Plant.</u> As with all ammonia-based reagent technologies, SNCR represents an exchange between NOx removed and residual NH_3 added to power plant flue gas. For SNCR, this exchange can require accepting relatively high levels of residual NH_3 for NOx removal. The Atlantic Electric G.L. Englund and PSE&G Mercer demonstrations showed that 35-40% NOx removal can be obtained in exchange for nominally 5-10 ppm residual NH_3. Although 5 ppm is a generally accepted residual NH_3 level based on coal-fired SCR experience in Europe, some installations required lower residual NH_3 to avoid ash contamination or air heater plugging. The ability of balance-of-plant equipment and ash handling/disposal practices to tolerate residual NH_3 of greater than 5 ppm concentration is not known. In addition, the use of urea may produce N_2O as a byproduct, with potential environmental impacts. *Uncertainty: residual NH_3 limit in flue gas tolerable for Group 2 boilers, without inducing air heater plugging or other balance-of-plant equipment problems, or complicating or increasing the cost of ash disposal/reuse. Also, production of N_2O and associated environmental impacts.*

5.3. SCR (all Group 2 boilers): **NOx Removal/Catalyst Life; SO_3 Production**

• <u>Catalyst Life.</u> Experience in Europe with commercial systems, and in the U.S. with pilot-scale test facilities, shows that at least 18 months of operation is necessary to identify trends in catalyst activity. The Mercer SCR demonstration was successful in determining the NOx/residual NH_3 control achievable with a new catalyst for slag tap (wet bottom) wall-fired boilers; however data is based on only 5 months of operation and does not reflect long term results. The coal fired by PSE&G at Mercer is similar in sulfur and ash alkaline content to coals applied widely in Europe, and accordingly the experience base in Europe will be relevant to Mercer conditions. However, given the role of arsenic poisoning on SCR catalysts following slag tap (wet bottom) wall-fired, high heat release boilers, uncertainty remains regarding performance and catalyst life until Mercer achieves sufficient commercial experience. This minimum experience should include at least an 18 month period to establish activity trends, to define NOx control and catalyst replacement frequency. *Uncertainty: NOx removal and residual NH_3 control after 2 years, and the commercially required catalyst replacement frequency, particularly for the Mercer compact reactor which does not employ a spare layer.*

• <u>SO_3 Production.</u> The most significant feature distinguishing world-wide SCR experience from the conditions anticipated for broad U.S. application is SO_3 production, particularly for high sulfur coals. Most SCR commercial experience in Europe on coal is for sulfur content below 1.5%; accordingly the oxidization of 1-2% of SO_2 to SO_3 produces only several additional ppm of SO_3 which does not contribute to fouling or corrosive conditions. For many U.S. applications coal sulfur content is 2-4%, and the production of an additional 20 ppm of SO_3 in addition to a background levels of 10-20 ppm significantly elevates SO_3 entering the air heater. As a result, this elevated SO_3 concentration (up to 40 ppm) could induce significant corrosion of cold-end material. *Uncertainty: SO_3 addition by the catalyst (as oxidized from SO_2) that can be tolerated without balance of plant impacts.*

5.4. LNB Retrofit to Cell-fired boilers: **Furnace Erosion/Corrosion, Fuel Utilization.**

• <u>Furnace Corrosion/Erosion.</u> The key risk for deploying LNB in cell-fired boilers is the potential for erosion and corrosion of furnace walls. The risk for Group 2 boilers can be significant, as by design LNB and OFA technologies delay fuel/air mixing to create process conditions for low NOx production. Generally, delayed fuel and air mixing extend flame length, and require greater residence time to complete combustion. Accordingly, the compact furnace geometry may be susceptible to impingement by combusting pulverized fuel or ash particles, or the limited residence time may restrict complete fuel utilization.

Most Group 2 boiler LNB demonstrations have not operated for a sufficient time to completely clarify potential erosion and corrosion issues. Early results from the American Electric Power Muskingum Station have to date not identified furnace corrosion/erosion, thus all units may not encounter this potential problem. Most major demonstration programs have elements in place to address this as part of the cost analysis. *Uncertainty: furnace corrosion and erosion due to delayed fuel/air mixing and extended flame length and oxygen-deficient conditions.*

• <u>Fuel Utilization.</u> As identified in the preceding discussion, delayed fuel/air mixing extends the residence time required in the furnace for complete combustion. Depending on the bulk residence time offered by the furnace, combustion reactions may be quenched by flame impingement or simply inadequate residence time. As a result, fuel carbon may not be completely utilized, lowering boiler thermal efficiency. *Uncertainty: higher carbon loss dependent upon the extent of delayed fuel/air mixing and furnace size.*

Section 6

SUMMARY COSTS AND OBSERVATIONS:
GROUP 2 BOILERS

This section summarizes levelized control cost per ton of NOx removed for Group 2 boilers, according to control technology and capital requirement.

This information is intended to provide input for the following decisions as described in Section 407:

The Administrator shall base such rates on the degree of reduction achievable through the retrofit application of the best system of continuous emission reduction, taking into account available technology, costs and energy and environmental impacts; and which is comparable to the costs of nitrogen oxides controls set pursuant to subsection (b)(1).

EPA Acid Rain Division staff have stated the index by which cost, energy, and environmental impacts will be assessed for the Group 2 boiler rulemaking is cost per ton ($/ton). EPA staff also stated a maximum "threshold" capital requirement may be identified as a limit that a utility would not be required to exceed. This "threshold" capital requirement could eliminate capital intensive control technologies, such as SCR.

As shown in example calculations in this paper, the levelized cost per ton ($/ton) index can reflect capital and direct operating cost, energy impacts (fuel use efficiency), and environmental impacts (higher fly ash carbon content). However, this index can be distorted by extremely high baseline NOx emissions. The most relevant example of cost per ton providing misleading results is the SCR application at the Public Service New Hampshire Merrimack Station, which due to extremely high baseline emissions (2.66 lbs/MBtu) provides NOx reduction in a first phase of deployment for $537/ton. A baseline NOx emission rate of 1.5 lbs/MBtu, considered more typical for this type of boiler, when considering adjustments to capital and operating cost would entail NOx control costs of $1000-1400/ton, similar to SNCR.

Figure 6 presents levelized NOx control cost per ton ($/ton) for each of the major demonstration projects discussed in this paper. The results are ordered according to the approximate range of capital cost, and identified by control technology as well as host utility.

The results summarized in Figure 6 show:

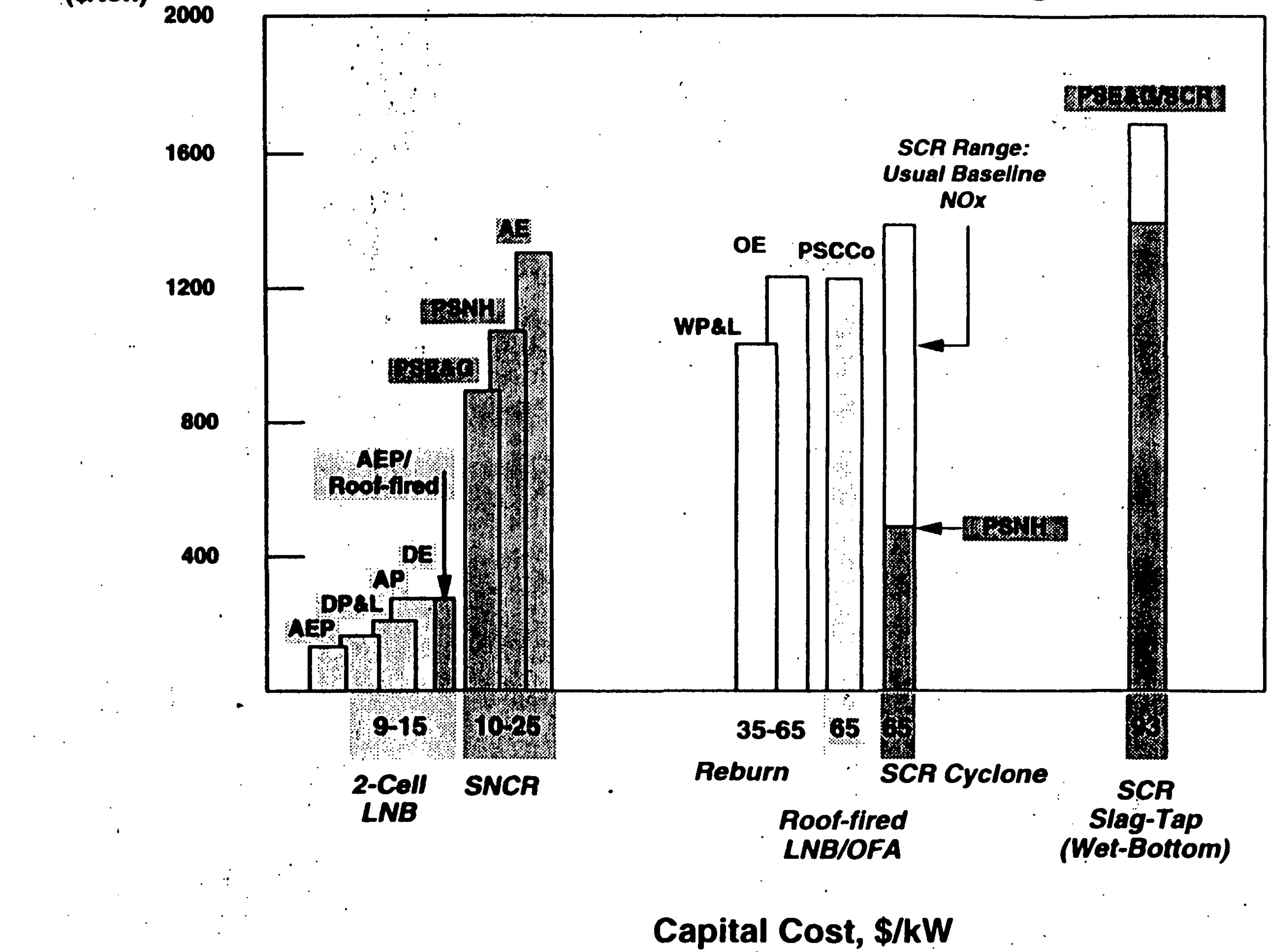
• Combustion control strategies for 2 burner cell-fired boilers provide NOx removal from approximately $125-275/ton, which represents the least cost reductions achievable with Group 2 boilers. These estimates are based on the results of commercial demonstrations on units of approximately 600 MW capacity. The range of cost shown reflects variation in capital requirement, and thermal efficiency penalties that could be incurred across the national boiler population. Capital requirement for most demonstrations is $10-15/kW.

• SNCR provides a second level of NOx control for a cost of approximately $900-1500/ton, based on reasonable assumptions for additional auxiliary power, reagent consumption, and achievable NOx reductions. Unlike cell-fired boiler combustion control technology, SNCR reductions are based on results from relatively small units of nominally 100-160 MW. As a result, there is uncertainty regarding scale-up that may influence NOx removal, capital requirement, and reagent consumption. Capital requirement for most SNCR demonstrations is anticipated to be $10-25/kW.

• Reburn (either coal or gas) provides NOx reduction for approximately $1000-1300/ton. For natural gas reburn, control costs are strongly dependent on the assumed differential cost of coal and natural gas ($0.50/MBtu used for this analysis). Similar to SNCR, both coal and natural gas reburn cost estimates are based on results from nominally 100 MW units. Capital requirement for the relevant demonstrations is $35-66/kW.

• Based on results from the sole operating SCR process (on a Group 2 slag tap (wet bottom) wall-fired boiler), SCR provides NOx reductions for $1400-1700/ton, exceeding the cost of all Group 2 boiler technologies. In addition, SCR requires significantly greater capital that any other technology, with approximately $90/kW necessary for the PSE&G Mercer test facility. If the planned SCR demonstration at Public Service New Hampshire Merrimack Unit 2 is considered, a capital requirement of $65/kW is necessary to provide NOx reduction of $500-600/ton. However, Merrimack capital and operating costs are design estimates, not operating results, and could be revised. Also, it is significant that capital requirement for Merrimack (a) does not address a full reactor catalyst inventory, and (b) may be revised higher if additional scope items are required to maintain a commercially operable plant. The low NOx control cost per ton estimated based on these assumptions ($556/ton) is a consequence of the relatively high baseline NOx production rate.

FIGURE 6. Comparison Of Levelized Cost Per Ton Group 2 Boiler NOx Control Technologies



These statements in the context of the Group 2 boiler population described in Section 4 suggest the following:

- Cell-fired boilers will be candidates for Group 2 boiler NOx reduction of approximately 50%, due to the (a) relatively modest cost of NOx control, and (b) significant capacity at which the control technology demonstrations were conducted.

- Cyclone boilers may be subject to pressure for 40-50% NOx reduction from SNCR or reburn, regardless of the fact that levelized control cost for these options is $900-1500/ton, significantly above the generally reported NOx control cost for Group 1 boilers. Almost half of the cyclone boiler population generate less than 200 MW capacity, thus scale-up required for SNCR and reburn is at most a factor of two for this segment of the boiler population. The remaining half of the cyclone boiler population will require scale-up from demonstration capacities by a factor of 2-10, and thus will incur significantly higher risk. Finally, the strict requirement for a minimum upper furnace residence time for successful reburn deployment may limit the utility boiler population to which reburn can be applied.

- The significant capital cost of SCR will likely eliminate its consideration for broad Group 2 deployment.

REFERENCES

Cichanowicz, 1993	"Factors Affecting SCR Capital Costs For Utility Boilers", J.E. Cichanowicz, D.E. Eskinazi, and K.D. Zammit, UARG and EPRI White Paper, December , 1993
Babcock & Wilcox, 1994	"Demonstration of Coal Reburning Cyclone Boiler NOx Control", final project report, February 1994, report no. DEFC2290PC89659.
EPA, 1994	"Alternative Control Techniques Document - NOx Emissions from Utility Boilers", U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, March 1994
EPRI, 1983	"NOx Emissions Characterization From Arch-fired Furnaces", EPRI Final Report CS-1339, June 1983
Hunt, 1994	"Current Progress With The Integrated Dry NOx/SO2 Emissions Control System", T. Hunt et. al., Third Annual Clean Coal Technology Conference, August 1994, Chicago, Illinois
May, 1994	"Gas Reburning In A Tangentially-fired Boiler", T. May, M. Krueger, R. Keen, J. Opatrny, C. Hong, T. Sommer, and B. Folsom", paper presented at the EPRI Workshop for NOx Controls For Utility Boilers, Scottsdale, AZ, May 1994.
STAPPA/ ALAPCO, 1994	"Controlling Nitrogen Oxides Under The Clean Air Act - A Menu of Options", State and Territorial Air Pollution Program Administrators/Association of Local Air Pollution Control Officials, July 1994
UARG, 1993a	"NOx Emission Controls For Utility Boilers", position paper issued by the Utility Air Regulatory Group, January, 1993.
UARG 1993b	"Comments Submitted to the U.S. Environmental Protection Agency Regarding the Draft Alternative Control Techniques Document - NOx Emissions from Utility Boilers", Utility Air Regulatory Group, August 1993.

UARG, 1995c "Database of Group 2 Utility Boilers" UARG, 1995, prepared by L. Smith.

UARG, 1995d "Analysis of NOx Emissions From Group 2 Utility Boilers", UARG, 1995, prepared by L. Smith.

Wallace, 1995 "Demonstration of Post Combustion NOx Control Technology On a Pulverized Coal, Wet Bottom Utility Boiler", A. Wallace, F. Gibbons, R. Roy, J. O'Leary, and E. Knell, paper presented at the Conference on Acid Rain & Electric Utilities: Permits, Allowances, Monitoring & Meteorology, Tempe, Arizona, January 1995.

APPENDIX A

SELECTED REFERENCES FOR GROUP 2
NOx CONTROL DEMONSTRATIONS

ACCORDING TO

GROUP 2 BOILER CATEGORY

GROUP 2 BOILERS:
SELECTED DEMONSTRATION DEMONSTRATIONS

Category	Host Utility/ Station	Technology	References
1. Cyclone	a. Wisconsin Power & Light/ Nelson Dewey	coal reburn	*Coal Reburn Application On A Cyclone Boiler*. Newell et. al. 1993 Joint Symposium on Stationary Combustion NOx Control, May 1993
			Demonstration of Coal Reburning for Cyclone Boiler NOx Control: Final Report, U.S. Dept. of Energy/PETC, Report No. DE FC 2290 PC 89659
	b. Ohio Edison/ Niles	gas reburn	*Long Term NOx Emissions Results With Natural Gas Reburning On a Coal-fired Boiler,* Borio et. al. 1993 Joint Symposium on Stationary Combustion NOx Control, May 1993
	c. City Water, Light & Power (Springfield, Ill)., Lakeside Station	gas reburn	*Gas Reburn In Tangential-, Wall-, and Cyclone-Fired Boilers: An Introduction To Second-Generation Technology,* May et. al. Third Annual DOE Clean Coal Technology Symposium, September 1994
	d. Atlantic Electric/ Englund	SNCR	*NOx Control For Cyclone-fired Boilers* Cunningham, et. al. 1994 EPRI Workshop On NOx Controls For Utility Boilers, May 1994

GROUP 2 BOILERS:
SELECTED DEMONSTRATION REFERENCES (CONT'D)

Category	Host Utility/ Station	Technology	References
Cyclone (cont'd)	e. Public Service of New Hampshire/ Merrimack 2	SNCR	*PSNH To Install German SCR System At Merrimack Unit-2 To Reduce NOx*, McGraw Hill Utility Environment Report, December 1994
	f. Public Service of New Hampshire/ Merrimack 2	SCR	*PSNH To Install German SCR System At Merrimack Unit-2 To Reduce NOx*, McGraw Hill Utility Environment Report, December 1994
2. Cell-fired/ (2 cell array)	g. Dayton Power & Light/Stuart Station	B&W low NOx cell burner (LNCB)	*Results of The Low NOx Cell Burner Demonstration At Dayton Power & Light Company's J.M. Stuart Station, Unit 4* Laursen et. al. 1993 Joint Symposium on Stationary Combustion NOx Control, May 1993
	h. Allegheny Power/Hatfield	B&W LNCB	startup stage; no public information available; unit operational since 3Q/1994
	i. AEP/Muskingum River, Unit 5	Riley LNB	startup stage; no public information available; unit operational since 3Q/1994
3. Slag Tap, (Wet Bottom) Wall-fired	j. OVEC/Kyger Creek	2-stage OFA	planning stage; no public information available; unit operational by 4Q/1995
	k. PSE&G/Mercer (325 MW)	SNCR	*A Demonstration Of Urea-Based SNCR NOx Control On A Utility Pulverized Coal, Wet-Bottom Boiler*, Gibbons et. al. 1994 EPRI Workshop On NOx Controls For Utility Boilers, May 1994

GROUP 2 BOILERS:
SELECTED DEMONSTRATION REFERENCES (CONT'D)

Category	Host Utility/ Station	Technology	References
3. Slag Tap, (Wet Bottom) Wall-fired (cont'd)	k. PSE&G/Mercer (325 MW)	SCR, possibly combined w/SNCR	*Demonstration of Post Combustion NOx Control Technology On A Pulverized Coal, Wet Bottom Utility Boiler* Wallace et. al., Conference on Acid Rain & electric Utilities: Permits, Allwances, Monitoring & Meteorolgy, January 1995
4. Vertically-fired	l. Public Service Co. of Colorado/ Arapahoe (110 MW)	vertically oriented LNB + OFA plus SNCR	*Current Progress With The Integrated Dry NOx/SO2 Emissions Control System* Hunt et. al. Third Annual DOE Clean Coal Technology Symposium, September 1994