EPA-450/3-77-048

December 1977

IMPACT OF MODIFICATION/ RECONSTRUCTION OF STEAM GENERATORS ON SO_2 EMISSIONS

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Waste Management
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

EPA-450/3-77-048

IMPACT OF MODIFICATION/RECONSTRUCTION OF STEAM GENERATORS ON SO_2 EMISSIONS

by

M. Bornstein, P. Fennelly,
R. Hall, and D. Roeck

GCA Corporation
GCA/Technology Division
Burlington Road
Bedford, Massachusetts

Contract No. 68-02-2607
Work Assignment No. 3

EPA Project Officers:

K.R. Durkee & K.R. Woodward

Program Manager

Joseph A. McSorley

Prepared for

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Waste Management
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

December 1977

This report is issued by the Environmental Protection Agency to report technical data of interest to a limited number of readers. Copies are available free of charge to Federal employees, current contractors and grantees, and nonprofit organizations - in limited quantities - from the Library Services Office (MD-35), Research Triangle Park, North Carolina 27711; or, for a fee, from the National Technical Information Service, 5285 Port Royal Road, Springfield, Virginia 22161.

This report was furnished to the Environmental Protection Agency by GCA Corporation, GCA/Technology Division, Burlington Road, Bedford, Mass., in fulfillment of Contract No. 68-02-2607, Work Assignment No. 3. The contents of this report are reproduced herein as received from GCA Corporation. The opinions, findings, and conclusions expressed are those of the authors and not necessarily those of the Environmental Protection Agency. Mention of company or product names is not to be considered as an endorsement by the Environmental Protection Agency.

Publication No. EPA-450/3-77-048

ABSTRACT

This report discusses the terms "modification" and "reconstruction" as related to New Source Performance Standards (NSPS) for SO_2 emissions from coal-fired boilers greater than 250 million Btu per hour input. An analysis of current boiler technology indicates there are few physical or operational changes that would qualify as modifications or reconstruction in the sense of altering SO_2 emissions from a boiler system. This is true because SO_2 emissions are a function of the sulfur content of the fuel and are not affected by furnace and boiler design and operating parameters. Two situations which could be construed as modifications affecting SO_2 emissions would be conversion of a wood burning facility to coal or the use coal/oil slurries in a boiler originally designed for oil. Neither of these are expected to be widespread occurrences. First, there are few wood-fired boilers in the size range covered by NSPS and, secondly, it is doubtful there would be any incentive for such units to switch from a cheap waste fuel to a more expensive primary fuel. Boilers using coal/oil slurries have only recently been proposed and are still at an experimental stage.

Also discussed in this report are some of the constraints that could inhibit an existing facility from installing flue gas desulfurization equipment.

CONTENTS

SECTION 1

INTRODUCTION AND SUMMARY

New Source Performance Standards (NSPS) were promulgated by the Environmental Protection Agency (EPA) on December 23, 1971, as part of 40 CFR Part 60. Fossil fuel-fired steam generating units larger than 73 megawatts (250 x 10^6 Btu per hour) heat input were covered under subpart D.

The limit on emissions of sulfur dioxide from affected coal-fired facilities is 520 nanograms per joule (1.2 lb per million Btu) heat input, which is equivalent to about a 75 percent reduction in SO_2 emissions from plants burning 3 percent sulfur coal. This emission limitation is effective for any facility firing coal which is greater than the stated size and which began construction after the date of proposal of the standard (August 17, 1971) or for any existing facility which is significantly modified or reconstructed after that date.

On October 15, 1974, EPA proposed amendments to these regulations with respect to modification, notification, and reconstruction. These amendments were adopted and became effective on the date they were published - December 16, 1975.

It is the purpose of this study to identify and asess possible and typical changes to steam generators that are affected by the amendments to NSPS dealing with modifications and reconstruction. A further objective is to assess constraints which might hinder the application of flue gas desulfurization to modified facilities.

Few physical or operational changes have been identified which would qualify as modifications or reconstruction of an existing boiler. This is true primarily because SO_2 emissions are a function of the sulfur content of the fuel and are not affected by furnace and boiler design and operating parameters.

Certain obvious constraints attributable to cost, land and water availability, and the configuration of equipment at an existing facility tend to hinder the installation of flue gas desulfurization systems to control SO_2 emissions from coal-fired boilers. Many of these constraints are site related and must be considered on an individual basis.

SECTION 2

MODIFICATIONS OF COAL-FIRED POWER PLANTS

MODIFICATION AS COVERED BY NSPS

In certain situations, modifications of already existing industrial operations can cause these facilities to be regulated by New Source Performance Standards. Situations in which this can occur are delineated in Paragraph 60.14 of Part 60 of Chapter I, Title 40 of the Code of Federal Regulations (CFR). Specifically the amended regulations state:

§60.14 Modification

- 60.14(a)—Except as provided under paragraphs (d), (e), and (f) of this section, any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of Section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.

As indicated above, there are certain exceptions to the rule for describing source modifications with respect to New Source Performance Standards. These are summarized below:

- 60.14(d)—(Simply stated, this exception indicates that physical or operational changes are allowed for one facility within a source, with a corresponding increase in emissions from that facility, provided that the overall emissions from the source do not increase. If the owner can demonstrate that the overall emissions have not increased, then a "Modification" is deemed *not* to have occurred. The burden of proof is on the operator.)

- 60.14(e)—The following shall not, by themselves be considered modifications:

  - Routine maintenance, repair, and replacement

  - An increase in production without an increase in capital expenditure

  - An increase in the hours of operation

- Use of an alternative fuel or raw material for which the facility was designed to use
- The addition of air pollution control equipment
- Relocation or change in ownership

Relative to an increase in production, a capital expenditure is defined as an expenditure for a physical or operational change which exceeds the product of the applicable "annual asset guideline repair allowance percentage" (AAGRAP) (as specified in the Internal Revenue Service Publication 534) and the existing facility's "basis," as defined by Section 1023 of the Internal Revenue Code. For the purposes of 60.14(e)(2), the total amount of expenditures necessary to increase the facility's operating rate must not be reduced by any excluded additions as given in Publication 534. The tabulation of annual asset guideline repair allowance (AAGRAP) percentages at the end of Publication 534 shows values for three categories that could be applicable to coal-fired boilers. The first lists an AAGRAP of 5 percent for an electric utility steam production plant producing electricity for sale. The second shows an AAGRAP of 2.5 percent for central steam production and distribution for sale. The third category is for steam and electric generation systems for use by the taxpayer in his industrial manufacturing process or plant activity and a value of 2.5 percent is given. Further information concerning the economics of boiler operations is provided in Appendix A.

- 60.14(f)— Special provisions set forth under an applicable support of this part shall supercede any conflicting provision of this section.

"MODIFICATIONS": THEIR EFFECT ON COAL-FIRED POWER PLANTS AND SO_2 EMISSIONS

Changes which could be deemed *modifications* break down into two categories— physical and operational. The physical boundaries of the facility are currently defined as the coal reduction equipment on the front end of the boiler, through the boiler and its accessories; e.g., air preheaters, economizers, ash hoppers, etc., up to the stack. (If control equipment is installed the system terminates before the control devices.) The essential feature in the case of either physical or operational changes is that the activity must result in an increase in emissions. In power plants, SO_2 emissions are related only to the amount of sulfur contained in the fuel. In general, 90 percent or more of the sulfur in the fuel is emitted as SO_2 although high alkali fuels; i.e., lignites and many low rank coals, do retain more sulfur in the ash.

There are very few situations which would cause an existing facility to become affected through the "modification" provision. The obvious example of fuel switching (oil or gas to coal) which would lead generally to substantial increases in sulfur emissions is not likely to occur because of the high cost of the many physical changes required to connect the facility, the increased land requirements, other problems associated with the storage and handling of coal and ash and the considerable downrating of the facility, typically 40 to 50 percent[1] which occurs. As an example, connection of a 300,000 lb/hr oil/gas unit for spreader stoker operations would require the facility operator to:[2]

- Modify the furnace to accommodate a spreader and dual fire air system
- Provide space for the dropped furnace rotor, an ash hopper and ash removal system
- Add superheater surfaces
- Add additional sootblower and associated piping, etc.
- Add hoppers for fly ash collection and reinjection
- Modify the air heater and install an economizer
- Install a dust collector ahead of the regenerative a.c. heater
- Install new foundations, support timer etc. as required
- Modify combustion and safety controls
- Add an induced-draft fan for balanced draft operation
- Modify furnace backstays and add duct work stiffeners for balanced draft operations

The above modifications will take about 18 to 24 months and will result in a downrating of the unit to between 150,000 to 175,000 lb/hr. The connection to pulverized coal firing would require even more extensive modifications and would take about 24 to 30 months.[2]

Numerous literature references indicate that conversion of oil or gas units to coal is basically impractical.[1-4] In addition to literature sources, contacts with utility operators and individuals associated with combustion oriented organizations (see Appendix B), confirmed that conversions, except for the case of units designed primarily to burn coal, would be costly and impractical. These individuals were also unable to identify practical physical or operational changes that would cause a facility to become affected by the "modification" provision. Changes such as the conversion of a stoker unit to a slag-tap or cyclone furnace would increase emissions by approximately 5 to 10 percent but are unlikely to occur because of the unfavorable economics associated with such conversions.

A boiler designed originally for gas firing may be almost impossible to convert economically to coal firing.[3] Furthermore, it should be noted that a conversion to coal carried out because of energy considerations is exempt from NSPS. A more practical conversion would be the conversion from a wood burning facility to coal. Although some modification of equipment (e.g., fuel feed and replacement of burners) would usually be required, the change could be accomplished relatively inexpensively. Based on EPA SO_2 emission factors, the conversion would increase SO_2 emissions and would be covered by the "modification" provision. However, very few conversions of this type seem likely to occur since wood burning units were planned to take advantage of a cheap, available fuel which might otherwise be considered waste.

One development,[5] the combustion of coal suspended in oil in conventional oil-fired boilers, may be of interest as a "modification." If this development proves successful, the boiler could be considered coal-fired. If used in this fashion, such a boiler would result in an increase in SO_2 emissions.

SECTION 3

RECONSTRUCTION OF COAL-FIRED POWER PLANTS

RECONSTRUCTION AS COVERED BY NSPS

As stated in §60.15, Title 40 of Code of Federal Regulations (CFR), "Reconstruction" means the replacement of components of an existing facility to such an extent that the fixed capital costs of the new components exceeds 50 percent of the fixed capital costs required to construct a comparable entirely new facility. For the "reconstruction" criteria to apply, it is also necessary that it is technically and economically feasible to meet the NSPS standards for the pollutant in question.

RECONSTRUCTION/COAL-FIRED POWER PLANTS

Conceivably, a switch from natural gas (or oil), to coal may classify as a "reconstruction" since such an action may well exceed 50 percent of the cost of a comparible facility. If the cost did not exceed 50 percent the changes would constitute a "modification" (provided the conversion to coal was not required for energy considerations), because of increased SO_2 emissions.

Approximately 50 to 80 boilers[6] will be required by the Federal Energy Administration to convert back to coal. While switches from oil or gas to coal which are federally mandated have been defined as not subject to NSPS a certain number of voluntary conversions may occur. State legislation, such as the Texas Railroad Commissions' Ruling No. 600, may also force facilities to convert to coal. This ruling was passed in December 1975 and amended in March of 1976; it specifies that gas utilities must limit new natural gas sales to 3 million cubic feet per day to any company wishing to use that premium fuel in boilers. For those companies already operating above the 3 million limit, gas deliveries are to be cut by January 1, 1981 to 90 percent of the highest consumption attained in 1974 or 1975. Given this impetus, Texas firms are beginning the switch away from natural gas.[6]

Voluntary conversion will be few in number because of the high cost of boiler modification as discussed previously. For the most part changes will occur because of fear of shortages in natural gas and oil supplies.

SECTION 4

CONSTRAINTS PREVENTING APPLICATION OF FGD

An objective of this program is to identify and assess the constraints which might prevent the application of FGD to a modified facility. Generally, difficulties regarding the installation of FGD are technically solvable although the cost impact will be increased. Section 3 of the Clean Air Act specifies that cost must be considered in promulgating new source performance standards as quoted below:

> "A standard for emission of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction) the Administrator determines has been adequately demonstrated."

Therefore, potential constraints are identified and discussed in relationship to their potential cost impacts.

The capital investment required for a FGD system applied to an existing plant will typically be 10 to 20 percent higher than at a new plant.[7,8] However, in specific instances difficulties can be much more severe than the typical case, potentially increasing capital investments 60 percent.[7] An additional and important factor is that existing plants will tend to have shorter life expectancies. A new plant can be expected to last 30 years while an existing plant may only last 10 years and operate at lower loads during that period. Annual FGD costs in terms of mills/kWh for the existing plant in the above example operating at the same load as the new plant, should be two to three times as high as the new plant.[8]

LAND RESTRICTIONS

Land availability can be a major constraint. Space in the immediate vicinity of the flue gas ducting is required for the scrubber modules, fans, pumps and associated ducting. For a typical 500 MW plant about 17,000 to 34,000 ft^2 will be needed.[8] While the amount of land required for the scrubbers is not large, the location is critical— it must be in close proximity to the boilers where space is often limited. Additional land (4 to 8 acres) is required for raw material (i.e., lime/limestone), receiving, storage and preparation, access roads, and a process control building.

Land for each of the three requirements (scrubber modules, raw material storage and handling, and sludge disposal) can be constraints on the installation of FDG systems. The actual land area required for the scrubber modules is not large and will seldom create problems that are not solvable. Longer duct runs, staking and elevating equipment, and other engineering modifications can usually be successfully employed to meet space limitations. Raw material storage and handling requires more land but more options for location are available. In addition, the amount of limestone required is much less than the amount of coal and the storage area is also relatively smaller. For example, at a plant using a 3.5 percent sulfur coal, the quantity of limestone required would be 5 to 10 percent of the coal quantity. A coal-fired power plant should be able to locate space for limestone storage.

The disposal of sludge generated by a nonregenerative scrubbing system is responsible for significant land requirement. A new 500 MW plant burning 3.5 percent sulfur coal would require 130 acres for disposal of sludge over a 30-year period.[8] The same plant would also require 75 acres for disposal of fly ash.[8] At some existing sites the availability of land may be a serious constraint.

An additional problem is that some land will not be suitable because of environmental considerations. Offsite disposal may be an option as evidenced by the practice at the Bruce Mansfield station, where sludge is pumped 7 miles for disposal.[9] A situation could, however, arise at an existing plant where the cost of sludge disposal would be prohibitive. If onsite land is unavailable, expansion may be impossible (within reasonable economic limits) because the surrounding land is already developed and pipe lines through developed areas may also be prohibitively expensive. The use of a regenerative system could eliminate or minimize any sludge disposal problem. However, for systems producing sulfuric acid, markets must be available or storage problems will be serious. On the other hand, sulfur can be easily stored in outdoor piles if markets are not available.

CONSTRAINTS CAUSED BY EQUIPMENT CONFIGURATIONS

During the design and construction of a new plant FGD equipment will be included as an integral part of the plant. Flue gas at a specified temperature and maximum dust loading will be specified and included in the design. Space for FGD will be provided and the location of particulate removal equipment, FGD system, fans and the stack will be provided so that extensive ducting and other problems are avoided.

At an existing plant, equipment locations and configurations can present problems. For instance, it is not uncommon at existing plants to have the stack located on the roof of the building. Many steam electric plants in operation prior to 1971 have roof-mounted stacks in order to take advantage of building elevations of 100 to 200 feet. Some examples are facilities at

Sunbury, Pennsylvania and some older units at Mystic and Salem, Massachusetts. Even the modern Canal Plant at Sandwich, Massachusetts has a roof mounted stack. This may require long runs of ducting to ground level and back to the stack or construction of a new stack. Another typical problem is the location of the particulate control device (usually an electrostatic precipitator) in relationship to the stack and other equipment. If the electrostatic precipitator is very close to the stack, it may be difficult to install new ducting between the ESP and the stack without disturbing the flow patterns and decreasing efficiency.

Figure 1 is a drawing of a boiler that exemplifies some of the equipment configuration problems. The application of FGD to the boiler in Figure 1 is technically feasible but the cost will be higher than application to a new plant. Devitt, et al.[10] have estimated that typical capital cost increases for long duct runs will range from 4 to 7 percent, tight space will range from 1 to 18 percent and a new stack from 6 to 20 percent.

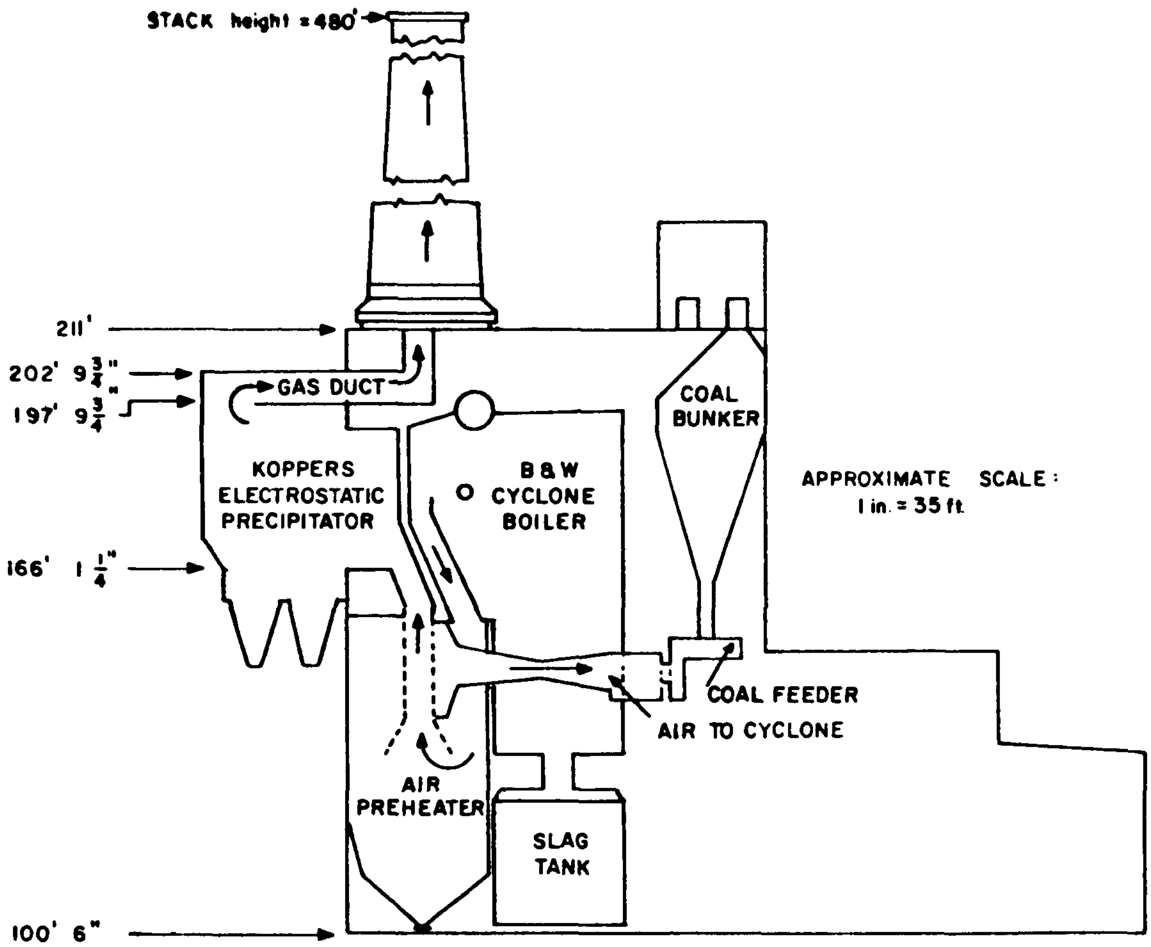

Figure 1. Diagram of a boiler exhibiting some retrofit problems.

REFERENCES

1. Schweiger, R. Industrial Boilers, What's Happening Today. Power. p.516, February 1977.

2. Should you Convert to Coal. Power. p. 38. July 1976.

3. Bell, A.W. and B.P. Breen. Converting Gas Boilers to Oil and Coal. Chemical Engineering. April 26, 1976. p. 93.

4. Bogot, A. and R. C. Sarreiz. Principal Aspects of Converting Steam Generators Back to Coal Firing. Combustion. March 1976.

5. Coal/Oil Burned in Oil Burner. Coal Age. p. 24. October 1976.

6. Conversion to Coal Firing Picks up Steam. Chemical Enginnering. February 14, 1977. p. 40.

7. Ponder, T. C., L. V. Yerino, V. Katari, Y. Shah, and T. W. Devitt. Simplified Procedures for Estimating Flue Gas Desulfurization System Costs. PEDCo-Environmental Specialists, Inc. EPA-600/2-76-150, U.S. Environmental Protection Agency, June 1976.

8. McGlamery, G. G., R. L. Torstrick, W. J. Broadfoot, J. P. Simpson, L. J. Henson, S. V. Tomlinson, and J. F. Young. Detailed Cost Estimates for Advanced Effluent Desulfurization Process. Tennessee Valley Authority. EPA-600/2-75-006, U.S. Environmental Protection Agency, January 1975.

9. Summary Report— Flue Gas Desulfurization Systems— November-December 1976. PEDCo-Environmental Specialists, Inc. Prepared for U.S. Environmental Protection Agency, Contract No. 68-02-1321, Task Order No. 28. January 1977.

10. Devitt, T. W., L. V. Yerino, T. C. Ponder, and C. J. Chatlynne. Estimating Costs of Flue Gas Desulfurization Systems for Utility Boilers. J Air Pollut Control Assoc. Volume 26, Number 3, March 1976.

APPENDIX A

ECONOMICS OF NEW CONSTRUCTION, REPAIR AND MAINTENANCE

This section is for the purpose of establishing the costs involved for construction of new power plants and for routine repair and maintenance. New construction costs will serve as a guide in assessing the fixed capital cost required for new facilities. This is applicable in determining whether or not an existing facility has been reconstructed to the extent that it will become an affected facility under NSPS.

The types of repair and maintenance to be enumerated and their relative costs can be used in determining what types of repair and maintenance activities are routinely performed at an electric plant so that they can be distinguished from "modifications" as defined in the NSPS.

NEW CONSTRUCTION

The cost of construction of new coal-fired power plants is projected to increase dramatically in the next several decades. In 1967, the cost of constructing a new coal-fired plant was approximately $115 per kilowatt (kW). The cost of putting a 1000 megawatt (MW) coal plant on line in mid 1975 was about $200 million or $200 per kW. The projection for 1980 is $450 per kW and for 1990 is $950 per kW.[1,2] An example of the breakdown of the costs involved for the various system components is given in Table A-1 for a 1000 MW coal-fired facility going on line in July 1969. The total direct cost incurred would be approximately 117 million dollars. In addition to this cost, there would be another 10 million dollars for indirect costs, 8 million for contingency, 39 million for escalation, and 21 million in interest to make a total of 195 million dollars. The same total costs for a comparable nuclear facility would be about 239 million dollars for the same start-up date.

REPAIR AND MAINTENANCE

Repair and maintenance of coal-fired boilers can result in significant costs to power plant operators. While there is a difference between the two terms, they are most often considered together in available cost information. The National Boiler Inspection Code does, however, distinguish between repair and maintenance and as an example defines repairs as the following items:

1. Replacement of sections of boiler tubes, provided the remaining part of the tube is not less than 75 percent of its original thickness.

2. Seal welding of tubes.

TABLE A-1. DIRECT CAPITAL COSTS FOR CONSTRUCTION OF A 1000 MW COAL-FIRED PLANT - JULY, 1969 START-UP[1]

Direct costs only	Cost - 10^6 dollars
Boiler	24
Boiler erection	8
Boiler structural steel	3
Draft system	3
Ash handling system	5
Coal handling including chimneys and high-efficiency ESP	7
Turbine-generating unit	20
Turbine-generator erection	2
Heater cycle and condensing system	18
Accessory and auxiliary electrical equipment	10
Miscellaneous power plant equipment	5
Instrumentation	1
Other structures	7
Site improvement	4
Total	117

3. Building-up of certain corroded surfaces.

4. Repairs of cracked ligaments of drums or headers within certain definite limits.

In order to obtain information on the maintenance costs incurred by various power plants, a survey was made of 20 different coal-fired units greater than 73 MW (250 x 10^6 Btu). This information is presented in Tables A-2 and A-3 and was obtained from the 25th annual supplement of "Steam-Electric Plant Construction Cost and Annual Production Expenses" put out by the Federal Power Commission in April 1974.[3] The data are for the year 1972.

Table A-2 gives data for coal boilers firing only coal and shows that on the average, boiler maintenance is about 65 percent of total plant maintenance. Whereas the percentage of total maintenance attributed to the boiler is nearly the same in all cases, the cost per megawatt is highly variable. A low figure of $800 per MW was obtained at a Missouri plant while a high value of $2,834 per MW was obtained for a plant in Florida. As can be seen from the data in the first two columns, the cost of fuel is greater that 75 percent of the total production expenses in almost every case.

The data presented in Table A-3 is for coal boilers firing some combination of coal plus oil and/or gas. Again, the average percent of plant maintenance associated with the boiler is 65 percent. Also, the cost of boiler maintenance per megawatt varies along the same lines as those boilers firing only coal except that one higher value was obtained. The range was from $950 per MW to $3,828 per MW. In terms of absolute dollars spent on boiler maintenance, the data show values ranging from $160,000 to $4 million for all the boilers surveyed.

The types of maintenance that will usually require substantial amounts of time are boiler cleaning, repair or replacement of various parts, generator stator or rotor repair, and recoating or welding of eroded or damaged hydroturbine runner blades.

Some national figures are available relative to dollars spent on repair and maintenance in the different regions of the country. For example, electric utilities in New England (investor-owned) spent $61 million in 1974 for maintenance and repair of generating equipment. The figure for the entire contiguous United States was $1.1 billion.[6]

Some specific maintenance items are available for cyclone and pulverized coal-fired boilers. For a cyclone, the principal items requiring maintenance are the coal crusher and the cyclone furnace boiler. The crusher will usually require replacement of hammers and grid bars at yearly or less frequent intervals, depending on the coal used. The burner should be checked carefully.

Pulverizers will usually require only minor repairs which can be accomplished at the annual outage or overhaul. Burner parts subject to abrasion may require replacement at more frequent intervals. Regardless of the maintenance work performed annually, the unit should have a complete overhaul every 5 years.

As has been mentioned previously in this report, SO_2 emissions vary directly with the amount and percent sulfur of the fuel burned. For this reason, maintenance of coal-fired boilers - whether routine or not - should have little or no effect on total SO_2 emissions.

TABLE A-2. MAINTENANCE COSTS FOR BOILERS FIRING ONLY COAL DURING 1972[3]

Power plant location and size	1972 production expenses							
	Cost, $ × 10^{-6}				Cost of boiler maintenance per megawatt $	Percent		
	A_1 Total product expenses (including fuel)	A_2 Total product expenses (excluding fuel)	B Total cost for plant maintenance	C Total cost for boiler maintenance only		$B/A_1 \times 100$	$B/A_2 \times 100$	$C/B \times 100$
1. Alabama Power Co. Barry Plant Bucks, AL 1770.8 MW	36.2	6.1	3.7	2.7	1,525	10.2	60.6	73.0
2. Alabama Power Co. Gorgas Plant Gorgas, AL 1545.7 MW	23.6	4.3	2.1	1.4	906	8.9	48.8	66.7
3. Colorado-Ute Elec. Assoc. Inc. Hayden Plant Hayden, CO 163.2 MW	3.1	0.8	0.38	0.16	980	12.2	47.5	42.1
4. Tampa Elec. Co. Big Bend Plant Tampa, FL 445.5 MW	10.0	1.7	0.9	0.6	1,347	9.0	52.9	66.7
5. Tampa Elec. Co. F.J.Gannon Plant Tampa, FL 1270.4 MW	28.4	7.2	5.3	3.6	2,834	18.7	73.6	67.9

TABLE A-2 (continued). MAINTENANCE COSTS FOR BOILERS FIRING ONLY COAL DURING 1972[3]

Power plant location and size	1972 production expenses							
	Cost, $ × 10^{-6}				Cost of boiler maintenance per megawatt $	Percent		
	A_1 Total product expenses (including fuel)	A_2 Total product expenses (excluding fuel)	B Total cost for plant maintenance	C Total cost for boiler maintenance only		$B/A_1 \times 100$	$B/A_2 \times 100$	$C/B \times 100$
6. Central Illinois Light Co. E.D.Edwards Plant Bartonville, IL 779.8 MW	11.6	2.0	0.96	0.71	910	8.3	48.0	74.0
7. Central Illinois Public Service Co. Grand Tower Plant Grand Tower, IL 179.6 MW	5.34	1.55	0.68	0.5	2,784	12.7	43.9	73.5
8. Empire District Elec. Co. Asbury Plant Asbury, MO 212.8 MW	3.9	0.6	0.25	0.17	800	6.4	41.7	68.0
9. Minnesota Power and Light Aurora Plant Aurora, MN 116.1 MW	3.7	0.9	0.52	0.32	2,756	14.1	57.8	61.5
10. Basin Electric Power Cooperative Leland Olds, ND 240 MW	3.76	1.05	0.54	0.33	1,375	14.4	51.4	61.1

TABLE A-3. MAINTENANCE COSTS FOR BOILERS FIRING COAL PLUS OIL AND/OR GAS DURING 1972[3]

Power plant location and size	1972 production expenses							
	Cost, $ × 10^{-6}				Cost of boiler maintenance per megawatt $	Percent		
	A_1 Total product expenses (including fuel)	A_2 Total product expenses (excluding fuel)	B Total cost for plant maintenance	C Total cost for boiler maintenance only		$B/A_1 \times 100$	$B/A_2 \times 100$	$C/B \times 100$
1. Duke Power Co. Marshall Plant Terrell, NC 2000 MW	59.3	4.0	2.6	1.9	950	4.4	65.0	73.1
2. Potomac Electric Power Co. Chalk Point Plant Chalk Point, MD 728 MW	22.9	4.6	3.4	1.95	2,679	14.8	73.9	57.4
3. Appalachian Power Co. Clinch River Plant, Carbo, VA 713 MW	17.1	2.3	1.2	0.7	982	7.0	52.2	58.3
4. Detroit Edison St. Clair Plant E. China Twp.,MI 1905 MW	58.8	7.4	4.9	4.1	2,152	8.3	66.2	83.7
5. Indiana & Michigan Elec. Co. Tanners Creek Plant Lawrenceburg, IN 1100 MW	22.4	6.0	4.1	2.8	2,545	18.3	68.3	68.3

TABLE A-3 (continued). MAINTENANCE COSTS FOR BOILERS FIRING COAL PLUS OIL AND/OR GAS DURING 1972[3]

Power plant location and size	1972 production expenses							
	Cost, $ × 10^{-6}				Cost of boiler maintenance per megawatt $	Percent		
	A_1 Total product expenses (including fuel)	A_2 Total product expenses (excluding fuel)	B Total cost for plant maintenance	C Total cost for boiler maintenance only		B/A_1 × 100	B/A_2 × 100	C/B × 100
6. Public Service Co. of Colorado Cherokee Plant Denver, CO 801.3 MW	17.9	2.7	1.4	0.77	961	7.8	51.9	55.0
7. Northern States Power Co. Black Dog Plant Minneapolis, MN 486.7 MW	14.2	3.8	2.5	0.86	1,767	17.6	65.8	34.4
8. Montana Power Co. J.E.Corette Plant Billings, MT 172.8 MW	2.05	0.48	0.27	0.2	1,157	13.2	56.3	74.1
9. Omaha Public Power District North Omaha Plant Omaha, NE 600 MW	15.2	2.5	1.4	0.9	1,500	9.2	56,0	64.3
10. Nevada Power Co. Reid Gardner Plant Moapa, NV 227.3 MW	7.8	1.75	1.1	0.87	3,828	14.1	62.9	79.1

REFERENCES

1. Power Engineering. August, 1974.

2. Vierath, D. R. and W. W. Walkley. Costs of Meeting Clean Air Requirements. Power Engineering. September, 1976.

3. Steam-Electric Plant Construction Cost and Annual Production Expenses - 1972. Federal Power Commission. April, 1974.

4. Rowsome, Frank H. The Role of System Reliability Prediction in Power Plant Design. Power Engineering. February 1977.

5. Federal Power Commission News Release No. 22083. January 22, 1976.

6. Maintenance-Repair Costs to Top $3 Billion. Electrical World 183(6). March 15, 1975.

APPENDIX B

LIST OF INDIVIDUALS CONTACTED

W. H. Axtman, Executive Director, American Boiler Manufacturers Association, Arlington, Virginia

S. Baruch, Edison Electric Institute, New York, New York

L. Davis, Station Superintendent, Public Service Company of New Hampshire, Concord, New Hampshire

E. M. Diehl, Bituminous Coal Research Inc., Monroeville, Pennsylvania

F. Gottlich, Boston Edison Company, Boston, Massachusetts

W. McKinney, Supervisor of Environmental Research, TVA, Chattanooga, Tennessee

J. Taylor, Arizona Public Service Company, Phoenix, Arizona

TECHNICAL REPORT DATA *(Please read Instructions on the reverse before completing)*		
1. REPORT NO. EPA-450/3-77-048	2.	3. RECIPIENT'S ACCESSION NO.
4. TITLE AND SUBTITLE IMPACT OF MODIFICATION/RECONSTRUCTION OF STEAM GENERATORS ON SO_2 EMISSIONS		5. REPORT DATE December 1977 6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) Mark I. Bornstein; Paul F. Fennelly; Robert R. Hall; Douglas Roeck.		8. PERFORMING ORGANIZATION REPORT NO. GCA-TR-77-21-G
9. PERFORMING ORGANIZATION NAME AND ADDRESS GCA Corporation; GCA/Technology Division Burlington Road Bedford, Massachusetts 01730		10. PROGRAM ELEMENT NO. 11. CONTRACT/GRANT NO. 68-02-2607, Work Assignment No. 3
12. SPONSORING AGENCY NAME AND ADDRESS U.S. Environmental Protection Agency Research Triangle Park, North Carolina 27711		13. TYPE OF REPORT AND PERIOD COVERED Final Report 14. SPONSORING AGENCY CODE
15. SUPPLEMENTARY NOTES		
16. ABSTRACT		
17. KEY WORDS AND DOCUMENT ANALYSIS		
a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
18. DISTRIBUTION STATEMENT Distribution Unlimited	19. SECURITY CLASS *(This Report)* UNCLASSIFIED 20. SECURITY CLASS *(This page)* UNCLASSIFIED	21. NO. OF PAGES 29 22. PRICE

EPA Form 2220-1 (9-73)