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November 24, 1993

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Air Docket Section (A-131)
Attention: Air Docket No. A-92-15
U.S. Environmental Protection Agency
401 M Street, S.W.
Washington, D.C. 20460

Air Docket No. A-92-15

Dear Sir or Madam:

Enclosed for filing in the above-captioned docket are the original and one copy of the Second Supplemental Comments of the Utility Air Regulatory Group. Please call me if you should have any questions about this filing.

Very truly yours,

David S. Harlow

David S. Harlow

Enclosures

A-92-15

BEFORE THE
UNITED STATES
ENVIRONMENTAL PROTECTION AGENCY

PROPOSED RULES ON THE NITROGEN OXIDES EMISSION REDUCTION PROGRAM (PROPOSED 40 C.F.R. PART 76)	)	Docket No. A-92-15

SECOND SUPPLEMENTAL COMMENTS OF THE UTILITY AIR REGULATORY GROUP

Edison Electric Institute
National Rural Electric Cooperative Association
American Public Power Association

and

Alabama Power Company
Appalachian Power Company
Baltimore Gas and Electric Company

(Continued on next page)

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Counsel to the Utility Air Regulatory Group

November 24, 1993

Boston Edison Company
Carolina Power & Light Company
Centerior Energy Corporation
- **Cleveland Electric Illuminating Company**
- **Toledo Edison Company**

Central and South West Services, Inc.
- **Central Power and Light Company**
- **Public Service Company of Oklahoma**
- **Southwestern Electric Power Company**
- **West Texas Utilities Company**

Central Hudson Gas & Electric Corporation
Central Illinois Light Company
Central Illinois Public Service Company
The Cincinnati Gas & Electric Company
Columbus Southern Power Company
Commonwealth Edison Company
Consolidated Edison Company of New York, Inc.
Consumers Power Company
The Dayton Power and Light Company
Delmarva Power & Light Company
The Detroit Edison Company
Duke Power Company
Duquesne Light Company
Florida Power & Light Company
Florida Power Corporation
Georgia Power Company
Gulf Power Company
Illinois Power Company
Indiana Michigan Power Company
Indianapolis Power & Light Company
Jacksonville Electric Authority
Kansas City Power & Light Company
Kentucky Power Company
Kentucky Utilities Company
Long Island Lighting Company
Los Angeles Department of Water and Power
Louisville Gas and Electric Company
Madison Gas and Electric Company

(Continued on next page)

Midwest Power Systems, Inc
Minnesota Power Company
Mississippi Power Company
Monongahela Power Company
Montaup Electric Company
New England Power Company
New York State Electric & Gas Corporation
Niagara Mohawk Power Corporation
Northern Indiana Public Service Company
Oglethorpe Power Corporation
Ohio Edison Company
  Pennsylvania Power Company
Ohio Power Company
Ohio Valley Electric Corporation
Oklahoma Gas and Electric Company
PacifiCorp Electric Operations
Pennsylvania Power & Light Company
Philadelphia Electric Company
The Potomac Edison Company
Potomac Electric Power Company
PSI Energy, Inc.
Public Service Company of New Mexico
Public Service Electric and Gas Company
Salt River Project
Savannah Electric and Power Company
South Carolina Electric & Gas Company
Tampa Electric Company
Tucson Electric Power Company
Union Electric Company
Virginia Power
West Penn Power Company
Wisconsin Electric Power Company
Wisconsin Public Service Corporation

SECOND SUPPLEMENTAL COMMENTS ON § 407 NO_x RULES

On November 25, 1992, the U.S. Environmental Protection Agency (EPA) published proposed regulations to implement the nitrogen oxides (NO_x) emission reduction provisions of the acid deposition control program under Title IV of the Clean Air Act (CAA or Act).[1/] On February 8, 1993, the Utility Air Regulatory Group (UARG) submitted 750 pages of comments on those proposed rules.[2/] On June 15, 1993, UARG submitted extensive supplemental and reply comments.[3/] Because one year has passed since proposal, and because EPA is reportedly collecting new data to support its proposed rule, UARG now submits the following second supplemental comments. UARG is an association of 75 electric utilities from the public and private sectors, the Edison Electric Institute, the National Rural Electric Cooperative Association and the American Public Power Association.

I. If EPA Intends to Base its Final Rule on Information and Analyses that Were Not Available for the Proposed Rule, it Should Place that Information in the Docket and Solicit Public Comment on Those Analyses.

UARG has learned from many of its member companies that the Acid Rain Division and its contractors, including Radian

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1/ 57 Fed. Reg. 55632 (1992).

2/ Comments of Utility Air Regulatory Group on proposed NO_x rules (February 8, 1993), Docket A-92-15, Doc. No. IV-D-111 ("UARG Comments").

3/ Comments of UARG (June 15, 1993), Doc. No. IV-D-138 ("UARG Supplemental Comments").

Corporation and ICF, has contacted utilities during the past few months to obtain additional information concerning the costs and capabilities of low NO_x burners and other combustion modifications. UARG understands that the Acid Rain Division may be using these analyses to re-evaluate the technical basis for the final rule.

UARG's extensive comments in this rulemaking have pointed out numerous technical flaws in the analyses that underpin the proposed rule.[4/] The U.S. Department of Energy has also criticized the technical basis for the proposed rule,[5/] but EPA apparently has declined to adopt the analyses of UARG or the U.S. Department of Energy. Given that it is currently gathering new information to support its rule, the Acid Rain Division evidently now recognizes that there are serious weaknesses in the technical basis for the proposed rule.

For this reason, UARG believes that any new data and associated analyses will be of central relevance to this rulemaking, including any data and analyses addressing:

- the capabilities of low NO_x burner technology;
- the costs and benefits of low NO_x burner technology, overfire air technology or the combination of low NO_x burner technology and overfire air technology; and
- the environmental effects of the proposed early election program.

4/ See, e.g., UARG Comments, pp. 62-66.

5/ Comments of the U.S. Department of Energy on proposed NO_x rules (January 4, 1993), Doc. No. IV-D-02.

In this regard, § 307(d)(4)(B)(i) of the Clean Air Act provides that "[a]ll documents which become available after the proposed rule has been published and which the Administrator determines are of central relevance to the rulemaking shall be placed in the docket <u>as soon as possible after their availability</u>" (emphasis added). In light of this legal standard, we believe that EPA must place any new studies, analyses and reports on which it might base the final rule in the public docket and reopen the comment period for at least thirty days for the purpose of allowing public analysis and comment on those new reports and information. Reopening the comment period to address new data and analysis is critically important in this case because the rulemaking has been controversial, EPA has acknowledged fundamental technical errors in its data analysis for the proposed rule, and some aspects of EPA's proposed rule ignore the recommendations of an advisory committee that was formed under the Federal Advisory Committee Act to examine options for implementing § 407 of the Clean Air Act.[6/]

It is settled law that courts will require EPA to make available for public review and comment the factual or methodological information that is critical to a final rule. In <u>Portland Cement Association v. Ruckelshaus</u>,[7/] the D.C. Circuit remanded a final rule on procedural grounds because of EPA's

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6/ 5 U.S.C. App. §§ 1-14. <u>See</u> UARG Comments, pp. 12-16.

7/ 486 F.2d 375, 402 (D.C. Cir. 1973), <u>cert. denied</u>, 417 U.S. 921.

failure to disclose its detailed findings and analytical methodologies. In Sierra Club v. Costle, while upholding EPA because the petitioner failed to show any particular vital documents to which it lacked an opportunity to respond, the D.C. Court of Appeals noted that if

> documents of central importance upon which EPA intended to rely had been entered on the docket too late for any meaningful public comment prior to promulgation, then both the structure and the spirit of section 307 would have been violated. The Congressional drafters, after all, intended to provide "thorough and careful safeguards . . . [to] insure an effective opportunity for public participation in the rulemaking process."[8/]

The D.C. Circuit has reached the same result in numerous other cases.[9/] Accordingly, EPA must provide the regulated community with a fair opportunity to comment on its new information, analyses and reports, including those addressing the capabilities of low NO_x burner technology and overfire air, the costs and benefits of low NO_x burner technology or overfire air, and any new analyses regarding the proposed early election program.

8/ 657 F.2d 298, 398 (D.C. Cir. 1981).

9/ See, e.g., Home Box Office, Inc. v. FCC, 567 F.2d 9, 55 (D.C. Cir.), cert. denied, 434 U.S. 829 (1977) (information relevant to a proceeding must be disclosed to allow adversarial comment); United States v. Nova Scotia Food Products Corp., 568 F.2d 240, 252 (2d Cir. 1977) (invalidating rule due to failure to put scientific data in the record); International Harvester Co. v. Ruckelshaus, 478 F.2d 615, 631-32 (D.C. Cir. 1973) (remanded rule and criticized EPA's failure to provide opportunity to comment on methodology used in investigations concerning its decision not to suspend application of new auto emission standards).

II. Capabilities of Low NO_x Burner Technology

A. Tangentially-fired Boilers

In response to the proposed rule, the U.S. Department of Energy estimated that LNCFS1 at tangentially-fired (T-fired) boilers will reduce NO_x emissions by 35-37 percent.[10/] In UARG's initial comments, we noted that two current applications of LNCFS1 have achieved NO_x reductions of 37 percent (Plant Smith) and 35 percent (Fiddler's Ferry).[11/] We also stated that, "based on the best data available (i.e., the U.S. Department of Energy's Clean Coal Technology Program), the reductions that can be achieved with LNCFS3 (45 percent) are only marginally better than the reductions with LNCFS2 (37 percent) or LNCFS1 (37 percent)."[12/] UARG also noted that "the limited amount of operating experience to date with LNCFS3 has resulted in one characterization that, following vendor optimization, this system is (1) more difficult to operate, (2) results in carbon monoxide and NO_x spikes and (3) produces a more restrictive excess oxygen operating range."[13/]

10/ 57 Fed. Reg. 55647, Table 4; U.S. Department of Energy, Projected NO_x Emission Changes (1992), Doc. No. II-D-48.

11/ UARG Comments, pp. 60-61.

12/ UARG Comments, pp. 102-103. UARG's initial comments did not mention that Union Electric's Labadie 4 has demonstrated NO_x reductions of 30-50% with LNCFS3. Smith, LNCFS Level III Low NO_x Burner Retrofit: Labadie 4, EPRI NO_x Control Workshop, Cambridge (July 1992).

13/ UARG Comments, p. 104.

Since we filed our initial comments, additional experience and analysis at Plant Smith has confirmed that reductions that can be achieved with LNCFS3 are only marginally better than the reductions with LNCFS2 or LNCFS1.[14/] Moreover, the information that has been submitted recently to EPA at the request of its contractor, Radian, indicates that after one year of experience, LNCFS1 at Electric Energy, Inc.'s Joppa Unit 3 has achieved emissions reductions that range from 33 to 55%.[15/] This exceeds the 35-37% NO_x control range for LNCFS1 that UARG estimated in its initial comments.

The following recent information submitted to EPA at the request of its contractor regarding LNCFS2 retrofits confirms the experience at Plant Smith. These four units have an average NO_x reduction of 37%, which is identical to the reduction achieved at Plant Smith.

14/ Hardman, 180-MW Demonstration of Levels I, II, & III of ABB Combustion Engineering's Low-NO_x Concentric Firing System, EPRI/EPA NO_x Symposium (May 1993).

15/ Letter from William H. Shepherd, Electric Energy, Inc., to Jim Devon, Radian (October 27, 1993), Attachment 1.

Company	Unit	Technology	Percent Reduction	lb/mmBtu
Georgia Power	Wansley 1[16]	LNCFS2	42%	0.42-0.47
Georgia Power	Bowen 4[17]	NEI[18]	31%	0.40
Georgia Power	Yates 6[19]	NEI	38%	0.37-0.41
Centerior	Eastlake 2[20]	LNCFS2	38-43%	0.39-0.42

EPA's contractor has recently obtained information regarding an additional LNCFS3 retrofit at Indianapolis Power and Light's Stout 7. This retrofit has achieved only a 31% reduction, although the company believes that it will eventually achieve at least a 36% reduction to meet the proposed 0.45 lb/mmBtu emission limit.[21]

In sum, the most recent available information on T-fired retrofits confirms UARG's initial analysis that the reductions that can be achieved with LNCFS3 are only marginally better than the reductions with LNCFS2 or LNCFS1. Indeed, some LNCFS1 and LNCFS2 retrofits achieve greater NO_x reductions than some LNCFS3 retrofits, which suggests that separated overfire air may achieve less NO_x reductions than close-coupled overfire air in some applications. As UARG observed in its initial comments, this

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16/ Attachment 2.

17/ Attachment 3.

18/ For purposes of this discussion, we consider NEI's offering to be similar to ABB-CE's LNCFS2.

19/ Attachment 4.

20/ Attachment 5.

21/ Attachment 6.

recent information confirms that the capabilities of LNCFS technologies are very site specific, and that there is no technical support for a rule that would define LNCFS3 as low NO_x burner technology for all boilers. Finally, the most current information suggests that EPA would have no basis to lower the limit for T-fired boilers below 0.45 lb NO_x/mmBtu for Phase II units because more effective low NO_x burner technology is not available.

B. Wall-fired Boilers

In response to the proposed rule, the U.S. Department of Energy estimated that low NO_x burners alone on wall-fired boilers would achieve NO_x reductions of 45-55 percent.[22/] UARG's initial comments included an assessment of the capabilities of this technology, which found that low NO_x burners alone would achieve average NO_x reductions of about 47% reduction, while acknowledging that individual applications will fall within a range on either side of this average.[23/]

Central Illinois Light Company has recently retrofit low NO_x burners alone at its Edwards Station Unit 2. The baseline emissions were about 1.13 lb/mmBtu. Based on short term data, the unit can barely meet 0.50 lb/mmBtu, but can do so only at the price of high loss on ignition.[24/] Low NO_x burners at this

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22/ 57 Fed. Reg. 55647, Table 4.

23/ UARG Comments, pp. 59-60.

24/ For further information on this project, contact Cheryl Miller at (309) 693-4805.

project have achieved a 56% reduction, but only accompanied by high carbon losses.

Georgia Power recently reported that at Hammond Unit 4, the "full load, long-term NO_x emissions reduction in the LNB + AOFA configuration with the partial data set is approximately 67 percent at full load."[25/] The most recent analysis of this data indicates LNB contributed about 61% of the reduction to .48 lb/mmBtu, and that separated overfire air reduced NO_x an incremental 17%.[26/] This information suggests (1) that LNB performance without OFA is at least as good as reported earlier by DOE and UARG, and (2) that EPA has no basis to lower the limit for dry-bottom wall-fired boilers below 0.50 lb NO_x/mmBtu for Phase II units, because more effective low NO_x burner technology is not available.

III. Coal Fineness and NO_x Reduction

A. Cost of New Coal Pulverizers

In its initial comments, UARG noted that § 407 is a LNB retrofit program, and that even for LNBs it is not always possible to refurbish used equipment to the same specifications as new equipment.[27/] Nevertheless, EPA proposed a requirement

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25/ Sorge and Baldwin, Performance and Operating Results from the Demonstration of Advanced Combustion Techniques for Wall-fired Boilers, U.S. Department of Energy Second Annual Clean Coal Technology Conference, Atlanta (September 1993) (emphasis in original).

26/ Letter from John Sorge, Southern Company Services, to Mary Nichols, EPA, Attachment 7.

27/ UARG Comments, p. 126.

that the percentage of coal particles passing through 200 mesh in a plant's coal mills be at least the percentage given in the original design specifications.[28/] Since existing mills cannot typically be refurbished to "as new" condition, this would require owners or operators of many boilers to install new pulverizers.

Electric utilities seldom install new pulverizers to existing units because it is extremely expensive to do so. For example, in 1991, Ohio Edison Company replaced the mills at the 600 MW Sammis Unit 6 at a cost of approximately \$20 million, or \$33.33/Kw.[29/] In 1992, Georgia Power replaced the mills at the 500 MW Hammond Unit 4 at a cost of approximately \$9 million, or \$18/Kw.[30/]

ICF's report to Congress during consideration of the 1990 Clean Air Act Amendments assumed capital costs for low NO_x burners at wall-fired and T-fired boilers to be \$15.20/Kw and \$4.74/Kw, respectively.[31/] The § 407 NO_x program is intended

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28/ Proposed 76.13(d)(3)(i).

29/ For further information, contact Dale Kanary, Ohio Edison Company at (216) 384-5744.

30/ For further information, please contact John Sorge, Southern Company Services at (205) 877-7426.

31/ ICF Resources, "Comparison of the Economic Impacts of the Acid Rain Provisions of the Senate Bill (S. 1630) and the House Bill (S. 1630)" (prepared for U.S. EPA), at C-14 (July 1990), Doc. No. II-A-6.

to control NO_x cost effectively,[32/] and EPA is directed not to require a utility to install anything "beyond low NO_x burners."[33/] Because pulverizers cost more than low NO_x burner technology, it is evident that Congress could not possibly have intended that new pulverizers be considered to be "low NO_x burner technology."

Because equipment such as coal pulverizers is so expensive, we reiterate our initial recommendation that the total cost of all ancillary equipment, modifications or upgrades in applying for an alternative emission limitation be limited to 25 percent of the capital cost of the low NO_x burners.

B. Cost/Benefit of Requiring New Coal Pulverizers to Reduce NO_x

EPA stated in the proposed rule that coal fineness "critically affects" NO_x emissions, and therefore proposed standards for coal fineness that must be met before an alternative emission limitation can be granted.[34/] In UARG's initial comments, we noted that coal fineness in certain circumstances can affect unburned carbon levels, but improvements in coal fineness do not directly contribute to NO_x reductions.[35/] Indeed, we provided technical information from

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32/ See UARG Comments, pp. 48-49. For example, Senator Baucus stated that § 407 "essentially encourages the most cost-effective utilization of new NO_x production technologies." 136 Cong. Rec. S2976, col. 2 (daily ed. Mar. 22, 1990).

33/ CAA, § 407(d).

34/ Proposed § 76.13(d)(3).

35/ UARG Comments, pp. 123-26.

two boilers (Gaston Unit 2 and Smith Unit 2) where varying the coal fineness had no effect on NO_x emissions. UARG's supplemental comments also noted that data from a third boiler (Arizona Public Service's Four Corners Unit 3) confirmed that varying coal fineness had no effect on NO_x emissions.[36/] Finally, a paper has been recently located with a fourth data set that reached the same conclusion as the above analyses, and this information has been provided to the Agency.[37/]

While UARG has provided several data sets that establish that coal fineness does not contribute to NO_x reductions, EPA has provided no data sets that would support reaching a different conclusion. As discussed above, if EPA has any such data sets, we request that EPA place them in the docket and allow UARG an opportunity to review the information.

UARG understands that EPA may now acknowledge that improvements in coal fineness do not directly affect NO_x reductions. However, EPA may contend that improvements in coal fineness allow the operator of a unit to decrease excess oxygen while maintaining the same loss on ignition, thereby indirectly reducing NO_x. In response to this hypothesis, the attached memorandum analyzes the cost effectiveness of replacing a coal

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36/ Supplemental Comments, pp. 24-25.

37/ Letter from Robert Hardman, Southern Company Services, to Doris Price, EPA (September 2, 1993), Doc. No. IV-D-140.

pulverizer to improve NO_x reductions.[38] It uses NO_x emissions data from the U.S. Department of Energy's Clean Coal Technology Program Demonstration at Plant Smith to estimate the additional NO_x reductions that might be achieved by varying excess oxygen. This analysis is conservative because it is based on the NO_x emissions characteristics at full load. Applying the NO_x reduction estimates to a cost range of $15-$35/Kw for replacing coal pulverizers yields an estimate of the cost effectiveness of EPA's proposed provision to require that pulverizers meet new coal fineness specifications, in order to promote indirectly NO_x reductions.

This analysis indicates that requiring a utility to replace a coal pulverizer for the purpose of reducing NO_x ranges in cost effectiveness from about <u>$4,000 to $8,000 per ton of NO_x removed</u>, ignoring operation and maintenance costs.[39] For pulverizer replacements at the high end of the cost range, the cost effectiveness could exceed $11,000 per ton of NO_x removed.

EPA estimated in the preamble to the proposed rule that the cost effectiveness of its various proposed options for low NO_x burner technology ranged from $120 to $300/Kw.[40] Thus, requiring a utility to install a new pulverizer as part of an application for an alternative emission limitation would be

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38/ Memorandum from Lowell Smith, ETEC, to Craig S. Harrison, UARG (November 3, 1993), Attachment 8.

39/ *Id.*

40/ 57 Fed. Reg. 55645, Table 4.

grossly disproportionate to any benefits to the environment. We reiterate our request that the final rule clearly state that a utility will not be required to replace its coal pulverizers under § 76.13.[41]

IV. Benefits of Early Election

In our recent meeting with EPA concerning the early election provisions, EPA staff stated that the comments concerning the early election program were "highly polarized." To the contrary, our review of the comments in the docket indicate that 57 commenters favor the early election program, and that only one commenter, the Natural Resources Defense Council (NRDC), expressed any opposition whatsoever. NRDC's opposition is primarily limited to objections concerning (1) the need to demonstrate the environmental benefits of grandfathering;[42] and (2) allowing units that already meet the emission limits to be grandfathered. Indeed, NRDC endorsed an early-election program that is "crafted to ensure an actual emission reduction benefit." While UARG would not agree with some of NRDC's

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41/ We note that just last month the President directed each regulatory agency, including EPA, to "draft its regulations to be simple and easy to understand, with the goal of minimizing the potential for uncertainty and litigation arising from such uncertainty." Executive Order 12866, § 1(b)(12), 58 Fed. Reg. 51735, 36 (October 4, 1993). Accordingly, the final rule should not be vague or ambiguous regarding whether a permitting agency may require a utility to replace coal pulverizers as part of an application for an alternative emission limitation.

42/ NRDC did not have the benefit of the analysis already provided with UARG's initial Comments or of the further analysis submitted today. Accordingly, this objection is moot.

proposed criteria, we believe that our analyses clearly demonstrate that the early election program proposed by EPA will result in an actual emission reduction benefit.

The enclosed analysis of the environmental benefits of the early election program predicts future annual NO_x emissions with and without an early election option.[43] It assumes that low NO_x burner retrofits will proceed in an orderly fashion and that the technology can be installed within four to six years.

The analysis then evaluates three scenarios. Under scenario 1, Phase II limits equal Phase I limits. Under this scenario, there is no question that the early reduction program will result in an environmental benefit. The only question is the magnitude of the benefit (e.g., 2.4 to 3.9 million tons).

Under scenario 2, Phase II limits are lowered to 0.40 lb/mmBtu (T-fired boilers) and 0.45 lb/mmBtu (wall-fired boilers). Under this scenario, a cumulative environmental benefit remains until at least the year 2020, even if retrofits could be accomplished within four years.

Under scenario 3, Phase II limits are lowered to 0.35 lb/mmBtu for T-fired boilers and to 0.40 lb/mmBtu for wall-fired boilers. Under scenario 3, a cumulative environmental benefit remains until at least the year 2020 if retrofits take six years to accomplish. Even if retrofits take only four years, the

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43/ *See* Memorandum from Ralph L. Roberson to UARG Control Technology Committee (November 5, 1993), Attachment 9.

cumulative environmental benefit remains until at least the year 2011.

In this regard, it should be noted that low NO_x burner on NSPS units have generally been replaced after about 15 years. Accordingly, most burners that will be installed during an early election program between 1995 and 1997 will be replaced around 2010-2012. At that time, utilities will install the most current generation of low NO_x burners. It is likely that the generation of low NO_x burners that will be installed in 2010-2012 will have lower NO_x emissions than the burners that are available in the mid-1990s, so that even under scenario 3, and assuming retrofit of the entire industry in a four year time span, there will be a permanent benefit to the environment.

Furthermore, in examining the three scenarios presented in this study, the study indicates that the environmental benefit of an early election program is sensitive to two parameters: (1) the Phase II emission limits, and (2) the time needed to install low NO_x burners at Phase II boilers. We have discussed above the capabilities of low NO_x burners based on the latest information available,[44/] and it appears that there will be little or no justification for lowering Group 1 boiler emission limits during Phase II. If this is the case, the early reduction program entails a very substantial benefit to the environment.

Regarding the period of time needed to install low NO_x burners, EPA estimates that 628 Group 1 boilers will be subject

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<u>44</u>/ <u>See</u> pp. 8 to 12, above.

to NO_x regulation in Phase II.[45] There are also about 230 Group 2 boilers (cyclones, cell burners, wet bottom wall-fired boilers, etc.) that must be retrofit once EPA issues rules in 1997.[46] It will be a major challenge for electric utilities and vendors to accomplish these retrofits over a short time period without compromising the reliability of the nation's supply of electricity. Scheduling outages to install low NO_x burner technology is complicated by the fact that optimization often takes much longer than initially estimated.[47] Increased optimization time lowers the availability of the units that are retrofit and further decreases the reserves that are needed to insure the reliability of this nation's electricity supply.

We believe that the maximum number of NO_x retrofits that the four major vendors will be able to accomplish is 75-100 per year.[48] Assuming that 100 low NO_x burner retrofits can be

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45/ Radian, Analysis of Low NO_x Burner Technology Costs, Doc. No. II-A-18.

46/ CAA, § 407(b)(2).

47/ Optimization time for 11 low NO_x combustion systems in the Southern electric system ranged from 24 to 476 days. Letter from Robert R. Hardman, Southern Company Services, to Craig S. Harrison, Hunton & Williams (October 21, 1993), Attachment 10.

48/ We understand that 75-100 retrofits are scheduled for installation during 1994. Because utilities face a putative January 1, 1995 statutory deadline for § 407 and a May 1995 deadline for the installation of reasonably available control technology under Title I, we believe that 1994 represents the maximum capacity for the NO_x retrofit industry. The capacity to undertake NO_x retrofits is limited by (1) the ability of vendors to install and optimize low NO_x burners, and (2) the number of overlapping outages that can be scheduled during one year.

accomplished each year, it would take over six years to complete the Phase II program. If 125 retrofits could be accomplished, it would take five years to accomplish the Phase II program. If it takes six years to retrofit the boiler population, the enclosed analysis shows that the early election option will result in an environmental benefit under any of the options selected.

This analysis is conservative because it ignores the fact that retrofitting cyclones, roof-fired boilers, cell burners, wet-bottom wall-fired boilers, stoker boilers and all other coal-fired boilers will proceed simultaneously, and strain the same vendors and the same margins of electric reliability. Some boilers may avoid installing low NO_x burner technology by participating in an averaging plan with over-controlled units if the Phase II limits remain at the Phase I levels. However, if EPA were to lower the emission limits for Phase II, this option would effectively be foreclosed for many boilers. For example, if the limits decreased by 0.10 lb/mmBtu, there would probably be little, if any, emissions averaging and the number of alternative emission limitations would increase substantially.

In sum, in order for the early election program not to produce a significant environmental benefit, two conditions would have to occur. First, the emission limits for <u>both</u> T- and wall-fired boilers would have to be decreased by 0.10 lb/mmBtu or more for Phase II boilers. Second, all 858 Phase II boilers would have to be retrofit with low NO_x burners within four years or less. It is unlikely that either, much less both, of these conditions will occur. More effective low NO_x burner technology is not available that would allow emission limits for Group 1 boilers to be lowered by 0.05 lb/mmBtu, let alone 0.10 lb/mmBtu. Moreover, the 628 Phase II Group 1 boilers themselves cannot be retrofit within a period of four years. Since the early election program is therefore environmentally beneficial, the final rule should include an early election program similar to the proposed program.

V. Emissions Averaging

We understand that EPA is reconsidering certain aspects of the emissions averaging program. UARG reiterates its support of the proposed emissions averaging rule, which is flexible and consistent with congressional intent. We firmly believe that Congress intended that utilities could engage in interstate averaging, and that there is no more basis to restrict NO_x averaging to state borders than there would be to restrict SO_2 allowance trading in a similar fashion. It is especially important to allow utilities that own plants in contiguous states to establish averaging plans within their companies. Interstate averaging is equally important to small companies, that may not otherwise be able to form a workable averaging group.

CONCLUSION

For the foregoing reasons, UARG urges EPA to finalize its § 407 NO_x rules in a way that (1) limits the definition of low NO_x burner technology to low NO_x burners, (2) eliminates any requirement for replacing coal pulverizers prior to obtaining an alternative emission limit, (3) includes an early election program similar to the proposed program, and (4) provides for broad and flexible emissions averaging, as was done in the proposed rule.

ATTACHMENT 1

EEI

Electric Energy, Inc.

October 27, 1993

Mr. Jim Devon
Radian Corporation
P. O. Box 13000
Research Triangle Park, NC 27709

Dear Jim:

The following information is being supplied to augment that which was provided in a recent RACT survey Radian conducted.

Electric Energy, Inc. Joppa plant installed Combustion Engineering LNCFS level 1 (modified to include close-coupled over-fired air) burners on Unit #3 in late 1992. The burner configuration is such that CCOFA damper 1 (CCOFA1) is just above the top elevation fuel nozzle ("E" level) and CCOFA2, 3 and 4 are stacked above CCOFA1.

Since installation, we have fine tuned the boiler operation and the burners. The following data is typical and repeatable for operation while burning Illinois Basin fuels.

Load (MW)	Burner Configuration	NOx (lb/MBtu)
179	Baseline - CCOFA's closed	.548
181	CCOFA1, 2 & 3 100% open	.373
181	CCOFA4 50% open	.340
181	CCOFA4 100% open and Fuel Air 35% open	.310

Sincerely,

W H Sheppard

William H. Sheppard
Plant Manager

WHS:dk

Street address for overnight mail
Progress Center
3200 East Chapel Hill Road / Nelson Highway

Post Office Box 165 Joppa, Illinois 62953 (618) 543-7531 Fax: Ext. 399

ATTACHMENT 2

ATTACHMENT 3

RADIAN CORPORATION

EPA ACID RAIN PROJECT
LNBT RETROFIT DATA REQUEST

1. NO_x Emission Data : WANSLEY UNIT 1
   - Matched data points preferred (i.e., baseline and controlled NO_x values at same unit operating loads).
   - If only one data point available, please specify unit operating load.
   - Please specify if data is long term (i.e., more than 50 days of CEM data) or short term (anything else).

Load	Baseline NO_x	Controlled NO_x
Max (905 MW)	.73 Lbs/mBTU	.42 Lbs/mBTU **
~~Average~~ (678 MW)	.62 "	.42 "
Min (467 MW)	.50 "	.42 "
Other coal chng MW)		.47 "
Duration (circle one)	Short term / Long term	Short term / Long term

2. LNBT Retrofit Information
   - A. Vendor ABB/CE
   - B. Retrofit date SOFA - MAY 1992, LNB - MAY 1993
   - C. Total number of burners 56
   - D. Total number of corners 8
   - E. Type of coal burned (E. Bit, W. Bit, Sub-bit) E. BIT.
   - F. Unburned carbon data
     - Before retrofit LOI 1.8%
     - After retrofit LOI 5%
   - G. Coal fineness

	Before Retrofit	After Retrofit
% through 200 mesh	70 %	70 %
% through 50 mesh	98.5 %	98.3 %

   - H. Total Installed Capital Cost (million of $)
     $ 6.0

** IT IS ANTICIPATED THAT NOx EMISSIONS WILL INCREASE WHEN BURNING LOWER SULFUR COAL.

RADIAN CORPORATION

EPA ACID RAIN PROJECT
LNBT RETROFIT DATA REQUEST

1. NO_x Emission Data : BOWEN UNIT 4

- Matched data points preferred (i.e., baseline and controlled NO_x values at same unit operating loads).
- If only one data point available, please specify unit operating load.
- Please specify if data is long term (i.e., more than 50 days of CEM data) or short term (anything else).

Load	Baseline NO_x	Controlled NO_x
Max (880 MW)	.58 LBS/MBTU	.40 LBS/MBTU **
~~Average~~ (644 MW)	.67 "	.40
Min (508 MW)	.52 "	.40
Other (MW)		
Duration (circle one)	Short term Long term	~~Short term~~ * Long term

2. LNBT Retrofit Information

A. Vendor RR / ICL

B. Retrofit date MAY 1993

C. Total number of burners 56

D. Total number of corners 8

E. Type of coal burned (E. Bit, W. Bit, Sub-bit) E. BIT.

F. Unburned carbon data
   Before retrofit LOI 3.30
   After retrofit LOI 3.75

G. Coal fineness

	Before Retrofit	After Retrofit
% through 200 mesh	70 + %	70 + %
% through 50 mesh	99.3 %	99.3 %

H. Total Installed Capital Cost (million of $)
$ 8.0

* SHORT TERM GURANTEE TEST AFTER OPTIMIZATION

** IT IS ANTICIPATED THAT NOx EMISSIONS WILL INCREASE WHEN BURNING LOWER SULFUR COAL.

ATTACHMENT 4

RADIAN
CORPORATION

EPA ACID RAIN PROJECT
LNBT RETROFIT DATA REQUEST

1. NO_x Emission Data : YATES UNIT 6
   - Matched data points preferred (i.e., baseline and controlled NO_x values at same unit operating loads).
   - If only one data point available, please specify unit operating load.
   - Please specify if data is long term (i.e., more than 50 days of CEM data) or short term (anything else).

Load	Baseline NO_x	Controlled NO_x
Max (368 MW)	.60 Lbs./MBTU	.37 Lbs/MBTU **
~~Average~~ (233 MW)	.62 "	.40 "
Min (135 MW)	.45 "	.37 "
Other (FULL) (350 MW)	.67 "	.41 "
Duration (circle one)	Short term Long term	Short term Long term

2. LNBT Retrofit Information
   - A. Vendor RR/ICL
   - B. Retrofit date DEC. 1992
   - C. Total number of burners 20
   - D. Total number of corners 4
   - E. Type of coal burned (E. Bit, W. Bit, Sub-bit) E. BIT.
   - F. Unburned carbon data
     - Before retrofit LOI 3.80
     - After retrofit LOI 5.32
   - G. Coal fineness

	Before Retrofit	After Retrofit
% through 200 mesh	74.1 %	68.5 %
% through 50 mesh	98.5 %	98.5 %

   - H. Total Installed Capital Cost (million of $)
     $ 6.0

** IT IS ANTICIPATED THAT NOX EMISSIONS WILL INCREASE WHEN BURNING LOWER SULFUR COAL.

ATTACHMENT 5

CORPORATION

EPA ACID RAIN PROJECT
LNBT RETROFIT DATA REQUEST

1. NO_x Emission Data

- Matched data points preferred (i.e., baseline and controlled NO_x values at same unit operating loads).
- If only one data point available, please specify unit operating load.
- Please specify if data is long term (i.e., more than 50 days of CEM data) or short term (anything else).

Load	Baseline NO_x [1]	Controlled NO_x [1]
Max (140 MW)	0.68#/mmBtu	0.39 - 0.42#/mmBtu
Average (-- MW)	--	--
Min (70 MW)	0.50#/mmBtu	0.36 - 0.42#/mmBtu
Other (100 MW)	0.55#/mmBtu	0.36 - 0.42#/mmBtu
Duration (circle one) [2]	Short term Long term	Short term Long term

2. LNBT Retrofit Information

A. Vendor ABB/Combustion Engineering

B. Retrofit date December 1993

C. Total number of burners 16 - LNCFS II

D. Total number of corners 8

E. Type of coal burned (E. Bit, W. Bit, Sub-bit) Eastern Bituminous

F. Unburned carbon data
Before retrofit 12.3% carbon on average
After retrofit 13.0% loss on ignition on average

G. Coal fineness

	Before Retrofit	After Retrofit
% through 200 mesh	70 %	70 %
% through 50 mesh	99+ %	99+ %

H. Total Installed Capital Cost (million of $)
$ 5,000,000 not including pulverizers, windboxes and ignitors/scanners.

----

1. Measured at Economizer Outlet
2. Further optimization of the Eastlake Unit 2 LNCFS II System is planned. The short duration of testing has not allowed the completion of the system optimization.

RADIAN
CORPORATION

EPA ACID RAIN PROJECT
LNBT RETROFIT DATA REQUEST
(Continued)

3. LNBT Retrofit Description

Please briefly explain the scope of your LNBT retrofit. In particular, please describe if any of the following were modified or replaced.

Windboxes

Water wall panels

Ignitors/Scanners

Burner Management Systems

Pulverizers

Fans

Other (describe)

The following modifications or replacements were made for Eastlake Unit 2 LNCF II installation:

- Eight windboxes were placed for ease of construction and installation of overfire air registers dug to the boiler configuration.
- Water wall panels were replaced to allow installation of burners and air registers.
- Ignitors were replaced in all corners and scanners were added to meet insurance requirements and boiler safety codes.
- A Burner Management System was installed for scanners, ignitors, air registers, tilts and pulverizers.
- Pulverizers were completely rebuilt to improve grind of coal.

ATTACHMENT 6

IPL

INDIANAPOLIS POWER & LIGHT COMPANY

October 26, 1993

Mr. T. James Devon
Radian Corporation
Progress Center
3200 E. Chapel Hill Road
P.O. Box 13000
Research Triangle Park, N.C. 27709

Dear Mr. Devon,

Indianapolis Power & Light Company (IPL) regrets to inform you that it does not have all of the information that you have requested. The low NOX combustion controls installed on E. W. Stout Station Unit #7 tangentially fired boiler have not met the acceptance criteria of the construction contract. The ABB-CE Level III Low NOX Concentric Fired Burner System was retrofitted in June 1993; a description of the installation is attached.

The most recent NOX emission data was collected on October 19, 1993. The boiler was operated at full load for 4 hours and certified CEMs were used to collect the data. The emission levels ranged from .48 #/MMbtu NOX to .49 #/MMbtu of NOX. The thirty percent reduction achieved on this date does not meet the emission limit that will be required in 1995. IPL expects to meet the January 1, 1995 deadline to comply with the .45 #/MMbtu NOX emission limit. The contractor continues to work making adjustments to the CCOFA and SOFA damper positions at specific boiler conditions in an attempt to achieve the necessary NOX and CO emission reductions.

If you have any question about the information submitted please call me at 317-261-5185.

Sincerely,
Indianapolis Power & Light Company

R. James Meiers

R. James Meiers
Environmental Affairs

RADIAN
CORPORATION

EPA ACID RAIN PROJECT
LNBT RETROFIT DATA REQUEST

1. NO_x Emission Data

- Matched data points preferred (i.e., baseline and controlled NO_x values at same unit operating loads).
- If only one data point available, please specify unit operating load.
- Please specify if data is long term (i.e., more than 50 days of CEM data) or short term (anything else).

Load	Baseline NO_x (lb/mmBtu)	Controlled NO_x (lb/mmBtu)
Max (~~430~~ 450 MW)	.70	NOT AVAILABLE AT THIS TIME
Average (360 MW)	.52	
Min (180 MW)	.43	
Other (314 MW)	.32	
Duration (circle one)	Short term Long term	Short term Long term

2. LNBT Retrofit Information

A. Vendor ABB-CE

B. Retrofit date Completed

C. Total number of burners 5

D. Total number of corners 4 (Four)

E. Type of coal burned (E. Bit, W. Bit, Sub-bit) Bit. - INDIANA COAL

F. Unburned carbon data
Before retrofit 3.8%
After retrofit NOT AVAILABLE AT THIS TIME

G. Coal fineness – PULVERIZERS NOT MODIFIED.

	Before Retrofit	After Retrofit
% through 200 mesh	70 %	70 %
% through 50 mesh	98 %	98 %

H. Total Installed Capital Cost (million of $)
$ 3,300,000

October 12, 1993

Scope of Work Description
Low NOx Concentric Fired Burner System
E. W. Stout Generating Station - Unit No. 7

The Scope of Work associated with the installation of the ABB-CE Level III Low NOx Concentric Fired Burner System was as follows:

I. Windboxes

The windboxes were modified as described below:

A. All internal components of windbox were removed, new partition plates installed to accommodate re-sectionalization, existing warped or damaged partition plates either repaired or replaced to achieve square compartments.

B. The top and bottom elevation coal nozzle tip assemblies were replaced with the LNCFS flame attachment coal nozzle tips.

C. The top of windbox reconfigured to accommodate two compartments of close coupled overfire air. An auxiliary air compartment utilizing straight tilting air nozzle tips is located between these two CCOFA compartments.

D. Each of the remaining air compartments are partitioned and new auxiliary air dampers are added to control air flow.

II. Waterwall Panels

A. Separated Overfire Air (SOFA) was added which required new tube panels on each of four corners.

III. Ignitors and Scanners

A. Ignitors were not affected by this work.

B. New scanner guide pipes and scanner air cooling hoses were installed due to significant deterioration.

IV. Burner Management System

A. A Westinghouse DCS system was installed simultaneously with the ABB-CE Level III Low NOx Concentric Fired Burner System.

V. Pulverizers

A. No modifications were required for LNCFS.

VI. FD and ID Fans

A. No modifications were required for LNCFS.

ATTACHMENT 7

Southern Company Services, Inc.
Post Office Box 2625
Birmingham, Alabama 35202-2625
Telephone 205 870-6011

Southern Company Services
the southern electric system

November 24, 1993

Ms. Mary D. Nichols
Assistant Administrator for Air and Radiation
U. S. Environmental Protection Agency
Acid Rain Division, 4th Floor
501 3rd Street NW
Washington, DC 20001

RE: ICCT Wall-Fired Combustion Demonstration Project

Dear Ms. Nichols:

Over the past several years, The Southern Company has cooperated with your staff by providing the most recent data from the low-NOx burner (LNB) demonstration projects being conducted in our system. Building on this cooperation, I would like to share with you the most recent data from the U. S. Department of Energy's Innovative Clean Coal Technology demonstration at Georgia Power Company's Plant Hammond Unit 4. As you are aware, we are testing Foster Wheeler Energy Corporation's (FWEC) Controlled Flow/Split Flame (CF/SF) low-NOx burner and advanced overfire air (AOFA) system at this site. During August 1993, long-term testing in the LNB plus AOFA configuration was completed. Results from this phase are substantially different than the preliminary data previously transmitted to EPA on March 19, 1992. Specifically, the purpose of this letter is to provide you and your staff with (1) a rationale for the differences between the data from the abbreviated and recently completed LNB plus AOFA and (2) revised estimates on the cost effectiveness of the Hammond 4 LNB and AOFA systems. The brief history of Hammond 4 testing that follows is beneficial in this regard.

Baseline, AOFA, LNB, and LNB plus AOFA test phases have been completed. Short-term and long-term baseline testing was conducted in an "as-found" condition from November 1989 through March 1990. Following retrofit of the AOFA system during a four-week outage in spring 1990, the AOFA configuration was tested from August 1990 through March 1991. The FWEC CF/SF low-NOx burners were installed during a seven-week outage starting on March 8, 1991 and continuing to May 5, 1991. Following configuration of the LNBs and ancillary combustion equipment by FWEC personnel, LNB testing commenced during July 1991. However, due to significant post-LNB increases in precipitator fly ash loading and gas flow rate and also, increases in fly ash loss-on-ignition (LOI) which adversely impacted stack particulate emissions, the unit was run below 300 MW from September to November 1991. Following installation of an ammonia flue gas conditioning system, the unit was able to return to full-load operation and complete the LNB test phase during January 1992.

Given the extended LNB test phase, insufficient time was available to complete the full requirements of the LNB plus AOFA test phase prior to the spring 1992 outage; therefore, it was decided to collect abbreviated data prior to this outage and comprehensive data following the outage. In that it was the only data available, data from the LNB plus AOFA abbreviated testing was used in the preparation of the cost effectiveness calculations transmitted to EPA on March 19, 1992. Following the spring 1992 outage, it was found that the AOFA had exacerbated the stack particulate emissions and the unit was again load limited, this time to 450 MW. Following state granted permission to resume full-load operation on March 26, 1993 for the purpose of completing testing, FWEC personnel re-configured the low-NOx burners starting March 30, 1993 and continuing through May 6, 1993. Comprehensive testing began following this re-configuration and was completed during August 1993.

During the comprehensive LNB plus AOFA test phase, full-load, long-term NOx emissions were approximately 0.40 lb/MBtu (Figure 1). As shown in Figure 2, NOx emissions for the latest round of testing are considerably below the 0.55 lb/MBtu NOx levels found in the abbreviated testing performed during the first quarter 1992.

Based on the data analysis to date, the additional NOx reduction is likely the result of the following factors:

- *Re-Configuration of the CF/SF Low-NOx Burners.* As previously mentioned, FWEC personnel re-configured the burners following Georgia Power obtaining permission from the State of Georgia to resume full load operation on Hammond Unit 4. Prior to the LNB plus AOFA tests, FWEC performed boiler optimization for 34 days. After these abbreviated 1992 LNB plus AOFA tests and prior to comprehensive LNB plus AOFA testing, FWEC personnel were on site an additional 35 days to conduct further boiler and burner configuration. During the latter 35 days, FWEC made adjustments to (1) burner register settings (2) burner sliding tip settings, and (3) secondary and overfire air distribution with no change in total overfire air flow. Further efforts on the LNBs alone may have provided similar increases in their NOx reduction effectiveness. FWEC was on site 29 days conducting optimization in the LNB only configuration.

- *More NOx Favorable Biasing of the Primary Coal and Air Flows.* The fuel bias pattern used in the latest LNB plus AOFA test phase produced lower NOx emissions than the fuel bias patterns used during the LNB test phase. As was found during parametric testing of this unit, other than excess O_2, fuel biasing had a greater impact on NOx emissions than the burner adjustments. As this and other demonstrations progress, the operators and vendors continue to learn more about the proper operation of low-NOx burners.

- *Lower Excess O_2 Levels.* The unit ran at lower excess O_2 levels during the LNB plus AOFA test phase than in any of the previous test phases. During the LNB plus AOFA long-term testing, plant operators may have limited the maximum O_2 levels to help maintain stack particulate compliance. This was not an issue during the AOFA or the abbreviated LNB plus AOFA test phases.

- *Unavailability of Long-Term Data from the Abbreviated Tests.* Data from the abbreviated LNB plus AOFA testing was limited and did not include a statistically significant quantity of long-term data needed to accurately determine the NOx emission characteristic of the unit.

In order to assess the actual incremental effectiveness of the AOFA system accurately, the factors discussed above should be taken into consideration. One method of performing this analysis is to use the NOx vs. AOFA flow sensitivity developed during parametric testing of the unit. Figure 3 shows NOx emissions as a function of AOFA flow for the LNB plus AOFA test phase. Using this curve to extrapolate to zero overfire air flow, the NOx emission level of the furnace without AOFA can be estimated. Using this procedure for the LNB plus AOFA test phase, the effectiveness of the AOFA system when added to the LNBs was approximately 17 percent indicating that much of the incremental NOx reduction achieved was not a result of the AOFA system, but was a result of burner adjustments and other furnace operating conditions. This leads to the conclusion that this unit could achieve approximately 0.48 lb/MBtu (61 percent NOx reduction) with LNBs alone. This NOx reduction is consistent with original projections made by the vendor for this boiler operated with low-NOx burners only.

Given the most recent data and the assumptions described above, a cost analysis similar to the one transmitted to you on March 19, 1992 has been performed. As discussed in the March 19, 1992 transmittal, the installed LNB and AOFA cost data used in these calculations are not actual Hammond 4 cost but reflect more realistic costs based on recent procurement studies prepared by The Southern Company. As shown in Table 1, the incremental annualized cost effectiveness of the AOFA system is \$930 per ton of NOx removed. This value compares with only \$113 per ton NOx removed for the LNBs. Therefore, the incremental NOx reduction benefit of the AOFA system is over 8 times less cost effective in dollars per ton NOx removed than is the incremental benefit of LNBs above uncontrolled emissions.

Detailed analysis of the data obtained from all test phases from this project is in progress with a charge to determine the actual cost effectiveness of the technologies tested at this site divorced from the externalities not directly related to the demonstration. We will be glad to share with you and your staff the results of these studies as they become available. Furthermore, additional tests are planned in the summer of 1994 following installation of a new electrostatic precipitator to evaluate the incremental NOx reduction of AOFA with all six of the new mills in service.

I trust this information is useful. Should you have any questions or comments, please feel to call me at (205) 877-7426.

Sincerely,

John N. Sorge

John N. Sorge
ICCT Project Manager

cc(w/att): Environmental Protection Agency
Carol M. Browner, Administrator for the Environmental Protection Agency

Southern Company Services
S. M. Wilson

Figure 1
NOx Emissions

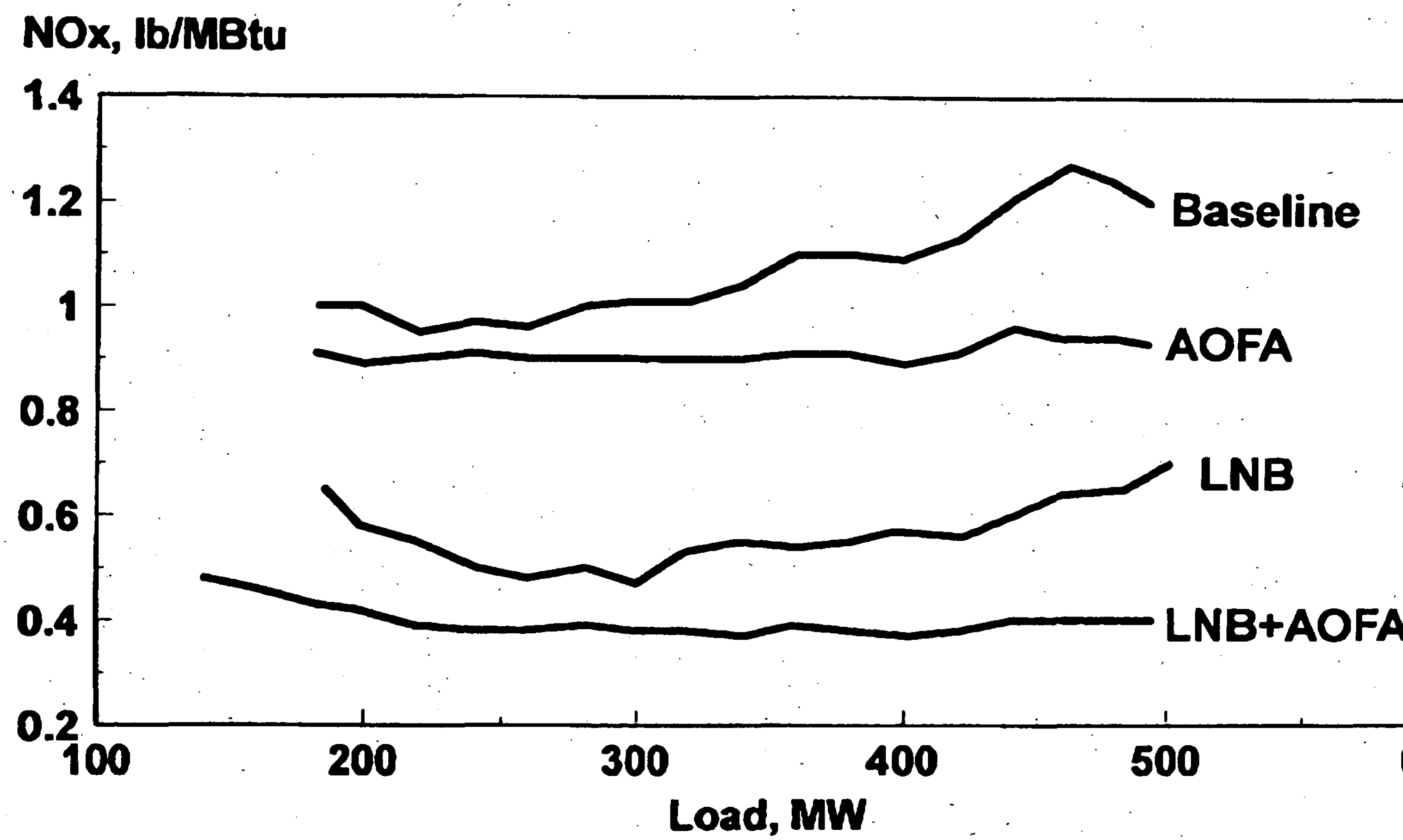


Figure 2
LNB+AOFA NOx Emissions

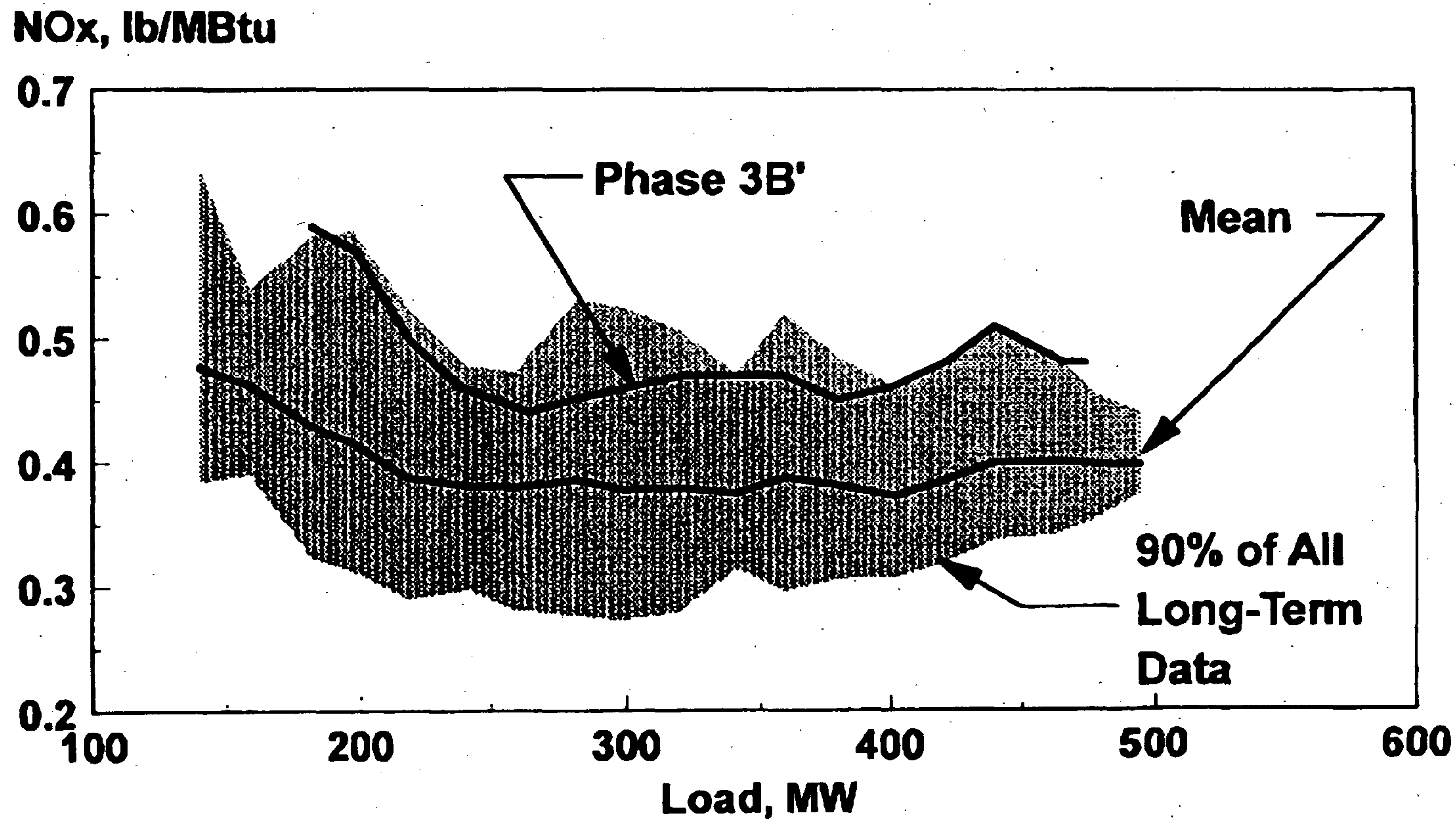


Figure 3
LNB+AOFA - OFA Effectiveness

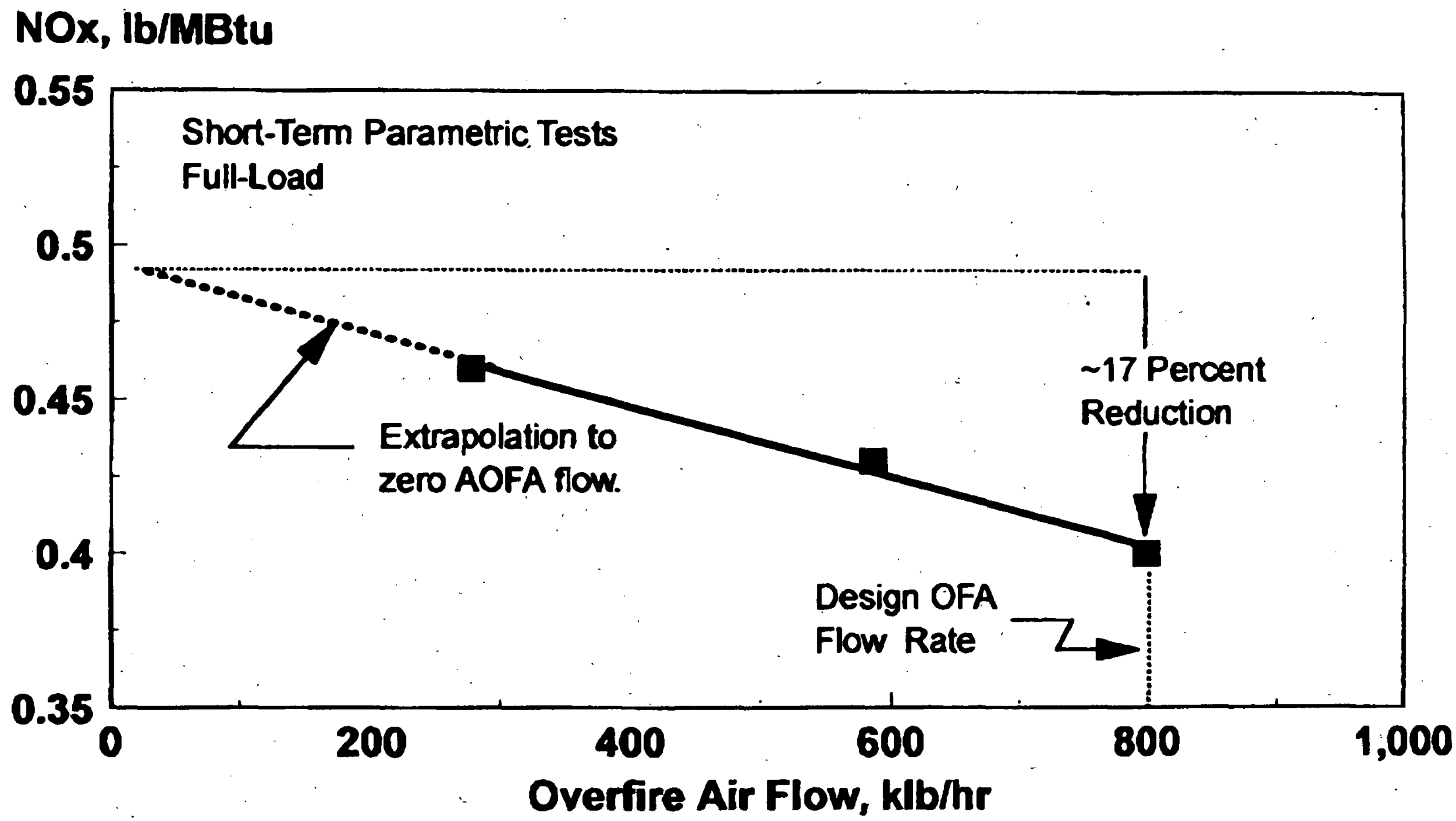


Table 1
Cost Effectiveness

Operating Parameters		
Maximum Load	500000	KW
Capacity Factor	0.7	
Heat Rate	10000	KW/BTU/HR
Capital Annualization Factor (15 Year, Current $)	0.163	
Fuel Cost	35	$/Ton
Fuel HHV	12000	BTU/LB
Fuel Ash	10	PCT

NOx Reductions			
Test Phase	NOx lb/MBtu	NOx Tons/Yr	Incremental NOx Reduction Tons/Yr
Baseline	1.23	18856	-
LNB	0.48	7358	11498
+AOFA	0.40	6132	1226

Loss of Ignition (LNB) Impacts				
	LOI PCT	Change in LOI PCT	Increase of Carbon in Flyash Tons/Yr	Increase Fuel Usage Tons/Yr
Baseline	5	-	-	-
LNB	8	3	3833	4663
+AOFA	8	0	0	0

NOx Control Technology Incremental Cost Effectiveness Capital & Installation Cost Only			
Technology	Technology Incremental Cost $/KW	Cost per Ton NOx Removed $/Ton	Annualized Cost per Ton NOx Removed $/Ton
LNB	14	609	99
+AOFA	14	5708	930

Cost Increase Due to Change in Flyash Loss on Ignition			
Technology	Additional Fuel Required Tons/YR	Incremental Cost $/YR	Cost per Ton NOx Removed $/Ton
LNB	4663	163201	14
+AOFA	0	0	0

NOx Control Technology Incremental Cost Effectiveness Annualized Over 15 Years in $/Ton of NOx Removed			
Technology	Capital & Installation $/Ton	LOI $/Ton	Total $/Ton
LNB	99	14	113
+AOFA	930	0	930

ATTACHMENT 8

ETEC

November 3, 1993

TO: Craig Harrison - Hunton & Williams

FROM: Lowell Smith - ETEC

SUBJECT: Impact of Improved Coal Fineness on Potential Additional NOx Reduction and on Incremental Cost Effectiveness

As we have pointed out numerous times in conferences as well as personal conversations with EPA, UARG and others have determined that coal fineness variations in the range normally experienced in utility boilers does not change the NOx emissions appreciably. The issue has been raised that the improvement in coal fineness could allow operators to decrease the excess oxygen while maintaining the same LOI levels since LOI has been shown to be affected by coal fineness. This decrease in excess oxygen level could result in decreased NOx emissions depending upon the sensitivity of NOx to excess oxygen excursions.

During the comments to EPA, UARG submitted data to support our contention that NOx emissions is not appreciably affected by coal fineness. Those same comments included information that shows that LOI could be improved with improved coal fineness. The following calculations will show to what extent the improved fineness could result in improved NOx reductions. The attached figure illustrates the procedure for making this determination.

The most definitive data that explicitly shows the impact of coal fineness on NOx emissions and LOI was provided in my letter to Robert Hardman dated January 18, 1993 which was included in the UARG comments to EPA. This data was obtained from tests performed on the Lansing Smith Unit 2 under the DOE Clean Coal II project. This same information was presented in the 1993 Joint Symposium on NOx Control in Maimi. Coal fineness measurements at Lansing Smith were performed according to the methods that have been recommended by EPA. The Lansing Smith coal fineness impact results show that LOI can be represented by:

$$\text{LOI} = 69.5 - 1.88\ (\%\text{Fineness}) + 0.0133\ (\%\text{Fineness})^2 \qquad \text{Eq. 1}$$

within the fineness range of 60 to 70 percent through 200 mesh. Assuming that the unit was initially operating at 60 percent through 200 mesh and that new mills were required to achieve 70 through 200 mesh, the decrease in LOI would be approximately 1.522 percentage points.

ENERGY TECHNOLOGY CONSULTANTS, INC.
One Technology Drive, Suite I-809, Irvine, CA 92718 (714) 753-9129 Fax (714) 753-1528
51 Virginia Avenue, West Nyack, NY 10994 (914) 353-0306 Fax (914) 353-0308
12337 Jones Road, Suite 400, Houston, TX 77070 (713) 894-1091 Fax (713) 894-1094

For the Lansing Smith results presented in the UARG comments, the LOI versus excess oxygen sensitivity can represented by:

$$LOI = 13.45 - 2.38 * O_2 \qquad \text{Eq. 2}$$

at the nominal fineness setting. Similar results were obtained for Gaston Unit 2 which were also presented in the UARG comments to EPA. Assuming that LOI was decreased by 1.522 percent by achieving fineness of 70 percent through 200 mesh, the possibility exists for reducing the excess oxygen level by:

$$\Delta\, O_2 = \Delta\, LOI/2.38 = 0.64 \text{ Percent} \qquad \text{Eq. 3}$$

while maintaining the same LOI that was achieved at the 60 percent through 200 mesh mill condition.

Assuming that a 0.64 percent excess oxygen reduction was practical one can determine the NOx reduction potential by utilizing the slopes for the NOx versus excess oxygen curves. It should be pointed out that with some coals reducing the excess oxygen can be limited by the carbon monoxide emissions that are experienced at low levels of excess oxygen, consequently the full range of potential excess oxygen level might not be achievable. Similarly, on many boilers the excess oxygen is utilized to maintain steam temperatures. Decreasing the excess oxygen could result in decreased boiler efficiency (higher fuel costs) or the necessity for modifying the convective pass tubes (increased capital cost). In the following determination, it was assumed that these constraints did not exist.

The Lansing Smith Unit 2, Gaston Unit 2 and Hammond Unit 4 boilers have been tested extensively and their results have been presented in UARG's comments as well as in the public literature. For these three units the NOx versus excess oxygen slopes are as follows:

Unit	Slope
Lansing Smith 2	0.0303 lb/MMBtu / Percent O_2
Hammond 4	0.0460
Gaston 2	0.0580

The potential improvement in NOx emissions can be determined by

$$\Delta\, NOx = Slope * \Delta\, O_2 = Slope * 0.64 \qquad \text{Eq. 4}$$

For each of the units the change in NOx emission would be

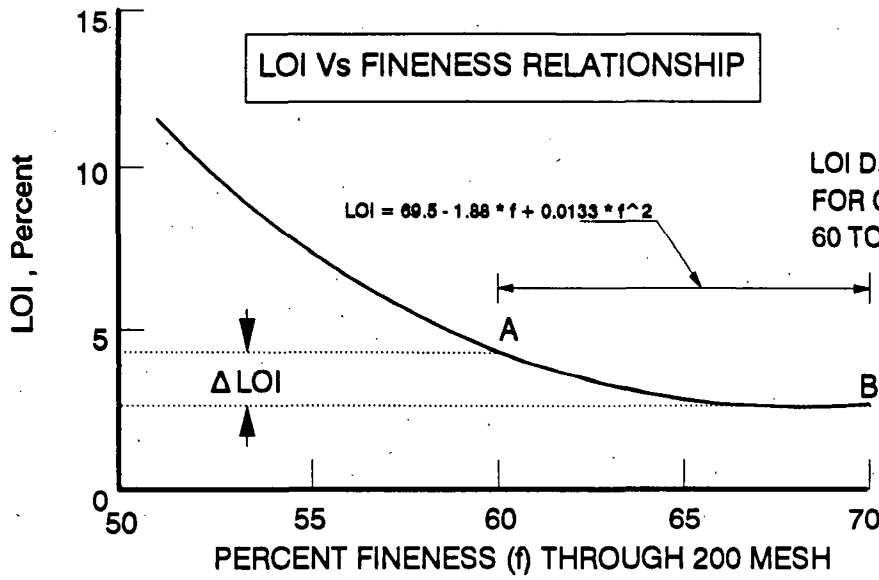
Lansing Smith 2	0.019 lb/MMBtu
Hammond 4	0.029
Gaston 2	0.037

This change in NOx level due to the excess oxygen level reduction covers the range of values that might be expected for utility boilers.

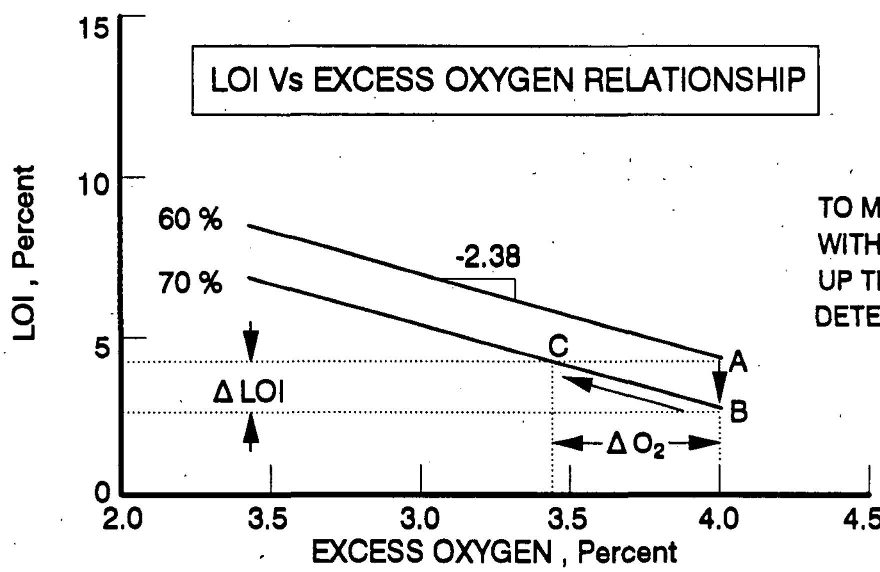
For the sake of estimating the cost effectiveness of a typical 500 MWe boiler, the above potential range of the change in NOx emissions was used along with the range of costs associated with mill replacements. For the Hammond Unit 4, the mill replacement was approximately $20/Kw and for Ohio Edison's Sammis 6, the replacement cost was $33/Kw. The attached table presents the results of an analysis covering the range of potential change in NOx emissions and for mill replacement costs ranging from $15 to $35/Kw. The cost effectiveness values presented in the attached table were for levelized capital costs of mill replacements only and do not include any potential increases in operating costs that may be associated with maintenance required to continuously operate at or above 70 percent through 200 mesh or for any decreases in boiler efficiency. Assuming that the mill replacement cost was the median value of $25/Kw, the cost effectiveness would range from 4115 to 8000 dollars per ton of NOx removed or an order of magnitude higher than that for complete replacement of the original burners with new Low NOx burners.

Based upon this analysis it is my opinion that the potential for improved NOx reduction associated with mill replacement would not be cost effective and may not be practical as a means to minimize NOx emissions since mills degrade over time. The degradation would reduce the potential for NOx reduction at constant LOI levels in this case. If it were required to maintain the 70 percent through 200 mesh, the operating cost would be increased significantly and consequently the cost effectiveness would be significantly higher. In addition, reduction of the excess oxygen may not be practical on many coal-fired boilers due to other considerations such as high CO emissions or decreased steam temperatures.

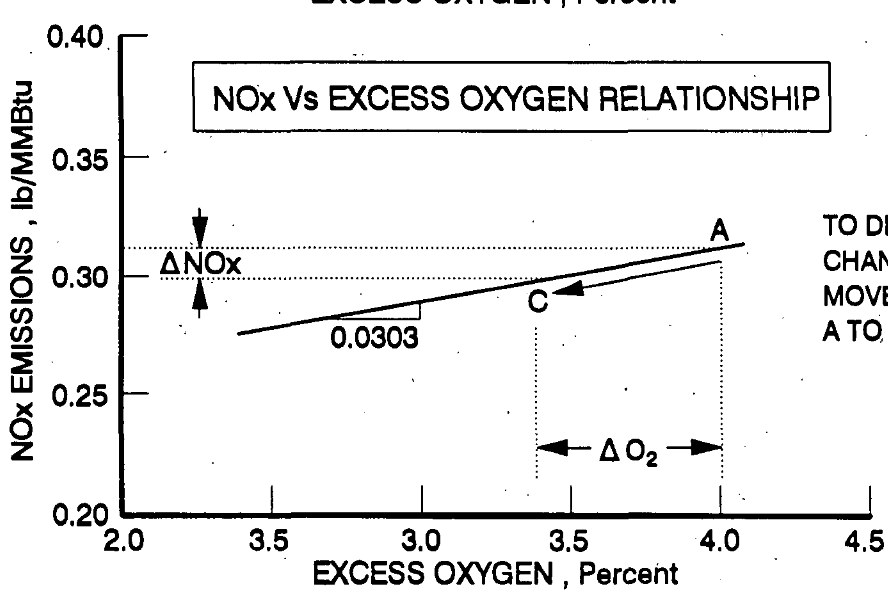
DETERMINATION OF IMPACT OF FINENESS IMPROVEMENT ON NOx REDUCTION POTENTIAL



LOI DECREASES FROM A TO B FOR CHANGE IN FINENESS FROM 60 TO 70 PERCENT THRU 200 MESH



TO MAINTAIN THE SAME LOI WITH IMPROVED FINENESS MOVE UP THE SLOPE FROM B TO C DETERMINE Δ EXCESS OXYGEN



TO DETERMINE THE POTENTIAL CHANGE IN NOx EMISSIONS MOVE DOWN THE SLOPE FROM A TO C

COST EFFECTIVENESS ASSOCIATED WITH MILL REPLACEMENT

NOx Reduction (lb/mmBtu)	NOx Reduction (1) (Tons/Yr.)	Mills' Total Capital Cost (K$)		Levelized Capital (2) Cost (k$/Yr.)	NOx Reduction Cost Effectiveness ($/Ton NOx)
0.019	250	15 $/kw	7,500	1,200	4,800
		25 $/kw	12,500	2,000	8,000
		35 $/kw	17,500	2,800	11,200
0.029	381	15 $/kw	7,500	1,200	3,150
		25 $/kw	12,500	2,000	5,249
		35 $/kw	17,500	2,800	7,349
0.037	486	15 $/kw	7,500	1,200	2,469
		25 $/kw	12,500	2,000	4,115
		35 $/kw	17,500	2,800	5,761

1) NOx reductions are calculated for a 500 MW unit, operating at 60% capacity factor with a Heat Rate of 10,000 BTU/Kwh.

2) The levelized capital cost were calculated using a levelizing factor of 0.160, based on a 9.41% after tax return rate, 20-year economic life and 20-year tax plant life.

ATTACHMENT 9

Systems Applications International

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919/460-2500 Facsimile 919/460-2510
A Division of ICF Kaiser Engineers

MEMORANDUM

TO: UARG Control Technology Committee

FROM: Ralph L. Roberson, P.E.

DATE: November 5, 1993

SUBJECT: Environmental Benefit of Early NO_x Reduction Option

EPA proposed to allow an early election for Group 1, Phase II boilers that comply with the NO_x emission limitation for 1997 and beyond, and proposed to grandfather such units from any revisions that the Agency might make to future NO_x emission limits, in order to encourage early compliance and its concomitant benefits.[1] EPA's proposed approach will not only mitigate the rule's impact on the nation's electrical supply by reducing unplanned or overlapping boiler outages for equipment installation but can also have a significant environmental benefit. The Utility Air Regulatory Group (UARG) asked Systems Applications International (SAI) to design and conduct an analysis that would quantify, or at least bracket, the environmental benefit that could be expected from including an early reduction option in the Agency's final Part 76 NO_x rule.

BASIC ANALYTICAL APPROACH

The basic approach developed by SAI is to predict future annual NO_x emissions with and without an early election option. SAI designed its analysis to focus on the difference in annual NO_x emissions between having and not having an early reduction option in order to mitigate the importance of certain assumptions (e.g., future capacity factors; average, uncontrolled NO_x emission rates; etc.). Also, we know that low NO_x burners (LNBs) tend to achieve a given percentage reduction in NO_x emissions; the reduction simply does not cease when some arbitrary emission limit is reached. However, by examining the difference in annual emissions between having and not having an early reduction option, any overestimate, or more likely underestimate, in LNB performance will be included in the both sets of annual emission estimates (i.e., with and without option) and tend to cancel out when annual differences are computed. Thus, SAI's analysis assumes that installation of LNBs just achieves the emission limit that is defined for each scenario examined.

[1] 57 Fed. Reg. 55632 (1992)

SAI assumes, in all of its calculations, that if an early reduction option exists, LNB retrofits will begin in 1995 and proceed in an orderly fashion, with 20 percent of the boilers being retrofitted each year. Thus, 20 percent of the Group 1, Phase II boilers will be in compliance beginning January 1996, and full compliance will be achieved beginning January 2000. However, retrofits must be completed by December 1997 for the boilers to be "grandfathered" from any lower Phase II emission limits that EPA might promulgate.

The next step in developing the approach is to define several scenarios to examine with respect to NO_x emission limits that EPA could promulgate for Group 1, Phase II boilers. SAI believes that the following three scenarios reasonably bracket potential Group 1 Phase II emission limits:

Scenario 1 - Phase II limits equal Phase I limits
Scenario 2 - Phase II limits: T-fired = 0.40, Wall-fired = 0.45
Scenario 3 - Phase II limits: T-fired = 0.35, Wall-fired = 0.40.

The last step of the approach is to develop a retrofit schedule in the absence of an early reduction option. The absence of an early reduction option will lead to uncertainty with respect to specifying, ordering, and installing equipment. Without an early reduction option, SAI believes that retrofits cannot begin until 1997, the year in which EPA is to issue a final NO_x rule for Group 1, Phase II boilers. Based on information available from LNB vendors and reasonable outage schedules for Group 1 Phase II boilers, SAI believes that from 75 to 100 LNB retrofits can be accomplished in any given year. Accordingly, at least 4 to 6 years will be required for all Group 1, Phase II boilers to achieve compliance with the NO_x emission limits. This implicitly assumes that some Group 1, Phase II boilers will not require retrofits to achieve compliance; otherwise, 100 to 150 LNB retrofits would be required each year to achieve compliance in 4 to 6 years. It is possible that 8 or more years will be required to achieve compliance if installing low NO_x technology for Group 2 boilers (i.e., cell burners, wet bottom wall-fired, and cyclone boilers) were included in this analysis. Moreover, if emission limits for Group 1, Phase II boilers were lowered, many of the boilers that otherwise might comply by emission averaging or operational modifications would be forced to install LNBs.

Thus, SAI's basic approach consists of examining three scenarios, assuming 4 years and 6 years for full compliance without an early reduction option, and comparing estimated annual NO_x emissions <u>without</u> an early reduction option to those estimated <u>with</u> an early reduction option. Basic data used to estimate annual NO_x emissions are taken from the extensive information contained in the rulemaking docket and are summarized as follows:[2]

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[2]See, for example, *Analysis of Low NO_x Burner Technology Costs,* draft report prepared by Radian Corporation for U.S. Environmental Protection Agency, November 24, 1992 (II-A-18).

Boiler Type	No. of Units	Avg. Uncontrolled Emissions, lb/10^6 Btu	Total Annual Heat Input, Btu/yr
T-fired	292	0.69	1.79×10^{13}
Wall-fired	336	0.90	1.41×10^{13}

SUMMARY OF ASSUMPTIONS AND RESULTS OF ANALYSIS

Scenario 1 - Assumptions

- Phase II NO_x emission limits are equal to the Phase I presumptive limits.

- First, without an early reduction option, compliance begins in 1998 and full compliance is achieved in 4 years (January 2001).

- Second, without an early reduction option, compliance begins in 1998 and full compliance is achieved in 6 years (January 2003).

Scenario 1 - Results

- If Phase II limits are equal to Phase I limits, cumulative NO_x emissions will be 3.9 million tons less with the early reduction option assuming full Phase II compliance, in the absence of the option, is not completed until 2003. If full Phase II compliance, in the absence of the option, is completed by 2001, cumulative NO_x emissions would still be 2.4 million tons less with the early reduction option.

- If Phase II limits are equal to Phase I limits, there will always be an early reduction NO_x benefit -- the only real issue is how large will the benefit be.

Scenario 2 - Assumptions

- Phase II limits are as follows: 0.40 lb/10^6 Btu for T-fired and 0.45 for wall-fired boilers.

- First, without an early reduction option, compliance begins in 1998 and full compliance is achieved in 4 years (January 2001).

- Second, without an early reduction option, compliance begins in 1998 and full compliance is achieved in 6 years (January 2003).

Scenario 2 - Results

- For the assumed Group 1, Phase II limits, NO_x emissions will be about 100,000 tons per year less without the option than with the option. However, assuming full compliance beginning January 2001, a cumulative NO_x benefit of about 2.2 million tons is built up by 2001. At the end of 2020, a cumulative benefit of about 0.29 million tons remains.

- Assuming full compliance is achieved beginning January 2003, a cumulative benefit of about 3.8 million tons is accrued by 2003. While NO_x emissions are estimated to be about 100,000 tons per year less without the option than with the option, the cumulative benefit is 3.1 million tons at the end of 2010 and 2.1 million tons at the end of 2020.

Scenario 3 - Assumptions

- Phase II limits are as follows: 0.35 lb/10^6 Btu for T-fired and 0.40 for wall-fired boilers.

- First, without an early reduction option, compliance begins in 1998 and full compliance is achieved in 4 years (January 2001).

- Second, without an early reduction option, compliance begins in 1998 and full compliance is achieved in 6 years (January 2003).

Scenario 3 - Results

- For the assumed Group 1, Phase II limits, NO_x emissions will be about 200,000 tons per year less without the option than with the option. However, assuming full compliance beginning January 2001, a cumulative NO_x benefit of about 2.0 million tons is built up by 2001. At the end of 2010, a cumulative benefit of about 0.22 million tons remains. The benefit is not eroded away, on paper, until 2011.

- Assuming full compliance is achieved beginning January 2003, a cumulative benefit of about 3.7 million tons is accrued by 2003. While NO_x emissions are estimated to be about 200,000 tons per year less without the option than with the option, the cumulative benefit is 2.3 million tons at the end of 2010 and 0.3 million tons at the end of 2020.

A table further summarizing the results of SAI's analysis is attached. Also attached are the Lotus® spreadsheets that show the environmental benefits, for each scenario examined, for individual years.

Attachments

CUMULATIVE BENEFIT OF EARLY NO_x REDUCTION OPTION (million tons)

	2000	2005	2010	2015	2020
Scenario 1					
4 Years	2.36	2.36	2.36	2.36	2.36
6 Years	3.15	3.94	3.94	3.94	3.94
Scenario 2					
4 Years	2.29	1.79	1.29	0.79	0.29
6 Years	3.20	3.61	3.11	2.62	2.12
Scenario 3					
4 Years	2.21	1.22	0.22	<0.78>	<1.77>
6 Years	3.25	3.29	2.29	1.30	0.30

<u>Scenario 1</u>

Phase II limits equal Phase I limits.

<u>Scenario 2</u>

Phase II limits: T-fired = 0.40, Wall-fired = 0.45.

<u>Scenario 3</u>

Phase II limits: T-fired = 0.35, Wall-fired = 0.40.

ASSUMPTIONS:

With early reduction option, LNB retrofits begin in 1995 and proceed in an orderly fashion, with 20 percent of the units being retrofitted each year. Twenty percent of the units will be in compliance by January 1996, and full (100% of the units) compliance is achieved beginning January 2000.

Without early reduction option, compliance with applicable NO_x emission limits begins in 1998 and requires from 4 to 6 years for full (100% of the units) compliance to be achieved. This is consistent with assuming that the range for the number of retrofits that can be completed each calendar year is from about 75 to 100. If 4 years are required, full compliance is achieved beginning January 2001; if 6 years are required, full compliance is acheived beginning January 2003.

SCENARIO 1

			1996	1997	1998	1999	2000
292	T–fired	Low NOx	235,206	470,412	705,618	940,824	1,176,030
	T–fired	Baseline	1,442,597	1,081,948	721,298	360,649	0
336	Wall–fired	Low NOx	236,880	473,760	710,640	947,520	1,184,400
	Wall–fired	Baseline	1,705,536	1,279,152	852,768	426,384	0
		SUM	3,620,219	3,305,272	2,990,324	2,675,377	2,360,430
	Fraction Installed		0.0	0.0	0.25	0.50	0.75
	T–fired	Low NOx	0	0	294,008	588,015	882,023
	T–fired	Baseline	1,803,246	1,803,246	1,352,435	901,623	450,812
	Wall–fired	Low NOx	0	0	296,100	592,200	888,300
	Wall–fired	Baseline	2,131,920	2,131,920	1,598,940	1,065,960	532,980
		SUM	3,935,166	3,935,166	3,541,482	3,147,798	2,754,114
	Annual Benefit		314,947	629,894	551,158	472,421	393,684
Cumulative Benefit			314,947	944,842	1,495,999	1,968,420	2,362,104

			1996	1997	1998	1999	2000
292	T–fired	Low NOx	235,206	470,412	705,618	940,824	1,176,030
	T–fired	Baseline	1,442,597	1,081,948	721,298	360,649	0
336	Wall–fired	Low NOx	236,880	473,760	710,640	947,520	1,184,400
	Wall–fired	Baseline	1,705,536	1,279,152	852,768	426,384	0
		SUM	3,620,219	3,305,272	2,990,324	2,675,377	2,360,430
	Fraction Installed		0.0	0.0	0.167	0.333	0.500
	T–fired	Low NOx	0	0	196,397	391,618	588,015
	T–fired	Baseline	1,803,246	1,803,246	1,502,104	1,202,765	901,623
	Wall–fired	Low NOx	0	0	197,795	394,405	592,200
	Wall–fired	Baseline	2,131,920	2,131,920	1,775,889	1,421,991	1,065,960
		SUM	3,935,166	3,935,166	3,672,185	3,410,779	3,147,798
	Annual Benefit		314,947	629,894	681,861	735,402	787,368
Cumulative Benefit			314,947	944,842	1,626,702	2,362,104	3,149,472

Phase II limits: 0.45/0.50

2001	2002	2003	2004	2005	2010	2015	2020	SCENARIO 1
1,176,030	1,176,030	1,176,030	1,176,030	1,176,030	1,176,030	1,176,030	1,176,030	W/ Early Election
0	0	0	0	0	0	0	0	
1,184,400	1,184,400	1,184,400	1,184,400	1,184,400	1,184,400	1,184,400	1,184,400	Phase II Limits:
0	0	0	0	0	0	0	0	T: 0.45
2,360,430	2,360,430	2,360,430	2,360,430	2,360,430	2,360,430	2,360,430	2,360,430	W: 0.50
1.00	1.00	1.0	1.0	1.0	1.0	1.0	1.0	
1,176,030	1,176,030	1,176,030	1,176,030	1,176,030	1,176,030	1,176,030	1,176,030	
0	0	0	0	0	0	0	0	W/O Early Election
1,184,400	1,184,400	1,184,400	1,184,400	1,184,400	1,184,400	1,184,400	1,184,400	Compliance 2001
0	0	0	0	0	0	0	0	Phase II Limits:
2,360,430	2,360,430	2,360,430	2,360,430	2,360,430	2,360,430	2,360,430	2,360,430	T: 0.45
0	0	0	0	0	0	0	0	W: 0.50
2,362,104	2,362,104	2,362,104	2,362,104	2,362,104	2,362,104	2,362,104	2,362,104	

2001	2002	2003	2004	2005	2010	2015	2020	
1,176,030	1,176,030	1,176,030	1,176,030	1,176,030	1,176,030	1,176,030	1,176,030	W/ Early Election
0	0	0	0	0	0	0	0	
1,184,400	1,184,400	1,184,400	1,184,400	1,184,400	1,184,400	1,184,400	1,184,400	Phase II Limits:
0	0	0	0	0	0	0	0	T: 0.45
2,360,430	2,360,430	2,360,430	2,360,430	2,360,430	2,360,430	2,360,430	2,360,430	W: 0.50
0.667	0.833	1.0	1.0	1.0	1.0	1.0	1.0	
784,412	979,633	1,176,030	1,176,030	1,176,030	1,176,030	1,176,030	1,176,030	
600,481	301,142	0	0	0	0	0	0	W/O Early Election
789,995	986,605	1,184,400	1,184,400	1,184,400	1,184,400	1,184,400	1,184,400	Compliance 2003
709,929	356,031	0	0	0	0	0	0	Phase II Limits:
2,884,817	2,623,411	2,360,430	2,360,430	2,360,430	2,360,430	2,360,430	2,360,430	T: 0.45
524,387	262,981	0	0	0	0	0	0	W: 0.50
3,673,859	3,936,840	3,936,840	3,936,840	3,936,840	3,936,840	3,936,840	3,936,840	

Phase II limits: 0.45/0.50

SCENARIO 2

			1996	1997	1998	1999	2000
292	T–fired	Low NOx	235,206	470,412	209,072	418,144	627,216
	T–fired	Baseline	1,442,597	1,081,948	721,298	360,649	0
	T–fired	Grandfather			470,412	470,412	470,412
336	Wall–fired	Low NOx	236,880	473,760	213,192	426,384	639,576
	Wall–fired	Baseline	1,705,536	1,279,152	852,768	426,384	0
	Wall–fired	Grandfather			473,760	473,760	473,760
		SUM	3,620,219	3,305,272	2,940,502	2,575,733	2,210,964
	Fraction Installed		0.0	0.0	0.25	0.50	0.75
	T–fired	Low NOx	0	0	261,340	522,680	784,020
	T–fired	Baseline	1,803,246	1,803,246	1,352,435	901,623	450,812
	Wall–fired	Low NOx	0	0	266,490	532,980	799,470
	Wall–fired	Baseline	2,131,920	2,131,920	1,598,940	1,065,960	532,980
		SUM	3,935,166	3,935,166	3,479,205	3,023,243	2,567,282
	Annual Benefit		314,947	629,894	538,702	447,510	356,318
Cumulative Benefit			314,947	944,842	1,483,544	1,931,054	2,287,371

			1996	1997	1998	1999	2000
292	T–fired	Low NOx	235,206	470,412	209,072	418,144	627,216
	T–fired	Baseline	1,442,597	1,081,948	721,298	360,649	0
	T–fired	Grandfather			470,412	470,412	470,412
336	Wall–fired	Low NOx	236,880	473,760	213,192	426,384	639,576
	Wall–fired	Baseline	1,705,536	1,279,152	852,768	426,384	0
	Wall–fired	Grandfather			473,760	473,760	473,760
		SUM	3,620,219	3,305,272	2,940,502	2,575,733	2,210,964
	Fraction Installed		0.0	0.0	0.167	0.333	0.500
	T–fired	Low NOx	0	0	174,575	348,105	522,680
	T–fired	Baseline	1,803,246	1,803,246	1,502,104	1,202,765	901,623
	Wall–fired	Low NOx	0	0	178,015	354,965	532,980
	Wall–fired	Baseline	2,131,920	2,131,920	1,775,889	1,421,991	1,065,960
		SUM	3,935,166	3,935,166	3,630,584	3,327,825	3,023,243
	Annual Benefit		314,947	629,894	690,081	752,092	812,279
Cumulative Benefit			314,947	944,842	1,634,923	2,387,015	3,199,294

Phase II limits: 0.40/0.45

2001	2002	2003	2004	2005	2010	2015	2020	SCENARIO 2
627,216	627,216	627,216	627,216	627,216	627,216	627,216	627,216	W/ Early Election
0	0	0	0	0	0	0	0	
470,412	470,412	470,412	470,412	470,412	470,412	470,412	470,412	Phase II Limits:
639,576	639,576	639,576	639,576	639,576	639,576	639,576	639,576	T: 0.40
0	0	0	0	0	0	0	0	W: 0.45
473,760	473,760	473,760	473,760	473,760	473,760	473,760	473,760	
2,210,964	2,210,964	2,210,964	2,210,964	2,210,964	2,210,964	2,210,964	2,210,964	
1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
1,045,360	1,045,360	1,045,360	1,045,360	1,045,360	1,045,360	1,045,360	1,045,360	W/O Early Election
0	0	0	0	0	0	0	0	Compliance 2001
1,065,960	1,065,960	1,065,960	1,065,960	1,065,960	1,065,960	1,065,960	1,065,960	Phase II Limits:
0	0	0	0	0	0	0	0	T: 0.40
2,111,320	2,111,320	2,111,320	2,111,320	2,111,320	2,111,320	2,111,320	2,111,320	W: 0.45
(99,644)	(99,644)	(99,644)	(99,644)	(99,644)	(99,644)	(99,644)	(99,644)	
2,187,727	2,088,083	1,988,439	1,888,795	1,789,151	1,290,931	792,711	294,491	

2001	2002	2003	2004	2005	2010	2015	2020	
627,216	627,216	627,216	627,216	627,216	627,216	627,216	627,216	W/ Early Election
0	0	0	0	0	0	0	0	
470,412	470,412	470,412	470,412	470,412	470,412	470,412	470,412	Phase II Limits:
639,576	639,576	639,576	639,576	639,576	639,576	639,576	639,576	T: 0.40
0	0	0	0	0	0	0	0	W: 0.45
473,760	473,760	473,760	473,760	473,760	473,760	473,760	473,760	
2,210,964	2,210,964	2,210,964	2,210,964	2,210,964	2,210,964	2,210,964	2,210,964	
0.667	0.833	1.0	1.0	1.0	1.0	1.0	1.0	
697,255	870,785	1,045,360	1,045,360	1,045,360	1,045,360	1,045,360	1,045,360	W/O Early Election
600,481	301,142	0	0	0	0	0	0	Compliance 2003
710,995	887,945	1,065,960	1,065,960	1,065,960	1,065,960	1,065,960	1,065,960	Phase II Limits:
709,929	356,031	0	0	0	0	0	0	T: 0.40
2,718,661	2,415,902	2,111,320	2,111,320	2,111,320	2,111,320	2,111,320	2,111,320	W: 0.45
507,697	204,938	(99,644)	(99,644)	(99,644)	(99,644)	(99,644)	(99,644)	
3,706,991	3,911,929	3,812,285	3,712,641	3,612,997	3,114,777	2,616,557	2,118,337	

Phase II limits: 0.40/0.45

SCENARIO 3

		1996	1997	1998	1999	2000
T-fired	Low NOx	235,206	470,412	182,938	365,876	548,814
T-fired	Baseline	1,442,597	1,081,948	721,298	360,649	0
T-fired	Grandfather			470,412	470,412	470,412
Wall-fired	Low NOx	236,880	473,760	189,504	379,008	568,512
Wall-fired	Baseline	1,705,536	1,279,152	852,768	426,384	0
Wall-fired	Grandfather			473,760	473,760	473,760
	SUM	3,620,219	3,305,272	2,890,680	2,476,089	2,061,498
Fraction Installed		0.0	0.0	0.25	0.50	0.75
T-fired	Low NOx	0	0	228,673	457,345	686,018
T-fired	Baseline	1,803,246	1,803,246	1,352,435	901,623	450,812
Wall-fired	Low NOx	0	0	236,880	473,760	710,640
Wall-fired	Baseline	2,131,920	2,131,920	1,598,940	1,065,960	532,980
	SUM	3,935,166	3,935,166	3,416,927	2,898,688	2,380,449
Annual Benefit		314,947	629,894	526,247	422,599	318,951
Cumulative Benefit		314,947	944,842	1,471,088	1,893,687	2,212,638

			1996	1997	1998	1999	2000
292	T-fired	Low NOx	235,206	470,412	182,938	365,876	548,814
	T-fired	Baseline	1,442,597	1,081,948	721,298	360,649	0
	T-fired	Grandfather			470,412	470,412	470,412
336	Wall-fired	Low NOx	236,880	473,760	189,504	379,008	568,512
	Wall-fired	Baseline	1,705,536	1,279,152	852,768	426,384	0
	Wall-fired	Grandfather			473,760	473,760	473,760
		SUM	3,620,219	3,305,272	2,890,680	2,476,089	2,061,498
	Fraction Installed		0.0	0.0	0.167	0.333	0.500
	T-fired	Low NOx	0	0	152,753	304,592	457,345
	T-fired	Baseline	1,803,246	1,803,246	1,502,104	1,202,765	901,623
	Wall-fired	Low NOx	0	0	158,236	315,524	473,760
	Wall-fired	Baseline	2,131,920	2,131,920	1,775,889	1,421,991	1,065,960
		SUM	3,935,166	3,935,166	3,588,982	3,244,872	2,898,688
	Annual Benefit		314,947	629,894	698,302	768,782	837,190
	Cumulative Benefit		314,947	944,842	1,643,144	2,411,926	3,249,116

Phase II limits: 0.35/0.40

2001	2002	2003	2004	2005	2010	2015	2020	SCENARIO 3
548,814	548,814	548,814	548,814	548,814	548,814	548,814	548,814	W/ Early Election
0	0	0	0	0	0	0	0	
470,412	470,412	470,412	470,412	470,412	470,412	470,412	470,412	Phase II Limits:
568,512	568,512	568,512	568,512	568,512	568,512	568,512	568,512	T: 0.35
0	0	0	0	0	0	0	0	W: 0.40
473,760	473,760	473,760	473,760	473,760	473,760	473,760	473,760	
2,061,498	2,061,498	2,061,498	2,061,498	2,061,498	2,061,498	2,061,498	2,061,498	
1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
914,690	914,690	914,690	914,690	914,690	914,690	914,690	914,690	
0	0	0	0	0	0	0	0	W/O Early Election
947,520	947,520	947,520	947,520	947,520	947,520	947,520	947,520	Compliance 2001
0	0	0	0	0	0	0	0	Phase II Limits:
1,862,210	1,862,210	1,862,210	1,862,210	1,862,210	1,862,210	1,862,210	1,862,210	T: 0.35
(199,288)	(199,288)	(199,288)	(199,288)	(199,288)	(199,288)	(199,288)	(199,288)	W: 0.40
2,013,350	1,814,062	1,614,774	1,415,486	1,216,198	219,758	(776,682)	(1,773,122)	

2001	2002	2003	2004	2005	2010	2015	2020	
548,814	548,814	548,814	548,814	548,814	548,814	548,814	548,814	W/ Early Election
0	0	0	0	0	0	0	0	
470,412	470,412	470,412	470,412	470,412	470,412	470,412	470,412	Phase II Limits:
568,512	568,512	568,512	568,512	568,512	568,512	568,512	568,512	T: 0.35
0	0	0	0	0	0	0	0	W: 0.40
473,760	473,760	473,760	473,760	473,760	473,760	473,760	473,760	
2,061,498	2,061,498	2,061,498	2,061,498	2,061,498	2,061,498	2,061,498	2,061,498	
0.667	0.833	1.0	1.0	1.0	1.0	1.0	1.0	
610,098	761,937	914,690	914,690	914,690	914,690	914,690	914,690	
600,481	301,142	0	0	0	0	0	0	W/O Early Election
631,996	789,284	947,520	947,520	947,520	947,520	947,520	947,520	Compliance 2003
709,929	356,031	0	0	0	0	0	0	Phase II Limits:
2,552,504	2,208,394	1,862,210	1,862,210	1,862,210	1,862,210	1,862,210	1,862,210	T: 0.35
491,006	146,896	(199,288)	(199,288)	(199,288)	(199,288)	(199,288)	(199,288)	W: 0.40
3,740,122	3,887,018	3,687,730	3,488,442	3,289,154	2,292,714	1,296,274	299,834	

Phase II limits: 0.35/0.40

ATTACHMENT 10

Southern Company Services, Inc.
Post Office Box 2625
Birmingham, Alabama 35202-2625
Telephone 205 870-6011

Southern Company Services
the southern electric system

October 21, 1993

Mr. Craig S. Harrison, Esquire
Hunton and Williams
Post Office Box 19230
Washington, D. C. 20036

RE: Optimization Time for Low NOx Combustion Systems

Dear Craig:

Enclosed for your use is a table showing the time required to optimize eleven (11) low-NOx combustion systems that have been installed on nine (9) different boilers in the Southern electric system. This group of units includes tangentially-fired and wall-fired boilers ranging in size from 250 to 880 MW. Optimization time for this group of boilers ranged from 24 to 476 days.

In the table, two different periods of time are provided. The number of "days on site" refers to the actual number of days required to perform the optimization process. The number of "calendar days elapsed" refers to the period of time that elapsed from the time that optimization began until the optimization process was completed. The tasks included in the optimization process are:

1) Boiler start up,

2) Tuning by the low-NOx combustion system vendor,

3) Integration of combustion system operations with other plant systems, and

4) Acceptance (guarantee) testing.

I trust that this information is helpful. Should you have any questions, please call me at (205) 877-7772.

Sincerely,

Robert R. Hardman

Robert R. Hardman
Senior Research Engineer

enclosure

cc: D. M. Boylan
J. N. Sorge
A. L. Sumerlin
H. S. Williamson
S. M. Wilson

Optimization time

Operating Company	Unit	Size	Type	Vendor	Technology	Days On Site	Calendar Days Elapsed	Optimization Status**
Alabama Power	Gaston 2	250	WF	B&W	XCL LNB	20	28	complete
Alabama Power	Gaston 3	250	WF	B&W	XCL LNB	10	60	complete
Georgia Power	Bowen 2	700	TF	NEI	LNCFS	56	315	incomplete
Georgia Power	Bowen 4	880	TF	NEI	LNCFS	77	154	complete
Georgia Power	Hammond 4	500	WF	FWEC	CF/SF-LNB	29	53	complete
Georgia Power	Hammond 4	500	WF	FWEC	LNB+AOFA	69	476	complete
Georgia Power	Wansley 1	880	TF	ABB-CE	LNCFS II	66	75	complete
Georgia Power	Yates 6	350	TF	NEI	LNCFS	75	128	complete
Gulf Power	Smith 2	180	TF	ABB-CE	LNCFS II	28	28	complete
Gulf Power	Smith 2	180	TF	ABB-CE	LNCFS III	24	24	complete
Mississippi Power	Watson 4	250	TF	FWEC	IFS-LNB	177	177	incomplete

** Optimization includes vendor tuning, plant optimization, and acceptance testing