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CONTROL OF PARTICULATE MATTER FROM OIL BURNERS AND BOILERS

by

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This report was prepared under the guidance of an Ad Hoc Advisory Committee comprised of individuals who are knowledgeable in the field of oil burner technology and control programs. They are listed in Appendix E along with their affiliations and fields of expertise. Three meetings of this committee were held during the preparation of this document, all at the offices of the Control Programs Development Division, EPA, in Durham, North Carolina. During the first meeting (June 3, 1975) the scope of the project was discussed and the requirements of the individual constituencies defined. The purpose of the second meeting (July 30, 1975) was to review the proposed outline for the final report and to assist us in obtaining additional information on control technology and strategies. A draft of the first six chapters of this report (i.e., excluding the last one on recommended control strategies) was circulated to the members of the committee in October, and their responses received by mail or telephone. A summary of the revised draft plus the entire last chapter, was presented to the committee at its review meeting on January 20, 1976. This final report includes comments received during that meeting. Although we have exerted our best effort to incorporate the comments of the Ad Hoc Committee, it has not always seemed possible or advisable to do this. In such instances, our judgement has necessarily prevailed, and preparation of this report does not necessarily imply approval by each (or any) member of the Ad Hoc Committee.

Aerotherm extends its appreciation for the valuable assistance provided by the members of the Ad Hoc Committee; the staff of the nine air pollution regulatory agencies visited; burner, boiler, control equipment, and instrumentation manufacturers; users of this equipment; and other research organizations.

The need for this report was realized by Jean J. Schueneman, Director, Control Programs Development Division, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. The report was prepared under the general direction of Joseph Sableski, Chief, Plans Guidelines Section, Standards Implementation Branch, in the above Division. A. T. Creekmore was the Task Officer, assisted by T. M. Donaldson. Their guidance and assistance during the course of the project is greatly appreciated. The Aerotherm Project Manager was Dr. Larry W. Anderson. Drs. Carl B. Moyer and Howard B. Mason acted as advisors during the study, especially in the analysis of control technologies and possible control measures. The study was performed between May 1975 and February 1976.

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SECTION 1

INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

As more and more air quality data are becoming available from monitoring stations throughout the nation, it is becoming increasingly evident that the National Ambient Air Quality Standards for particulate matter have not been attained in many Air Quality Control Regions and will not be maintained in others, under provisions of existing control strategies.

According to the Monitoring and Air Quality Trends Report (Reference 1-1), 205 of the 247 AQCRs in the United States reported valid ambient particulate measurements for at least one station in 1973, and 128 of these regions exceeded the primary annual NAAQS for particulate (designed to protect health). Even more regions, namely 168, exceeded the secondary standard for the protection of welfare (animal and vegetable life, materials, and aesthetics, etc.). The 24-hour primary standard was exceeded in most regions of the country, as depicted in Figure 1-1. Among the individual monitoring stations which reported valid data for 1973, over one-quarter exceeded the primary annual standard and nearly one-half violated the secondary limits. Similarly, for the 24-hour standard, about 10 and 40 percent exceeded the primary and secondary standards, respectively.

Although progress has been made in reducing ambient particulate concentrations in many areas of the country, both through the application of controls and the introduction of improved equipment, further reductions are still required in some regions. Inadequate regulations and programs for the control of particulate emissions from oil burning furnaces and boilers may be one of the more important reasons that areas where large amounts of oil are used cannot meet current ambient air quality standards for particulate. More importantly, economic and population growth will cause emissions of all pollutants, including particulates, to increase with time unless controlled beyond the current level. Therefore, it may be necessary to control sources which are not regulated now and/or to increase the degree of control (i.e., reduce the allowable emission limits) for sources that are already regulated at a moderate level. It will certainly be necessary to do so in some AQCRs to maintain the ambient air concentrations below the NAAQS through the next 10 to 25 years.

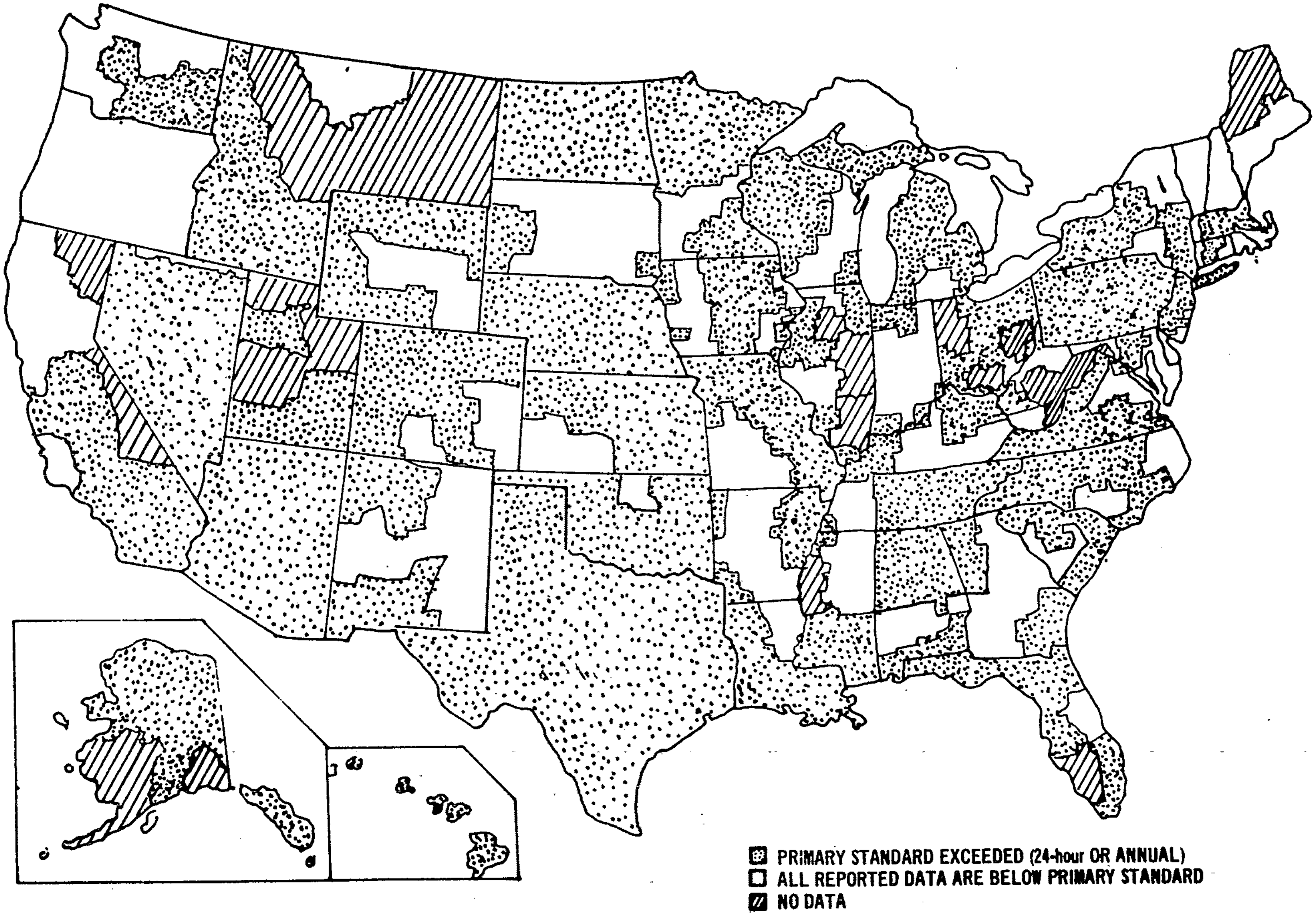

Figure 1-1. Status of suspended particulate levels, 1973 (Reference 1-1).

For these reasons the Control Programs Development Division, Office of Air Quality Programs and Standards, U.S. Environmental Protection Agency (EPA), has sponsored the preparation of this document for the use of local, state, and federal governmental air pollution control agencies in the design and operation of programs for the control of particulate matter emissions. This document is limited to particulate emissions from oil-fired boilers that are used to generate hot water or steam and furnaces that are used to provide warm air for space heating. These sources are frequently called indirect heating fuel combustion sources. Gas turbines, reciprocating internal combustion engines, process furnaces that use oil for direct heating of materials (e.g., kilns, glass melting furnaces, open hearth furnaces, metal heat treating units, etc.), and furnaces which burn various waste oils are excluded.

The importance of particulate emissions from oil-fired boilers and indirect heating furnaces varies from region to region. This fact is clearly demonstrated in Table 1-1, which shows the percentage contributions from this source category to the total particulate emissions in each of the AQCRs. As one might expect, oil-fired units contribute significant fractions to the total in the northeast — e.g., 32 percent in the Boston AQCR — but relatively little in areas like Los Angeles where natural gas is, or was, the predominate fuel. In eight AQCRs this source category now accounts for more than 10 percent of the total particulate emissions. Not only are there regional differences in total emissions from oil-fired units, but also in the distribution of emissions among the various categories (user groups) within each AQCR. For example, emissions from oil-fired units in Niagara Frontier (AQCR 162) are dominated by industrial boilers, those in Southeast Florida (AQCR 050) by utility boilers, and those in Boston by all four categories. Particulate emissions from residential units can amount to 3.4 percent of the total emissions in any one AQCR, those from commercial and institutional systems up to 9.5 percent, from industrial boilers up to 9.5 percent, and from utilities up to 19 percent.

It should be noted, however, that Table 1-1 shows only where oil-fired boilers and space heating furnaces contribute significantly to the total particulate emissions; it does not necessarily provide an indication of where particulate air quality standards are being exceeded. A case in point is Los Angeles, whose ambient air particulate concentrations are above the standard, but where indirect heating oil-fired sources account for only 5 percent of the region's total particulate emissions. Nationwide, other major sources of particulate emissions are coal-fired boilers, a variety of industrial processes, and transportation, depending on the region of the country. Moreover, in some areas, fugitive dust and natural sources of particulates can account for a non-negligible fraction of the measured particulate. These sources are not included in the NEDS data from which Table 1-1 was developed.

TABLE 1-1. RELATIVE IMPORTANCE OF PARTICULATE EMISSIONS FROM OIL-FIRED EXTERNAL COMBUSTION SOURCES IN SELECTED AQCR's (Percent from each source relative to total in that AQCR)[a]

Source	024 - Los Angeles, CA	029 - San Diego, CA	030 - San Francisco Bay Area, CA	031 - San Joaquin Valley, CA	042 - Hartford-New Haven-Springfield (CT, MA)	043 - New Jersey-New York-Connecticut	045 - Philadelphia (DE, NJ, PA)	047 - National Capital (DC, MD, VA)	049 - Jacksonville-Brunswick (FL, GA)	050 - Southeast Florida	052 - West Central Florida	067 - Chicago (IL, IN)	070 - St. Louis (IL, MO)	115 - Baltimore, MD	118 - Central Massachusetts	119 - Boston, MA	120 - Providence (MA, RI)	121 - Merrimach Valley - Southern New Hampshire (MA, NH)	131 - Minneapolis-St. Paul, MN	150 - New Jersey (Except 043)	158 - Central New York	161 - Hudson Valley, NJ	162 - Niagara Frontier, NY	223 - Hampton Roads, VA	225 - State Capital, VA	229 - Puget Sound, WA	Total United States
Residential																											
Distillate	-	-	-	-	1.3	1.7	0.4	0.4	0.1	-	-	0.1	0.1	0.3	1.6	3.2	2.2	2.3	0.4	1.3	2.4	1.3	1.1	0.4	0.4	0.4	0.1
Residual[b]	0	0	0	0	0	1.7	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0.1	0.1	0.1	0	0	0.2	-
Commercial/Institutional																											
Distillate	0.1	-	0.1	-	0.2	0.9	0.1	0.1	-	0.2	-	0.1	-	-	0.5	1.7	0.7	0.8	0.2	0.5	0.3	0.1	0.3	-	0.1	0.1	-
Residual	0.7	0.5	0.7	0.1	1.2	5.0	0.5	2.3	0.1	0.6	0.1	0.2	-	0.2	2.4	7.8	4.3	2.8	0.2	1.3	1.7	0.7	2.0	1.2	1.1	0.4	0.1
Industrial																											
Distillate	0.1	-	0.1	-	0.2	0.4	0.1	-	-	-	-	0.1	0.1	-	0.7	0.8	0.5	0.4	0.2	0.2	0.6	0.1	1.2	0.1	0.1	0.1	-
Residual	0.5	0.1	1.4	2.2	2.5	2.8	1.3	0.2	1.1	2.1	0.3	0.3	0.2	0.3	0.7	5.2	3.8	4.1	1.7	2.8	5.0	1.2	8.3	2.5	1.9	0.7	0.3
Utility (Elec. Gen)																											
Distillate	-	0	0	0	-	-	-	-	-	0	0	0	-	-	-	-	0	0	-	-	0	0	0	-	-	0	-
Residual	3.5	4.0	0.5	0	3.1	6.6	0.7	2.3	3.3	19.0	15.6	0.1	0.1	1.1	0.5	14.0	14.5	2.7	0	-	0	1.6	0	1.2	3.0	-	0.4
Total Percentage in AQCR from oil-fired indirect heating	5.0	4.7	2.8	2.3	8.5	19.2	3.2	5.3	4.6	22.0	15.0	0.9	0.5	1.9	6.3	32.5	26.0	13.1	2.8	6.1	10.1	5.2	13.0	5.5	6.7	2.0	0.9

[a]Source: 1975 NEDS data (Reference 1-2) as revised by Reference 1-3. Revision based on assumption that all residual is either No. 4 oil or 0.5 percent sulfur No. 6. Dash signifies less than 0.1 percent, 0 signifies no entry in NEDS. Totals may not equal sum of individual entries due to round-off.

[b]Data reported as in NEDS. Virtually no boilers <0.4 MBtu/hr burn residual oil. Stated emissions probably due to apartment building units labelled residential.

The importance of particulate emissions from oil-fired sources, in general, has recently been estimated for several northeast metropolitan areas (Reference 1-7). High volume sampler filters (used to measure ambient concentrations) collected during 1974 were examined by optical microscope to provide a semiquantitative estimate of the oil soot present. Filters in these areas (Washington, D.C., Providence, Philadelphia, Baltimore, Chattanooga) showed that oil soot particles were estimated to comprise from 8 - 13 percent by weight of the total mass visible under the optical microscope. This represented the average estimated percent visible mass of from 20 - 30 filters per area. They were selected to represent several seasons of the year.

While this is not a quantitative technique, it does provide some perspective on the extent of the problem — a significant though not overwhelming fraction of the mass was believed to be oil soot. One should realize that over half of the typical ambient concentration in these areas is not amenable to traditional control strategies (i.e., resuspended street dust, natural background, automobile exhaust particles, and particles formed by transformation of gases in the atmosphere). Thus, the importance of identifying the impact of controllable emission categories is most important.

It is important to note that this same study found that while all of these areas are violating the primary standard at one or more sites, the reasons for these violations are varied and in some cases identifiable as localized problems such as resuspended dust or construction activity. The control agency has the responsibility of weighing these factors in the development of a new control strategy.

The control techniques and regulatory programs discussed here are directed towards the maintenance and attainment of current NAAQS for particulate. Compliance with these ambient air standards is based on measurements by High Volume Samplers (Hi Vols) that are placed at strategic locations throughout the region. Therefore, this report deals mainly with efforts to reduce mass emissions as measured in the conventional manner — i.e., either by opacity, Smoke Spot Number according to ASTM Procedure D2156-65, or particulate loading according to EPA Method 5.* The EPA recognizes that these standards may not be sufficient to protect health and welfare from particulate pollution and is currently evaluating the need for an additional air quality standard for fine particulates. Some of the potential shortcomings associated with the current standard are attributed to the following concerns:

*The Smoke Spot Number is frequently reported as the Bacharach-Shell Smoke Spot Number, the Bacharach Smoke Spot Number, or simply the Bacharach Number. All four descriptions refer to the same measurement technique.

- Heavy particles contribute most of the mass measured by the Hi Vols although they account for only a few percent of the material collected on a number basis. According to the results of one analysis of an ambient sample by microscopic count, 60 percent of the particles by number were under 3 microns in diameter (i.e., in the respirable range) and accounted for about 4 percent of the total mass; in contrast, 4 percent by number were over 11 microns in diameter and contributed nearly 80 percent of the total weight (Reference 1-4).
- There is some evidence to indicate that toxic materials tend to concentrate on the small particles (Reference 1-5). Hence, reductions in mass emissions of particulates to the point where the NAAQS are not exceeded may not be sufficient.
- Secondary particulates (those generated in the atmosphere) may be more hazardous than primary ones (those emitted into the atmosphere from combustion, industrial, transportation, and natural sources).

Although a standard for fine particulates would probably require the implementation of additional controls beyond those required to meet the primary standards, many of the controls that can be used to meet the primary standard also reduce the emissions of submicron particles.

The body of this report lays the groundwork for the final chapter, which presents control strategies that could be used by air pollution control authorities in the metropolitan areas and the States to reduce particulate emissions from oil-fired boilers and furnaces. Thus, in Section 2, we present descriptions of the equipment under consideration and inventories of their installed capacity, by region within the United States. In that discussion, as in the remainder of the document, boilers and furnaces are subdivided further into four user categories based on size: residential, commercial (e.g., apartment buildings, institutions, and public buildings), industrial and utility.* The equipment descriptions will include a discussion of the particulate emissions from these units and the factors which affect those emissions. Next, in Section 3, we consider the question of fuel, such as the effects of fuel properties on emissions, the costs of various fuels, and the effect of fuel additives or water/fuel emulsions on particulate emissions. All techniques other than fuel switching and fuel additives which can reduce particulate emissions from oil-fired burners are discussed in Section 4. These techniques tend to fall into one of the following categories.

*These categories are distinguished by size because it is easier for enforcement purposes to subdivide sources on that basis. The NEDS system, for which Table 1-1 was developed, theoretically identifies sources on the basis of their application; thus the "Electric Generation" category may contain steam power plants that are located in an industrial facility and supply electricity only to that facility.

- Operation and maintenance procedures
- Design changes to the burner and/or combustion chamber
- Flue gas treatment

A brief review of industry standards for the construction and performance of boilers and furnaces is then presented in Section 5 to show the relationships, albeit limited, between these standards and particulate control strategies. Since any control program that is recommended should take past experience into account, Section 6 is devoted to a summary and review of existing regulatory programs for the control of particulates from oil-fired units. This summary includes a compilation of pertinent regulations throughout the United States and a more detailed review of the regulations and enforcement procedures used by nine metropolitan or State control authorities to reduce particulate emissions from indirect heat fuel burning combustion sources. Based on this review of the characteristics of the sources, their utilization patterns, existing particulate control technologies for these sources, and current regulatory practices, we then list and rank control measures (by user group) in Section 7 that local authorities could adopt to reduce particulate emissions within their areas of jurisdiction.

Thus, this material is discussed in detail in Sections 2 through 7; it is summarized in the following three subsections of this Introduction and Summary.* Appendix A contains recommendations for research and development programs aimed at reducing particulate emissions from oil-fired boilers and space heating furnaces. Suggested topics include equipment redesign, demonstration tests on suggested improvements, development of new monitoring systems, etc. Appendix B presents a brief comparison of the various methods used to measure smoke and particulate emissions, and Appendix C lists the conversion factors between engineering and SI (System International) units. Appendix D presents sample calculations analyzing costs. Appendix E lists the members of the Ad Hoc Advisory Committee.

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*Since the following subsections merely summarize the remainder of this document, detailed references are given only in the main body of text.

1.2 SUMMARY OF EXISTING CONTROL PROGRAMS

This subsection presents a summary of existing control programs for particulate emissions from oil-fired boilers and furnaces. The summary begins with tabulation of the emission limits by state and then continues with a discussion of the regulations and enforcement procedures used by nine control authorities which are believed to have active control programs for oil-fired sources. A summary of these regulations as they specifically relate to each user category is presented in the next subsection at the end of the summary of technical background information for each category.

Before proceding to the discussions of regulatory programs, we note that certain nonregulatory programs exist which aim to reduce particulate emissions. Chief among these are the various private, industry, and trade association sponsored training programs for burner servicemen and boiler operators/ maintenance staff. Voluntary operational changes that result in energy conservation are indirect particulate control programs since they cause a reduction in fuel consumption. This category of activities includes the use of more building insulation, more attention to energy efficient operation, the installation of energy recovery devices such as waste heat recovery units, and a shift to greater recycling of metals, glass, and paper products. And, finally, information campaigns ("PR") can educate both the public and the owners of commercial or small industrial boilers about the value of proper, periodic maintenance programs. Such campaigns seem to be most effective if they stress the fuel savings that come from correct maintenance practices in addition to describing environmental benefits.

Table 1-2 presents the particulate limits by each State for new oil-fired indirect heating fuel burning sources.* This table shows that there is considerable variation among the regulations from State to State. Some States do not place emission limitations on smaller units, and where all the States restrict emissions from a given size source, these restrictions can sometimes differ by an order of magnitude. Typically regulations range from about 0.6 lb/MBtu (258. ng/J) for units with a heat input of 10 MBtu/hr (2.93 MW) (in those States which regulate units of that size) to values of 0.1 to 0.2 lb /MBtu (43 to 86. ng/J) for the very large utility boilers.† Some States are more restricting, with limits as low as 0.06 lb/MBtu (25.8 mg/J) for 10 MBtu/hr (2.93 MW) boilers and

*Tables 1-2 through 1-4 are identical to Tables 6-2 through 6-4, respectively, except that the footnotes for Tables 6-2 and 6-4 are not repeated here.

†Throughout this report the letter M represents 10^6 in accordance with System International practices. Thus MBtu = 10^6 Btu.

TABLE 1-2. STATE REGULATIONS FOR PARTICULATE EMISSIONS FROM OIL-FIRED INDIRECT HEATING SOURCES[a], lb/MBtu

	Footnotes[b]	Source Heat Input Rate, MBtu/hr																			
		<1	≤10	>10	20	50	100	≤200	>200	≤250	>250	≤500	>500	1000	2500	5000	7500	10000	>10000	50000	≥10^5
Alabama	*			0.5						0.12											
Alaska	*	0.083																			
Arizona	*		0.6		0.51	0.4	0.35		0.30		0.28		0.243	0.21	0.17	0.13	0.11	0.09		0.036	0.025
Arkansas			0.25				0.15							0.10				0.025			
California	*	0.167																			
Colorado		0.5	0.21		0.23	0.18	0.15		0.13		0.12		0.1								
Connecticut	*	0.1																			
Delaware	*	0.3																			
D.C.	*		0.13				0.06							0.035				0.02			
Florida	*	0.1																			
Georgia	*		0.50								0.10										
Hawaii	*																				
Idaho	*		0.6				0.35							0.21				0.12			
Illinois		0.10																			
Indiana	*		0.6							0.1											
Iowa	*	0.6																			
Kansas			0.6		0.51	0.41	0.35		0.30		0.28	0.24		0.21	0.17	0.14	0.13	0.12			
Kentucky	*		0.56			0.38	0.33				0.10										
Louisiana		0.6																			
Maine	*		0.60					0.3													
Maryland	*		0.06	0.05		0.03			0.02												
Massachusetts	*		0.1								0.05										
Michigan							0.3														
Minnesota	*	0.4																			
Mississippi		0.6	0.6															0.19			
Missouri	*	0.6	0.6		0.56	0.46	0.4		0.375		0.36	0.30		0.26	0.23	0.2	0.19	0.18			
Montana	*		0.6				0.35							0.20				0.12			
Nebraska			0.6			0.41	0.35					0.24		0.21	0.17	0.14	0.13	0.12			
Nevada	*		0.6				0.35							0.20				0.09			0.02
New Hampshire	*		0.6			0.40	0.35				0.10										
New Jersey		0.6	0.6		0.4	0.22	0.15		0.1												
New Mexico	*		0.005																		
New York											0.1										
North Carolina	*	0.6	0.6				0.33							0.18				0.10			
North Dakota	*		0.6			0.486	0.443					0.359		0.328	0.291	0.266	0.252	0.242		0.197	0.180
Ohio	*		0.4											0.10							
Oklahoma	*		0.6				0.35							0.20				0.12			
Oregon	*	0.33																			
Pennsylvania	*		0.4			0.4							0.1								
Rhode Island			0.20								0.1										
South Carolina	*	0.60	0.60											0.60		0.2		0.12	0.1		
South Dakota		0.3																			
Tennessee	*		0.6		0.41	0.24	0.17				0.10										
Texas	*			0.1																	
Utah	*																				
Vermont	*		0.5									0.1		0.02							
Virginia	*	0.4			0.4													0.10			
Washington	*	0.33																			0.33
West Virginia			0.34		0.28		0.166									0.10					
Wisconsin	*	0.15								0.15	0.10										0.10
Wyoming	*	0.1																			
A. Samoa		0.1																			
Guam	*																				
Puerto Rico		0.3																			
Virgin Islands	*		0.6				0.352							0.207					0.09		

a,b,* Footnotes — See Section 6. Limits are for new units if state has separate limits for new and existing sources. See Appendix C for conversions to SI units.

0.02 lb/MBtu (8.6 ng/J) for utility boilers in Maryland. New Mexico currently limits oil-fired boilers even further to 0.005 lb/MBtu (2.15 ng/J) for all units greater than 10 MBtu/hr (2.93 MW) heat input, but they are considering revising these limits upwards. Conversion factors between SI and the more familiar engineering units are presented in Appendix C. New boilers greater than 250 MBtu/hr (73.25 MW) must also comply with an NSPS of 0.1 lb/MBtu (43. ng/J). Since the regulations differ so much from State to State, a condensed version of this large table has been prepared to facilitiate comparisons among the states (Table 1-3). In this abbreviated version of the State regulations, each column approximately represents one of the four user categories discussed in this report. A quick review of this table shows, for example, that 29 states and territories (i.e., slightly more than half of the 55 states and territories included on the table) do not restrict particulate emissions from residential and small commercial units ($\leq$1 MBtu/hr or 0.293 MW). Limitations for large commercial and industrial units (nominal 10 and 100 MBtu/hr or 2.33 and 29.3 MW, respectively) range from 0.06 to 0.6 lb/MBtu (25.8 to 258. ng/J) and those for utility boilers (nominal 1,000 MBtu/hr or 293 MW) range from 0.02 to 0.6 lb/MBtu (8.6 to 258 ng/J) (excluding New Mexico, which may revise its limits soon).

Opacity limits are presented in Table 1-4 for fuel burning sources. Many states now limit opacity to 20 percent (Ringelman #1), although some restrict visible emissions to 10 percent and three even permit no visible emissions. Frequently a more lenient limit is placed on existing sources than on new sources. In addition, sources are allowed to emit more than the limits shown on this table for short periods of time, e.g., 3 to 6 minutes during each 1-hour period. In some states there is no restriction on the opacity of the plume during these exception periods, whereas in other states the plume can obscure no more than 40 or 60 percent of the transmitted light. Some states apply these opacity limitations to all sources, irrespective of their size.

More detailed information on the regulations and enforcement procedures used by local authorities was obtained by direct contact with personnel in nine agencies which were believed to have active control programs. The enforcement procedures in eight of the nine districts visited appeared to depend heavily on the use of construction and operation permits. These permits are used to identify sources of emissions. The applications for construction permits are generally reviewed by the engineering and/or enforcement staff in the control agency to determine whether the equipment and the proposed operating procedures will enable the source to comply with local regulations. After the new source has been installed, the control district inspects the facility to check its performance with the application and to observe the procedures used by the operating personnel. If the inspector's report is favorable, an operating permit is then issued to the installation. Enforcement through the use of permits is generally supplemented by roaming inspectors who look for violations of the visible emission limits, by stack testing upon the request of the control district if

TABLE 1-3. PARTICULATE LIMITS AT SELECTED HEAT RATES[a], LB/MBTU

State	Source Input Heat Rate, MBtu/hr			
	<1	≤10	100	1000
Alabama	0.5	0.5	0.5	0.12
Alaska	0.083	0.083	0.083	0.083
Arizona		0.6	0.35	0.21
Arkansas		0.25	0.15	0.10
California	0.167	0.167	0.167	0.167
Colorado	0.5	0.21	0.15	0.10
Connecticut	0.1	0.1	0.1	0.1
Delaware	0.3	0.3	0.3	0.3
D.C.		0.13	0.06	0.035
Florida	0.1	0.1	0.1	0.1
Georgia		0.50	0.16	0.10
Hawaii[b]				
Idaho		0.6	0.35	0.21
Illinois	0.1	0.1	0.1	0.1
Indiana		0.6	0.6	0.1
Iowa	0.6	0.6	0.6	0.6
Kansas		0.6	0.35	0.21
Kentucky		0.56	0.33	0.10
Louisiana	0.6	0.6	0.6	0.6
Maine		0.6	0.32	0.3
Maryland		0.06	0.03	0.02
Massachusetts		0.1	0.1	0.05
Michigan		0.3	0.3	0.19
Minnesota	0.4	0.4	0.4	0.4
Mississippi	0.6	0.6	0.41	0.26
Missouri	0.6	0.6	0.28	0.14
Montana		0.6	0.35	0.2
Nebraska		0.6	0.35	0.21
Nevada		0.6	0.35	0.20
New Hampshire		0.6	0.35	0.10
New Jersey	0.6	0.6	0.15	0.10
New Mexico		0.005	0.005	0.005
New York				0.10
North Carolina	0.6	0.6	0.33	0.18
North Dakota		0.6	0.44	0.33
Ohio		0.4	0.2	0.1
Oklahoma		0.6	0.35	0.20
Oregon	0.33	0.33	0.33	0.33
Pennsylvania		0.4	0.27	0.1
Rhode Island		0.2	0.2	0.1
South Carolina	0.6	0.6	0.6	0.6
South Dakota	0.3	0.3	0.3	0.3
Tennessee		0.6	0.17	0.10
Texas		0.1	0.1	0.1
Utah[b]				
Vermont		0.5	0.1	0.02
Virginia	0.4	0.4	0.29	0.17
Washington	0.33	0.33	0.33	0.33
West Virginia		0.34	0.166	0.10
Wisconsin	0.15	0.15	0.15	0.15
Wyoming	0.10	0.10	0.10	0.10
Samoa	0.10	0.10	0.10	0.10
Guam[b]				
Puerto Rico	0.3	0.3	0.3	0.3
Virgin Islands		0.6	0.352	0.21

[a]Abstracted from Table 6-2. Limits are for new sources whenever a state has different regulations for new and existing sources. For further detail see Table 6-2 and accompanying footnotes.

[b]No limits on particulate emissions from oil fired sources in state regulations.

TABLE 1-4. VISIBLE EMISSION LIMITATIONS FOR OIL-FIRED INDIRECT HEATING SOURCES[a]

State	% Opacity	State	% Opacity
Alabama	20	Nevada	20
Alaska	20	New Hampshire	20[j]
Arizona	40	New Jersey	20
Arkansas	20[b]	New Mexico	20
California	20[c]	New York	20[k]
Colorado	20	North Carolina	20
Connecticut	20	North Dakota	20[l]
Delaware	20	Ohio	20
D.C.	0	Oklahoma	20
Florida	20[d]	Oregon	20[m]
Georgia	20[e]	Pennsylvania	20
Hawaii	20[f]	Rhode Island	0
Idaho	20[g]	South Carolina	20[n]
Illinois	30[h]	South Dakota	20
Indiana	40	Tennessee	20
Iowa	40	Texas	20
Kansas	20[i]	Utah	20[o]
Kentucky	20	Vermont	20[p]
Louisiana	20	Virginia	20
Maine	40	Washington	20[q]
Maryland	0	West Virginia	10
Massachusetts	20	Wisconsin	10[r]
Michigan	20	Wyoming	20[s]
Minnesota	20	A. Samoa	20
Mississippi	40	Guam	20
Missouri	20	Puerto Rico	20
Montana	20	Virgin Islands	20[t]
Nebraska	20		

Footnotes: See page 6-10.

a problem is suspected, by permanent installation of continuous opacity monitors in units which exceed a certain size or which use residual fuel, and, in the case of Connecticut, by annual stack tests for all units which emit more than 100 tons per year (TPY) total pollutants.

The regulations were generally stringent in these nine regions by comparison with many of the states. For example, two of the regions prohibited all visible emissions, and the other seven only allowed up to 20 percent obscuration, whereas several of the other states permitted plumes to have opacities as great as 40 percent (Ringelman #2). With respect to particulate emissions the regulations were strict in that they imposed relatively low limits on all sources, and that limits were applied even to the smaller units in the district. Thus, in some regions all units had to conform with the particulate loading limits, irrespective of size. In all regions which were studied in detail, burners that were larger than 5 MBtu/hr (1.5 MW) had to comply.

Most of the regions contacted also had stringent restrictions on the allowable sulfur content of the fuel. Since desulfurization also results in the removal of some of the solid matter in the fuel and in a decrease in weight (increase in API gravity), the sulfur restriction has a beneficial side effect by reducing sources of particulate emissions. Three of the nine control districts also prohibited the use of residual oil in small units.

Different regions need different control strategies because of differences in the distribution of sources. For example, New York City needs to stress emission reductions in commercial sized units as a result of the larger number of apartment buildings in that area, whereas a less densely populated, more industrialized area would emphasize emissions from industrial and utility boilers.

The major differences between the control programs in the metropolitan and in the state agencies visited during the course of this study appears to be in the stringency of the limitations, especially those for sulfur in the fuel. As one would expect, the metropolitan regions, with their high concentration of sources and human receptors, generally place tighter restrictions on the sulfur content of the fuel and lower emission limits on the sources than do the states. There is also a tendency within metropolitan control agencies to place greater emphasis on the control of emissions from commercial size units than is the case in the states. And finally, the size of the enforcement staff in the metropolitan control districts is generally larger than it is in the state regions. For example, Philadelphia had approximately the same number of inspectors as did the State of Connecticut. The need for a large staff is a consequence of the need to control the many smaller units, along with large units, which exist in the metropolitan areas. Beyond these three areas, the major differences are individual and probably due to the approaches preferred by the people who establish the programs. That is the use of an equipment standard in Maryland and a performance standard in New York City is probably not at all related to the fact that one is a state and the other a metropolitan area.

1.3 SUMMARY OF BACKGROUND INFORMATION

1.3.1 Residential Units — 0 - 0.4 MBtu/hr (0 - 0.12 MW)

1.3.1.1 Usage and Emissions

Oil-fired units in residences tend to be nearly equally divided between warm air and hot water or steam systems. Together they account for slightly over one-quarter of all residential heating units in the United States, and their market share may increase in the future as oil becomes less expensive than electricity (total life cycle costs) and more available than gas. Four times as much energy (all fuels, including electricity) is used for space heating as for the generation of hot water for washing. The most common units are lined with refractory brick and use conventional high pressure burners. The average age of residential oil-fired furnaces and boilers is about 15 years, and about one-quarter of these have had the original burner replaced.

Mechanical atomization is the primary atomization method used in domestic sized furnaces. Other methods used are wall flame rotary, vaporizing and low pressure burners, but the combined usage of these types account for only about 10 percent of the total.

Filterable particulate emissions from currently installed, well maintained residential furnaces average around 0.018 lb/MBtu (7.74 ng/J), and those for boilers 0.013 lb/MBtu (5.56 ng/J). The current recommended emission factor for all residential units, as a group, is 0.017 lb/MBtu (7.31 ng/J). This factor applies to areas where the units receive periodic inspection and maintenance service by qualified personnel.

Particulate emissions from newer burners are lower than those from older ones, primarily due to improved design practices in recent years. However, particulate emissions from properly maintained oil burners should not increase as the burner ages.

1.3.1.2 Fuels and Fuel Additives

Virtually all oil-fired residential units burn distillate oil. No. 1 distillate is used in burners which prepare the fuel for burning solely by vaporization, while No. 2 oil is used in burners which prepare the fuel for burning by a combination of vaporization and atomization. The majority of residential units are fired with No. 2 oil.

According to one study no significant difference in particulate measurements was found by firing a wide range of No. 2 oils. The API gravity of the oils ranged from 30 to 37, sulfur content from 0.05 to 0.3 percent, and carbon residue from 0.1 to 0.3 percent. The influence of fuel gravity on emissions varied, depending on whether the unit was tested in an as-found or tuned condition. In well-tuned units, a change to a heavier fuel of the same grade (i.e., increasing specific weight within the allowable limits for No. 2 oil) did not automatically cause an increase in smoke or solid particulate emissions.

Based on one study only metallic additives containing cobalt, iron or manganese appreciably decrease particulate emissions from distillate oil-burning units. Another study found that certain proprietary organic additivies reduced particulates but only when the weight added, approached one percent of the weight of the fuel. The known toxicity of the metallic emissions produced from all but the iron-based additives makes their use questionable. Moreover, there is some concern that the iron oxides which are discharged when iron-based additives are used may interact with hydrocarbons in the atmosphere to become potentially carcinogenic.

1.3.1.3 Particulate Control by Improved Burner Servicing

Since the main fuel used in oil-fired residential heating units is No. 2 distillate, and not residual oil, high smoke readings in the exhaust are due mostly to improper air-to-fuel ratios, inadequate draft, or worn-out burner components. Therefore, an effective and practical technique to reduce particulate emissions from residential oil burners is to keep serviceable units well maintained and to replace worn-out components or the entire burner. Significant improvements can also be obtained through the use of new, well designed burners and combustion chambers.

Average smoke emissions from a number of properly adjusted burners can be at mean Smoke Spot Numbers as low as 1.1 to 1.3. These levels were reported by two separate teams who investigated representative samples of currently installed units. Individual systems had Smoke Spot Numbers as low as 0. They were able to obtain smoke reductions of 40 to 60 percent through proper servicing. Moreover, all units in one of these samples could have complied with a standard of Smoke Spot No. 3 when tuned according to commercial practices, and nearly 90 percent could have complied with a level of No. 2. Alternatively, over 90 percent of the units could achieve a level of 3 at exhaust gas CO_2 concentrations of at least 8 percent (corresponding approximately to a thermal efficiency of 77.5 percent) and three-quarters even could achieve Smoke Spot No. 1 at 8 percent CO_2 or No. 2 at 9 percent CO_2 (about 79 percent efficiency).

Tuning produced little change in NO_x, while filterable particulates were reduced 24 percent, from 0.021 to 0.016 lb/MBtu (9.03 to 6.88 ng/J). The results also indicated that some 71 percent of the reduction in particulate emissions came from the replacement of malfunctioning units. These burners accounted for 10 percent of the units tested, a condition indicating the desirability of a periodic (e.g., yearly) inspection of all burners by a qualified serviceman. In both samples the thermal efficiency increased an average of 1.7 percent, to about 79 percent, when the burner was tuned for minimum smoke.

The value of a systematic, district-wide burner maintenance program for some areas is demonstrated further by the results of a study in the Maryland and Washington, D.C., areas. Here investigators found that less than 42 percent of the units tested (over 400 total) complied with the local Bacharach No. 2 standard. Moreover, thermal efficiency ranges from 54 to 80 percent. However, personnel who surveyed the particulate emissions problems in the Boston region concluded residential and commercial burners were already well maintained in that area, and, therefore, no further improvement could be obtained by a regulation that mandated periodic inspection. This conclusion was based on discussions with oil suppliers and burner servicing companies, which reported that most domestic and commercial units were serviced at least annually in an effort to conserve energy. No emission tests were conducted to substantiate this belief.

The importance of annual servicing is not so evident if one just looks at burner performance before and after a tune-up of one unit that customarily receives yearly maintenance. Burners which do not receive yearly maintenance will begin to perform progressively worse during the second, third, and succeeding years. Thus, periodic service is preventive maintenance; it generally does more to keep burners from becoming high emitters than to actually reduce emissions from these burners. Usually, burner maintenance service can be obtained from an oil supplier on a contractual basis. The cost for such service is approximately \$30 to \$35 per year, excluding parts. Although periodic replacement of the filter for the house air or cleaning of the boiler surfaces does not directly affect particulate emissions, it does so indirectly by maintaining the system's efficiency.

In light of the importance of proper burner maintenance in reducing air pollution, upgrading the competence of servicemen and supplying them with good diagnostic instruments can be considered a particulate control technique. Guidelines have been published recently by EPA to aid servicemen in maintaining burners for high efficiency and low emissions. Training programs for maintenance personnel are available in some localities where oil is in heavy use. These programs are usually offered in community colleges or trade schools. A few private or trade organizations in the United

States also specialize in setting up training programs and preparing textbooks for oil burner servicemen. A typical course takes 3 days and costs \$45. Diagnostic instrumentation to measure CO_2, CO, Smoke Spot No., stack temperature, and draft are commercially available. Kits that include units to measure all five of these parameters cost about \$300 to \$500.

1.3.1.4 Particulate Control by Equipment Design Changes

Nearly all of the design variables for warm air furnaces or boilers affect particulate emissions to some degree. The more significant effects are associated with the burner, specifically, its design and nozzle type. Additionally, tuning, usage patterns, and combustion chamber materials can cause significant variations in particulate emissions. The burner design features which most strongly affect particulate emissions include:

- Fuel atomization techniques
- Combustion aerodynamics (including the use of flame retention devices, swirl, and/or recirculation)
- Combustion chamber shape as it affects residence time
- Combustion chamber materials (and hence wall temperatures)

New burner developments center mainly on the improvement of oil atomization and vaporization schemes and on the optimization of the combustion aerodynamics, particularly by adaptation of the internal or flue gas recirculation concepts. According to one source (Reference 1-6), "Commercially used atomization nozzles which are available at low cost (less than about \$1.00 per nozzle, nominally) do an excellent job of atomization". Therefore, most development work in atomization is directed at improvements which reduce maintenance requirements for the nozzle or allow optimization of the fuel spray pattern for given combustion aerodynamics.

Optimization of combustion aerodynamics is considered by many experts in the field to be the best approach toward achieving the triple goals of low particulate, low NO_x, and high thermal efficiency. Such an optimization attempts to control mixture (i.e., flow patterns and turbulence levels) and residence time to achieve complete combustion at a temperature that, locally or throughout the combustion chamber, never falls below the level required to sustain combustion nor rises above the level at which NO_x formation becomes significant. Although most of the research in this area has been directed at NO_x reductions, with smoke merely a limiting factor, several burners have been developed which reduce smoke concurrently with lowered NO_x.

One such unit is a "blue-flame" burner, which has just become available commercially for single-family warm air furnaces. Because this burner has to be matched to the combustion volume to obtain the desired (internal) recirculation pattern, it can be purchased only as a burner-furnace package. In laboratory tests on this unit, a thermal efficiency of over 80 percent was achieved simultaneously with a Bacharach Smoke Number close to zero and NO_x emissions just over 20 ppm (typical distillate burners emit about 75 to 90 ppm). Its only drawbacks are high CO emissions for 3 to 4 seconds during ignition and 10 percent higher initial costs than for a furnace with a conventional burner. Because of its high efficiency, this first cost difference would pay back in a fairly short time.

Another new "optimized" burner is nearing commercialization. It produces negligible quantities of smoke (less than Bacharach No. 1) and nitric oxide emissions that are about one-half to two-thirds the amount generated in typical, new commercially available burners. This is accomplished while operating at only 10 percent excess air (in laboratory tests) instead of typical values of 25 percent for other new burners. This burner was designed as a retrofit (see next paragraph) and is expected to be available from several manufacturers within 1 to 3 years. A matched burner and combustion chamber that operates on the same principle but can achieve still lower NO_x emissions and higher thermal efficiency with no increase in smoke is expected to be developed within the next 3 to 6 years.

Retrofitting of existing units which are difficult to maintain or defective in design is another method of reducing particulate emissions. These retrofits generally involve replacement of malfunctioning burners at a cost of approximately $300. In the future they may also involve the replacement of operational burners, with the "optimized" burners just mentioned above. Another presently used retrofit is to add one of the commercially available combustion-improving devices to an existing burner for the purpose of improving the mixture of air and fuel. One such add-on, a retention head device, was tested on a standard, high pressure atomizing burner and found to reduce smoke emissions almost 60 percent (average Bacharach No. of 1.2 with the retention head versus 2.9 without it). In addition, thermal efficiency was nearly 10 percent higher for the retention head unit (83 versus 76 percent). Data from other tests on retention heads showed an average particulate emission rate of 0.0056 lb/MBtu (2.39 ng/J) for a burner with a flame retention device versus 0.012 lb/MBtu (5.16 ng/J) for one with a conventional head (i.e., a 54 percent reduction). The flame retention burners also produced lower CO, HC, and NO_x emissions than did the conventional types. However, laboratory experiments have shown that not all flame retention burners simultaneously reduce particulates and NO_x. These combustion improving devices cost about $30 installed.

One of the major factors contributing to high particulate emissions from domestic burners is on-off cycling. The high emissions during the transients are caused mainly by variations in the combustion chamber temperature. Since a cold chamber wall will not assist the combustion, peaks of CO, HC, smoke and particulate are produced just after ignition. Moreover, the oil nozzle may dribble during ignition and shutdown, and the large droplets which then fall out result in high particulate emissions. Modulation and underfiring have been suggested as methods of reducing the significance of the startup transient. When a system is controlled by modulation, the burners are run continuously during peak heating periods at firing rates that vary between a low level and the rated one, rather than alternating between operation at rated condition and shutdown. Underfiring consists of using a smaller (undersized) unit which has to stay on longer and, therefore, cycles less. However, no data are available on the effectiveness, cost, and public acceptability (more complex system or inability to heat house as comfortably during very cold periods) of these proposals.

To summarize, commercially available burners, add-on devices, and/or optimized combustion chamber geometries can be used in distillate-fueled residential furnaces and boilers to achieve low smoke emissions. New units can operate with Smoke Spot Numbers of less than 1 at steady-state thermal efficiencies of more than 80 percent. Based on a sample of units presently installed in the field, most furnaces and boilers can ahieve a Smoke Spot Number of 2 at an efficiency of 79 percent, or better, after being tuned according to normal practices. Significant reductions in area-wide particulate emissions (about 20 percent of those due to residential units) can be obtained by replacement of malfunctioning burners. Reductions of over 50 percent in particulate mass emissions from residential units should be achievable by installing a properly selected flame retention head (one that is suited for the burner in question and has been shown to reduce particulates without increasing NO_x). Such devices usually also decrease fuel consumption.

1.3.1.5 Particulate Control by Conservation

Conservation measures, and especially improved building insulation, reduce particulate emissions indirectly by reducing fuel consumption. In the long run — i.e., after most of the homes in an area have been properly insulated — particulate emission reductions of up to 1.4 percent of the area total could be achieved in northeastern U.S. areas with cold climates and heavy reliance on oil-fired home furnaces.

1.3.1.6 Industry Standards

Residential and small commercial boilers and furnaces are generally designed and fabricated to meet Underwriters Lab (UL) and/or American National Standards Institute (ANSI) standards. Although the primary aim of these standards is consumer protection, several features impact emissions. Distillate fired units will soon be required to emit no more than a Smoke Spot No. 1, concurrently with a CO_2 concentration of at least 10 percent to obtain UL and/or ANSI certification, and the burner ignition and control system must satisfy certain requirements designed to minimize "ignition puffs" and particulate emissions caused by misaligned or malfunctioning units.

1.3.1.7 Existing Regulatory Programs

Most States do not limit mass emissions from boilers or furnaces that are classified resisidential. Usually control is imposed on units which are in 1 to 2 family residences or rated at less than 0.35 MBtu/hr (0.10 MW), but some states imposed no mass limits on systems which are smaller than 1.0 MBtu/hr (0.29 MW). However, most areas require that all sources, including residential boilers and furnaces, obey the visible emission limits. Residential units should have no trouble satisfying even a "zero visible emissions" limit, as in the Maryland, Washington, D.C., and Rhode Island areas, but units which are not well maintained may not meet Maryland's stringent smoke spot limits (Smoke Spot No. 2). Several areas prohibit the use of residual oil in residential and commercial units smaller than about 3 to 5 MBtu/hr (0.88 to 1.5 MW) and place limits on the sulfur content of the distillate oil (e.g., 0.2 to 0.3 percent by weight). None of the air pollution control authorities contacted required mandatory service or maintenance procedures for residential units. However, several of the staff members in the control districts believe such a requirement would be a good one, especially if it were also combined with a mandatory licensing and certification program for servicemen.

1.3.2 Commercial Units 0.4 to 12.5 MBtu/hr (0.117 to 3.66 MW)

1.3.2.1 Usage, Fuels and Emissions

Commercial oil-fired furnaces and boilers are used for space heating and hot water in apartment buildings, public offices, and commercial areas. Warm air furnaces are used mainly in moderate climates if comfort heating is the only requirement. Elsewhere, boilers which can supply hot water or steam for multiple purposes are used. Nationwide, in this size category about one-sixth as much energy is consumed to generate hot water for washing as is used to provide space heating.

Warm air furnaces are generally upgraded, roof mounted versions of residential units. Al-through the burners tend to be more versatile than the ones used in residential units (i.e., can operate properly over a much wider range of firing rates), burner and combustion chamber modifications generally have the same effect on emissions and efficiency in both size ranges.

Boilers can be cast iron or packaged firetube (watertube boilers comprise only 5 percent of this category). Smaller units tend to be cast iron, whereas larger ones are most often firetube. The most popular firetube boilers now are the compact, efficient Scotch and firebox designs. Commercial boilers are approximately equally distributed between oil and gas firing, regardless of size. The trend is strongly toward dual fuel (oil and gas) capabilities. Among the oil users, approximately 95 percent of the smaller units burn distillate, whereas 50 percent of the larger ones use preheated Nos. 5 and 6. Overall, fuel grades Nos. 2 through 6 are used with distillates and residuals being almost equally in demand. No. 4 oil can be a distillate or a mixture of distillate and residual oils. It is used in some schools and apartment buildings and in situations where the equipment cannot handle higher viscosity oils such as Nos. 5 or 6.

Filterable particulate emissions from commercial boilers in steady-state operation range from an average of 0.0086 lb/MBtu (3.70 ng/J) for those fired on No. 2 oil to an average of 0.24 lb/MBtu (103 ng/J) for those on No. 6 oil. Discharge rates as low as 0.0036 lb/MBtu (1.54 ng/J), and as high as 0.38 lb/MBtu (163 ng/J) were measured during the tests from which the above averages were derived. Recently revised EPA emission factors for commercial units range from 0.014 lb/MBtu (6.02 ng/J) for distillate fired units to 0.053 lb/MBtu (22.9 ng/J) for units fired on No. 6 with 0.5 percent sulfur content and 0.22 lb/MBtu (94.6 ng/J) for those using 3 percent sulfur resid. These factors assume the burners receive proper maintenance. Ash content increases as the fuel becomes heavier (lower API gravity), but not enough to account for the higher particulate levels when these heavier fuels are used. A 1 percent sulfur residual oil (LSR) was also investigated in the above-mentioned tests and found to yield filterable particulate levels about equal to those from No. 4 oil and only one-third of those from No. 6 oil. In units which are correctly designed for their intended fuel, the single most important fuel property influencing filterable particulate is carbon residue. API gravity and sulfur content also have a significant effect.

The sulfur content of domestic No. 6 oil ranges from 0.2 to 3.5 percent, depending on the crude source and the method of processing it. With the advent of oil desulfurization processes the refining industry can now make low sulfur residuals, but not yet in unlimited quantities. Moreover, a 1 percent sulfur resid costs about 13 percent more than a high sulfur resid (i.e., unspecified sulfur content about 1 percent), and an 0.3 percent sulfur resid costs 16 to 24 percent more than the high sulfur fuel. In addition, the energy requirements of the desulfurization process are about 3 to 10 percent of the refined fuels heat content, depending upon the process, the sulfur content of the crude oil, and the desired sulfur content of the refined products.

Particulate emissions from commercial units may depend upon atomizing methods (as in industrial and small utility boilers). The trend in small commercial units is towards mechanical atomizing (for simplicity) and in large units towards air atomization. Both types are gaining in popularity as the more difficult to maintain rotary burners are phased out.

1.3.2.2. Particulate Control by Improved Burner Servicing

The most commonly proposed techniques for the control of particulates for commercial oil-fired furnaces and boilers are the widespread implementation of, and adherence to, proper operating and maintenance procedures for existing units, the use of new improved burners or combined burner/combustion chamber designs, and the prohibition of residual oil as an allowable fuel. Although particulate collectors can be used in the exhaust system of commercial units, they are generally not used for this purpose because of their cost (about 12 percent of the initial cost of the boiler or, when annualized, 11 percent of the fuel costs) and need for greater attention by operators than is normally given to boilers in commercial applications.

Several studies have shown that smoke emissions can be reduced by as much as 40 percent in existing units by proper burner tuning, cleansing of dirty burner cups or nozzles, and/or replacement of work or damaged components. Thermal efficiency is generally improved by these adjustments, in some cases significantly, but on the average slightly less than 2 percent. After adjustment boilers fired on low sulfur residual (No. 6) can achieve Smoke Spot Number 3 at steady-state thermal efficiencies of at least 80 percent whereas those burning No. 6 oil of unknown sulfur content (presumably greater than 1 percent) can achieve No.4 at the same efficiency (based on data from a sample of furnaces and boilers that was selected to be representative of the installed population). Distillate units can be tuned to emit less than Bacharach No. 2 at the same thermal efficiencies.

The cost for proper burner maintenance is slight compared with the cost of annual fuel usage. Normally, this service requires 4 to 8 hours of labor at approximately $25 an hour. At a median cost of $150, this would represent about 5 percent of the annual fuel bill for a 10 gph burner (assumed to use 10,000 gal/yr) neglecting any credit for improved fuel consumption. The effective cost would be reduced by about 2 percent, on the average, due to fuel savings.

Proper training is essential for boiler operators and maintenance personnel in order to realize the potential reductions cited earlier. Guidelines have been published recently by EPA to aid servicemen in maintaining burners for high efficiency and low emissions. A few local agencies have done the same and/or have instituted brief courses for boiler operators. Training programs for maintenance and operating personnel are also offered by community colleges, trade schools, or private trade organizations in some localities where oil is in heavy use. The same diagnostic instrumentation can be used on commercial boilers as on residential units. Kits that contain instruments to measure CO_2, CO, Smoke Spot Number, draft pressure, and stack temperature are available commercially at a cost of $300 to $500.

1.3.2.3 Particulate Control by Equipment Design Changes

Proper oil atomization is essential for complete, smoke-free combustion. Conventional atomizers can perform satisfactorily to give low smoke and high thermal efficiency. However, one manufacturer claims that solid particulate emission reductions of 90 percent and combustion efficiencies of over 83 percent can be realized with the use of an acoustic nozzle. Unfortunately, no quantitative emission data are available to substantiate this claim.

Researchers have attempted to optimize the combustion aerodynamics in commercial burners as well as in residential ones. These efforts have led one team of investigators to the development of a 9-gph distillate oil burner that can operate "smoke-free" (i.e., Bacharach No. 1) with as little as 2 percent excess air (typical new commercial burners require up to 25 percent excess air). In addition, this burner produces about one-half as much NO_x as do commercially available units. It should be on the market within three years. Another group has developed a new burner for No. 6 oil which uses swirl, recirculation, and a multistage atomizer to operate over a wide range of oil viscosity and at excess air levels as low as 2.4 percent without exceeding Bacharach No. 4 or emissions of 0.2 lb/MBtu (86 ng/J). Although this burner does not achieve lower smoke levels than other commercially available units, it reduces fuel consumption (and, hence, particulates indirectly) and, therefore, could be used in areas that do not need to achieve significant particulate reductions.

The retrofitting of existing units which are difficult to maintain or defective in design is another way to reduce the particulate emissions. Such retrofits usually consist of burner control replacements, minor modifications to the combustion chamber, changes to the draft system, or even burner replacement. Both new burners described above are designed to be used on existing boilers.

At present one commonly practiced retrofit is replacement of rotary cup burners with pressure or air atomizing units. Experience has shown that rotary burners usually emit more particulates than other types, especially when burning residual oil. Therefore, at least one regulatory agency has prohibited the use of these burners. The cost to replace a rotary cup burner with an air atomizing type varies with burner size from about $1500 installed (parts and labor) for a 10 gph (10.5 cm^3/sec) burner to about $5200 for a 50 gph (52.5 cm^3/sec) unit. These costs are equal to about 10 to 14 percent of 1 years total annualized costs (amortized initial cost, fuel, and maintenance) and would be repaid in 3 to 4 years if the new unit reduces fuel consumption by 10 percent, as expected (through operation at lower excess air without violating smoke regulations).*

Another potential retrofit is the addition of a modulating unit to eliminate cyclic, or on-and-off, operation in furnaces and boilers that provide mainly space heating. It has been well documented that the transient nature of cyclic operation contributes significantly to total particulate emissions because the emission rates are very high during the starting transient. The modulating operation should eliminate the peak particulate, smoke, HC, and CO emissions associated with on-and-off or step turn down controls (the effect on NO_x emissions is minimal). Unfortunately, data to substantiate this claim are not available (i.e., comparison of total particulate emissions from one days operation). Most new burners over 10 gph (10.5 cm^3/sec) can be ordered with modulating control at an additional cost of about $500. Labor charges to retrofit a modulating control to an existing burner add an additional $300 (for a total of $800).

*Based on fuel consumption of 10,000 gal/yr at a cost of 40¢/gal.

Improperly designed combustion chambers can also contribute to particulate emissions, and some of these problems can be corrected in the field (especially if they were caused by an ad hoc field modification, as is often the case).

1.3.2.4 Particulate Control by Fuel Additives and Emulsions

Additives for distillate oil are covered under residential burners. Additives for residual fuels have been studied by a number of investigators.* One study found that chelates of iron and cobalt, and also hydrazine, reduced smoke in heavy fuel oils. The additives were used in rather high concentrations,† ranging from 0.01 to 0.1 percent. Iron chelate was most effective. At a concentration of 0.01 percent it reduced Bacharach Smoke Number from 2.6 to 0.6. Other additives achieving varying degrees of smoke reductions were manganese compounds and copper, iron, manganese inorganic salts and some organic compounds (at concentrations approaching 1 percent). Even though additives may decrease smoke emissions, some (especially the metallic-based ones) might create potentially harmful new emissions. Moreover, additives which are compatible with one fuel may be incompatible with fuel of the same grade that comes from a different crude. Sludge which can form due to interactions between the additive and the fuel can cause burner plugging.

Both water/distillate and water/residual oil emulsions were tested on a packaged commercial boiler using (1) low pressure air atomization and an ultrasonic energy emulsifier and (2) high pressure mechanical atomization and a high pressure emulsifier. In the distillate case, an emulsion with 25 percent water allowed the first unit to be run with approximately 4 percent less excess air without increasing smoke emissions, but the resulting gain in thermal efficiency was offset by heat lost to vaporization of the water, water supply problems, and emulsifier energy requirements firing residual. The results depended significantly on the emulsifier used, and baseline oil-only results varied significantly due to the difference in atomization technique used. In the first of the two systems tested the smoke density of the boiler with oil only and 0.9 percent sulfur content in the fuel tended to stabilize at about Bacharach No. 6 beyond 40 percent excess air. It could achieve the same smoke level with only 15 percent excess air or it could achieve Bacharach No. 3 with 32 percent excess air if it burned a 25 percent water emulsification. Particulate emissions at a stoichiometric ratio of 1.47 were cut in half, from about

*Additives for use with distillate fuel were discussed in Subsection 1.3.1.2, under residential systems.

†The iron oxides which are emitted when iron chelate is added to the fuel are not thought to be harmful by themselves. However, recent studies suggest that they may combine with polycyclic organic matter in the atmosphere to become potentially carcinogenic substances.

0.064 to 0.032 lb/MBtu (27.5 to 13.8 ng/J). With the other system, smoke with oil only was No. 3.5 and could not be reduced much below No. 3 by the addition of water. Baseline particulate emisssions of 0.12 lb/MBtu (51.6 ng/J) (at a stoichiometric ratio of 1.35) were reduced to 0.042 lb/MBtu (18.1 ng/J) with 25 percent emulsification. These baseline (oil only) variations were attributed to the different atomizer used in each test; one resulted in unusually high smoke, even with oil only and the other in unusually high particulate mass emissions — 0.127 lb/MBtu (54.5 ng/J) as compared with the EPA emission factor of 0.08 lb/MBtu (34.4 ng/J) for this 0.9 percent sulfur resid. In both cases, the thermal efficiency first increased 1 to 2 percent when 15 percent water was added and then decreased as more water was added reaching a loss of 4 to 5 percent with a 25 percent water emulsion. In conclusion, emulsions were optimized with approximately 15 percent water, had little effect on thermal efficiency, and reduced particulate mass emissions significantly.

1.3.2.5 Particulate Control by Conservation

Just as in residential units, energy conservation practices can reduce particulate emissions by reducing fuel consumption.

1.3.2.6 Industry Standards

Both the Hydronics Institute and the American Boiler Manufacturers Association (ABMA) rate boilers in an attempt to provide a uniform method of determining boiler capacity. In order to be listed with the ABMA, a boiler must be capable of continuous operation at its stated capacity without violating smoke ordinances. The Hydronics Institute specifically requires compliance with Bacharach No. 2 for distillated-fired boilers and No. 4 for residual-fired units. The American Society of Mechanical Engineers (ASME) publishes detailed maintenance and testing procedures which, if followed, lead to optimized combustion for that system and, hence, minimum particulate production. These procedures are in addition to the design standards (structural, electrical, etc.) which were developed for safety and do not impact particulate emissions.

1.3.2.7 Existing Regulatory Programs

All but three states limited mass emissions from units that were rated $\leq$10 MBtu/hr (2.9 MW). These limits ranged from 0.06 to 0.6 lb/MBtu* (25.8 to 258 ng/J). All the control districts contacted during this study had both opacity and particulate limits which applied to at

*Excluding New Mexico which may soon revise its limits upwards.

least some boilers and furnaces in this user category. In a few regions units which were smaller than 1 to 5 MBtu/hr (0.29 to 1.46 MW) were not subjected to the particulate loading regulations. New York City requires commercial boilers to pass a Bacharach smoke test with a reading of No. 3 or less and a stack thermal loss no greater than 20 percent of the heat input. This joint stipulation of a smoke reading and a thermal efficiency is important because many people elsewhere satisfy Bacharach limits by the use of excess air. Most of the regions contacted also restricted the sulfur content in the fuel to 0.3 to 0.5 percent by weight.

Maryland is the only region of the nine studied in detail which attempts to limit emissions by an equipment standard. They recently banned the installation of rotary cup burners in new units in the 1 to 13 MBtu/hr (0.29 to 3.8 MW) size category, and required that all units throughout the state phase out rotary cup burners by 1976. This equipment standard was based on their observations that rotary cup burners require more maintenance to insure low particulate emissions than do other burners, and that the operators of commercial size boilers are not likely to give these units the required maintenance. Therefore, they decided to solve the problem by simply prohibiting the use of these burners. New York City also requires that new and upgraded boilers meet performance specifications and installation criteria.

The enforcement procedures used in these nine control districts for commercial boilers and furnaces varied from no activity after the granting of the permit to equipment restrictions to periodic inspections. Generally, districts which use periodic inspections restrict their review to operating procedures and equipment. They only resort to stack tests if they suspect a problem with the installation. Only New York City requires a test for smoke, temperature, draft, and CO_2 for every permit renewal (3 years).

In order to supplement the enforcement program, which relies heavily on the skill of boiler operators, New York City offers a basic boiler operator course to all boiler operators. Erie County requires the operators of the boilers in the public school system to attend a similar class.

1.3.3 Industrial Boilers — 12.5 MBtu/hr to 250 MBtu/hr (3.7 to 73 MW)

1.3.3.1 Usage and Emissions

Industrial boilers cover the size range from commercial units on the small side to utility boilers on the large side. Therefore, the smaller industrial boilers are similar to large commercial units, and the large industrial boilers have much in common with small utility boilers. Thus, steam generators in this size category are either of firetube or watertube construction.

The former design predominates the market among the smaller size units, whereas the latter prevails among larger boilers (above 70 MBtu/hr or 20.5 MW). Units that produce steam above about 150 psig (1.03 MPa) are generally also watertube boilers. Although most installed units are designed to burn only one fuel, the trend is toward a dual fuel design (e.g., oil and gas). The smaller industrial boilers are now distributed about equally between gas and oil (90 percent residual), whereas the larger units are distributed evenly among coal, gas, and residual oil. Overall, in this size range, more than 60 percent of the fuel oil used is residual. Air and rotary cup atomizing predominate among the lower capacity boilers in use today, although steam atomizing is also common. Rotary cup type burners are expected to be replaced by air or steam atomizing types in the near future. Steam is, and apparently will remain, the major atomizing medium in the large units. Air atomization produces about one order of magnitude less particulate than does mechanical atomization. Moreover, particulates from an air atomized unit contain proportionally less combustible matter than those from the other unit.

Although many industrial boilers were field erected in the past, projections suggest that by 1990 over 90 percent of the industrial units sold will be packaged boilers. Boilers greater than about 30 MBtu/hr (8.8 MW) are equipped with soot blowing equipment to clean the heat transfer surfaces. Soot blowing procedures (e.g., frequency and duration of each blow) are known to affect visible and particulate emissions, at least during the blow. However, data are not available to show the effects of different soot blowing procedures on particulate emissions averaged over complete operating cycles.

As with commercial boilers, particulate emissions from heavy oil-fired industrial boilers are higher than those from units burning lighter oils. Thus, uncontrolled industrial boilers emit 0.0186 to 0.0371 lb/MBtu (8.0 to 15.9 ng/J) when burning No. 2 oil, 0.037 to 0.112 lb/MBtu (15.9 to 48.2 ng/J) when burning No. 5 oil, and 0.042 to 0.103 lb/MBtu (18.1 to 44.3 ng/J) when consuming No. 6 oil (0.10 lb/MBtu corresponds approximately to 43 ng/J which is the maximum allowable limit in many states for large boilers — see Tables 1-2 and 1-3). Emission rates decrease with increasing size for steam atomized No. 6 fired boilers. However, for units that burn No. 2 or No. 5, the emission rates appear to be more a function of atomizing type than of size. Recently revised emission factors for industrial boilers depend upon the fuel used, ranging in value from 0.013 lb/MBtu (5.6 ng/J) for distillate fired boilers to 0.220 lb/MBtu (94.6 ng/J) for units which burn No. 6 oil containing 3 percent sulfur.

Particulate emissions increase with increasing carbon residue in the fuel oil. The limited data available on particule size distribution suggest that over 90 percent of the number of particles emitted from correctly adjusted No. 6 oil-fired industrial boilers are less than 6 microns in diameter. The open literature does not contain any reports on tests with additives specifically for particulate control from industrial boilers but an EPA sponsored study in this area will be completed soon by Battelle Columbus Labs.

1.3.3.2 Particulate Control

Large industrial boilers are generally well maintained to minimize fuel consumption. Therefore, particulate collectors have been viewed as the only method of controlling particulate emissions from these sources. However, a recent study has suggested that the maintenance procedures designed to minimize costs (labor for maintenance versus fuel penalty) do not minimize emissions. This study concluded that particulate emission reductions of up to 30 percent could be obtained by reducing intervals between successive shutdowns for system inspection and cleaning (i.e., quarterly instead of annually). Since the smaller industrial boilers are similar to the large commercial ones, control strategies for the latter, such as improved maintenance procedures and operator/serviceman training, could be applied beneficially to these industrial units, too.

When low sulfur oils are used, smoke is frequently eliminated by the use of high excess air (e.g., 15 percent instead of the 3 to 5 percent desired for minimum fuel consumption). New, better designed burners or closer combustion control should be used in these boilers to improve thermal efficiency by operating with less air. Moreover, when high sulfur fuels are used, low excess air is necessary to minimize the formation of SO_3. This effluent not only leaves the stack as a visible plume but also accumulates on the heat transfer surfaces, causing reduced heat transfer and tube wall corrosion.

Electrostatic precipitators are the most common collectors. When properly designed and maintained, the electrostatic precipitators can capture up to 95 percent (by weight) of the solid particulates emitted from oil-fired boilers. At this efficiency smut fallout and plume visibility can be eliminated. ESP's are limited more by their inability to reduce emissions below about 0.01 lb/MBtu (4.3 ng/J) than by their maximum collection efficiency. The cost to own and operate precipitators designed to capture 90-95 percent by weight is less than 2.5 percent of the cost to fuel an industrial boiler rated at 150 MBtu/hr (44 MW) heat input (about 120,000 lb/hr steam output). Draft losses across the precipitator are only about 2 inches of water (498 Pa).

Mechanical cyclone collectors are the other type of collectors used for oil-fired boilers, but they are not effective for particles smaller than 10 microns. However, this type of collector is useful to control acid smut emissions during soot blowing, and the large particles that are emitted from units which do not receive adequate maintenance or careful combustion control.* Total annual costs for mechanical collectors are about one-fifth those for precipitators, and draft losses are only slightly higher.

The other two types of collectors, bag filterhouses and wet scrubbers, have been rarely used in oil-fired boilers. However, particulate or combined particulate and SO_x scrubbers are being developed and prototype units have recently been installed. Although some problems remain to be solved, including disposal of the spent scrubber solution, these preliminary results suggest that wet scrubbers can remove 99 percent of the particulate (by weight) at costs which are comparable to those of a precipitator with 90 percent collection efficiency. Bag filterhouses for oil-fired units also await the solution of some difficult problems, but it is believed that they could collect 99 percent of the particulate emissions at about the same cost as a 90 percent efficient precipitator.

Virtually all watertube boilers greater than 30 MBtu/hr (8.8 MW) and some large firetube boilers are equipped with soot blowers to remove ash and slag deposits which accumulate in the heat transfer surfaces. There is no reason to believe that equipment characteristics or medium used (steam or air) affect the particle emissions since all systems are designed to remove the deposits effectively. Soot blowing frequency can alter the plume visibility, grain loading, and size distribution during the blow. Therefore, it can affect the impact of the particulate emissions on the ambient air if the boiler is uncontrolled. If the boiler is equipped with a sufficiently large precipitator, the outlet grain loading will be the same during a blow as during other periods.

Opacity monitors are available commercially for the continuous checking of particulate emissions from stacks. Units which satisfy EPA specifications for in-stack continuous monitors on boilers smaller than 250 MBtu/hr (73 MW) cost $1000-1500 installed. They have generally been connected to alarm systems and/or continuous recorders but not to automatic burner shut-off systems. (It is also not clear that automatic shutdown of an entire boiler is necessary every time excessive smoke appears.) Oxygen meters (flue gas concentration) have also been relegated to a monitoring function in most cases, but as they now are quite reliable, more and more will probably be used in closed-loop burner control systems.

*This can be a problem with units smaller than 25,000-100,000 lb steam/hr (25-100 MBtu/hr, or 7 to 29 MW, heat input), especially when the facility has only one boiler. Usually plants with many boilers maintain them well, even if each individual boiler is small.

Opacity monitors which cost only about $500-600 are available for the smaller industrial boilers and can be used as an alarm system to notify the operator of a problem.

Industrial boilers typically operate at between 60 and 100 percent of their design capacity, depending on the load requirement. However, information about the effect of boiler load on particulate emissions is scarce. The limited available data suggest, for example, that a 40 percent reducation in particulate emissions could be realized by decreasing the boiler load to 50 or 60 percent of rated conditions. However, the capital expenditure penalties of prohibiting boilers from operating above 60 percent of their design capacity are significant and most probably would not be acceptable given current shortages in both capital and electric generation capacity. If additional tests confirm the limited data which show decreasing particulate emissions with reduced load, mandatory output restrictions could be used during air pollution episodes.

Although there have been claims of up to 50 percent reduction of SO_3 in the exhaust system by the use of flue gas additives (e.g., limestone, dolomite, magnesium oxide, or ammonia), total mass emissions actually increased when these additives were used. The difference was that the particulate was now in the form of dry, powdery solid sulfates instead of acid smut. In general, post-combustion additives are used only to reduce cold-end corrosion and smut deposits inside the furnace. When resids with high vanadium content must be burned, flue gas additives have to be used to protect the superheater tubes.

1.3.3.3 Industry Standards

The industry standards that were summarized under the section on commercial boilers also apply to units in this size category.

1.3.3.4 Existing Regulatory Programs

Virtually all the states regulate mass emissions from industrial boilers, with limits ranging from 0.04 to 0.6 lb/MBtu (17.2 to 285 ng/J) for a 100 MBtu/hr (29.3 MW) boiler (or equivalent grain loading expressed in terms of grains/scf.)* Maryland also requires the use of a dust collector on all resid-fired units greater than 13 MBtu/hr (3.8 MW) heat input and specifies the collection efficiency for the dust collector. Naturally all boilers in the size group are allowed to burn residual oil, but the sulfur content in the fuel is generally restricted to less than 1 percent by weight except for heavily impacted regions. In Massachusetts the allowable

*Excluding New Mexico, which expects to relax its limits.

limits were 0.5 percent in nonmetropolitan areas and 0.3 percent in metropolitan areas such as Boston. In 1975 these limits were temporarily relaxed to 2.2 and 1.0 percent, respectively, for boilers that could satisfy certain conditions (see Table 6-5). The issue may be reexamined in mid-1976. Four of the nine districts contacted require the installation of continuous monitoring smoke meters in all industrial (and utility) boilers, and one additional region requires it only for utility boilers. One state, New Jersey, prohibits any visible emissions from boilers with heat input less than 200 MBtu/hr (58.6 MW) or with a stack whose diameter is less than 60 inches.

The enforcement procedures for industrial and utility boilers were generally the same in all the regions contacted. Units in this size are the relatively few, easily identified ones. Any differences in enforcement procedures between the various regions are probably more subtle than in the other user groups because the practices used for large sources tend to depend mainly on the specific experiences gained by the enforcement staff in their dealings with industrial or utility boiler operators.

1.3.4 Utility Boilers — over 250 MBtu/hr (73 MW)

1.3.4.1 Usage and Emissions

Boilers in the utility size range are all of the watertube type. They are classified by their firing type — i.e., the particular way in which the oil is injected into the boiler. The three primary firing types for oil-fired units are single wall (or front face) firing, in which a bank of burners mounted on a plane wall ejects fuel in one direction only; opposed firing, in which two banks of burners eject fuel toward one another from opposing walls; and tangential firing, in which the burners are located at the corners of a square and impart a rotational motion to the combustible mixture. Three others, vertical, turbo-fired, and cyclone firing, are primarily used with coal, but can be used with oil. The majority of the oil-fired utility boilers in use today are opposed or tangential fired, although approximately one-half of the smaller ones employ single wall firing. Coal is the primary fuel, especially in the very large units (>600 MW_e). Approximately one-half of the boilers which are not restricted to coal are configured to burn gas and oil. Virtually all of the power generated in 1973 by utilities in New England came from oil-fired boilers. The Middle Atlantic and Pacific regions also depend upon oil to a large extent. Some of this oil-fired capacity is being shifted to coal in response to oil shortages. Approximately 96 percent of the oil used by utilities is residual oil, and over half of this fuel (55.5 percent) is burned in units which are equipped with particulate control devices.

Particulate emissions from utility boilers are a function of boiler size more than anything else. Measurements indicate that particulate emission levels from uncontrolled boilers range from 0.01 to 0.26 lb/MBtu (4.3 to 112 ng/J) for 10 to 100 MW_e units (approximately 100 to 1000 MBtu/hr) but only from 0.03 to 0.06 lb/MBtu (12.9 to 25.8 ng/J) for 300 to 600 MW_e units (3000 to 6000 MBtu/hr). The average emission rate for these uncontrolled boilers is about 0.07 lb/MBtu (30.1 ng/J) for the smaller units (<100 MW_e) which account for about 40 percent of the fuel consumed, and approximately 0.047 to 0.053 lb/MBtu (20.2 to 22.8 ng/J) for the larger units (350 to 600 MW_e).

EPA has proposed emission factors for utility size boilers that depend upon fuel grade and, in the case of No. 6 oil, sulfur content. For a boiler firing a No. 6 oil with 0.5 percent sulfur content (by weight), the emission factor is 0.053 lb/MBtu (22.8 ng/J); if the oil contains 3 percent sulfur, the emission factor is 0.22 lb/MBtu (94.6 ng/J).

1.3.4.2 Particulate Control

The techniques that were described for the control of particulates from industrial boilers, especially the large ones, can be applied equally well to utility boilers. The only difference is that utility boilers can generally reach lower emission levels (per unit heat input) than industrial units fired on the same fuel because of the size effect. The most promising control techniques are frequent cleaning of the fuel and air handling equipment, the use of electrostatic precipitators designed for oil-fired boilers, matching of soot blowing procedures with the particulate collection equipment, continuous (or at least frequent) flue gas measurements (CO_2 or O_2) to maintain optimum combustion conditions, and the use of opacity monitors to warn the operator of abnormal combustion conditions that result in smoke and other particulate emission. The effectiveness of the last three approaches are not known.

It has been suggested that emission reductions of up to 30 percent could be achieved by reducing the interval between major cleaning and inspections from one year to three months. Electrostatic precipitators have been shown to be capable of reducing mass emissions by 50 to 99 percent, on the average, and eliminating any visible plume. Reduction of over 90 percent (by weight) can be obtained with correctly sized precipitators that are designed specifically for oil or converted from a coal system to an oil system. Such precipitators would add about 0.5 percent to the charge for electricity.

Emissions from controlled units (at an estimated 50 percent collection efficiency) range from about 0.07 lb/MBtu (30.1 ng/J) for small units to 0.01 lb/MBtu (4.3 ng/J) for the largest units when no additives are employed to reduce cold-end corrosion and slagging. Additives must be used when fuels with high vanadium and sodium content are burned, but they result in controlled emissions which are approximately twice as large as they are from boilers which do not need additives. An average emission factor of 0.025 lb/MBtu (10.8 ng/J) has been suggested for controlled utility boilers of all sizes. This average factor is based on existing units, many of which were designed and first installed on the boiler when it was firing coal. Since the precipitator was not changed when the boiler was converted to oil, its collection efficiency is only about 50 percent. If one specifies instead an efficiency of 90 percent, all utility boilers (>100 MW_e) should be able to meet a limit of 0.01 lb/MBtu (4.3 ng/J). The large (>300 MW_e) units should even reach levels as low as 0.004 to 0.006 lb/MBtu (1.7 to 2.6 ng/J).

1.3.4.3 Industry Standards

It is believed that the only industry standards that apply to utility boilers are the ASME design codes, which do not impact emissions. These large boilers are generally custom built to the utility's own specifications.

1.3.4.4 Existing Regulatory Program

State regulatory programs for utility boilers are very much like those for industrial units, except that the mass emission limits are frequently lower for the utilities. Thus 1000 MBtu/hr units (approximately 100 MW_e) and larger are limited to values as low as 0.02 lb/MBtu (8.6 ng/J) in some states.* New steam generating units greater than 250 MBtu/hr (73 MW) must also comply with a federal standard of performance of 0.1 lb/MBtu (43 ng/J) or, where more stringent, the applicable state or local agency standard. Since many uncontrolled boilers emit less particulate, the federal standard does not represent the best available control technology for particulate from oil-fired units.

1.4 SUMMARY CONTROL MEASURES

This subsection presents a summary of control measures which local or state air pollution control authorities can implement to attain and maintain particulate national ambient air quality standards (NAAQS) in their region. These control measures are expected to be applicable mainly in major urban centers where the need for control of particulate emissions is more demanding.

Since the contribution of any source category to the total emissions in an area varies from region to region, and since the seriousness of the problem (e.g., the current and anticipated ambient air concentrations of particulate matter) also varies from region to region, a control

*Excluding New Mexico, which expects to reduce its limits.

program should be area specific. That is, the user categories which need to be controlled and the degree to which each of these need to be controlled will depend upon the specific problems of a given area. Therefore, we shall present separately controls for each user category (residential, commercial/institutional, industrial, and utility). Within each category, we shall then rank the control measures in order of increasing effectiveness, taking into account the emphasis on future sources of emissions, cost, and public acceptance.

The control measures are presented here in tabular form only (text to explain and justify these accompanies the tables in Section 7). A separate table is used for each size category. For regulatory purposes the class of boilers and furnaces is divided into four categories based on size; the names residential, commercial, etc., are used here merely to facilitate reference to a particular size category.

The format of the tables which are used to present the control measure is shown and explained by Table 1-5. The tables themselves are repeated here as Nos. 1-6 through 1-9. In most cases, the control measures would be applied cumulatively. That is, if a local air pollution control agency decides that measure No. 1 is not sufficient to solve its ambient air problem, it should consider next the use of both measures No. 1 and 2. If these two still did not reduce emissions enough, the agency should then investigate the simultaneous implementation of measures No. 1, 2, and 3, etc. Where measure No. 2 is simply a more stringent version of measure No. 1, the second one automatically includes the first one.

Air pollution control authorities are encouraged to engage in public information campaigns ("PR") which stress the value to individual home owners of having their oil burner serviced annually. Periodic burner servicing can be a useful way to reduce emissions because tuned and well maintained burners emit less than those just left by themselves. This is especially true if burners which are found to be damaged or worn out are replaced. Despite the general awareness of increasing air pollution, individuals still seem to be reluctant to spend funds voluntarily to reduce their own contribution; therefore, programs which stress economic gains and treat pollution reductions as a side benefit will more likely be accepted than those which do not. All publicity campaigns for improved burner maintenance should be accompanied by exhortations to conserve energy. Energy conservation is a valid control strategy because particulate emission rates are generally a direct function of fuel consumption.

TABLE 1-5. POSSIBLE PARTICULATE CONTROL MEASURES FOR BOILERS AND FURNACES: "SAMPLE FORMAT"[a]

Rank	Control Measure[b]	Policy Instrument	Effectiveness		Cost Impact[d]		Energy Impact,[e] %	Public Acceptance[f]
			Reduction per unit, %	Reduction Per Air Region[c]	User, %	APCD		
1	Abbreviated statement of control measure for implementation as first step to reduce particulate emissions from this source category.	Regulatory or political activities needed to give legal basis to control measure	Estimated average percent reduction in emission from each source affected by this control strategy.	Estimated impact on total emissions to the air basin from this source category — i.e., a measure of the fraction of this source category affected by the recom- control measure	Cost to each affected user (annual operating and initial, as appropriate).	Indication of enforcement effort required to police sources regulated by this control measure	Impact of this control on energy consumption by source (including indirect changes, such as energy consumed by refinery to desulfurize oil).	Judgemental estimate of general public reaction to the control measure. In all categories but residential, this reaction assumed to be conditioned by cost pass-through or publicity that arouses sympathy. Reaction labelled good if most people unaffected even if some people significantly impacted.
2	Abbreviated statement of control measure for implementation, in addition to 1, above, if 1 is not sufficient to meet the emission reductions goals of the region.		Impact of reduction due to this control measure					

[a] See Appendix C for conversion to SI unit.

[b] SSN = Smoke Spot Number

[c] Relative to area-wide emissions from all sources in this category only; impact on region depends on relative importance of this source category.

[d] Sample calculation of cost impact on annualized basis given in Appendix D.

[e] (Increase) or decrease in efficiency.

[f] Judgement; no data to substantiate.

TABLE 1-6. POSSIBLE PARTICULATE CONTROL MEASURES FOR RESIDENTIAL BOILERS AND FURNACES: 0 TO 0.4 MBTU/HR (0 TO 0.12 MW)[a]

Rank	Control Measure[b]	Policy Instrument	Effectiveness		Cost Impact[d]		Energy Impact,[e] %	Public Acceptance[f]	Comments
			Reduction per unit, %	Reduction Per Air Region[c]	User, $	APCD			
1	Stringent limits for new and replacement burners — SSN 1, $CO_2 \geq 10\%$. Emission limit of 0.01 lb/MBtu suggested if certification agreement can be made with ANSI or UL. Regulation can be extended to sale of home.	Building codes, tax incentives, cooperation with standards laboratories, APCD regulations	50	Moderate (eventually)	30 to 100 less fuel savings	Low	(5 to 10)	Good	Should be acceptable due to fuel savings. Low cost impact based on flame retention retrofit. Impacts only small number of new units.
2	Moderate limits on existing units — SSN 2, $CO_2 \geq 8\%$, no visible emissions.	APCD regulations	10	Low	30/yr	Low	0	Fair	Approach is almost voluntary — too many sources to enforce. Probably ignored by worst offenders.
3	Moderate limits on existing units (as above) plus mandatory annual inspection/maintenance by licensed serviceman	APCD regulations, tax laws	20	Moderate	30/yr less fuel savings plus 0 to 300 once	Moderate	(1 to 2)	Fair	Impacts many units, especially on smoke. May force some users to replace burners.
4	Stringent limits on existing units plus inspection/maintenance (as above) — SSN 1, $\geq 8\%$ CO_2, 5% opacity	APCD regulations, tax laws	30	High	30/yr less fuel savings plus 0 to 300 once	High	(1 to 5)	Poor	Expect many users will have to replace burners. Could improve public acceptance with massive publicity campaign stressing energy conservation.
5	Fuel restricted to no heavier than No. 2 oil	APCD regulations	40	Low	0 to 300 + 10 to 15% of fuel costs	Low	(5 to 8)	Good	Does not affect many burners. May need to replace burner. Energy impact at refinery. Effectiveness assumes unit burned resid.
6	Combustion additives at optimized concentration to be added to fuel at suppliers distribution center	APCD regulations, coordination with nationally recognized standards	30 to 50	High	1 to 2% of fuel	Low	0	Poor	Supplier demonstrates that his concentration is optimum (see Figure 3-2), and additive is compatible with the fuel. Generalized use not recommended at this time because of possible toxic effects and interactions with fuel.

[a] See Appendix C for conversion of mass emission limits to SI units

[b] SSN = Smoke Spot Number

[c] Relative to area-wide emissions from all sources in this category only; impact on region depends on relative importance of this source category

[d] Sample calculation of cost impact on annualized basis given in Appendix D

[e] Unit (increase) or decrease in efficiency

[f] Judgement; no data to substantiate

TABLE 1-7. POSSIBLE PARTICULATE CONTROL MEASURES FOR COMMERCIAL BOILERS AND FURNACES: 0.4 TO 12.5 MBTU/HR (0.12 TO 3.66 MW)[a]

Rank	Control Measure[b]	Policy Instrument	Effectiveness: Reduction per unit, %	Effectiveness: Reduction Per Air Region[c]	Cost Impact[d]: User $	Cost Impact[d]: APCD	Energy Impact[e] %	Public Acceptance[f]	Comments
1	Following smoke limits @ ≤20% stack loss (alternatively CO_2 ≥12.5%) and no visible emissions Fuel / SSN (new) / SSN (old) No. 5 / 3 / 4 LSR (≤0.3%S) / 2 / 3 No. 2 / 1 / 2 For residual fired units >5 MBtu/hr suggest emission limit of 0.1 lb/MBtu if certification agreement can be made with ABMA or Hydronics Inst.	APCD regulations, building codes, tax incentives, cooperation with standards laboratory	10	Moderate	150/yr	Low	0	Good	Assumes new burners will cost no more than existing designs. Approach is almost voluntary for existing units — too many sources to enforce. Probably ignored by worst offenders. EPA presently considering certification agreement with ABMA or Hydronics Inst.
2	Installation and operating permit required. Renew every 3 years if pass emission test. Limits as per 1, above. Test program to determine need for design criteria.	APCD regulation, building codes, tax incentives, cooperation with standards laboratories	15	Low beyond impact from 1	165/yr less fuel savings 1500 (10 gph) 5200 (50 gph)	Moderate	(0 to 2)	Good	Most of cost born by user. First step to strengthen 1, above, without excessive enforcement costs
3	Prohibit rotary cup burners unless can prove compliance under typical operating conditions	APCD regulations	10 to 40	Low	1500 (10 gph) 5200 (50 gph) less 5% to 10% fuel savings	Low	(5 to 10)	Good	Has noticeable impact only in those regions with many rotary cup burners
4	No resid in units <5 MBtu/hr. (Residual oil defined as grades 5 and 6.)	APCD regulations	50	?	500 to 1500 (for 10 gph burner) + 15% of fuel cost	Low	5 to 8	Poor	Impact depends on current fuel usage pattern. Energy impact at refinery. High cost for cases where need new burner. Subject to availability of fuel.
5	Limits as per 1 above plus mandatory annual inspection/maintenance by licensed serviceman	APCD regulations, tax incentives	20	Moderate	150/yr less fuel savings also 1500 (10 gph) 5200 (50 gph)	Moderate	(1 to 2)	Good	Impacts many units. May force some to replace burner. States are encouraged to make reciprocal agreement for licensing servicemen.
6	No resid in any units (only No. 2 or 4 oil)	APCD regulations	≤75	High	500-1500 (10 gph) 1500-5200 (50 gph) + 15% of fuel	Low	5 to 8	Poor	Similar to above, but impacts more sources and will force more to change burners
7	All units limited to SSN 1 @ ≤20% stack loss (or CO_2 ≥12.5%), and no visible emissions	APCD regulations, building codes, tax incentives	50 to 90	High	1500 (10 gph) 5200 (60 gph) + 15% of fuel	High	5 to 8	Poor	Requires burner replacement in addition to above
8	Combustion additives at optimum concentration to be added to fuel at suppliers distribution center	APCD regulations, coordination with nationally recognized standards	50	High	1% to 2% of fuel	Low	0	Poor	Supplier demonstrates that his concentration is optimum and that additive is compatible with fuel. Generalized use not recommended at this time because of possible toxic effects and possible interaction with fuels.

[a]See Appendix C for conversion of mass emission limits to SI units
[b]SSN = Smoke Spot Number
[c]Relative to area-wide emissions from all sources in this category only; impact on region depends on relative importance of this source category
[d]Sample calculation of cost impact on annualized basis given in Appendix D
[e]Unit (increase) or decrease in efficiency
[f]Judgement; no data to substantiate

TABLE 1-8. POSSIBLE PARTICULATE CONTROL MEASURES FOR INDUSTRIAL BOILERS AND FURNACES: 12.5 TO 250 MBTU/HR (3.66 TO 73.2 MW)[a]

Rank	Control Measure[b]	Policy Instrument	Effectiveness: Reduction per unit %	Effectiveness: Reduction Per Air Region[c]	Cost Impact[d]: User $	Cost Impact[d]: APCD	Energy Impact[e]	Public Acceptance[f]	Comments
1	Require construction permits for all new or replacement units. Require operating permits (renewable annually) for all new or replacement units upon demonstration of compliance with following limits: Distillate SSN 2 Residual SSN 4 also 0.1 lb/MBtu Above limits to be achieved with 5% opacity.	APCD regulations, cooperation with standards laboratories	≤40	Low Moderate (eventually)	500-3000 yr	Low-High	(≥0)	Good	Need show compliance with mass emission limit only for first operating permit; renewal based on total engineering evaluation. Approval can be by model type. No cost impact assigned to this control for equipment because available systems can comply. Only cost impact for permit application (fee + engineers cost) and emissions test. For replacement assumes emissions due mainly to burner and not rest of boiler. Enforcement can be aided by a no-visible emission limit. Impact on APCD high if have no permit system.
2	Require operating permits for existing boilers, to be renewed annually if comply with following: Distillate SSN 2 Residual SSN 4	APCD regulations	≤30	Moderate	500 once plus 300 to 600/yr	Moderate	Positive	Good	Based on Maryland regulation as example. Presumes units now emit @ SSN 4 to 6 (barely visible). Cost for permit application.
3-A	Specify burner servicing and cleaning frequency: Units >30 MBtu/hr (10,000 lb steam/hr) on residual — 3 months All other units this category — 6 months Require operator and maintenance/servicemen to be licensed. Owner to advise APCD of service performed and post-service measurement of SSN and thermal efficiency (CO_2 and stack temperature).	APCD regulations, cooperation with trade or community-sponsored training program	≤30	Moderate	6000/yr 1200/yr	Low	Positive	Good	States are encouraged to make reciprocal agreements for licensing servicemen. Whenever a source can show that a different burner servicing and cleaning frequency can maintain the same emissions, these provisions could be waived.
3-B	Require flue gas monitors: For units <30 MBtu/hr — Smoke detectors. Connected to audible alarm set for 15% opacity For units >30 MBtu/hr — Transmissometer that meets EPA specifications, connected to audible alarm set for 10% opacity and a continuous recorder Oxygen monitor connected to continuous recorder Size cut-off based on total heat input of all boilers that exhaust through the same stack (if more than one).	APCD regulations	?	?	500 to 600 plus 300/yr	Low	Positive	Good	Effectiveness unknown because of lack of data on incidence and duration of unnoticed upset conditions. Enforcement through operating permit renewal system. Oxygen meter used to insure efficient combustion. Many boilers already equipped with these monitors. Control district to issue a list of approved smoke detectors for use on units <30 MBtu/hr.

TABLE 1-8. Concluded[a]

Rank	Control Measure[b]	Policy Instrument	Effectiveness		Cost Impact[d]		Energy Impact[e]	Public Acceptance[f]	Comments
			Reduction Per Unit %	Reduction Per Air Region[c]	User $	APCD			
3-C	Require dust collectors on residual fired boilers >50 MBtu/hr with design collection efficiency >75% for particulate >10 μm.	APCD regulations	20	Low	0.2% of fuel	Low	0	Good	Low effectiveness based on assumption that many units well maintained and hence do not emit much large particulate. Helps more with local nuisances (especially during soot blowing) than TSP. Collection efficiency is design value.
4	Limit new residual units >50 MBtu to 0.04 lb/MBtu	APCD regulations	50 to 70	High	< 1.5% of fuel	Moderate	<2	Good	Based on Maryland regulation and use of multicyclones or ESPs with collection efficiencies of 50-70%. An excess air level ≤15% could also be imposed to retard SO_3 formation and conserve energy.
5	Limit existing residual units >50 MBtu to 0.05 lb/MBtu	APCD regulations	40 to 60	High	<1.5% of fuel	Moderate	<2	Good	Same comment as #4 above. ESPs are capable of efficiencies of >90% to ultimate emissions of approximately 0.01 lb/MBtu. Thus, if further reductions are necessary more stringent limits may be possible.
6	Prohibit use of anti-corrosion and anti-smut accumulation additives	APCD regulations	50	?	15% of fuel	Low	5 to 8	Poor	May indirectly prohibit use of fuels with high S and V. Cost based on use of LSR. Energy impact at refinery. Region-wide impact depends on fuel usage patterns. Unlikely that will need to implement this or succeeding measure in addition to all previous ones.
7	Prohibit use of residual fuel in all boilers	APCD regulations	70	High	15% of fuel	Low	5 to 8	Poor	Subject to availability of distillate fuel. Cost depends on current fuel and distillate as replacement
8	Combustion additives at optimum concentration to minimize emissions to be added to fuel	APCD regulations, coordination with nationally recognized standards	50	High	1% to 2% of fuel	Low	0	Poor	User and APCD need agree on enforceable system to ensure all fuel treated optimally. Generalized use not recommended at this time because of possible toxic effects and possible interaction with fuels.

[a] See Appendix C for conversion of mass emission limits to SI units
[b] SSN = Smoke Spot Number
[c] Relative to area-wide emissions from all sources in this category only; impact on region depends on relative importance of this source category
[d] Sample calculation of cost impact on annualized basis given in Appendix D
[e] Unit (increase) or decrease in efficiency
[f] Judgement; no data to substantiate

TABLE 1-9. POSSIBLE PARTICULATE CONTROL MEASURES FOR UTILITY BOILERS AND FURNACES: >250 MBTU/HR (73.2 MW)[a]

Rank	Control Measure[b]	Policy Instrument	Effectiveness		Cost Impact[d]		Energy Impact,[e] %	Public Acceptance[f]	Comments
			Reduction per unit, %	Reduction Per Air Region[c]	User, $	APCD			
1	Limit new units <550 MW according to capacity (in MW) as per: $FP(lb/MBtu) = 0.15 \times 10^{-6}(MW)^2 - 0.21 \times 10^{-3}(MW) + 0.09$ For units >550 MW, FP = 0.02 lb/MBtu. Limit to apply during soot blowing, too.	APCD regulation	50	Low	<1% of cost to customer	Low	<1	Good	Based on particulate collector with 50% collection efficiency during normal operation. Region-wide impact may be low because new oil-fired utility boilers may be rare. Cost impact will be diluted by lower cost electricity from existing power plants.
2	Specify 3 month interval between burner servicing and cleaning. Advise APCD of post-servicing opacity and O_2 (or CO_2)	APCD regulation	30	Moderate	26,000/yr	Low	Positive	Good	
3	Require continuous stack gas monitor for opacity and O_2 with recorders. Transmissometer to meet EPA specifications and be connected to alarm set for 5% opacity.	APCD regulation	?	?	5000 to 11000 plus 800/yr	Low	Positive	Good	Effectiveness unknown due to lack of data on incidence and duration of unnoticed upset conditions. Oxygen meter used to insure efficient combustion.
4	Limit new units to 50% of limits in control measure #1. (0.042 - 0.01 lb/MBtu). Limit existing units to same values in #1 (0.08-0.02 lb/MBtu)	APCD regulation	75 (new) 50 (existing)	Low	<1% of the cost to the consumer	Low	<1	Good	Based on ESP of 75 & 50% for new & existing units respectively. During soot blowing efficiency would be approximately 97.5 & 95% respectively.
5	Limit all new units to 0.01 lb/MBtu. Limit existing units to 50% of limits in control measures #1 (0.042-0.01 lb/MBtu).	APCD regulation	90-75 (new) 75 (existing)	Low	<1% of the cost to the consumer	Low	<1	Good	For new sources based on ESP of 90-75% efficiency for normal operations and approximately 99% during soot blowing. For existing sources, based on 75% efficiency normally and approximately 97.5% during soot blowing.
6	Prohibit use of anti-corrosion and anti-smut accumulation additives.	APCD regulation	50	?	15% of fuel	Low	3 to 10	Poor	May indirectly prohibit use of fuels with high S and V. Cost based on use of LSR. Energy impact at refinery. Region-wide impact depends on fuel usage patterns. Unlikely that will need to implement this strategy in addition to all previous ones.

[a]See Appendix C for conversion of mass emission limits to SI units
[b]SSN = Smoke Spot Number
[c]Relative to area-wide emissions from all sources in this category only; impact on region depends on relative importance of this source category
[d]Sample calculation of cost impact on annualized basis given in Appendix D
[e]Unit (increase) or decrease in efficiency
[f]Judgement; no data to substantiate

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SECTION 2

SOURCE CLASSIFICATION

One of the essentials of an effective air pollution control plan is an appreciation of the sources to be controlled. It is necessary to understand which types of equipment are particularly large contributors to area-wide emissions in order that regulatory action can be properly applied. By "large contributor" is meant not only those units which have high emission factors, but also those which may have moderate emission factors, but comprise a large fraction of the source population. This chapter, therefore, presents both a population distribution for oil-fired units and a description of each unit type considered.

A 1970 report on particulate emissions from stationary sources (Reference 2-1) indicates that oil combustion accounts for less than 1 percent of the total nationwide particulate emissions from industry and utilities, and slightly more than 2 percent of the emissions from all industrial and utility sized combustion sources. Table 1-1 also shows that all oil-fired indirect heating combustion sources account for about 1 percent of the total 1975 particulate emissions. However, this national average does not apply to individual regions. In the northeast United States oil is a primary fuel, and the contribution of oil combustion to the total particulate emissions is considerably higher than the national average. In the New Jersey-New York-Connecticut area, for example, oil combustion accounts for nearly 20 percent of the combustion generated particulate, and about one-half of this oil generated pollution is produced by domestic and commercial sized units which are located in or near high population density areas. On the other hand, in the southeast Florida AQCR, utility boilers account for about 20 percent of the particulate emissions from all sources and 90 percent of those from oil burning boilers and furnaces. Nationwide, most of the particulate emissions from oil-fired sources come from commercial and small industrial boilers, up to about 50 MBtu/hr or 14.6 MW* (Reference 2-27).

*Conversion tables between conventional engineering and SI (System International) units are contained in Appendix C. Throughout this document the prefix M represents million in accordance with SI practices. Also watts, W, or megawatts, MW, refer to heat input rates unless subscripted with an "e" to designate electric output.

What is indicated here is that effective control programs for particulate must be sensitive to geographical variations in emission sources. Consequently, this chapter gives population distributions in terms of geographical location for the cases where data are available.

Size Categorization

EPA classifies boilers and furnaces by application, independent of size, for their emissions inventory. However, for the purposes of regulatory programs, oil-burning units are commonly divided into the following four categories depending on their size (based on heat input).

- Residential — 0 - 0.4 MBtu/hr (0 - 0.12 MW)
- Commercial — 0.4 - 12.5 MBtu/hr (0.12 - 3.66 MW)
- Industrial — 12.5 - 250 MBtu/hr (3.66 - 73.25 MW)
- Utility — Over 250 MBtu/hr (over 73.25 MW)

Although this categorization suggests a distinct transition from one group to another, a fraction of the units which belong to one category on the basis of application fall in the size range of another group. Moreover, in the course of this study, it was discovered that an excellent source of information exists on the population distribution of the boiler community for two size ranges: 0.3 - 10 MBtu/hr (0.088 - 2.93 MW) and 10 - 250 MBtu/hr (2.93 - 73.25 MW). In light of the small differences between these size ranges and the ones selected for the present document on the basis of common usage patterns, the boiler population given for the 0.3 - 10 MBtu/hr (0.088 - 2.93 MW) group was used for the commercial category and that given for the 10 - 250 MBtu/hr (2.93 - 73.25 MW) class for the industrial group. The remainder of this chapter presents population distributions and emission characteristics separately for each one of these four user categories.

2.1 RESIDENTIAL UNITS

Residential units are those boilers and furnaces whose rated heat input (fuel consumption) is less than 0.4 MBtu/hr (0.12 MW). Equipment in this size range is primarily warm air furnaces and small cast iron or steel boilers, although about 19 percent of the oil-fired units consist of stoves, fireplaces, and miscellaneous homemade units (see Reference 2-17 and Figure 2-1). Due to the diversity in the design of these units and to the uncertainty in their number, they will not be discussed here.

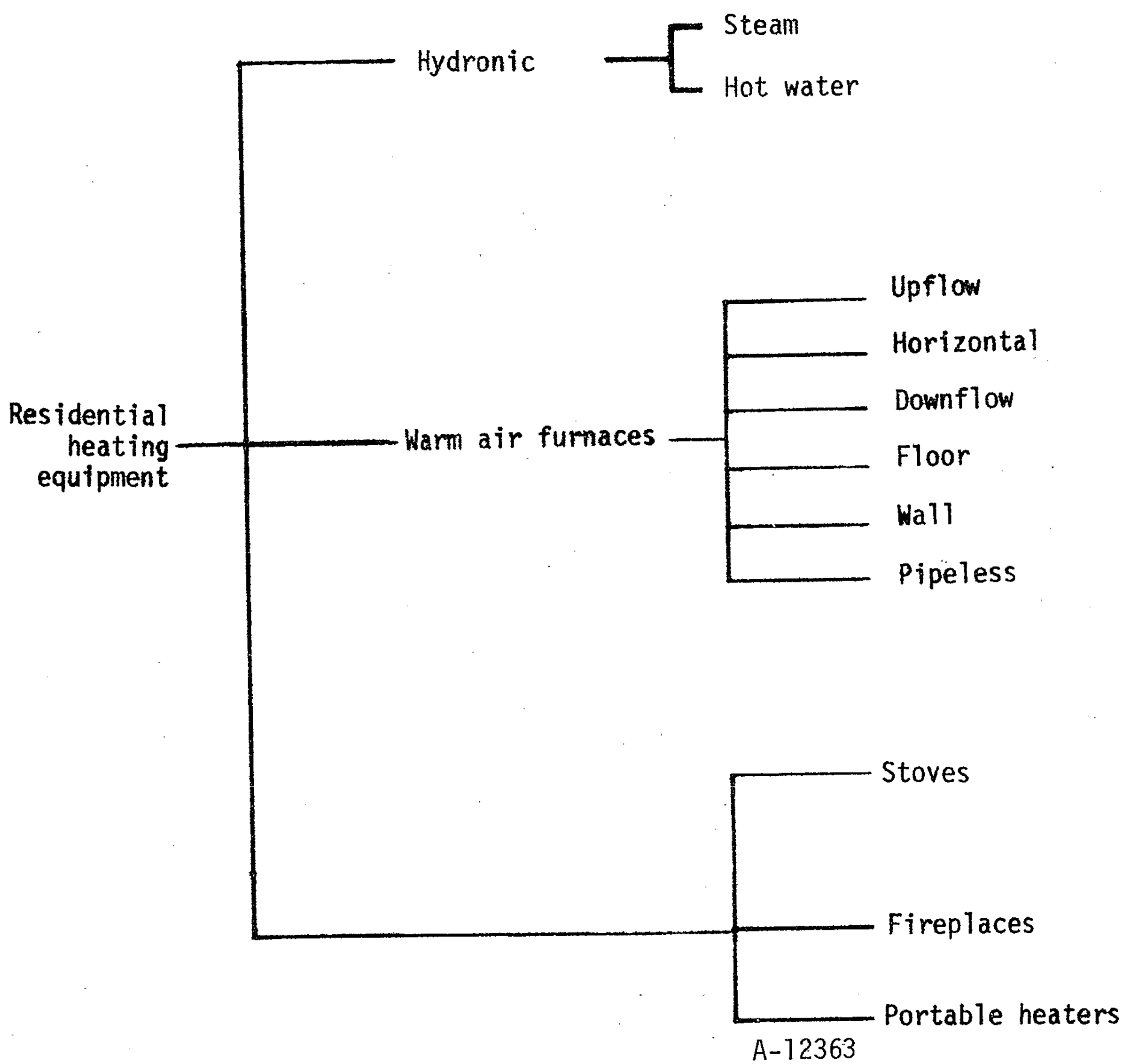


Figure 2-1. Classification of residential heating equipment.

2.1.1 Residential Equipment Description

2.1.1.1 Warm Air Furnaces

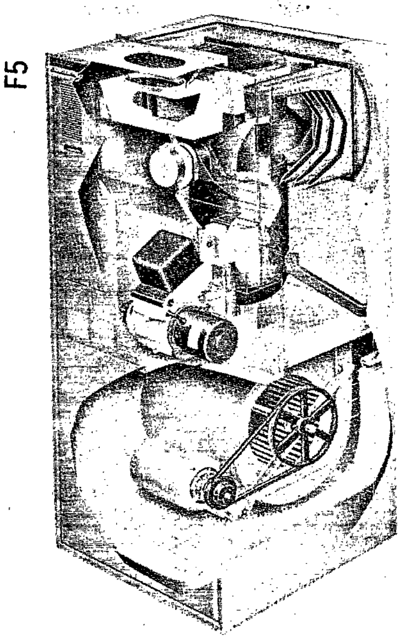
A warm air furnace is a self-enclosed appliance used for heating air for a house or building. It discharges hot air directly into the space being heated or more commonly through ducts which transport the warm air to the area to be heated. Some furnaces operate by gravity (buoyancy forces), but the majority are forced air systems, using a blower to move the air through the ducts and back to the furnace.

The furnace consists of a burner with related piping and controls, a heat exchanger, and a blower for forced air systems. The furnace package is enclosed in a steel casing and the heat exchanger compartment is insulated to improve efficiency and to limit the outer casing temperature for personnel safety. The combustion takes place in the primary combustion space of the metal-walled or refractory-lined heat exchanger, and the combustion products pass through secondary flue gas passageways of the heat exchanger to exit through a flue to the atmosphere. The air to be heated circulates over the outside of the heat exchanger to the warm air discharge, where it leaves at a temperature of 100°F to 150°F (38°C to 65°C). Furnaces are fired by natural gas and distillate oil and (rarely) by coal.

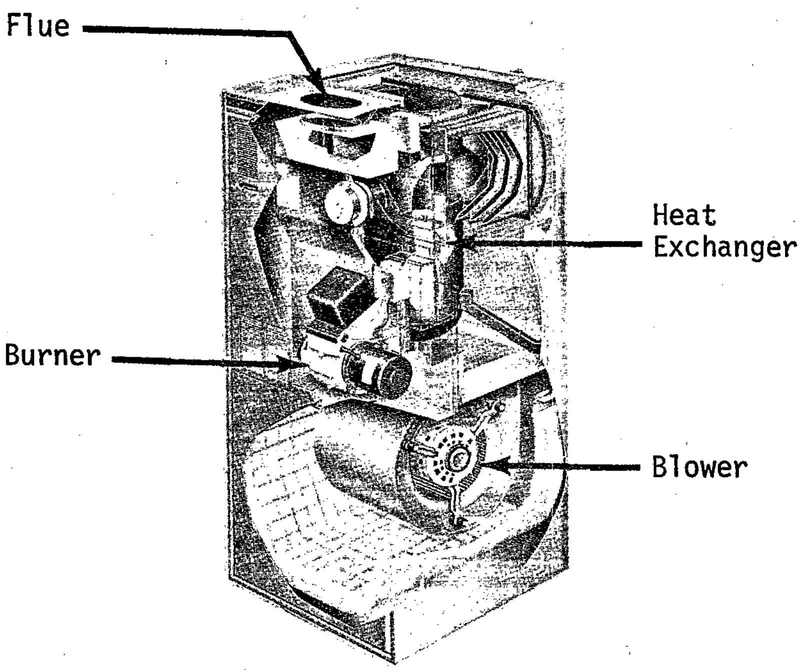
Domestic or residential warm air furnaces are available in capacities under 0.4 MBtu/hr (0.12 MW) and are generally classified into four types:

- Downflow, in which the blower is mounted above the heat exchanger, the flue gas discharges at the side or top, and the warm air discharges from the bottom of the unit (counter-flow).
- Upflow or "high-boy," which is similar to downflow except that the blower is mounted below the heat exchanger and both the warm air and flue gas discharge from the top of the unit (co-flow). Figure 2-2 shows a typical oil-fired upflow furnace.
- Horizontal, in which the blower is mounted next to the heat exchanger, the flue gas discharging at the top, and the warm air at the end, of the unit.
- Basement or "low-boy," which is very similar to the horizontal unit except that the flue gas discharges at the side and the warm air from the top. In addition, the heat exchanger may be higher and narrower than for a horizontal furnace.

All of these units are available in a wide range of capacities. The choice of the appropriate type is based most often on available installation space. For example, horizontal units are intended for use in situations where headroom is limited, such as in attics or crawl spaces.



Belt drive blower



Direct drive blower

Figure 2-2. Forced warm air oil-fired furnace — upflow (Courtesy: Lennox Industries).

Two types of blowers are found on modern forced warm air furnaces; direct drive and belt drive. Direct drive blowers are of the multiple speed type and usually are found on combination heating and cooling furnaces. However, they are also found on units used for heating only. When properly connected electrically, the blower will run at slower speeds in the winter months and at a faster speed during the summer months.

Belt drive blowers operate at one speed, which is dependent on the adjustment of the pulley system. This speed is sét by the serviceman during furnace installation and can have a major impact on efficiency if done improperly.

The heat in a typical warm air furnace is supplied by an oil burner of the type pictured in Figure 2-2. These burners consist of a combustion air blower, motor, fuel pump, spark ignition system, main air tube and swirlers, and fuel nozzle. The fuel flow rate is determined by the oil nozzle orifice size, and the total air flow rate by the blower and a damper in the exhaust flue. The proper air-to-fuel ratio is obtained by adjusting the damper until the optimum CO_2 and smoke levels are achieved.

The burner is mounted in a refractory or refractory-felt lined combustion chamber which is cooled by air drawn from the house. From the combustion chamber the flue gas passes through a heat exchanger and out the stack. The burner blower may supply the full pressure to exhaust the gas from the stack or it may just assist the buoyancy forces in the stack. Table 2-1 lists typical operating conditions for this type of furnace.

The procedure for the design of a warm air furnace is empirical and relies on prototype development, experience, and testing. Standards for construction and thermal efficiency are set by Underwriters Laboratory and American National Standaards Institute (ANSI).

TABLE 2-1. CHARACTERISTICS OF A TYPICAL 0.1 MBtu/hr (29.3 kW) WARM AIR OIL-FIRED FURNACE

Excess Air: 10 - 100 percent
Flue Exit Diameter: 5" to 7" (130 - 180 mm)
Heat Exchange Area; 20 ft^2 to 30 ft^2 (1.8 - 2.8 m^2)
Overall Heat Transfer Coefficient: 2 to 3 Btu/hr-ft^2-°F (11 - 17 watts/m^2-°C)
Exit Flue Gas Temperature: 500°F - 900°F (260°C - 482°C)
Combustion Chamber Pressure: 0.05" W.G. to 0.2" W.G. (12 - 50 Pa)
Recirculating Air Flow: 800 to 1300 scfm (0.38 - 0.61 m^3/sec)
Temperature Rise on Air Side: 75°F to 80°F (41°C - 45°C)
Overall Steady State Efficiency: 70 to 80 percent
Common Operating Mode: on/off
Ignition System: Spark
Draft System: Forced

Nearly all of the design variables for a warm-air furnace affect particulate emissions to some degree. As will be discussed below the more significant effects are associated with the burner, specifically, its design and nozzle type. Additionally, combustion chamber materials, usage patterns, and tuning can cause significant variations in particulate emissions.

The burner design features which most strongly affect particulate emissions include:

- Fuel atomization techniques
- Relative fuel droplet/air velocity
- Flame retention devices
- Combustion chamber material
- Combustion chamber wall temperature

These design parameters will be discussed briefly in the order presented. Throughout the discussion, it should be noted that the adjustment of a burner parameter to obtain low particulate emissions often results in a corresponding increase in NO_x due to improved and hotter combustion, or a decrease in efficiency due to the use of too much excess air. Consequently, a burner designed for low total emissions may involve a compromise among individual species emissions. The desirable situation is one in which combustion takes place over a long enough time in a hot enough environment to completely oxidize all hydrocarbons to CO_2 and water with little CO produced, and yet one in which the temperature is not so high as to provide significant amounts of nitrogen oxides. In other words, a long, slow (but complete) combustion is called for.

Fuel Atomization Techniques

Mechanical atomization is the primary method used in domestic sized furnaces. Other methods used are wall flame rotary, vaporizing, and low pressure burners, but the combined usage of these types accounts for only about 15 percent of the total. For a complete discussion of fuel atomization in domestic and commercial burners, the reader is referred to Reference 2-3.

High pressure mechanical atomization accounts for by far the majority of domestic and commercial fuel atomization systems. These units operate by supplying oil at high pressure (100 psig or 690 kPa, nominally) to one or more orifices in the nozzle. The design of the orifice influences the spray pattern and, to some degree, the droplet size. The flow channel to the orifice is routed in such a way as to impart a high degree of swirl to the exiting oil. Combustion air, which flows in an annular region around the gun, is also given swirl before it mixes with the fuel spray outside the nozzle.

In general, a higher atomization pressure leads to a more finely atomized spray which should lead to cleaner combustion. However, Sjorgren (Reference 2-4) has shown that although higher fuel pressures achieve better atomization, the relative droplet/air velocity may decrease resulting in inferior combustion (see internal recirculation, Section 4.1.4.2). Dickerson, et al. (Reference 2-5) determined that "commercially used atomization nozzles which are available at very low cost (less than about $1.00 per nozzle, nominally) do an excellent job of atomization," and particulate emissions from these nozzles can be very low.

The firing rate of a high pressure gun burner is determined by the oil pressure and the orifice size. The firing rate in turn dictates the air flow rate through the burner and, consequently, the residence time (i.e., the time during which a volume of fuel is subjected to a combustion environment). Short residence time is a major cause of high CO, unburned hydrocarbon, and particulate emissions (as shown again by Reference 2-6). Underfiring the burner by installation of a smaller orifice nozzle (at the nominal cost of one dollar) represents an elementary way of increasing the residence time and reducing emissions, provided the heat load can be carried. Underfiring also reduces emissions in another way. Particulate emission rates are higher immediately after ignition, due to the poor combustion which occurs at low temperatures. Underfiring causes the burner to remain on longer to provide a given total heat output and, consequently, the burner is turned on and off fewer times, resulting in a reduction in the number of high emission periods.

Low pressure mechanical atomization systems account for only about 8 percent of all burners in the residential section, and there is a continuing trend toward their elimination. Low pressure guns are unique with respect to other domestic burners in that oil and a portion of the combustion air are mixed inside the nozzle. Once this mixture is ejected from the nozzle, it contacts a highly turbulent supply of oxidizing air and combustion commences. The operation of this burner requires a supply of air at 1 to 15 psi (6.9 - 103 kPa) and oil at 1 to 5 psi (6.9 - 35 kPa). The need for pressurized air is an additional complication compared to high pressure nozzles.

Vaporizing burners are becoming rare although they are still common in the Southeast and some other regions with mild climates. They consist of a small container in which a fuel is heated to a highly volatile condition. The resulting vapor is mixed with air and burned. A small, continuously burning pilot flame is generally utilized for ignition purposes, and this flame can be a source of smoke.

Flame Retention Devices

Many small combustors use flame retention devices in the form of plates, grids, or cones to produce local recirculation zones and thus reduce smoke emission. These devices also allow the burner to be run on much less excess air than would otherwise be required. Operation at low excess air improves thermal efficiency (less heated air is discharged out the stack) and, therefore, reduces fuel consumption. In a study by Beach and Siegmund (Reference 2-11) a typical home heater oil burner required 85 percent excess air to achieve a Bacharach No. 2 Smoke reading, whereas with the flame retention device the burner required less than 10 percent excess air to achieve the same smoke number. Other studies along these same lines include those by Walsh and by Howekamp and Hooper (References 2-12 and 2-13). Howekamp and Hooper studied five combustion improving devices for domestic home heaters which produce either a swirling flow or recirculation zones with a flame retention device. Not all of these devices were effective in reducing smoke over the whole range of air-to-fuel ratios. These results are also summarized in Reference 2-6. A paper by T. D. Brown (Reference 2-14), which also compares a flame retention head to a swirl head in a domestic oil burner supports the theory that there exists an optimum amount of swirl to achieve minimum smoke for a given excess air level (see Section 4.1.4.2).

Barrett, et al. (Reference 2-15) measured particulate emissions from several oil burners installed for domestic and commercial use. The data indicated an average particulate emission rate of 0.012 lb/MBtu (5.16 ng/J) for a burner with a conventional head, versus 0.0056 lb/MBtu (2.39 ng/J) for one with a flame retention device.* The flame retention burners also produced lower CO, HC, and NO_x emissions than did the conventional types. Laboratory experiments (References 2-5 and 2-6) have shown that not all flame retention burners simultaneously reduce particulates and NO_x, and in fact, some showed marked increases in NO_x. Therefore care should be exercised in extrapolating the average reductions measured by Barrett, et al., to a special flame retention device.

Combustion Wall Temperature

Cool walls in a combustion chamber increase particulate emissions due to poor combustion in low temperature regions. The coupled effects of cool walls and a short residence time result in the incomplete combustion of carbon particles. A typical increase of 1 to 2 Bacharach smoke numbers is found to occur when the wall temperature is decreased from 2600°F to 1600°F (1430°C - 870°C) (Reference 2-10).

*These numbers are for tuned units and are inferred from measurements made by the "Modified EPA" (MEPA) method of Barrett, et al., using an average correlation factor of 1.67 to relate MEPA data to that obtained by the standard EPA sampling train.

While hot walls promote complete combustion of particulates (and at the same time reduce CO and unburned hydrocarbon emissions), they result in an increase in NO_x emissions. Again, a compromise must be made.

Combustion Chamber Material

Combustion chambers of domestic oil burners are usually cylindrical and are made of hard (noninsulating) refractory, soft (insulating) refractory, felt ceramic, or steel. Light materials, such as the soft refractory or felt ceramic, with low conductivity are preferrable, especially in burners which see cyclic operation, because their surface temperature reaches equilibrium with combustion gases faster than does that of a hard refractory or steel combustion chamber. As previously mentioned, a high combustion chamber wall temperature is essential to low particulate combustion. During the time in which the chamber temperature is low, excess air levels must be increased to counteract the poor combustion due to low temperature. Since it has not been practical to allow for altering the amount of excess air during a heating cycle, the initial high air level is maintained throughout, resulting in decreased efficiency. However, in units larger than 20 gph (21 cm^3/sec), combustion volume temperatures generally exceed 3000°F (1650°C) and, therefore, hard ceramic must be used.

Burner Use Pattern

The on-off cycling of an oil burner has a serious effect on particulate emissions as well as other pollutant species. Particulate produced during the incomplete combustion which occurs during ignition and shut-down contribute a large percentage of the total from a complete cycle. Therefore, short cycles, which turn the burner on and off many times a day, should be avoided

The dependence of emissions on cycling is discussed more completely in Section 4.2.2.1.

Burner Age

Barrett, et al. (Reference 2-15) measured emissions from a set of older oil burners and compared the results with those from newer units. They concluded that particulate emissions from newer burners are lower than from older ones, and they attribute this not to an aging effect, but to the improved design practice of recent years. Particulate emissions from a properly maintained oil burner should not increase as the burner ages.

Tuning

The importance of tuning as a means of controlling particulate emissions is witnessed by References 2-15 and 2-16 in which particulate emissions were measured for a number of oil burners in domestic and commercial installations.

The oil burners used were chosen as typical of the national distribution of equipment types, and particulate emissions were measured both in the "as found" condition and after tuning. (The tuning procedure was directed toward reduction of both CO and particulate while maintaining a high efficiency.) Results show an average emission of 0.021 lb/MBtu (9.03 ng/J) in the "as found" condition as compared to 0.016 lb/MBtu (6.88 ng/J) in the tuned condition. Tuning resulted in a 24 percent overall reduction, a condition indicating the desirability of a periodic (e.g., yearly) inspection of all burners by a qualified serviceman.

Tuning an oil burner consists primarily of cleaning and inspecting the pump, nozzle, and combustion chamber and readjusting the air flow to the optimum air/fuel ratio (i.e., excess air level). The variation of emissions as a function of excess air is shown in Figure 2-3. As indicated, low excess air is required for maximum efficiency. However, reduction of excess air below about 60 percent (for the burner whose characteristics are given in Figure 2-3) causes a marked increase in smoke and, to a lesser degree, CO and HC. The tuning must then be a compromise between emissions and efficiency, the determination of which involves several measurements (e.g., CO, CO_2, stack temperature, draft). The need for qualified service personnel is indicated. Tuning is discussed more fully in Chapter 4.

2.1.1.2 Steam and Hot Water Units

Approximately 36 percent of the residential heating in this country is supplied by steam or hot water units using a boiler. Heat for the production of steam or hot water is transferred from the combustion products to the boiler in the firebox. The boiler heat transfer surfaces usually consist of steel or cast iron tubes that are exposed to, or carry, the hot combustion gases.

Cast Iron Boilers — Capacities up to 13.5 MBtu/hr (3.95 MW)

Many domestic and small commercial boilers in use today have heat exchangers that are constructed of cast iron. They are designed for supplying low pressure steam at about 15 psig maximum (103 kPa) or hot water at 160 psig maximum (1.1 MPa) and 250°F (121°C) and are used primarily for hydronic heating systems. These boilers consist of an assembly of cast iron sections. Generally

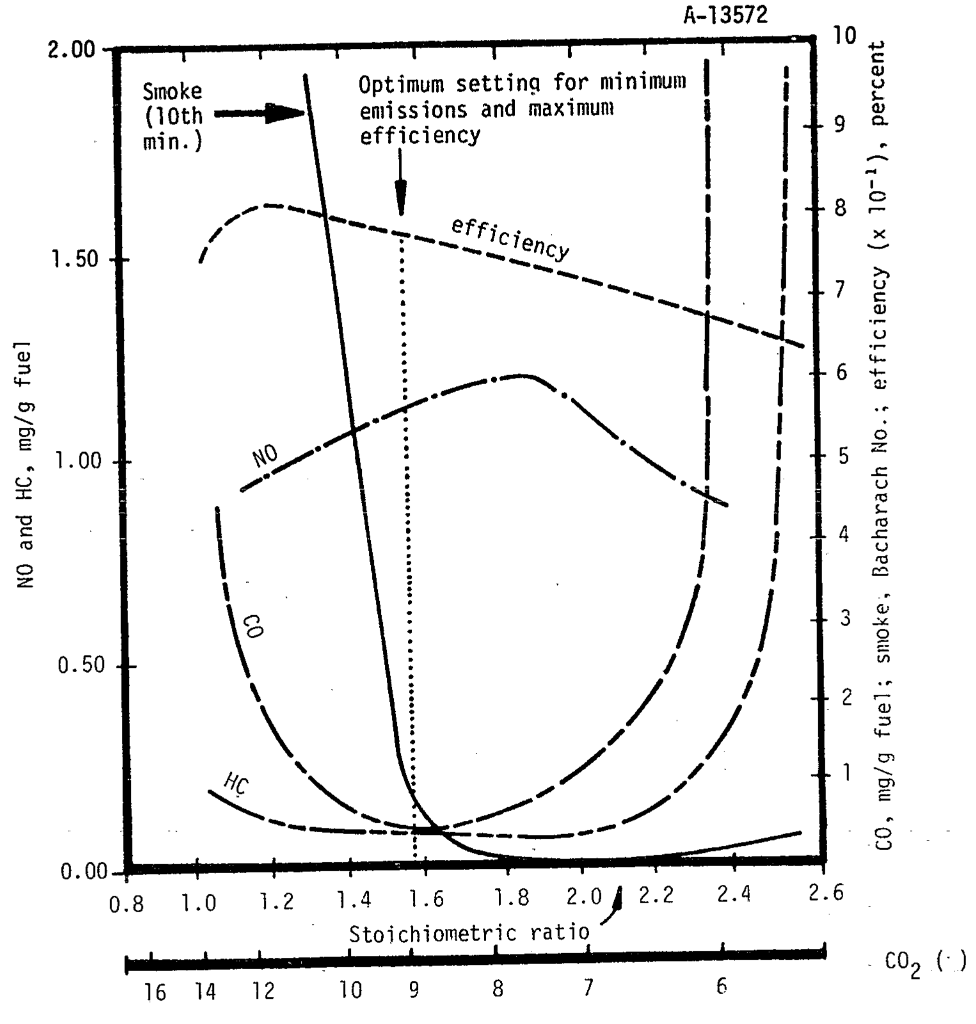


Figure 2-3. General trend of smoke, gaseous emissions, and efficiency versus stoichiometric ratio for a residential oil burner (Reference 2-6).

cool water enters at the bottom of the sections, and hot water or steam exits at the top. The products of combustion are conducted through labyrinth passages cast into the sections. The capacity of a sectional boiler may be varied by the addition or deletion of sections.

Figure 2-4 shows an oil-fired cast iron boiler, typical of those quite common in older homes in the Northcentral and Northeast states. These boilers are similar in some respects to oil-fired warm air furnaces in that they may employ a refractory-lined combustion chamber followed by the heat exchange surface.

It has been reported that poor matching of burner and combustion chamber requirements occurred frequently in the past, partly because the burner and the furnace manufacturers did not work together to avoid this problem (Reference 2-5). However, the recent emphasis on emission reductions has induced burner and furnace manufacturers to coordinate their designs, and mismatching is no longer a problem. Typically, because of careless installation considerable leakage of secondary air into the firebox is allowed, which serves to lower the flame temperature. Leakage probably results in overall lower boiler efficiency. Typical operating conditions and design characteristics for an oil-fired system are given in Table 2-2.

Cast iron boilers are rated by the Hydronics Institute (IBR ratings). They must be designed and constructed in accordance with the ASME Code, Section IV, Heating Boilers. The IBR Testing and Rating Code specifies the test conditions and such things as minimum efficiency, percentage of carbon dioxide in the flue gas, flue gas temperature, and smoke reading. The ratings cover a range of 0.048 MBtu/hr (0.014 MW) to 13.5 MBtu/hr (3.9 MW). Many of the design features associated with furnaces are also directly applicable to boilers. For instance, flame retention heads are used on burners in boilers as well as in furnaces, and they are as effective in boilers as in furnaces as a means of reducing particulate emissions. In fact, because of their relatively high noise level, flame retention head burners are less common on furnaces than on boilers. Similarly, considerations of nozzle type, residence time, combustion wall material and temperature, cycling patterns, tuning, etc., are equally applicable.

2.1.2 Emissions

Emission measurements from 15 residential cast iron boilers are reported in Reference 2-15 and compared to similar measurements on 11 warm air furnaces. These tests showed that mean CO and particulate emissions for the furnaces (0.018 lb/MBtu (7.74 ng/J)) were consistently and appreciably higher than for the boilers; however, the mean CO levels for the furnaces were not considered excessive. The higher CO level with furnaces could not be explained in view of higher combustion chamber

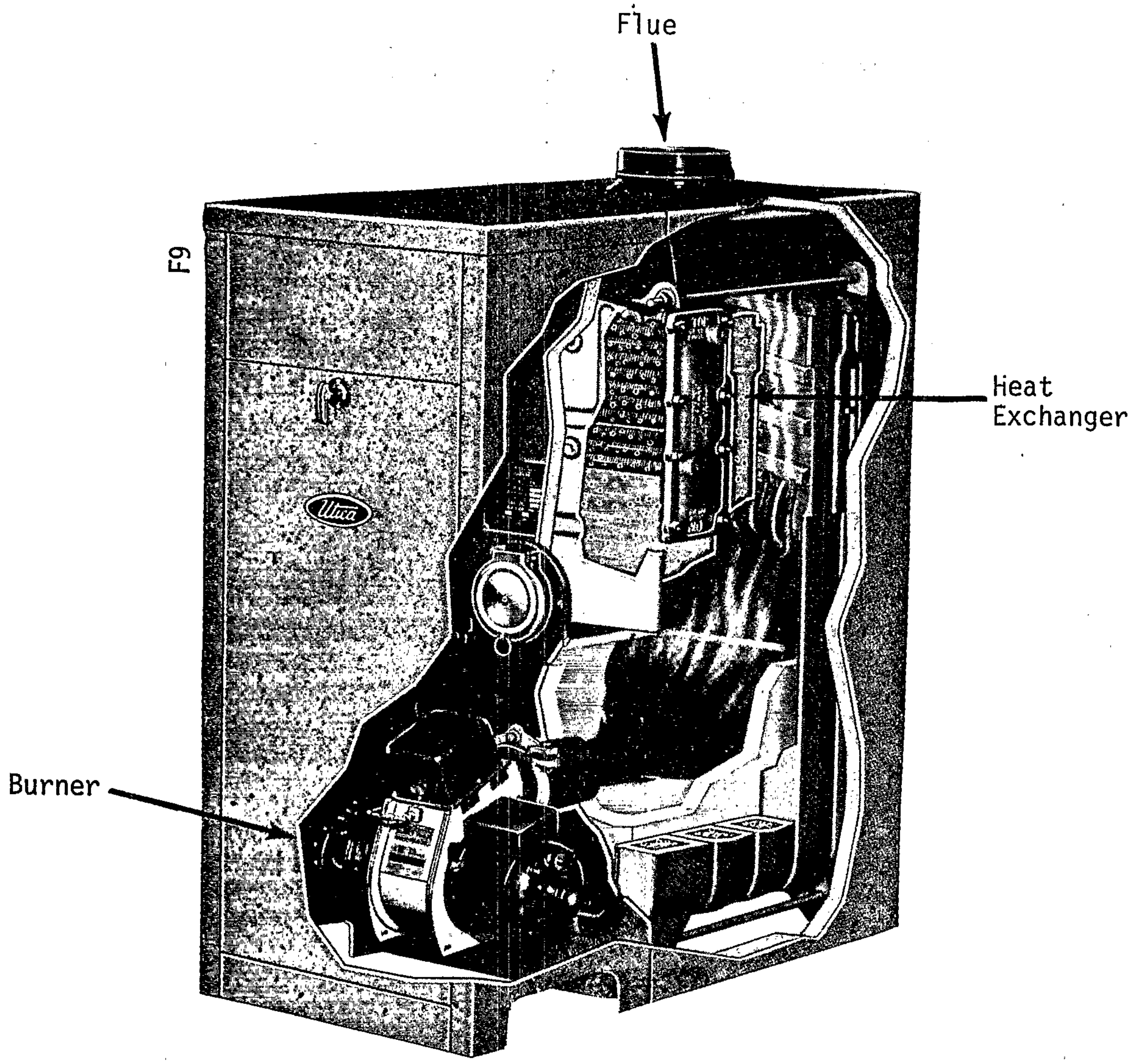


Figure 2-4. Oil-fired cast iron boiler (courtesy of the Utica Radiator Company).

TABLE 2-2. CHARACTERISTICS OF A TYPICAL 0.1 MBtu/hr (29.3 kW) OIL-FIRED CAST IRON BOILER

Recirculating Water Flow	3 - 15 gpm (189 - 945 cm^3/sec)
Excess Air	30 - 100 percent
Flue Exit Diameter	3.5 - 5 inch (89 - 127 mm)
Exit Flue Gas Temperature (Upstream Draft Control)	400°F - 600°F (204°C - 315°C)
Combustion Chamber Pressure	0.02 inch W.G. (4.98 Pa)
Temperature Rise on Water Side	10°F - 40°F (5.5°C - 22°C)
Overall Steady State Efficiency	80 - 85 percent

temperatures generally expected in furnaces. Mean NO_x emissions for the furnaces were slightly, but consistently, higher than for the boilers, probably reflecting the higher combustion chamber temperatures in the furnaces.

2.1.3 Population Distribution (Residential Units)

The population of oil burning residential units is categorized in the following subsections in terms of unit type, burner type, combustion chamber material, and average age with size and geographic location as parameters. According to data obtained from the Gas Appliance Manufacturers Association (GAMA), the trend in the last 10 years had been toward gas-fired forced warm air systems. The 1970 U.S. Census data substantiated this finding by indicating that almost 30 percent of the warm air furnaces were oil-fired in houses built prior to 1939 compared to approximately 15 percent in houses built during the period 1960 to 1970. Increasing gas shortages are expected to reverse this trend.

2.1.3.1 Population Distribution by Unit Type

Of the 53.7 million residential heating units in operation in the United States in 1970, 26.3 percent were oil-fired, 57.7 percent were gas-fired, and 14 percent used other fuels such as propane, coal, and wood (Reference 2-17). The generation of water for washing consumes about one-quarter the energy used for space heating (Reference 2-25). The population distribution of the primary types of oil-fired residential heating units in use in the United States is shown in Table 2-3.

TABLE 2-3. RESIDENTIAL OIL BURNING UNITS (1970) (SOURCE: REFERENCE 2-17)

Type of Unit	Percent of Total
Steam or hot water	36
Warm air furnaces	45
Other	19

In computing these percentages from census data, the following two assumptions were made:

- All steam units and central warm air furnaces listed as servicing buildings containing more than five residential housing units were assumed to have capacities over 0.4 MBtu/hr (0.12 MW), and were therefore not included in the residential category.
- All direct space heating systems used in residences of any size were assumed to have a capacity of less than 0.4 MBtu/hr (0.12 MW).

Some comment is necessary concerning the category denoted as "other." Statistics from the United States Census (1970) show this category to include approximately 19 percent of all oil burning units, and it therefore comprises a significant fraction of the total population. Units in this category include stoves, fireplaces and a variety of homemade units. Due to the unavailability of data on the population of units of this type, they have been omitted in the breakdown by size.

Table 2-5 shows the population distribution for oil-fired residential units by unit type for three size ranges. Since some of this information is based on 1970 sales data, which are not necessarily identical to sales in previous years, this table provides only a reasonable estimate of the current distribution. Gas burning units are included for comparison.

2.1.3.2 Population Distribution by Burner Type

Table 2-6 shows the population distribution of oil-fired units categorized by burner type, with size and geographic location as parameters. Unfortunately, published data are not available in the same size subcategories as were used in Section 2.1.2.1. However, the data here indicates the differences in the type of burner used in the "large" and "small" categories.

Approximately 10 percent of the burners now in use are of the low pressure type, 5 percent are rotary, and 1 percent are of the vaporizing variety. The majority of the burners are of the high pressure atomizing type.

Recent sales statistics (Table 2-4 below) indicate a significant trend toward the more efficient high pressure gun burners with a marked decrease in the rotary and vaporizing types.

TABLE 2-4. SALES TRENDS FOR RESIDENTIAL OIL BURNERS BY TYPE
(SOURCE: REFERENCE 2-16)

Oil Burner Type	1969 Percent	1941 Percent
High-pressure	95.0	71.7
Low-pressure	3.4	6.2
Wall flame rotary	0.4	11.0
Vaporizing	1.2	10.8
Misc. types	——	0.3

TABLE 2-5. POPULATION DISTRIBUTION OF RESIDENTIAL UNITS NOW IN SERVICE BY TYPE* (SOURCE: 1970 SALES OF GAS FIRED HEATING EQUIPMENT, REFERENCE 2-17)

Rated Capacity MBtu/hr (kW)	0 - 0.1 (0 - 29.3)	0.1 - 0.15 (29.3 - 44)	0.15 - 0.40 (44 - 120)
Oil Burners			
Steam or hot water	28.3	60.5	46.8
Warm air	71.7	39.5	53.2
Gas Burners			
Steam or hot water	6.1	24.0	85.6
Warm air	93.9	76.0	14.4

*Assumptions used in generating this table are listed in text.

TABLE 2-6. POPULATION DISTRIBUTION OF RESIDENTIAL OIL BURNERS BY BURNER TYPE*

	High Pressure			Low Pressure	Rotary	Vaporizing
	Conventional	Shell** Head	Retention Head			
	Percent of Total					
	Less than 0.120 MBtu/hr (35 kw)					
New England	44.9	7.2	14.7	26.4	5.8	1.0
Mid-Atlantic	66.3	8.4	3.8	10.6	8.5	2.4
South Atlantic	74.8	1.9	13.0	0.8	0.1	9.4
Midwest	63.0	9.4	13.1	5.6	8.6	0.3
West	80.3	0.6	5.2	8.1	0.5	5.3
All Sections	63.1	7.2	9.1	11.5	6.6	2.5
	0.120 - 0.360 MBtu/hr (35 - 105 kw)					
New England	61.4	7.9	13.6	9.0	7.6	0.5
Mid-Atlantic	69.0	5.2	8.2	10.7	6.8	0.1
South Atlantic	89.4	2.3	7.3	0.8	0.2	—
Midwest	73.3	13.1	6.2	6.0	1.3	0.1
West	80.3	0.6	2.9	13.2	1.8	1.2
All Sections	71.2	6.9	8.3	8.6	4.7	0.3
	All Oil Burners up to 0.360 MBtu/hr (105 kw)					
All Sections	68.3	7.0	8.6	9.6	5.4	1.1

*Source: Reference 2-15.

**A combustion improving device which utilizes swirl mixing to promote clean combustion.

The majority of wall flame rotary burners and vaporizing burners now in service are installed in older units; they are expected to be almost nonexistent (in residential equipment) in the future unless newly designed vaporizing burners for No. 2 oil gain widespread acceptance.

2.1.3.3 Population Distribution by Combustion Chamber Material

The type of material which lines the combustion chamber of an oil burner has been shown to have an effect on flame properties, and consequently, on emissions (see Section 2.1.1.1). For this reason, Table 2-7 is included showing the population distribution of oil burner combustion chamber material in two size ranges and several geographic areas. A majority of the chambers are constructed from firebrick (hard and soft), but new ceramic materials with improved characteristics are expected to gain a larger share of the market in years to come. The rate at which this distribution is changing due to current sales trends is unknown.

2.1.3.4 Average Age of Oil-Burning Equipment

The average age of various types of residential oil-burning equipment is shown in Table 2-8 with geographic location as a parameter. It should be noted that in constructing this table, a distinction has been clearly made between burners and furnaces or boilers (i.e., complete units).

The age of a unit is related to emissions in the usual sense of increasing discharge due to nozzle clogging, pump wear, etc. Moreover, since many residential units are seldom serviced, the age of a burner is often coincident with the length of time to the last maintenance. The small average age of retention head burners is due to their rather recent inception.

2.2 COMMERCIAL UNITS — 0.4 - 12.5 MBtu/hr (0.12 - 3.66 MW)

Commercial oil-fired systems are used mainly for space heating and hot water just as with residential equipment. Therefore, this category can also be subdivided into warm air furnaces and boilers. Unlike residential units, however, several different kinds of commercial boilers are manufactured (see Figure 2-5).

The distribution of equipment types for heating commercial buildings varies around the country. On the West Coast, or in other moderate climates, about 85 percent of the heating units are warm air furnaces. Nationwide, 11 percent of the housing units listed in the 1970 U.S. Census and estimated to be heated by units of commercial size utilize warm air furnaces. Warm air furnaces have a lower initial cost than boilers, and the latter require more elaborate piping systems. Therefore, if comfort heating is the only requirement, and if mildly fluctuating delivered air

TABLE 2-7. POPULATION DISTRIBUTION OF RESIDENTIAL OIL BURNERS BY COMBUSTION CHAMBER MATERIAL*

Geographic Location	All Sections	New England	Mid Atlantic	South Atlantic	Midwest	West
Firing Rate <0.112 MBtu/hr (33 kW)						
Refractory brick**	60	61	66	44	61	38
Ceramic fiber	22	19	22	13	25	27
Steel	18	20	12	43	14	35
Total	100%	100%	100%	100%	100%	100%
Firing Rate >0.112 MBtu/hr (33 kW)						
Refractory brick	74	78	84	63	61	66
Ceramic fiber	16	12	12	7	31	10
Steel	10	10	4	30	8	24
Total	100%	100%	100%	100%	100%	100%

*Source: Reference 2-15

**Includes hard and soft brick.

TABLE 2-8. AVERAGE AGE OF OIL BURNING EQUIPMENT (YEARS) RESIDENTIAL OIL BURNERS*

Geographic Location	All Sections	New England	Mid Atlantic	South Atlantic	Midwest	West
Oil Burners						
Hi pressure						
— Conventional	12.6	13.1	12.4	10.1	14.1	12.7
— Shell head	8.7	9.5	8.9	7.0	8.8	7.0
— Retention head	3.9	4.1	4.2	3.0	3.7	3.7
Low pressure	16.5	14.4	16.2	19.3	17.8	16.6
Rotary	17.5	16.8	17.7	—	17.8	—
Vaporizing	15.9	—	15.6	13.7	17.0	16.7
Central Oil-Heating Equipment						
Furnaces	13.8	14.9	14.7	11.1	14.1	13.0
Boilers	17.5	18.0	17.4	17.1	17.0	16.5
Combined Furnace/Boiler	15.6	16.9	16.4	12.5	14.9	13.3
Burners	12.2	11.9	12.4	9.5	13.0	12.8

*SOURCE: Reference 2-15

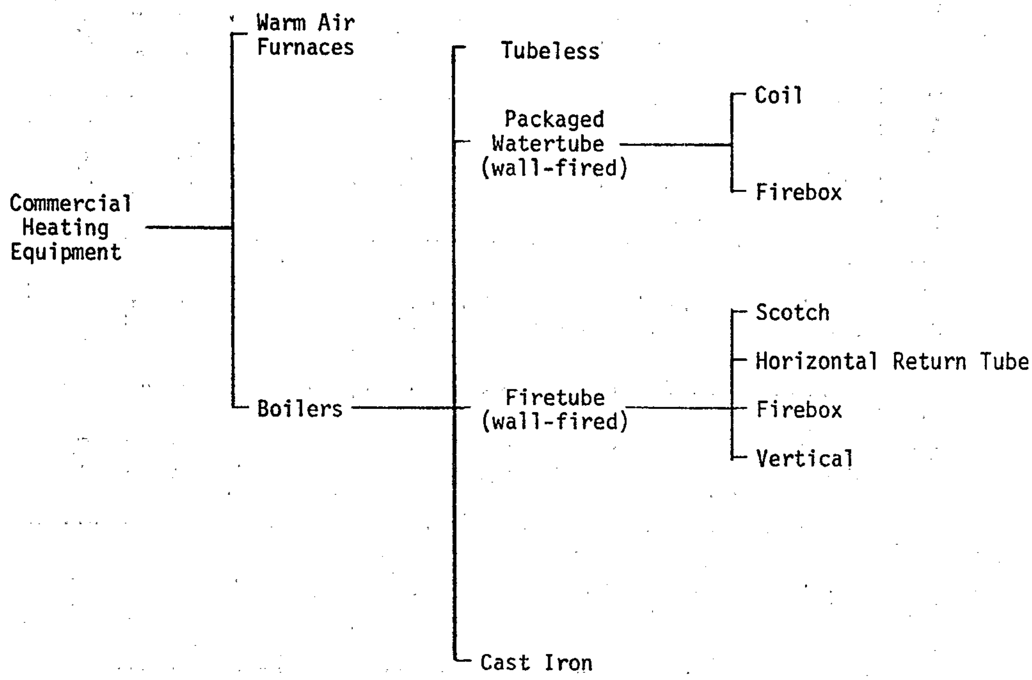


Figure 2-5. Commercial heating equipment types.

temperatures can be tolerated, warm air furnaces are chosen over boilers. High rise and spread-out buildings, however, almost always require boilers due to a demand for both hot water and warm air, to space limitations for ducting, and to equipment size limitations. Warm air furnaces are available in sizes up to approximately 5 MBtu/hr (1.46 MW) while boilers theoretically can be as large as central station power plants. Commercial warm air furnaces and boilers are fired primarily with distillate fuel oil and natural gas, although some boilers in this size group burn residual fuel oil and, to a small degree, process gas. Nationwide, about one-sixth as much energy is used to generate hot water for washing in commercial facilities as is used to provide space heating (Reference 2-20).

The type of boiler chosen for a given commercial heating application depends mostly on the size of boiler required or its function. Generally speaking, cast iron sectional boilers are used for supplying most low pressure steam or hot water in small to medium size projects. Firetube boilers, most of which are packaged, are available in sizes up to 50 MBtu/hr (14.65 MW), while packaged* watertube boilers are available in capacities between 0.4 MBtu/hr and 250 MBtu/hr (0.12 - 73.25 MW).

2.2.1 Commercial Equipment Description

Commercial size heating equipment is available as warm air furnaces, cast iron boilers, firetube boilers, and watertube boilers. Commercial size cast iron boilers are identical to residential units except for size, Since cast iron boilers were discussed in Section 2.1.1.2, they will not be described here. Watertube boilers, typical of operations larger than commercial size, comprise only about 5 percent of all commercial boilers and will be described in Section 2.3.1.1. Therefore, the remainder of this subsection is restricted to firetube boilers and commercial furnaces.

2.2.1.1 Commercial Warm Oil Furnaces

The commercial warm air furnace design concept resembles that used for residential heating purposes except that the larger scale equipment dictates that the unit usually be mounted on the roof of the building. The designs of these units vary considerably among manufacturers, unlike the domestic sector. The apparent standardization of the latter is due mainly to the large sales volume as well as the extremely competitive marketplace. These conditions differ sufficiently in the commercial heating sector to allow some design innovations, especially in gas-fired units.

*A packaged boiler is a unit which is engineered, built and warranteed by one manufacturer. Thus, the unit is assembled (packaged) at the manufacturers plant and fire tested before shipment.

The burners in these units tend to be inherently more versatile than in residential units. For example, many have the ability to operate at a greatly reduced load (large turndown capability). Novel heat exchangers are also more common in these units. These may include finned heat exchanger tubes, different heat exchanger materials, and more flexibility in design. Higher quality construction materials and larger interior volumes are other factors that distinguish commercial-size from domestic-size furnaces. In general, burner and combustion chamber design modifications have the same effect on emissions and efficiency in commercial furnaces as they do in the smaller domestic units discussed earlier. Therefore, that entire discussion applies to commercial size units and will not be repeated here.

2.2.1.2 Firetube Boilers — Capacities up to 25 MBtu/hr (7.3 MW)

In a firetube boiler the products of combustion are directed through tubes which are submerged in water. The tubes are normally straight and may be horizontal, inclined, or vertical, with one or more passes. They are held in place inside the boiler shell by tubesheets at either end of the bundle. Except for small domestic units, many of which are vertical, most units have horizontal tubes. Firetube boilers have larger water storage capacity than cast iron boilers which effectively dampens wide fluctuations in steam demand. In addition, they are more efficient than simple shell boilers because heat is absorbed by the tubes as well as the shell.

Firetube boilers are used where steam demands are relatively small. The principal uses of firetube boilers are for heating systems or industrial process steam. The heating boilers are restricted to 15 psig (0.1 MPa) steam pressure or 30 psig (0.2 MPa) hot water pressure. Power boilers in this class are usually limited to about 350 psig (2.4 MPa) steam pressure.

Most Scotch and firebox firetube boilers are now constructed with an internal furnace, which is substantially surrounded by water-cooled surfaces. The internal furnace in a firebox firetube boiler, described below, is surrounded by water-cooled surfaces except at the bottom.

There are many firetube boilers in operation which have been constructed with an external furnace, usually of brick construction. The brickset type is not very suitable if water scale or silt is to be expected.

The following types of firetube boilers are now commercially available or installed in existing buildings:

- Horizontal return tubular — Capacities up to 22 MBtu/hr (6.4 MW)

The horizontal return tubular (HRT) is a two-pass (one under the shell and one through the tubes) power boiler. It was formerly the most popular type of firetube boiler. At present, approximately 10 percent of all commercial-size boilers are HRT. Water circulation tends to be sluggish, contributing to a relatively low boiler efficiency.

- Firebox — Capacities up to 20 MBtu/hr (5.8 MW)

The two major types of firebox boilers are the short and the compact, the former employing two passes and the latter three. These units are constructed with an internal, steel encased, water-jacketed firebox. Since the furnace size is limited, proper matching of burner flame length and combustion volume is a critical factor. The greatest advantage of this type of boiler is its efficiency and the minimum floor space required for installation.

- Vertical — Capacities up to 3.5 MBtu/hr (1.02 MW)

Vertical boilers are normally single-pass boilers and are used for power boiler applications or as commercial hot water and steam boilers. Power boilers are designed for up to 3.5 MBtu/hr (1.02 MW) and high head room is required for these units. They have a limited steam release surface, are restricted to a maximum pressure of 150 psig (1.0 MPa) and, since the upper ends of the tubes are steam-cooled, require a slow startup to prevent tube damage by overheating.

- Scotch — Capacities up to 25 MBtu/hr (7.3 MW)

This type of boiler was developed 30 years ago based on the Scotch marine boiler and has since become one of the most popular firetube boilers. The trend toward increased use of this boiler type continues.

Figure 2-6 shows a typical oil-fired Scotch boiler. Its design emphasizes compactness and limited head room. It is capable of gas, oil, or combination firing. Inside shell diameters are normally limited to about 95 inches (2.4 m) and operating pressures to 350 psig (2.4 MPa) although some units are designed for 600 psig (4.1 MPa).

Characteristics of a typical Scotch boiler are given in Table 2-9. They can have either two, three, or four passes. The burner flame is contained in an elongated, water-cooled combustion chamber which also acts as the first pass. This characteristic is unique to this type of boiler. The rear wall of the furnace is either refractory-lined ("dry-back") or water-cooled ("wet-back") in the later versions. Due to the relatively small diameter firetubes and concomitant large pressure drop, three and four pass units generally require provision for mechanical draft.

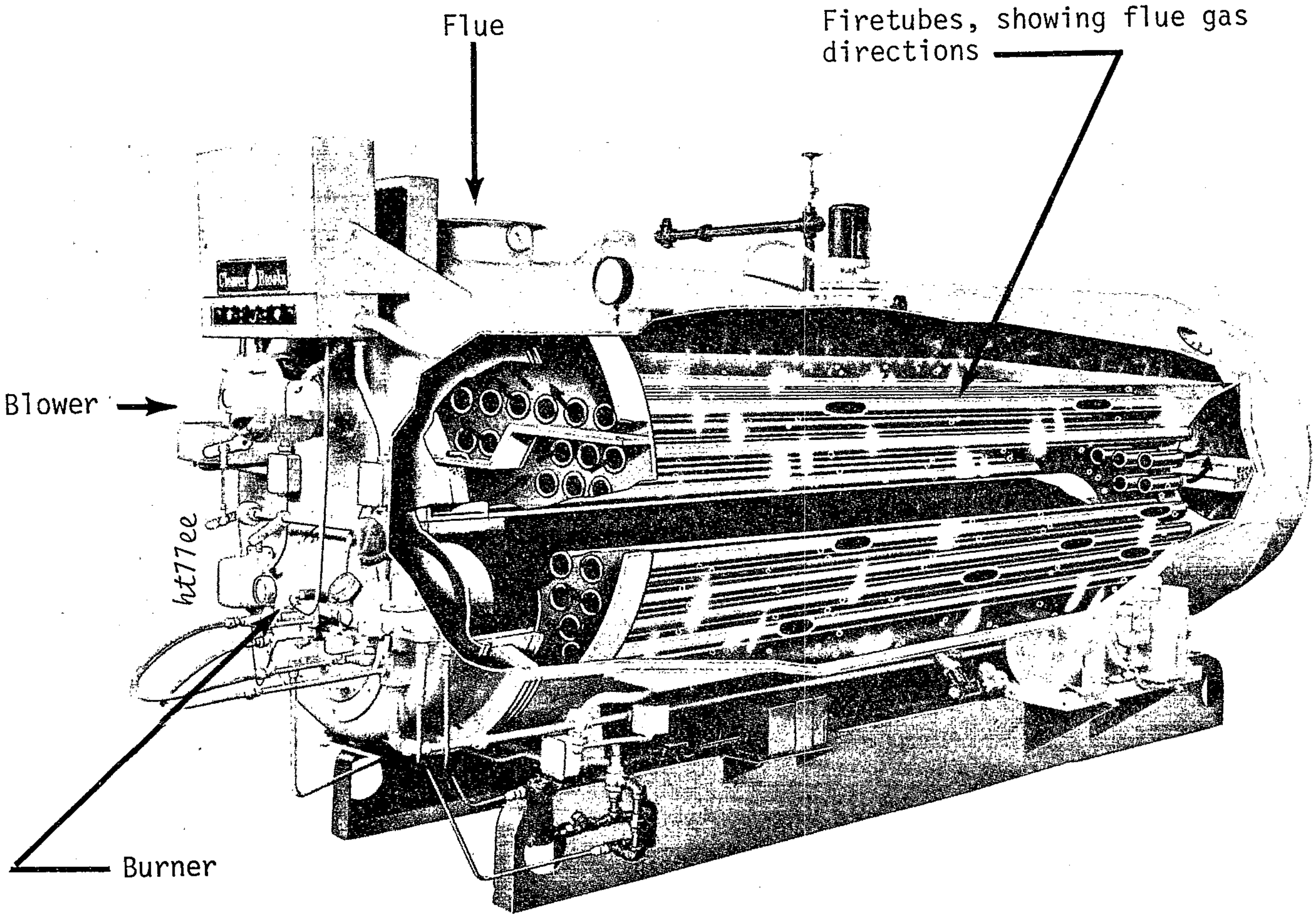


Figure 2-6. Four-pass scotch firetube boiler (courtesy of the Cleaver Brooks Company).

TABLE 2-9. CHARACTERISTICS OF A TYPICAL 3.2 MBtu/hr (0.94 MW) PACKAGED SCOTCH FIRETUBE BOILER

Excess air: 5% to 40%
Heat exchange area: 400 ft^2 (37 m^2)
Combustion chamber dimensions: D = 1 to 2 feet (0.3 - 0.6 m) L = 10 to 12 feet (3 - 3.6 m)
Firetube diameter: 1 to 2 inches (25 - 50 mm)
Common operating mode: Hi/Low fire modulation
Ignition system: Spark
Draft system: Forced
Maximum gas side heat exchanger temperature 900°F (482°C)
Overall steady state efficiency: 80%
Exit flue gas temperature: 450°F to 650°F (232°C - 343°C)
Natural gas fuel consumption: 3350 ft^3/hr (0.03 m^3/sec)
Light fuel oil consumption: 24 gal/hr (25 cm^3/sec)

Most Scotch boilers are designed with as little heating surface as is practical for firetube boiler construction. Typically, 5 square feet of heating surfaces are required to produce 1 boiler horsepower. Improved heat transfer is obtained by one or more of the following design features:

- High flue gas velocities throughout the boiler due to the use of a steadily diminishing number of constant-diameter firetubes in each subsequent pass
- Turbulators in the firetubes
- Improved water-side circulation by internal baffling and other means

Due to their compact design and multiple tube passes, the packaged Scotch boiler is more difficult to clean than other firetube boilers.

All firetube boilers must be designed in accordance with the ASME Power Boiler Code (Section I) or Heating Boiler Code (Section IV). They are rated by the American Boiler Manufacturers Association.

2.2.1.3 Atomization Methods

As was the case with domestic sized furnaces, a variety of burner types are used for commercial sized boiler applications. The main distinguishing feature is the method of atomizing the oil. Four techniques can be used:

- Air atomization
- Steam atomization
- Mechanical atomization (oil pressure atomization)
- Rotary cup burners

Most air atomizing oil burners used in commercial sized boilers are high pressure units. These are similar to the low pressure mechanical burners used in domestic furnaces, the oil flowing through a central tube in the nozzle and the atomizing air flowing in an annular tube around the oil passageway. The difference is that the mixing of oil and atomizing air is more violent than in the mechanical burners in order to atomize the oil into fine drops. This mixing can take place either outside or inside the nozzle, though a lower air pressure can be used if the former method is chosen.

Steam atomized burners are identical to high pressure air atomized burners except that steam is used in place of the pressurized air. The use of steam is often desirable since a supply of high pressure steam is readily available at the boiler. Steam atomization is limited to use in boilers which attain steam pressures in excess of 100 psi (690 kPa).

Mechanical (pressure) atomizing oil burners have been discussed previously (see Section 2.1.1.1). Rotary cup burners utilize a rapidly rotating cup to which oil is supplied. The rotary motion of the cup causes the oil to form a thin film on its sides. Centrifugal force pushes the oil to the lip of the cup at which point it is flung off in the form of tiny droplets. The mean droplet size decreases as the rotary speed is increased. Older rotary burners are being phased out at present, primarily because of their high maintenance requirements (see Section 4.1.2), although some new designs may be able to operate cleanly with no more than normal maintenance.

All four types of atomization can be used with fuels ranging from distillate to No. 6 residual oil as long as proper oil preheat is applied to reduce the viscosity of the heavier oils before they enter the nozzle.

2.2.1.4 Tuning

The tuning of commercial units is no less important than it is for domestic burners, and the procedures and effects are similar in both cases. In addition, oil preheat must be adjusted in commercial units which use heavy oil.

2.2.1.5 Cycling and Modulation

The operation of a boiler differs from that of a warm air furnace in that control of water temperature and steam pressure can be achieved by modulation of burner output as well as by cycling the burner in an on/off mode. The modulation method is preferable, especially in the case of residual oil firing. Data from Reference 2-16 indicates that particulate emissions from some boilers firing No. 6 oil can decrease by a factor of two as the load is reduced from 80 percent of rated conditions to normal low-load firing.

2.2.2 Emissions from Commercial Oil Burners

Particulate emissions from oil-fired commercial boilers vary over a wide range due to the variety of fuels burned. Barrett, et al. (Reference 2-15) have related carbon residue, carbon content, viscosity, and API gravity to particulate emissions. Since the first three properties are all related to the API gravity, particulate emissions are too. The net result is that as API gravity decreases, particulate emission increases. Average emission factors for the sample of commercial boilers tested in Reference 2-15 are given as:

Fuel Oil Grade	API Gravity	Filterable Particulate lb/MBtu (ng/J)
No. 2	35	0.011 (4.7)
No. 4	22	0.047 (20.2)
No. 5	19	0.087 (37.4)
No. 6	16	0.25 (107.5)
LSR*	23	0.087 (37.4)

Larger commercial boilers than those tested in Reference 2-15 will have emission characteristics similar to industrial size boilers.

The effect of boiler load on particulate emissions is shown in Figure 2-7. In general, increasing load does not significantly affect filterable particulates except for firing of No. 6 fuel oil. Increases in particulate emissions for four boilers fired on No. 6 ranged from 0.001 - 0.008 lb/MBtu (0.43 - 3.44 ng/J) for each 1 percent increase in load.

Barrett, et al. (Reference 2-15) have suggested appropriate emission factors based on emissions data from 27 boilers in steady operation at 80 percent load and 12 percent CO_2 in the flue gas. These numbers listed below represent a second degree curve fit to a plot of emission data versus API gravity.

Fuel Grade	Suggested Emission Factor lb/MBtu (ng/J)
No. 2	0.0086 (3.7)
No. 4	0.093 (40.0)
No. 5	0.18 (77.4)
No. 6	0.24 (103.2)
No. 6 (1% S)	0.08 (34.4)

*Low sulfur residual typical of that marketed on the East Coast in 1971-72. Most heavily impacted regions already require residuals to contain no more than 0.3 or 0.5 percent S.

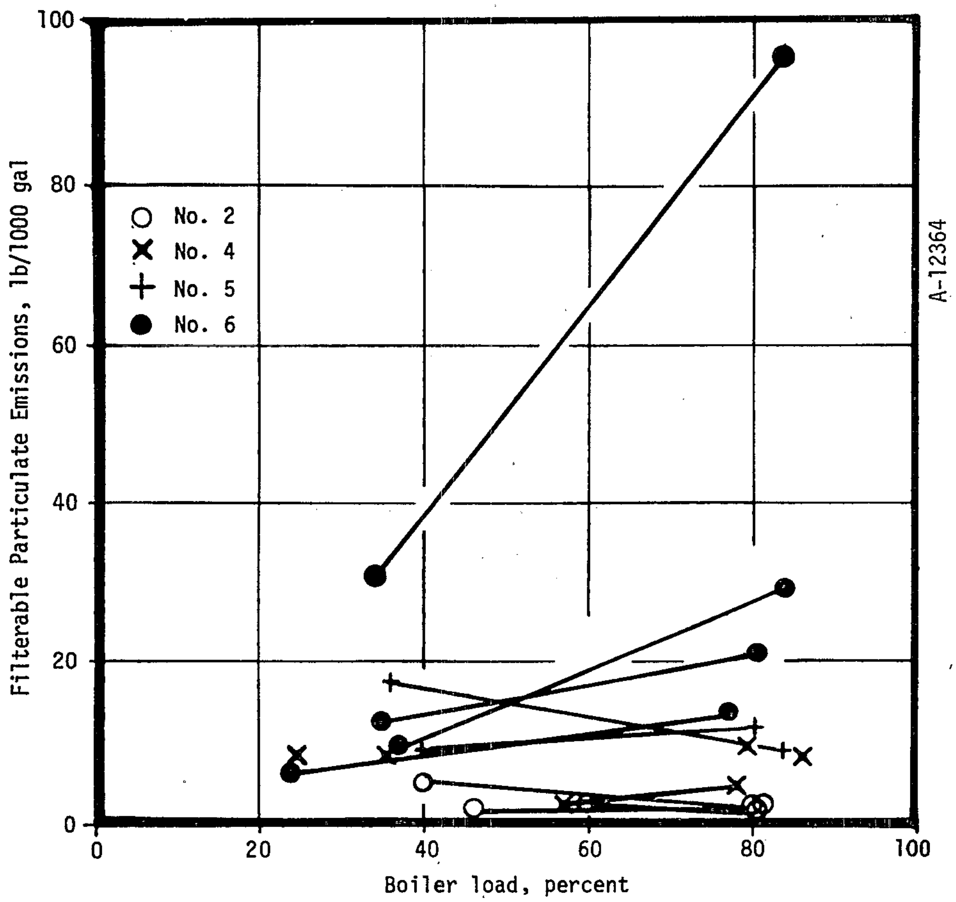


Figure 2-7. Effect of load on filterable particulate emissions from commercial boilers (particulate emissions by Battelle Modified EPA Procedure, Reference 2-15).

They represent an improvement over the customary method of assigning one emission factor to residual oils as a whole in that the considerable effect of API gravity on emission is included.

2.2.3 Population Distribution

In this section, the population of commercial boilers are characterized with respect to boiler type, fuel capability, and burner type. Recent and estimated future trends in boiler and burner type and fuel capability are also presented.

2.2.3.1 Population Distribution by Boiler Type

Table 2-10 shows the population distribution by boiler type for all commercial boilers currently in use. A review of the design features of the boiler types listed is given in Section 2.1.1.2, 2.2.1.2, and 2.4.1.1.

It is evident from Table 2-10 that watertube boilers comprise only a small fraction of the total commercial boiler population. A large fraction of the smaller size units are cast iron boilers, whereas most of the larger commercial ones are firetube boilers.

The sales data from 1975 (Reference 2-28) show that a large percentage of the commercial size boilers sold in that year were Scotch firetube units. This would indicate that Scotch boilers account for a larger fraction of the 1975 population than indicated in Table 2-10. This growing popularity of Scotch boilers is indicated in Table 2-11 which shows past and estimated future trends in the number of commercial boilers in service for the years noted. Thus, packaged Scotch boilers appear to have replaced horizontal return tubular boilers in the two larger size ranges. Other than this historical shift, no major changes have occurred since the 1950's nor are any predicted for the next 15 years.

2.2.3.2 Population Distribution by Fuel Capability

Table 2-12 shows the population distribution of commercial sized units in terms of fuel capabilities. The majority of the units are fueled with oil or gas, coal being used in only 1 or 2 percent of the systems. Less than 10 percent of the units have multiple fuel (oil/gas) capability, though 1975 sales data indicates a large number of oil/gas units sold in that year (Reference 2-28).

In the oil-fired units listed, the fraction of residual oil burned increases from 5 to 50 percent as the size of the unit increases from 0.3 - 10 MBtu/hr (88 kW - 2.93 MW). The relative amounts of the various types of oil used is important because particulate emissions are a strong function of fuel characteristics.

TABLE 2-10. POPULATION DISTRIBUTION OF COMMERCIAL BOILERS BY BOILER TYPE (1972)*

Rated Capacity Size Range	MBtu/hr (MW)	0.33 - 1.7 (0.096 - 0.50)	1.7 - 3.3 (0.50 - 0.96)	3.3 - 10.0 (0.96 - 2.93)
WATER TUBE				
Coil		2	3	2
Firebox		1	1	1
Other		3	4	2
FIRE TUBE				
Packaged scotch		15	20	30
Firebox		25	25	30
Vertical		1	0.5	nil
Horizontal Return Tubular (HRT)		5	10	15
Misc. (locomotive type, etc.)		2	3	5
CAST IRON		45	33	15
MISC. (TUBELESS, ETC.)		1	0.5	nil
TOTAL		100%	100%	100%

*Source: Reference 2-20

TABLE 2-11. ESTIMATED TRENDS IN COMMERCIAL BOILER TYPES*

Rated Capacity Size Range — MBtu/hr (MW)	0.33 - 1.7 (0.096 - 0.50)				1.7 - 3.3 (0.50 - 0.96)				3.3 - 10.0 (0.96 - 2.93)			
	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90
<u>WATER TUBE</u>												
Coil	nil	2	3	5	nil	3	5	4	nil	3	4	5
Firebox	8	5	3	1	8	5	3	1	3	3	4	5
Other	5	8	10	15	5	8	8	7	2	5	2	4
<u>FIRE-TUBE</u>												
Packaged scotch	nil	10	11	10	1	14	22	26	2	21	41	40
Firebox	6	11	18	20	20	15	17	23	20	30	35	30
Vertical	5	6	6	6	3	5	3	2	5	2	nil	nil
Horizontal return tubular (HRT)	5	1	nil	nil	5	2	nil	nil	60	25	1	nil
Misc. (locomotive type, etc.)	8	5	3	2	5	1	1	1	8	5	2	nil
<u>CAST IRON</u>	60	50	45	40	50	45	40	36	nil	5	10	15
<u>MISC (TUBLESS, ETC)</u>	3	2	1	1	3	2	1	nil	nil	1	1	1
TOTAL	100	100	100	100	100	100	100	100	100	100	100	100
	%				%				%			

*Source: Reference 2-20

TABLE 2-12. POPULATION DISTRIBUTION OF COMMERCIAL BOILERS BY FUEL CAPABILITY (1972)*

Rated Capacity Size Range	MBtu/hr (MW)	0.33 - 1.7 (0.096 - 0.5)	1.7 - 3.3 (0.5 - 0.96)	3.3 - 10.0 (0.96 - 2.93)
FUELS				
Oil only		42	42	40
Gas only		50	50	50
Coal only		2	1	1
Oil & gas and gas & oil		5	6	8
Misc. fuels (alone or with alternate fuels)		1	1	1
TOTAL		100%	100%	100%
OIL				
Distillate, No. 2		95	85	50
Resid		(5)	(15)	(50)
No. 4 and light No. 5 (no preheat)		4.5	14	30
Heavy No. 5 and No. 6 (preheated)		0.5	1	20
TOTAL OIL		100%	100%	100%

*Source: Reference 2-20.

Table 2-13 shows the past and estimated future trend in commercial boiler fuel capability. In response to recent gas and oil shortages, many units which now burn only gas are being replaced by dual fuel (oil and gas) systems, and some of these which now use only oil are being replaced by coal-fired boilers. This trend is projected for all commercial boiler sizes, although in varying degrees. Sales data for 1975 show that almost one-third of all units sold have multiple fuel capabilities (Reference 2-29).

2.2.3.3 Population Distribution by Burner Type

Table 2-14 gives the population distribution of commercial sized units in terms of burner type. Mechanical atomization predominates in the smaller size boilers, while air atomization and rotary type burners comprise a large fraction of the bigger units.

Classification of oil-fired units in terms of burner type is particularly important in any study dealing with particulate emissions. The size of the atomized oil droplets, which is a function of the type of atomization employed, has a direct effect on the amount of particulate emission, as discussed previously.

Table 2-15 shows past and estimated future trends in burner types in terms of the number of units of a particular type in service for a given year. The past trend away from rotary burners is projected to continue until they disappear entirely in the near future. In large units the rotary burners have been replaced mainly by air atomizing types whereas in the smaller boilers and furnaces they have been replaced by both air and mechanical atomizers.

2.3 INDUSTRIAL SYSTEMS — 12.5 - 250 MBtu/hr (3.7 - 73.25 MW)

Industrial size heating units are composed entirely of firetube and watertube boilers. Firetube boilers were discussed in Section 2.2.1.2, and watertube boilers are described below.

2.3.1 Equipment Description

2.3.1.1 Design Features of Watertube Boilers

Above a capacity of 30 MBtu/hr (8.8 MW), industrial boilers are almost exclusively of the watertube type. They also dominate the market where design pressure exceeds 150 psig (1.0 MPa). As the name implies, watertube boilers are designed to flow water through the heat transfer tubes, instead of combustion products as in the firetube design. Because of the smaller diameter of the pressurized components and the ability of tubes to accommodate expansion, watertube boilers are

TABLE 2-13. ESTIMATED TRENDS IN COMMERCIAL BOILER FUEL CAPABILITY*

Rated Capacity Size Range — MBtu/hr (MW)	0.33 - 1.7 (0.096 - 0.5)				1.7 - 3.3 (0.5 - 0.96)				3.3 - 10.0 (0.96 - 2.93)			
	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90
FUEL CAPABILITY												
Oil only	20	40	30	20	10	30	25	10	10	40	30	10
Gas only	10	30	45	25	10	30	38	10	5	25	30	5
Coal only	65	20	5	10	75	15	5	15	80	10	5	20
Oil & gas and gas & oil	nil	5	18	40	nil	10	30	60	nil	20	30	60
Misc. fuels	5	5	2	5	5	5	2	5	5	5	5	5
(alone or with alternate fuels)	100	100	100	100	100	100	100	100	100	100	100	100
		%				%				%		
TOTAL												
OIL												
Distillate, No. 2	40	50	70	100	20	30	40	70	10	10	20	40
Resid	(60)	(50)	(30)	(nil)	(80)	(70)	(60)	(30)	(90)	(90)	(80)	(60)
No. 4 & light No. 5 (no preheat)	40	40	25	nil	50	50	50	30	30	40	30	5
Heavy No. 5 & No. 6 (preheat)	20	10	5	nil	30	20	10	nil	60	50	50	55
TOTAL OIL	100	100	100	100	100	100	100	100	100	100	100	100
		%				%				%		

*Source: Reference 2-20

TABLE 2-14. POPULATION DISTRIBUTION OF COMMERCIAL BOILERS BY BURNER TYPE (1972)*

Rated Capacity Size Range	MBtu/hr (MW)	0.33 - 1.7 (0.096 - 0.50)	1.7 - 3.3 (0.5 - 0.96)	3.3 - 10.0 (0.96 - 2.93)
OIL BURNERS				
Air atomizing		15	35	40
Pressure atomizing (mechanical)		70	25	20
Rotary		15	40	40
TOTAL OIL		100%	100%	100%

*Source: Reference 2-20

TABLE 2-15. ESTIMATED TRENDS OF COMMERCIAL BOILER BURNER TYPES*

Rated Capacity Size Range	MBtu/hr (MW)	0.33 - 1.7 (0.096 - 0.50)				1.7 - 3.3 (0.50 - 0.96)				3.3 - 10.0 (0.96 - 2.93)			
		'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90
OIL BURNERS													
Air atomizing		10	15	15	15	15	20	30	30	20	30	55	60
Pressure atomizing		70	75	85	85	55	60	65	70	50	40	40	40
Rotary		20	10	nil	nil	30	20	5	nil	30	30	5	nil
TOTAL		100	100	100 %	100	100	100	100 %	100	100	100	100 %	100

*Source: Reference 2-20

better able to contain the high pressure than are firetube units, and, hence, they are an inherently safer design. Efficiencies attained in watertube boilers are about 80 percent without heat recovery.

Watertube boilers can be either field-erected or packaged. Common sizes for the former type fall between 50 and 500 MBtu/hr (14.6 and 146 MW) while the capacity range for the latter is 10 to 350 MBtu/hr (2.9 - 102 MW).

Since the industrial-sized watertube packaged boiler was first introduced in the early 1940's they have become very popular. In the period of 1930 - 1950, almost 95 percent of the units between 10 and 100 MBtu/hr (2.9 - 29 MW) were field-erected. However, it is anticipated that by 1990 about 99 percent of this class will be packaged. Similarly, until 1950 all of the watertube boilers in the range of 100 to 500 MBtu/hr (29 - 146 MW) were field-erected. Forecasts indicate that by 1990 about 90 percent of the sizes up to 250 MBtu/hr (73.25 MW) will be packaged.

Field-erected boilers are usually balanced draft* and, therefore, require both forced draft and induced draft fans. Field-erected boilers are commonly fired with coal, gas, oil, and/or waste fuels. Many such boilers exist today, but very few new applications have capacities lower than 200 MBtu/hr (58.6 MW), except for solid fired units. The packaged boiler's domination of the oil- and gas-fired market below 200 MBtu/hr (58.6 MW) is due to their low capital cost.

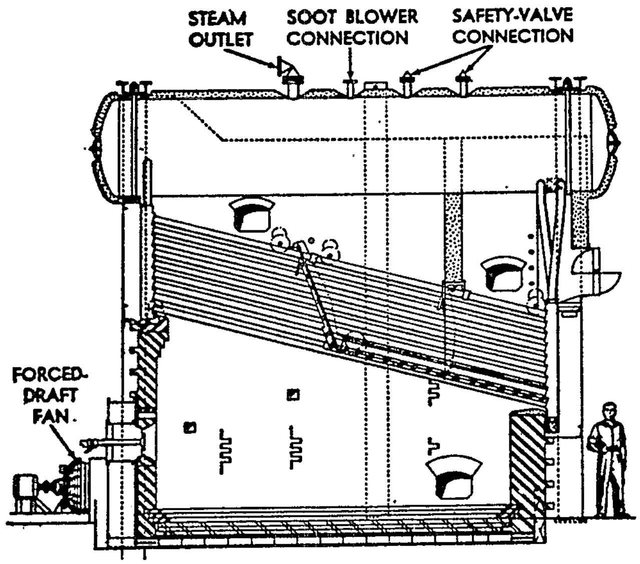
Packaged watertube boilers are used for gas and oil-firing applications. They are not used for coal-firing because they have much smaller furnace volumes than are permissible. They are designed to be rail-shipped as a complete, single package with minimum fieldwork. The furnaces are also designed to operate under positive pressure versus the balanced or slightly negative pressure found in larger field erected units.

The two general types of watertube boilers are horizontal, straight and bent tube boilers. Straight watertube boilers are no longer manufactured, having been completely supplanted by firetube boilers in the smaller sizes and bent watertube boilers in the intermediate sizes. There are, however, a large number of straight tube boilers still in operation.

Straight Tube Boilers

The straight tube boiler (Figure 2-8) owed its early popularity to its low draft loss, good tube visibility for inspection and cleaning, design that facilitated tube replacement, and low

*Balanced draft refers to a boiler where static pressure at a specified location is equal to atmospheric. The top of these boilers is at a slightly subatmospheric pressure.



Sectional Header, Long Drum

Figure 2-8. Horizontal straight tube boiler (courtesy, the Babcock & Wilcox Co.)

headroom requirements. However, it is often subject to leaks around the handholes, considerable labor is required to open a sectional header for inspection, and it has poor water distribution and low circulation rates.

These boilers are normally baffled to create two or three flue gas passes across the watertubes. The tubes are grouped into sections and expanded at the ends into headers. The headers are connected to the drum by downcomers for supplying water to the tubes and by risers for discharging water and steam from the tubes. The "horizontal" tubes are inclined at an angle of 5° to 15° for natural circulation of the water. The flue gas is normally moved by a forced circulation fan.

Horizontal straight tube boilers can be subdivided by type of header and/or type of drum. One variation of this type of boiler is a straight watertube boiler built with a steel encased, bricklined firebox with water cooled walls. The water and steam are contained in an enclosure above the crownsheet. It is designed for 1 to 18 MBtu/hr (0.293 - 5.3 MW) and 15 psig to 250 psig pressure (0.1 - 1.7 MPa).

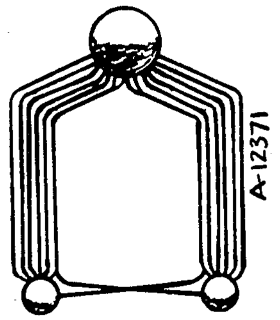
Horizontal Bent Tube Boilers

Horzontal bent tube boilers, the other major type of watertube boiler, are classified by the number of drums, headroom, and tube configuration, the latter of which is the most important distinguishing factor. In the boiler each tube is connected to the steam drum and to at least one lower drum or header (see Figures 2-9 and 2-10). The tubes enter a drum radially and are designed to allow for the anticipated expansion. The furance is of the waterwall type backed up with refractory. The tubes, which form the furnace waterwall, are an integral part of the boiler. The steam drum contains internals, such as separators and cyclones, to facilitate steam-water separation. Bent tube boilers have the advantage of great design flexibility, making them readily adaptable to space limitations by either extending their length or, more practically, the wdith. They provide good accessibility for inspection and cleaning, which normally entails mechanical cleaning from inside the steam drum.

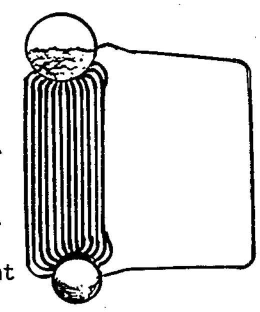
Most packaged units are oil-, gas-, or combination-fired, although there are some coal-fired packaged units. The furnace wall cooling tubes are usually oriented vertically. Vertical furnace tubes are particularly desirable in coal-firing since they are less susceptible to slag adherence.

Heat recovery from the flue gas is practical and often desirable with bent tube boilers, particularly in the intermediate and large sizes. The recovery unit may consist of an economizer which preheats feedwater, an air preheater to heat combustion air, or both.

A-type has two small lower drums or headers. Upper drum is larger to permit separation of water and steam. Most steam production occurs in center furnace-wall tubes entering drum.



D-type allows much flexibility. Here the more active steaming risers enter drum near water line. Burners may be located in end walls or between tubes in buckle of the D, right angles to drum.



O-type is also a compact steamer. Transportation limits height of furnace, so, for equal capacity, longer boiler is often required. Floors of D and O types are generally tile-covered.

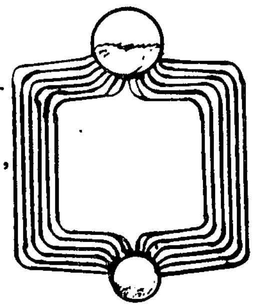


Figure 2-9. Types of bent tube packaged watertube boilers.

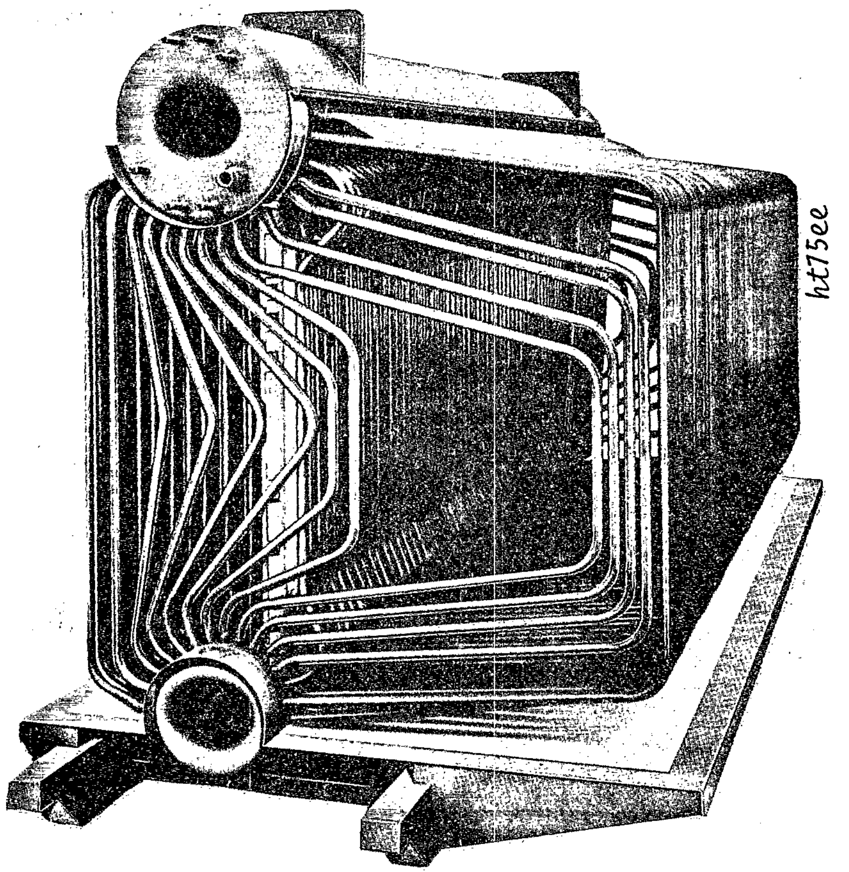


Figure 2-10. D-type bent tube configuration (courtesy of the Cleaver Brooks Company).

The larger industrial-size, field-erected watertube boilers, that is, larger than 25 MBtu/hr (7.3 MW), are identical to utility boilers used for generating electrical power. These multi-burner facilities are available in the tangentially-fired design as well as the wall-fired type found in the smaller units.

2.3.1.2 Atomization

The type of atomization employed in a given unit has been shown to affect both the total amount of particulates emitted and their size distribution. McGary and Gregory (Reference 2-19) compared particulate data for steam, air, and mechanical atomization techniques from the effluent of three large industrial boilers. They showed that air atomization produced an order of magnitude less particulate than the mechanical approach (Table 2-16). In addition, analysis of the particulate for combustibles showed that the lower emitters also produced particulate with proportionally less combustible content. Both these results indicate that air atomization leads to more complete combustion than steam, which is already much better than mechanical atomization.

Further evidence of the superiority of air to steam atomization is found in Reference 2-22 where a single boiler fueled with No. 5 oil was alternately fired using both types of atomization. Air atomization produced 32 percent less filterable particulates than did steam (total particulates were reduced by 16 percent.

2.3.1.3 Soot Blowing

In large boilers which see continuous operation, it is necessary to periodically remove the soot which accumulates on the heat exchanger tubes. This soot layer effectively decreases the heat transfer to the working fluid and, consequently, the overall boiler efficiency. In addition, it can cause "hot spots" or corrosion which eventually will cause the boiler tubes to fail. Nearly all industrial watertube boilers that produce more than about 30 MBtu/hr heat input (8.8 MW) are equipped with soot blowers, and occassionally units that are one-half this size also have them. Some firetube boilers that burn residual oil use soot blowers, too, but this practice is not common. One important reason is that firetube boilers generally do not produce the high pressure steam needed by the blowers.

The soot blowing operation is accomplished by activating a high pressure nozzle which travels the length of the boiler and directs a high pressure stream of air or steam onto the boiler tubes, thus dislodging the soot. The operation generally consumes less than 1 percent of the boiler's thermal output and lasts for 2 - 5 minutes, depending upon the size of the boiler, its design, the fuel, and the soot blowing procedure used. Frequently a boiler operator will clean one section

TABLE 2-16. PARTICULATE DATA VS. ATOMIZER TYPE*

	Type Burner		
	Air Atomized	Steam Atomized	Mechanical Atomized
Boiler load (MW_t)	69	80	84
Number of samples	10	8	9
Total mg	226.8	642.1	4032.3
Total mg normalized to 100 MW hr[a]	383.2	1069.7	7892.6
Particulate < 30μ; mg/avg test	8.9	21.6	109.0
Particulate < 30 μ; %	39.2	26.9	24.3
Particulate < 3.3μ; mg/avg test	6.5	10.8	40.4
Particulate < 3.3μ; %	28.5	13.5	9.0
Combustibles in particulate; %	40	80	99

[a]Normalized values calculated from: $\frac{\text{mg}}{100\ MW_t\ \text{hr}} = \frac{\text{mg of test sample}}{\text{min sample time}} \times \frac{60 \times 100}{MW_t \text{ unit rating}}$

*Source: Reference 2-19

of his boiler with a 2-minute blow and then the other section about 1 hour later with another 2-minute blow. Another approach is to use frequent 10 - 20 second puffs. Both air and steam can be used, and they are equally effective (when measured by effectiveness per unit energy input). The choice depends upon the economics of the situation at the facility where the boiler is located. If high pressure steam is readily available, as in a utility boiler, this medium will be used. If however, the boiler is relatively small, so that an ample steam supply is not available, and if the plant already has air compressors to supply "shop air" or processes which need high pressure air, then the boiler operator will probably opt for an air soot blower system. In any case, the system is always designed to effectively remove the accumulated deposits from the heat transfer surfaces. Therefore, there is no reason to suspect that differences in soot blowing equipment or configurations will affect the mass of particulate emitted during the cleaning cycle.*

Small oil-fired boilers may have only two soot-blowing heads, each servicing half the boiler heat exchanger section. When one of these blowers is activated, it cleans a large fraction of the total surface being blown and, consequently, the smoke emanating from the stack may have an opacity of 80 to 100 percent (Reference 2-21). Large boilers can have as many as 25 soot blowing heads which operate sequentially. In such a system, only a small fraction of the total blown surface is being cleaned at a given time, and, consequently, a less severe change in Ringelmann number is seen at the stack. In very large utility boilers, the soot-blowing operation may take place cyclically, with operation of the last blower in the sequence being followed by the first, again.

2.3.1.4 Emissions

There appears to be little available data on filterable particulate emission levels from industrial size boilers. However, emission levels have been measured for some of the smaller boilers in this category operating at baseline conditions (Reference 2-22). These data are shown in Figure 2-11. Industrial units in the size range 15 - 120 MBtu/hr (4.4 - 35.1 MW) fueled with distillate have emissions comparable to that of commercial units, that is 0.01 - 0.03 lb/MBtu (4.3 - 12.9 ng/J). As boiler capacity increases, this level appears to decrease.

A similar trend is seen in the case of those units tested which burned residual oil, for the mass emissions decreased from 0.1 to 0.04 lb/MBtu (43 - 17.2 ng/J) as boiler capacity increased from 50 to 130 MBtu/hr (14.7 - 38.1 MW).

*Since there is not data to substantiate this statement several boilers should be tested to determine how total emissions and particulate size distributions vary with time, both during and between soot blowing operations, and with soot blowing equipment and frequency.

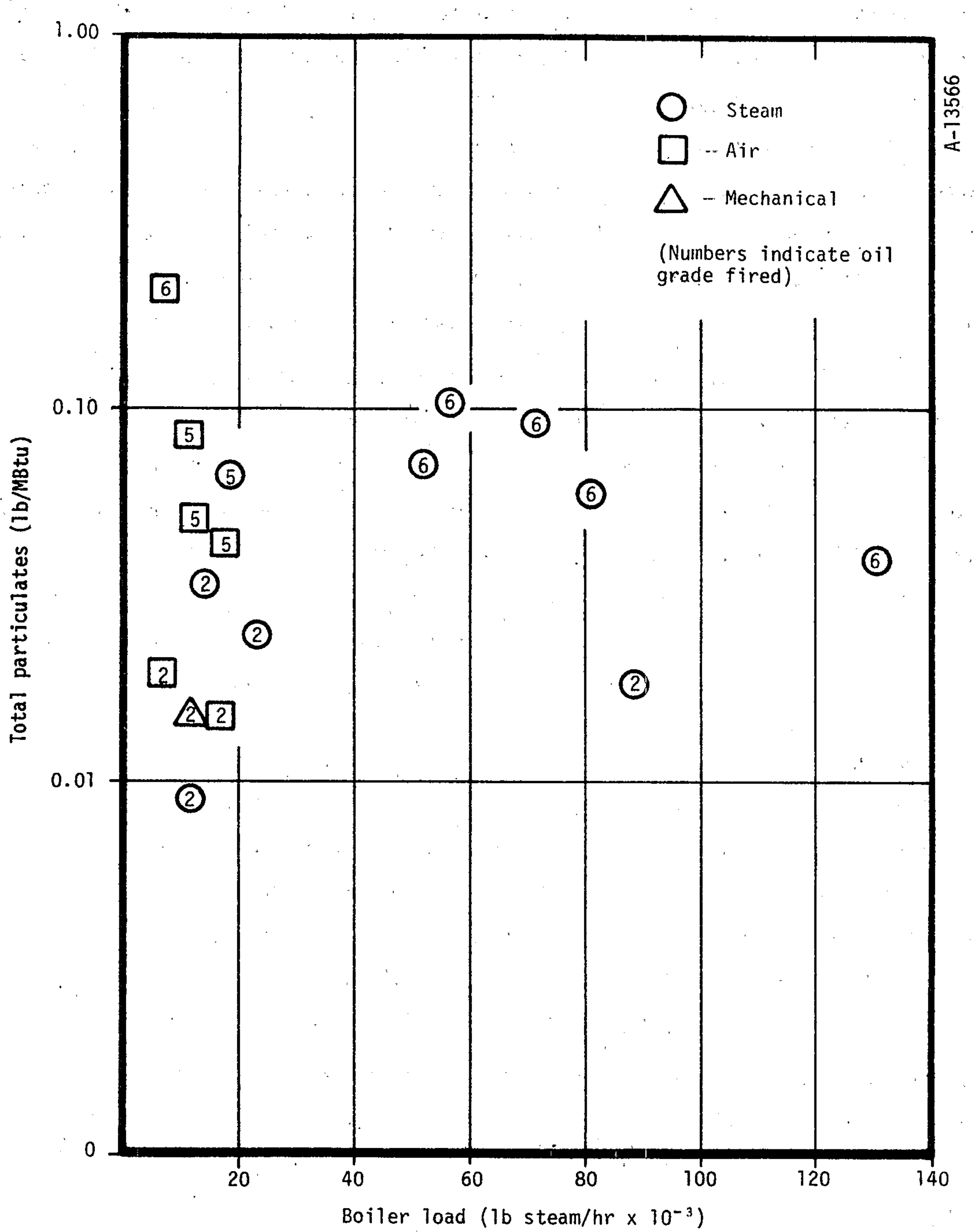


Figure 2-11. Particulate Emissions vs. Boiler Load

The larger industrial boilers, which are similar to the smaller size utility boilers, exhibit lower emissions than the smaller industrial boilers for two primary reasons. Due to the large quantity of fuel consumed in these units, any reduction in efficiency due to substandard combustion becomes very expensive. Therefore, the larger units often receive better maintenance and are operated under more carefully controlled conditions than the smaller units. Secondly, there is a certain degree of custom engineering involved in the design of utility and large industrial boilers, including expensive control systems. This often results in reduced emissions. Therefore, particulate emission concentrations from large industrial boilers are comparable to those from utility boilers and significantly lower than those from commercial and smaller industrial units.

EPA has recently revised the emission factors for particulates from oil-fired boilers and furnaces (Reference 2-26). These new factors recognize the effect of fuel on particulate emissions by specifying a separate factor for each residual fuel grade and, further, by relating emissions to sulfur content in No. 6 oil. Table 2-17 presents the new factors and also shows the old ones for comparison. The new emission factors are averages for each fuel grade and do not distinguish among different size units. Thus, they do not show that emissions decrease as the boiler size increases (see Reference 2-23).

2.3.2 Population Distribution

This subsection presents the population distributions of industrial size oil-fired firetube and watertube boilers. Separate tabulations are given for population by boiler type, fuel capability, and burner type.

2.3.2.1 Population Distribution by Boiler Type

Table 2-18 shows the population of industrial boilers classified in terms of boiler type. Firetube boilers account for more than three-quarters of the population in the size range below 16 MBtu/hr (4.7 MW), while nearly all boilers over 100 MBtu/hr (29.3 MW) are of the watertube type.

As shown in Table 2-19, firetube boilers have become increasingly popular in the smallest size range, and this trend is expected to continue. There is also an increasing preference for packaged, as opposed to field-erected, watertube boilers in the large size categories.

TABLE 2-17. REVISED EMISSION FACTORS FOR OIL-FIRED EXTERNAL COMBUSTION SOURCES*

Equipment	Fuel	Emission Factors††			
		Revised†		Old	
		lb/MBtu	ng/J	lb/MBtu	ng/J
Residential	Distillate	0.018	7.74	0.071	30.5
Commercial, Institutional, Industrial	Distillate	0.014	6.02	0.107	46.0
Above + Utility	No. 4	0.047	20.2	0.153**	65.8**
Above + Utility	No. 5	0.067	28.8		
Above + Utility	No. 6	0.067 x S + 0.020	28.8 x S + 8.6		
Utility	--	--	--	0.053	22.8

*Source: Reference 2-26

†S = percent sulfur in fuel (by weight). At 0.5%, the revised factor equals the old one for utilities

**Excluding utilities

††For conversion factors see Appendix C

TABLE 2-18. POPULATION DISTRIBUTION OF INDUSTRIAL BOILERS BY BOILER TYPE (1972)*

Rated Capacity Size Range	MBtu/hr (MW)	10-16 (2.9-4.7)	17-100 (5.0-29.3)	101-250 (29.6-73.3)
WATER TUBE				
Packaged		15	55	25
Field erected		7	24	75
FIRE-TUBE				
Packaged scotch		30	10	--
Firebox		25	10	--
Horizontal return tubular (HRT)		20	1	--
Misc. (locomotive type, etc.)		3	nil	--
TOTAL		100%	100%	100%

*Source: Reference 2-20.

TABLE 2-19. ESTIMATED TRENDS OF INDUSTRIAL BOILER TYPES*

Rated Capacity Size Range	MBtu/hr (MW)	10-16 (2.9-4.7)				17-100 (5.0-29.3)				101-250 (29.6-73.3)			
		'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90
WATER TUBE													
Packaged		0	2	18	20	0	8	80	89	0	0	80	90
Field erected		25	15	1	0	94	89	14	1	100	100	20	10
FIRE-TUBE													
Packaged scotch		nil	35	40	45	nil	2	5	9	--	--	--	--
Firebox		20	40	40	35	1	1	1	1	--	--	--	--
Horizontal return tubular (HRT)		50	5	nil	nil	5	4	nil	nil	--	--	--	--
Mixc. (locomotive type, etc.)		5	3	1	nil	nil	nil	nil	nil	--	--	--	--
TOTAL		100	100	100 %	100	100	100	100 %	100	100	100	100 %	100

*Source: Reference 2-20.

2.3.2.2 Population Distribution by Fuel Capability

Table 2-20 shows the population distribution of industrial boilers in terms of fuel capability. Oil and gas are the primary fuels for the smaller size units. However, coal is of almost equal importance in the larger sizes.

Of the oil-fired units smaller than 16 MBtu/hr (4.7 MW), approximately 30 percent use distillate, No. 4, or unpreheated No. 5. Boilers in the larger size ranges, however, are fired almost exclusively on preheated residual.

Table 2-21 shows past and estimated future fueling trends. Until recently, coal experienced a decrease in popularity, while at the same time, distillate use had been on the rise. Ever tightening air pollution regulations caused both trends, but oil and gas shortages are expected to stimulate a shift back to coal in all size ranges.

The types of fuel used depends to a large extent on the geographic region in which the user is located. Table 2-22 shows the national distribution of fuel usage for industrial sized boilers (Reference 2-21). The data is in terms of percentages of total fuel consumed in a particular geographic region based on the conversion of all fuel consumption into units of "ton equivalent coal."* A map showing the related geographic regions is presented in Figure 2-12.

The regions using the largest percentage of oil to fuel their industrial boilers are the Atlantic Section (AT), where oil accounts for over 92 percent of the total fuel usage, and the Rural North (RN), where oil accounts for 84 percent of this total. This reliance on oil, coupled with the large amount of industry located in those areas, makes them a particularly large source of oil-derived particulate emissions.

2.3.2.3 Population Distribution by Burner Type

As indicated in Table 2-23, all burner types are employed to a significant degree in small sized boiler applications. In the larger boilers, where production of sufficient quantities of high pressure atomizing air is a problem, steam atomizing burners predominate in spite of evidence (Reference 2-19) that air atomization produces signifiantly lower particulate levels. Rotary type

*The conversion was based on a heat content of 12,776 Btu/lb (29.7 MJ/kg) for coal, 19,570 Btu/lb (45.5 MJ/kg) for distillate oil, 19,050 Btu/lb (44.3 MJ/kg) for residual oil, and 20,000 Btu/lb (46.5 MJ/kg) for gas.

TABLE 2-20. POPULATION DISTRIBUTION OF INDUSTRIAL BOILERS BY FUEL CAPABILITY (1972)*

Rated Capacity Size Range	MBtu/hr (MW)	10-16 (2.9-4.7)	17-100 (5.0-29.3)	101-250 (29.6-73.3)	251-500 (73.5-146)
FUELS					
Oil only		35	35	30	22
Gas only		45	35	22	22
Coal only		3	10	18	22
Oil & gas and gas & oil		16	18	26	23
Oil & coal and coal & oil		—	—	0.5	3
Gas & coal and coal & gas		—	—	0.5	3
Misc. fuels (alone or with alternate fuels)		1	2	3	5
TOTAL		100%	100%	100%	100%
OIL					
Distillate, No. 2		10	2	2	2
Resid		(90)	(98)	(98)	(98)
No. 4 and light No. 5 (no preheat)		20	2	nil	nil
Heavy No. 5 and No. 6 (preheated)		70	96	98	98
TOTAL OIL		100%	100%	100%	100%

*Source: Reference 2-20

TABLE 2-21. ESTIMATED TRENDS IN INDUSTRIAL FUEL CAPABILITY*

Rated Capacity Size Range — MBtu/hr (MW)	10-16 (2.9-4.7)				17-100 (5.0-29.3)				101-250 (29.6-73.3)				251-500 (73.5-146)			
	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90
FUEL CAPABILITY																
Oil only	17	43	30	13	13	30	30	10	5	20	24	nil	5	15	20	nil
Gas only	5	20	30	6	10	30	30	4	5	20	24	nil	5	15	20	nil
Coal only	75	10	5	30	75	30	5	40	90	38	15	50	90	60	20	60
Oil & gas and gas & oil	nil	25	30	45	nil	5	30	40	nil	10	25	30	nil	5	20	20
Oil & coal and coal & oil									nil	5	5	10	nil	3	10	10
Gas & coal and coal & gas									nil	5	5	5	nil	2	10	5
Misc. fuels	3	2	5	6	2	5	5	6	nil	2	2	5	nil	nil	nil	5
(alone or with alternate fuels)																
TOTAL	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	%				%				%				%			
OIL																
Distillate, No. 2	5	2	10	30	nil	nil	10	20	nil	nil	5	10	nil	nil	5	10
Resid	(95)	(98)	(90)	(70)	(100)	(100)	(90)	(80)	(100)	(100)	(95)	(90)	(100)	(100)	(95)	(90)
No. 4 & light No. 5 (no preheat)	20	23	10	nil	nil	5	nil	nil	nil	nil	nil	nil	nil	nil	nil	nil
Heavy No. 5 & No. 6 (preheated)	75	75	80	70	100	95	90	80	100	100	95	90	100	100	95	90
TOTAL OIL	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	%				%				%				%			

*Source: Reference 2-20

TABLE 2-22. DISTRIBUTION OF FUEL USAGE IN INDUSTRIAL BOILERS BY REGION PERCENT ON A "TONS EQUIVALENT COAL" BASIS (Reference 2-21)

	Region	Coal	Distillate Oil	Residual Oil	Gas
	AT	5.7	25.9	66.9	1.5
	GL	24.5	25.3	38.3	11.9
	WS	0.9	5.4	62.7	30.9
	CU	22.1	9.1	32.5	36.4
	SE	29.2	13.5	43.8	13.5
	RN	10.9	26.6	57.8	4.7
Total	USA	11.9	20.9	57.3	10.8

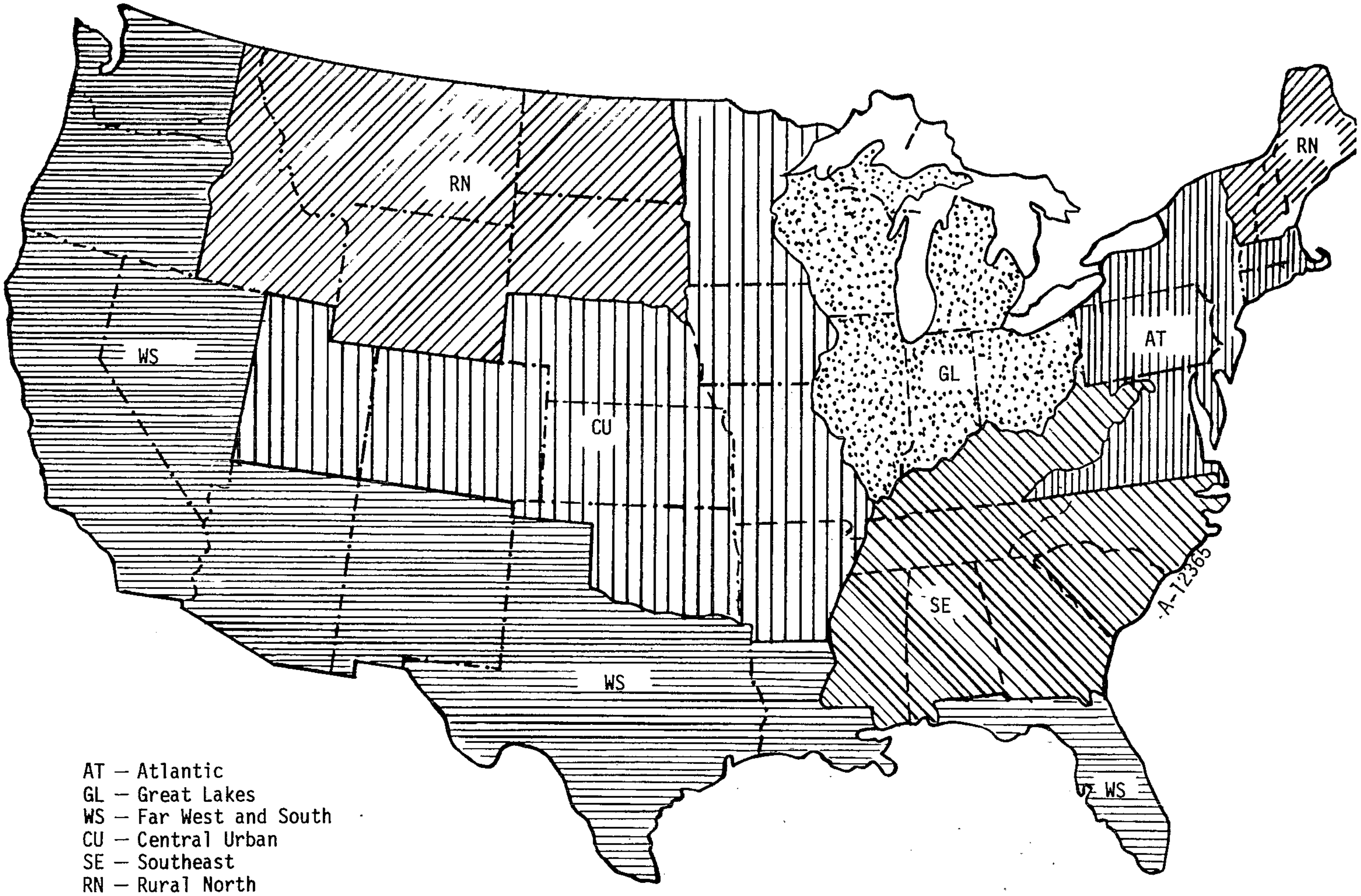


Figure 2-12. Regional boundaries.

TABLE 2-23. POPULATION DISTRIBUTION OF INDUSTRIAL BOILERS BY BURNER TYPE (1972)*

Rated Capacity Size Range	MBtu/hr (MW)	10-16 (2.9-4.7)	17-100 (5.0-29.3)	101-250 (29.6-73.3)
OIL BURNERS				
Air atomizing		40	15	5
Steam atomizing		20	70	85
Pressure or mechanical atomizing		10	10	10
Rotary		30	5	
TOTAL OIL		100%	100%	100%

*Source: Reference 2-20

burners are expected to be replaced by air or steam atomizing types in the near future (see Table 2-24).

A description of the various types of oil burners presently in use was given in Sections 2.1.1.1 and 2.2.1.3.

2.4 UTILITY — OVER 250 MBtu/hr (73.25 MW)

2.4.1 Equipment Description

Boilers in the utility size range are all of the watertube type, previously described in Section 2.3.1.1. Utility boilers are classified by their firing type — i.e., the particular way in which the oil is injected into the boiler. The three primary firing types for oil-fired units are single wall (or front face) firing, in which a bank of burners mounted on a plane wall ejects fuel in one direction only, opposed firing, in which two banks of burners eject fuel toward one another, and tangential firing, in which the burners are located at the corners of a square and eject oil in such a direction as to give a macroscopic rotational motion to the combustible mixture. These firing types are shown schematically in Figure 2-13.

In addition to these firing methods, two others, vertical and cyclone firing, are primarily used for coal firing but can be used with oil. These are included in the population distribution for completeness.

2.4.2 Emissions

Particulate emissions from utility boilers are a function of boiler size more than anything else. Measurements made in a recent study (Reference 2-23) indicate that the average particulate emission levels from a sample of uncontrolled boilers decreased from 0.085 to 0.045 lb/MBtu (36.6 - 19.4 ng/J) as the boiler size increased from 1 to 500 MW_e (see Figure 2-14). This sample includes boilers which emit between 0.01 and 0.26 lb/MBtu. Emissions from large boilers (>200 MW_e) are relatively low because these boilers tend to be new and equipped with sophisticated combustion controls. EPA has proposed an emission factor for utility size boilers that depends upon fuel grade and, in the case of No. 6 oil, sulfur content (see Subsection 2.3.2 and Table 2-17). For a boiler burning No. 6 oil with 0.5 percent sulfur content (by weight), the emission factor is 0.057 lb/MBtu (24.5 ng/J); if the oil contains 3 percent sulfur, the emission factor is 0.235 lb/MBtu (101 ng/J).

2.4.3 Population Distribution

Population data for utility boilers were obtained mainly from the Edison Electric Institute which maintains a data bank containing information on approximately 900 power plants. A total

TABLE 2-24. ESTIMATED TRENDS IN INDUSTRIAL BURNER TYPE*

Rated Capacity Size Range	MBtu/hr (MW)	10-16 (2.9-4.7)				17-100 (5.0-29.3)				101-250 (29.6-73.3)				251-500 (73.3-146)			
		'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90
OIL BURNERS																	
Air atomizing		10	20	35	40	5	3	2	1	2	1	nil	nil	2	1	nil	nil
Steam atomizing		30	30	35	40	75	80	88	90	93	94	95	95	93	94	95	95
Pressure or mechanical atomizing		25	20	20	20	15	14	10	9	5	5	5	5	5	5	5	5
Rotary		35	30	10	nil	5	3	nil	nil	—	—	—	—	—	—	—	—
TOTAL OIL		100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100

*Source: Reference 2-20

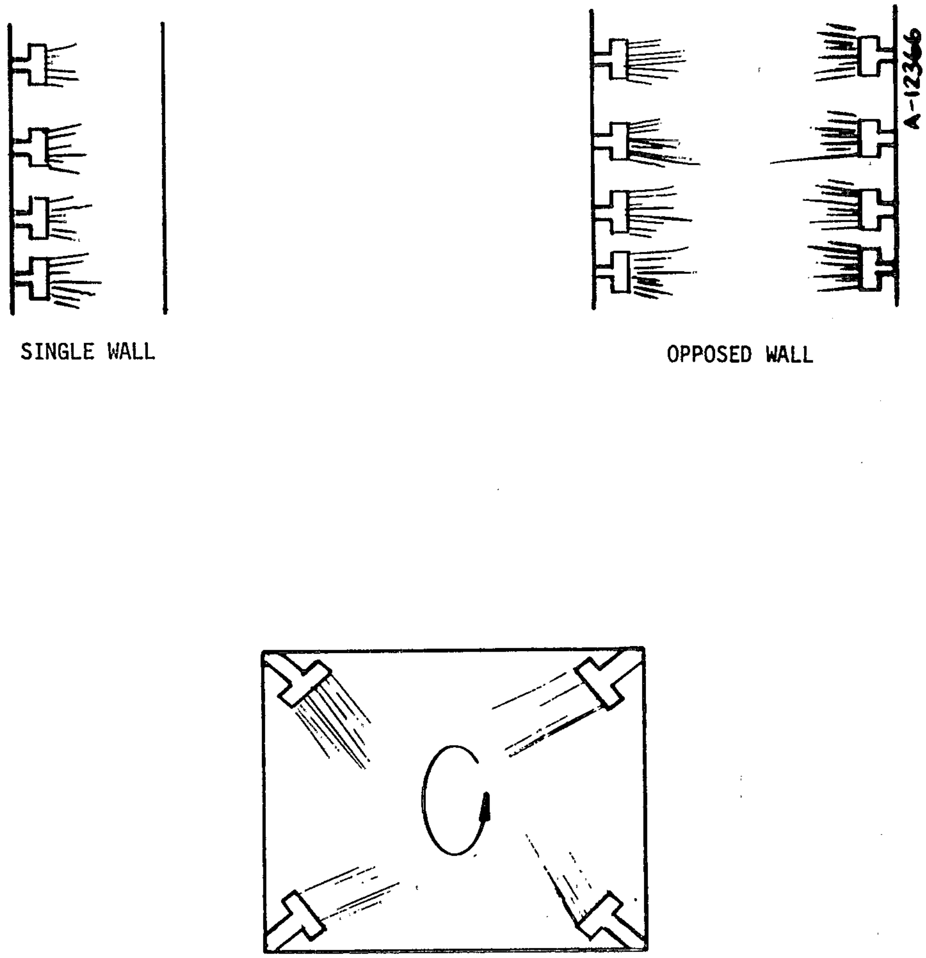


Figure 2-13. Standard firing types for oil-fired utility burners.

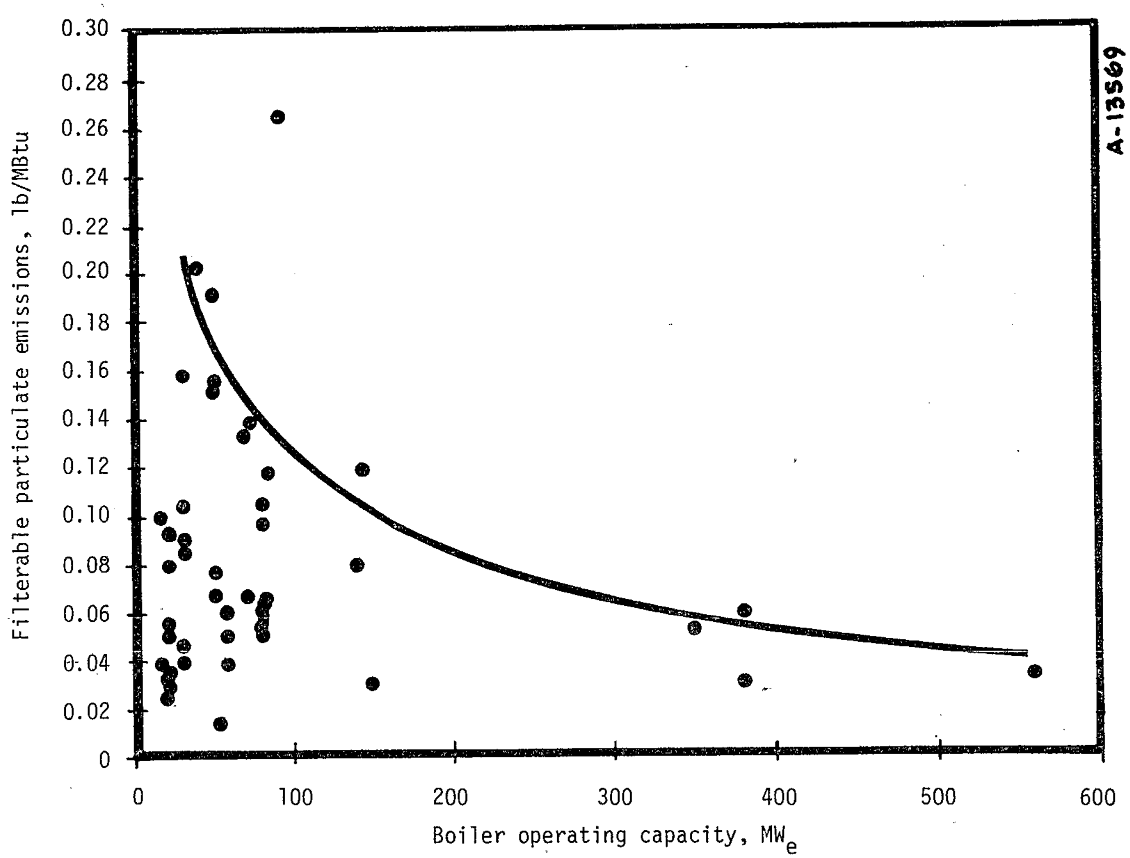


Figure 2-14. Uncontrolled electric utility emissions vs. capacity (no additives employed) (Source: Reference 2-23).

sample of 650 utility boilers was considered, 307 of which were fired on oil or oil with an alternate. Additional data came from the Electric World Magazine (principal design features of electric utility boilers under construction), the Electric World Directory of Electric Utilities (a list of power plants operating in the U.S.), and Moody's Public Utilities Manual (annual data on regional fuel consumption). The population distributions are presented by firing type and fuel capability.

2.4.3.1 Population Distribution by Firing Type

Table 2-25 shows the population distribution in terms of firing type. The majority of these oil-fired boilers use opposed or tangential firing, though approximately half of the smaller ones employ single wall firing.

2.4.3.2 Population Distribution by Fuel Capability

Table 2-26 gives a population distribution of utility boilers by fuel capability. No distinction is made between primary and secondary fuel in the case of multifuel plants. As one might expect coal is the primary fuel, especially in the very large units (>600 MW). Approximately one-half of the boilers which are not restricted to coal are configured to burn gas and oil.

A geographical distribution of 1973 fuel consumption by type is given in Figure 2-15. The source of the data, Moody's Public Utilities Manual, also includes annual data of this type for the last 25 years. Some mild trends are evident in that data, but they are not presented here because they will be altered by the need to rely more on coal.

What should be noted in the chart is the high percentage of oil used in New England. Reference to NEDS data (see Table 1-1) indicates that oil combustion does in fact, account for a significant fraction of the particulate emissions in some AQCRs within that area.

2.4.3.3 Population Distribution by Fuel Usage and Particulate Control

Table 2-27 shows how many oil-fired utility boilers are equipped with particulate control devices (usually electrostatic precipitators). These data were taken from the NEDS system and include only those units that satisfied at least 10 percent of their fuel demands with oil (Reference 2-23). Nearly 60 percent of the residual oil is burned in units whose heat input rate is larger than 1000 MW_e). Only about one-half (55.5 percent) of the residual oil consumed by utilities for the generation of electricity is burned in units that are equipped with particulate controls. Apparently many of these boilers were converted from coal, and, therefore, the electrostatic precipitators were designed for coal flyash. As noted in Section 4.3.1, precipitators

TABLE 2-25. POPULATION DISTRIBUTION OF OIL-FIRED UTILITIES BY FIRING TYPE (PERCENT BASIS)

Rated Capacity	MW_e	74-150	150-300	300-600	Over 600
(Output)	MBtu/hr[†]	740-1500	1500-3000	3000-6000	Over 6000
Opposed		2	13	47	33
Tangential		42	31	36	67
Vertical		1	1	—	—
Cyclone		2	3	3	—
Front or back		53	52	14	—
TOTAL		100%	100%	100%	100%

*Source: Edison Electric Institute

†Approximate energy input based on an overall efficiency of 34 percent.

TABLE 2-26. POPULATION DISTRIBUTION OF UTILITY BOILERS BY FUEL CAPABILITY

Rated Capacity (Output)	MW	74-150	150-300	300-600	Over 600
	MBtu/hr††	740-1500	1500-3000	3000-6000	Over 6000
Gas only		1†	3.3	10.1	3.6†
Oil only		5.7	1.5	4.6	3.6†
Coal only		43.8	50.7	41.1	67.8
Gas & oil		23.5	24.5	31.0	7.1
Gas & coal		8.7	6.3	3.9	7.1
Coal & oil		11.1	11.6	7.7	-nil-
Oil, gas & coal		6.2	2.1	1.6	10.8
TOTAL		100	100	100	100

*Source: Edison Electric Institute

†Indicates that a relatively small statistical sample was considered in calculating these percentages

††Approximate energy input based on an overall efficiency of 34 percent

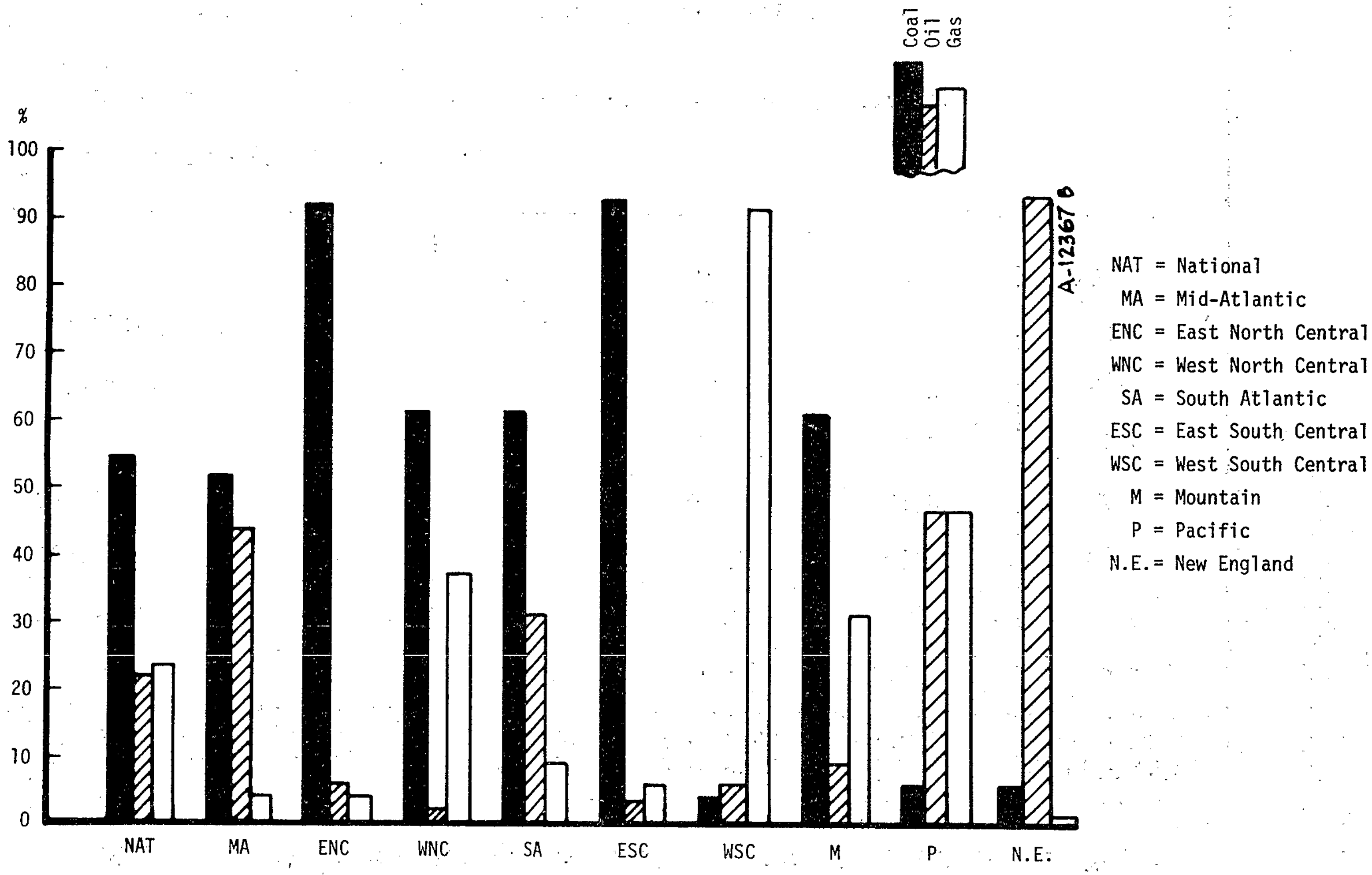


Figure 2-15. Geographic distribution of fossil fuel utilization (Source: Moody's Public Utilities Manual).

TABLE 2-27. SIZE BREAKDOWN OF CONTROLLED AND UNCONTROLLED ELECTRIC UTILITY EXTERNAL COMBUSTION BOILERS LISTED IN NEDS THAT SATISFY MORE THAN 10 PERCENT OF THEIR FUEL DEMANDS WITH OIL*

Controlled Electric Utility Oil-Fired External Combustion Boilers							
Distillate Oil				Residual Oil			
Boiler Size Categories (MBtu/hr)†	Number of Boilers in Each Size Range Category	Annual Distillate Fuel Oil Consumption of Boilers in Each Size Range Category (1000 gal)	% of Total Annual Distillate Fuel Oil Consumption by Both Controlled & Uncontrolled Boilers in All Size Range Categories	Boiler Size Range Category (MBtu/hr) (≈0.1 MW_e)	Number of Boilers in Each Size Range Category	Annual Residual Fuel Oil Consumption of Boilers in Each Size Range Category (1000 gal)	% of Annual Total Residual Fuel Oil Consumption by Both Controlled & Uncontrolled Boilers in All Size Range Categories
<10	0	0	0	<10	2	52	0
10 - 100	0	0	0	10 - 100	2	7,922	0.1
100 - 1000	1	17,573	3.4	100 - 1000	135	2,722,051	17.8
>1000	2	88,034	17.1	>1000	159	4,063,668	26.6
Uncontrolled Electric Utility Oil-Fired External Combustion Boilers							
<10	15	1,582	0.3	<10	25	6,375	0
10 - 100	7	3,370	0.7	10 - 100	134	210,628	1.4
100 - 1000	47	282,102	54.9	100 - 1000	339	3,310,050	21.7
>1000	3	121,191	23.6	>1000	84	4,956,136	32.4

*Source: Reference 2-23

†Based on 9.4 MBtu/hr heat input per 1 MW_e (i.e., assumes 36 percent overall thermal efficiency

that are built for coal, and are later used on oil, lose much of their efficiency. It is estimated that the average collection efficiency of the precipitators on these boilers is 40 - 55 percent.

2.4.4 Effects of NO_x Control Modifications on Particulate Emissions

Since large utility boilers are major contributors to the total nationwide emissions of NO_x newly installed units are required to meet stringent NO_x limits,* and many older units are also being regulated by local air pollution control authorities. Therefore, boiler manufacturers and operators are modifying their units to achieve the required NO_x reductions, and many of these modifications have an impact on particulate emissions. The following approaches are currently receiving the most attention in NO_x control programs for oil-fired utility boilers:

- Optimum combustion aerodynamics (especially turbulence level and swirl)
- Low excess air
- Off-stoichiometric combustion
- Flue gas recirculation
- Reduced wall temperatures

The flow patterns in the firebox determine how the air and fuel mix and how long the gases remain in the high temperature region of the boiler. That is, the aerodynamics affect the temperature-time history of the gases and, along with the primary and secondary air flow settings, dictate the amount of oxygen locally available to the combusting mixture. These are precisely the parameters which control the production of NO_x and particulate. Unfortunately, however, the optimum conditions for low particulates, namely intense, high temperature flames, as produced by high turbulence and rapid air-to-fuel mixing, are not the optimum conditions for low NO_x production. The latter pollutant is minimized in cooler, longer flames that come from low turbulence levels and slow mixing of the air with the fuel. Therefore, most attempts to reduce NO_x emissions through a redesign of the combustor aerodynamics have had to devise a flow pattern that resulted in a well-controlled flame whose temperature was high enough to avoid smoke and low enough to minimize NO_x generation.

Swirl is one of the most important variables in determining the aerodynamics of the combustor, but the effect on particulate emissions of optimizing swirl for low NO_x is unclear. Since

*New Source Performance Standards for boilers >250 MBtu/hr (40 CER 60.42), which also limits particulate emissions to 0.1 lb/MBtu (43.0 ng/J).

every burner has an optimum swirl ratio (a measure of ratio between circulatory and throughput velocities) for minimum NO_x and one for minimum particulate, the impact of NO_x reduction efforts on particulate depends upon the swirl ratio in the "uncontrolled" burner and the relationship between the two optima.

Since smoke and particulate emissions tend to increase as the available oxygen is reduced, the degree to which the excess air can be lowered to control NO_x is usually limited by the onset of smoke. The limiting excess air value depends upon the burner, and many modern systems can operate with as little as 3 to 5 percent excess air.

Off-stoichiometric combustion can be used to control NO_x from large boilers with multiple burners arranged in rectangular matrices. In general, this method employs locally fuel-rich combustion in the burner region. Combustion is then completed as the bulk gases rise to lower temperature regimes and are mixed with additional air.

Off-stoichiometric combustion for NO_x control has been variously achieved through (1) operation of all burners fuel rich with injection of additional air through overfire air ports, (2) operation of the lower array of burners fuel rich with upper burners operated on air only (burners out of service), (3) operation of burners in a fuel-rich or air-rich mode in a staggered pattern (biased firing). The degree to which off-stoichiometric combustion can be employed is frequently limited by particulate emissions which increase as the air supply to the primary fuel-rich stage decreases. To suppress particulate emissions it is crucial that the second stage air be well mixed with the primary stage products and that the residence time following mixing of second stage air be sufficient for carbon and CO burnout prior to quenching. It is particularly important to maintain the burners in good condition when operating them fuel-rich to avoid smoke and high particulate emissions.

Flue gas recirculation tends to decrease both NO_x and particulate emissions; hence, the use of this technique to comply with a NO_x limit should not interfere with attempts to reduce particulate emissions. The last technique, reduced wall temperatures, is probably the least likely to be used, which is fortunate because it increases particulates as it reduces NO_x.

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SECTION 3

FUEL OIL UTILIZATION AND IMPACT ON EMISSIONS

In order to properly assess the problem of particulate emissions from oil-fired furnaces and boilers, it is necessary to look at the types and quantities of oils used today and the impact of their utilization on particulate emissions. Therefore, we discuss below the availability and costs of various fuel oils, their properties and property variations, their impact on particulate emissions and the potential effects of fuel oil additives and pretreatment.

3.1 FUEL OIL PROPERTIES, AVAILABILITY, AND COSTS

The various grades of fuel oil available today are No. 1, No. 2, No. 4, No. 5 (light) No. 5 (heavy), and No. 6. The first two are distillates; the last three, residual oils. Grade No. 4 oil can be a distillate or a mixture of distillate and residual oils (Reference 3-24). These oils are classified according to their physical characteristics by the specifications in ASTM standard D-396. These specifications are presented in Table 3-1. Even though refiners and suppliers have agreed to conform to these specifications (see footnote g in Table 3-1), there are still wide variations in the properties of U.S. fuel oils. Table 3-2 shows the ranges of some selected fuel oil properties. These ranges change only slightly from year to year. From Table 3-2 it is evident that fuel oil properties can vary from below the minimum to above the maximum limits set forth in Table 3-1.

The amount of sulfur in fuel oils is related to the crude oil from which they are derived and to the additional processing they receive. These factors are responsible for the rather wide variation in the sulfur content of available fuel oils (see Table 3-2). Although the sulfur limit proposed by ASTM for Nos. 1 and 2 oil is 0.5 percent unless local regulations specify a lower level (see Table 3-1), the sulfur content of the distillate oils burned in most states is well below 0.5 percent. From Table 3-2, in 1975 an average sulfur content for No. 2 oil, for example, was 0.23 percent.

With the advent of oil desulfurization processes, the refining industry can produce low sulfur residuals at some increase in cost but not in unlimited quantities. Desulfurization to a level between 0.3 and 1.0 percent requires an equivalent of 3 to 6 percent of the quantity of oil desulfurized as energy for the desulfurization process (References 3-26 and 3-27). Oils with such low

TABLE 3-1. DETAILED REQUIREMENTS FOR FUEL OILS[a]

Grade of Fuel Oil	Flash Point, deg F (deg C)	Pour Point, deg F (deg C)	Water and Sediment, volume percent	Carbon Residue on 10 percent Bottoms, percent	Ash, weight percent	Distillation Temperatures, deg F (deg C): 10 percent Point	Distillation Temperatures, deg F (deg C): 90 percent Point		Saybolt Viscosity, s[e]: Universal at 100 F (38 C)		Saybolt Viscosity, s[e]: Furol at 122 F (50 C)		Kinematic Viscosity, cSt[e]: At 100 F (38 C)		Kinematic Viscosity, cSt[e]: At 122 F (50 C)		Gravity, deg API	Copper Strip Corrosion	Sulfur, percent
	Min	Max	Max	Max	Max	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Max
No. 1 A distillate oil intended for vaporizing pot-type burners and other burners requiring this grade of fuel	100 or legal (38)	0[c]	0.05	0.15	...	420 (215)	...	550 (288)	...	...	...	...	1.4	2.2	...	...	35	No. 3	0.5 or legal
No. 2 A distillate oil for general purpose heating for use in burners not requiring No. 1 fuel oil	100 or legal (38)	20[c] (−7)	0.05	0.35	...		540[c] (282)	640 (338)	(32.6)	(37.9)	...	...	2.0[c]	3.6	...	...	30	...	0.5[b] or legal
No. 4 Preheating not usually required for handling or burning	130 or legal (55)	20[c] (−7)	0.50	...	0.10	...	...	...	(45)	(125)	...	...	5.8	26.4[g]	...	...	...	...	legal
No. 5 (Light) Preheating may be required depending on climate and equipment	130 or legal (55)	...	1.00	...	0.10	...	...	...	(>125)	(300)	...	...	>26.4[g]	65[g]	...	...	...	...	legal
No. 5 (Heavy) Preheating may be required for burning and, in cold climates, may be required for handling	130 or legal (55)	...	1.00	...	0.10	...	...	...	(>300)	(900)	(23)	(40)	>65	194[g]	(42)	(81)	...	...	legal
No. 6 Preheating required for burning and handling	140 (60)	[h]	2.00[f]	...	...	...	...	...	(>900)	(9000)	(>45)	(300)	...	...	>92	638[g]	...	...	legal

[a] It is the intent of these classifications that failure to meet any requirement of a given grade does not automatically place an oil in the next lower grade unless in fact it meets all requirements of the lower grade.

[b] In countries outside the United States other sulfur limits may apply.

[c] Lower or higher pour points may be specified whenever required by conditions of storage or use. When pour point less than O F is specified, the minimum viscosity for Grade No. 2 shall be 1.8 cSt (32.0 s. Saybolt Universal) and the minimum 90 percent point shall be waived.

[d] The 10 percent distillation temperature point may be specified at 440 F (226 C) maximum for use in other than atomizing burners.

[e] Viscosity values in parentheses are for information only and not necessarily limiting.

[f] The amount of water by distillation plus the sediment by extraction shall not exceed 2.00 percent. The amount of sediment by extraction shall not exceed 0.50 percent. A deduction in quantity shall be made for all water and sediment in excess of 1.0 percent.

[g] Where low sulfur fuel oil is required, fuel oil falling in the viscosity range of a lower numbered grade down to and including No. 4 may be supplied by agreement between purchaser and supplier. The viscosity range of the initial shipment shall be identified and advance notice shall be required when changing from one viscosity range to another. This notice shall be in sufficient time to permit the user to make the necessary adjustments.

[h] Where low sulfur fuel oil is required, Grade 6 fuel oil will be classified as low pour (60 F max) or high pour (no max). Low pour fuel oil should be used unless all tanks and lines are heated.

TABLE 3-2. RANGES OF SELECTED FUEL OIL PROPERTIES*

	Fuel Oil Grade	
	No. 2	No. 6
Gravity, °API	30.0 - 46.8	2.4 - 25.7
Viscosity at 100°F, cST	1.3 - 3.6	32 - 750
Sulfur Content, wt. %	0.004 - 0.51	0.23 - 3.15
Carbon Residue[a], wt. %	0.005 - 0.31	0.35 - 18.0
Ash Content, wt. %	—	0 - 0.15

[a]Carbon residue on 10 percent bottoms for No. 2 and on 100 percent for No. 6.

*Source: Compiled from data for 1975 in References 3-23 and 3-25.

sulfur content are used, for example, in some areas of the northeast. Boiler operators are required to burn these low sulfur oils to reduce SO_2 emission; as will be discussed later (subsection 3.3.1), there is no unique relation between sulfur content and particulate emissions.

Approximately 70 percent of the U.S. domestic crude is low sulfur (less than 1 percent). Venezuelan and Middle Eastern crudes, on the other hand, are generally sour (greater than 1 percent sulfur). The Bureau of Mines publishes monthly statistics on fuel availability by surface level (Reference 3-31).

Recent prices for various grades and sulfur levels of fuel oils are presented in Table 3-3. The No. 6 oil price ranges in this table were used to produce the curve shown in Figure 3-1. It is clear from this figure that the prices for No. 2 and No. 6 oil are comparable only for residuals with a sulfur content less than about 0.5 percent. In order to show delivered fuel prices, we present in Table 3-4 recent tank wagon prices in Chicago. Note that the distillate oil prices in this table are higher than those presented in Table 3-3.

Owing to the increasing scarcity in some areas (e.g., New Jersey, Boston, etc.) of naturally low sulfur resid and the greater cost of desulfurized residual oil, limits on the sulfur content of this oil could be relaxed in the near future.

According to the most current data on U.S. annual fuel consumption, use in oil-fired furnaces and boilers comprises approximately two-thirds of the domestic demand (4.5×10^{10} gal/yr) for distillate oil and virtually all of the demand (4.0×10^{10} gal/yr) for residual oil (References 3-2 and 3-3).* The remaining demand for these fuel oils consists of on-highway, off-highway, railroad, vessel bunkering and miscellaneous uses (Reference 3-4). Table 3-5 shows the annual fuel consumption for the four user categories of oil-fired furnaces and boilers in the U.S.

The following subsections present data on the grades of fuel oil burned in each of the four user categories, and discuss for each category the effects of fuel oil properties, additives and pretreatment on particulate emissions.

3.2 RESIDENTIAL UNITS

Virtually all oil-fired residential units burn distillate oil. (Residual-fired residential units are classified as commercial for this study.) No. 1 distillate is used in burners which prepare the fuel for burning solely by vaporization, while No. 2 oil is used in burners which prepare the fuel for burning by a combination of vaporization and atomization. The majority of residential units are fired with No. 2 oil (see Table 3-6).

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*Distillate is used in this study to mean ASTM Grades No. 1, No. 2 and No. 4. Residual refers to ASTM Grades No. 5L, No. 5H and No. 6.

TABLE 3-3. FOB REFINERY OR TERMINAL PRICES FOR SELECTED U.S. OIL TERMINALS[a]
(IN CENTS PER GALLON — FEBRUARY 27, 1976)

Grade	New York	Chicago	Carolinas	So. East Terminals	Philadelphia
No. 1	31.75 - 33.50	31.00 - 33.50	32.25 - 33.30	32.00 - 33.05	31.60 - 32.50
No. 2	30.75 - 32.50	30.00 - 32.00	30.50 - 32.55	30.25 - 32.30	30.60 - 31.50
No. 4	31.79 - 33.21 (0.3)[b]	—	28.57 - 29.31 (1.1)[b]	28.57 - 29.31 (1.7)[b]	30.48 - 31.79 (0.3)[b]
No. 5	—	30.00 - 30.25 (1.0)	27.02 - 27.74 (2.1)[b]	28.57 - 29.52 (1.5)[b] 26.90 - 27.74 (2.1)[b]	—
No. 6	31.31 - 32.14 (0.3)[b] 28.45 - 28.93 (1.0)[b]	29.00 - 29.25 (1.0)	24.76 - 25.36 (2.4)[b]	24.76 - 25.00 (2.4)[b]	30.12 - 30.95 (0.5)[b] 27.50 - 28.57 (1.0)[b]

[a]The numbers in parentheses correspond to the maximum percent sulfur in the fuel at the quoted price.

[b]The original quoted prices were converted from dollars per barrel to cents per gallon to obtain these values.
Source: Reference 3-5.

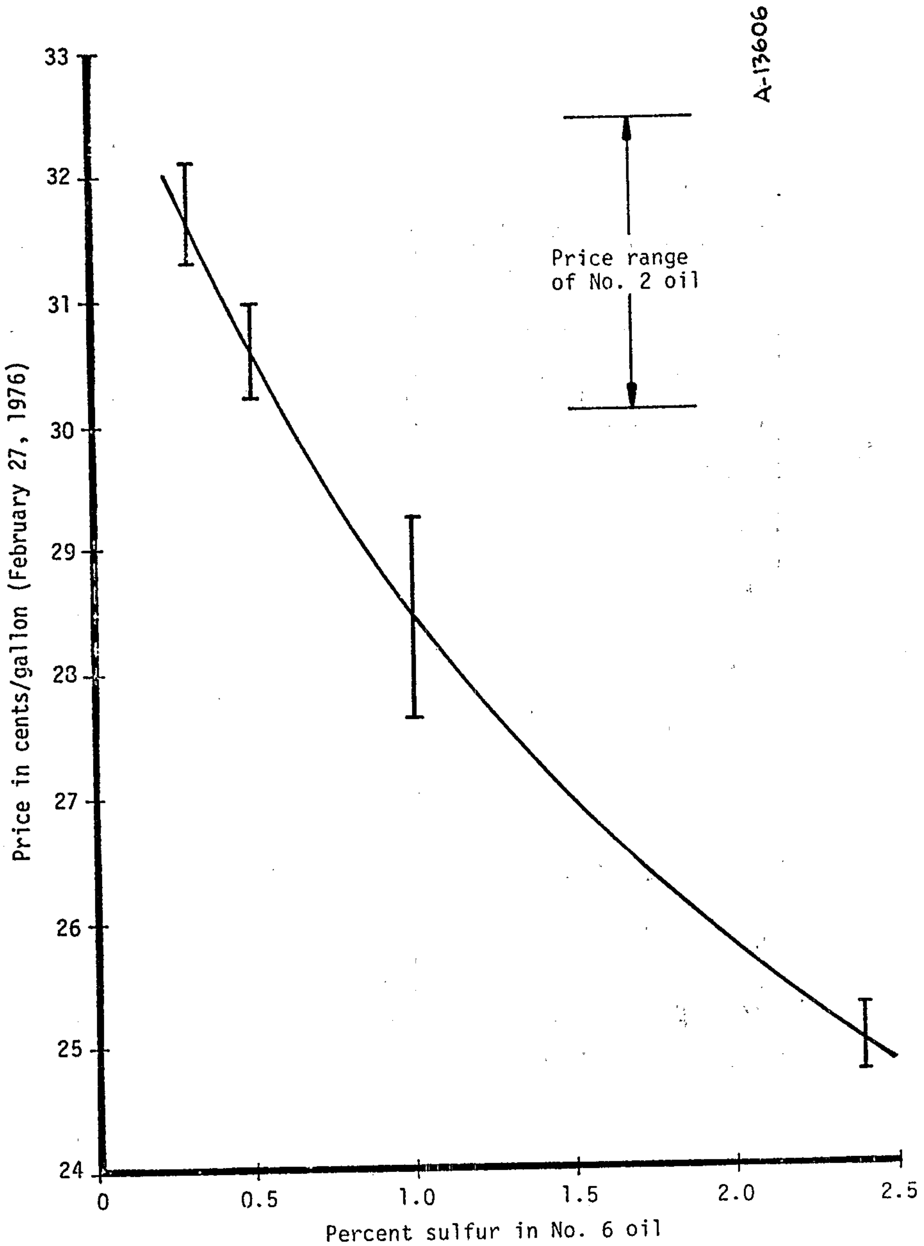

Figure 3-1. Price ranges of No. 6 fuel oil versus sulfur content.

TABLE 3-4. CHICAGO TANK WAGON PRICES (IN CENTS PER GALLON) FOR FEBRUARY 27, 1976[a]

Grade	Minimum Size Shipment (gallons)	Price (cents/gallon)
No. 1	150	39.5
No. 2	400	37.2
No. 5	1500	31.9 (1.0)
No. 5L[b]	6000	30.0 (1.0)
No. 5H[b]	6000	29.5 (1.0)
No. 6[b]	6000	29.0 (1.0)

[a]The numbers in parentheses correspond to the maximum percent sulfur in the fuel at the quoted price.

[b]The prices quoted for these oils are truck transport prices.

Source: Reference 3-5.

TABLE 3-5. U.S. DISTILLATE AND RESIDUAL FUEL OIL CONSUMPTION BY USER CATEGORY (10^{10} GAL/YR)[a]

	Residential	Commercial	Industrial	Utility	Total
Distillate	1.48	0.77	0.74	0.09	3.08
Residual	—[b]	0.73[b]	1.28	1.98	3.99
Total	1.48	1.50	2.02	2.07	7.07

[a]See Appendix C for conversion to SI units.

[b]Residual-fired residential units are classified as commercial for this study.

Source: Reference 3-2.

TABLE 3-6. CONSUMPTION OF ASTM FUEL OIL GRADES FOR HEATING IN RESIDENTIAL AND COMMERCIAL UNITS[a]

	Residential 10^{10}gal/yr	Commerical 10^{10}gal/yr	Residential + Commercial 10^{10}gal/yr
No. 1	0.037 (25)[b]	--	0.37 (12)
No. 2	1.11 (75)	0.67 (45)	1.78 (60)
No. 4	--	0.10 (7)	0.10 (3)
Total Distillate	--	0.15 (10)	0.15 (5)
No. 5	--	0.15 (10)	0.15 (5)
No. 6	--	0.58 (38)	0.58 (20)
Total Residual	--	0.73 (48)	0.73 (25)
Totals	1.48 (100)	1.50 (100)	2.98 (100)

[a]See Appendix C for conversion to SI units.

[b]Numbers in parentheses are approximate percent of totals.

Source: Compiled from data in References 3-2 and 3-5.

The latest particulate emission factor for distillate fired residential units (Reference 3-1) is 0.018 lb/mBtu (7.74 ng/J).* Using the distillate fuel oil consumption given in Table 3-6 for residential units, the total particulate emission rate amounts to 18.5 x 10^3 tons/yr.

3.2.1 Impact of Fuel Oil Properties on Particulate Emissions

The impact of fuel on emissions from oil-fired residential systems was studied in detail by Barrett, et al. (Reference 3-6) for the E.P.A. and A.P.I. The program covered emissions from 33 residential heating units and included the effects of various fuel oil compositions.

No significant difference in particulate measurements was found by firing a wide range of No. 2 oils. The A.P.I. gravity of the oils ranged from 30 to 37, sulfur from 0.05 to 0.3 percent, and carbon residue from 0.1 to 0.3 percent. The influence of fuel gravity on emissions varied, depending on whether the unit was tested in an as-found or tuned condition. For units in the as-found condition, lighter fuels produced lower smoke and total particulate, but heavier No. 2 fuels produced lower filterable particulate emissions. For tuned units, however, the heavier fuels produced less smoke and filterable particulate but more total particulate. Thus, if a unit is well-tuned, a change to a heavier No. 2 will not automatically cause an increase in smoke or solid particulate emissions.

3.2.2 Impact of Fuel Oil Additives and Pretreatment on Particulate Emissions

The effect of additives to distillate oils on pollutant emissions has been investigated in numerous studies (cf, References 3-7 to 3-11). Fuel oil additives have aroused considerable interest as they provide one expeditious remedy to the problem of smoke emissions. Martin, et al. (Reference 3-8) screened and tested over 200 distillate oil additives and found that only 17 reduced particulate emissions. Of these 17, only 7 were identified as substantially reducing total particulate emissions. In these cases, total particulate was reduced by 30 to 50 percent (see Table 3-7). From this study it was concluded that only metallic additives containing cobalt, iron or manganese appreciably decrease particulate emissions from distillate oil-burning units. However, the unknown toxicity of the metallic emissions produced from these additives makes their use questionable. Although the iron oxides which are emitted when iron based additives are used are not considered to be toxic by themselves, "recent study suggested that these oxides may combine with POMs in the ambient air to form a potentially carcinogenic substance" (Reference 3-28).

*Assuming 140,000 Btu/gal distillate

TABLE 3-7. DISTILLATE FUEL-OIL ADDITIVES THAT SUBSTANTIALLY REDUCED TOTAL PARTICULATE EMISSIONS[a]

Additive	Concentration		Composition	Total particulate with additive/total particulate without additive
	Weight	Molar[b]		
Arapahoe Ferrocene	1:7150	0.50	20% Fe	0.53
Ethyl CI-2	1:9000	0.36	18.0% Mn	0.56
Commercial Chemical Improsoot	1:150	0.50	0.3% Ca 0.1% Ca	0.57
Gamlen DP231	1:110	0.50	0.2% Mn 0.1% Fe	0.61
Fuel Combustion Corp. Fuelco SO_3	1:500	0.10	0.25% Mn	0.64
Commercial Chemical Formula LSD	1:200	0.40	0.9% CO	0.68
Industrial Chemicals Watco 130	1:500	0.05	0.15% Fe	0.69

[a]Source: Reference 3-8.

[b]Millimoles per kilogram

The influence of additive concentration is also very important. For example, the effect of concentration on particulate emissions for the Ethyl CI-2 additive is shown in Figure 3-2. From this figure we see that total particulate emissions can decrease with increasing additive concentration up to a point. Beyond this point, even though the carbon particulate continues to decrease, the total particulate emissions increases as a result of the increasing concentration of additive.

Other tests on the effects of distillate additives on particulate emissions produced similar results (cf, References 3-7, 3-10, and 3-12). At a given operating condition, the use of certain metallic additives can reduce the amount of particulate emitted from a distillate oil burner. However, burner modifications can produce an even greater reduction in particulate. The unknown toxicity of the new emissions which these metallic additives create makes their immediate and widespread use questionable. The cost of the additive required to achieve a 35 percent reduction is 0.3 to 3 cents per gallon. This corresponds to a 0.7 to 7 percent fuel cost increase to the consumer (based on additive costs ranging from \$0.60 to \$10 per pound) or about \$3.00 to \$30.00 per year (Reference 3-8).

In addition to additives for improving combustion and reducing pollutant emissions, other additives are frequently used to improve noncombustion functions, e.g., storage stability, handling characteristics, etc. In most cases, however, these additives do little to influence particulate emissions from distillate oil-burning residential units (cf, Reference 3-8).

In a recent study conducted by Hall (Reference 3-11), the effect of water/distillate oil emulsions on pollutants from residential heating systems was investigated during tests on a residential sized warm air furnace. When firing the water in oil emulsion, slightly higher Bacharach smoke numbers were measured, whereas the furnace heating efficiency remained unchanged and NO_x decreased as the water percentage increased. The percent water in the emulsion varied from 0 to 32.

3.3 COMMERCIAL UNITS

Both distillate and residual oils are fired in commercial systems (see Table 3-6). Fuel grades No. 2 through No. 6 are used, with distillates and residuals being almost equally in demand. No. 4 oil is used in some schools and apartment buildings and in situations where the equipment cannot handle higher viscosity oils such as No. 5 or No. 6.

The latest particulate emission factors for commercial units and the corresponding total emission rates using the data of Table 3-6 are presented in Table 3-8.

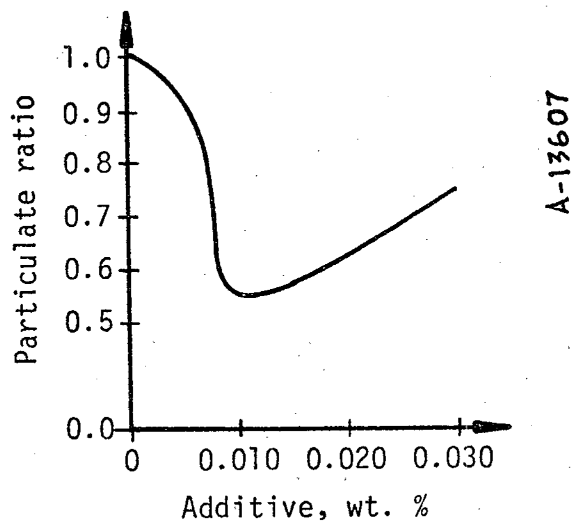

Figure 3-2. Particulate ratio (particulate with additive/particulate without additive) versus CI-2 additive concentration (Reference 3-8).

TABLE 3-8. PARTICULATE EMISSION FACTORS AND TOTAL EMISSION RATES FOR COMMERCIAL UNITS[a]

ASTM Fuel Oil Grade	Emission Factor lb/MBtu (ng/J)	Annual Emission Rate[b] 10^3 tons/hr
No. 2	0.014 (6.02)	6.7
No. 4	0.050 (21.5)	3.5
No. 5	0.067 (28.8)	7.5
No. 6	0.067S + 0.02 (28.8S + 8.6)[c]	37.7[d]
Total	--	55.4

[a]Emission factors assume 140,000 Btu/gal distillate and 150,000 Btu/gal residual.

[b]These values were obtained by multiplying the emission factors by the fuel consumption data in Table 3-6. See Appendix C for conversion to SI units.

[c]S = percent by weight sulfur in fuel.

[d]For purposes of illustration, S was chosen as 1.0 percent

3.3.1 Impact of Fuel Oil Properties on Particulate Emissions

Commercial units were included in the recent study by Barrett, et al. (Reference 3-6) mentioned during the discussion of residential burners. Five types of fuel oils were fired in the commercial boilers, No. 2, No. 4, No. 5, No. 6 and a low sulfur (1 percent) No. 6 (LSR). Significant effects of fuel properties were observed in the commercial boilers. Particulate emissions and smoke increased with increasing fuel grade when the above oils were fired at the same operating conditions. Figure 3-3 illustrates typical curves of smoke versus excess air for one commercial boiler fired at 80 percent load with three oils and natural gas. This figure shows that for existing units neither of the No. 6 oils can reach the low smoke levels obtainable with No. 2. Moreover, even if the goal were to comply with a smoke reading of Bacharach No. 3, residual-fired units would have to use much more excess air than distillate ones and, hence, would operate less efficiently. Since residual oils contain greater amounts of micellular clusters of true organic molecules, one would expect them to tend to burn less efficiently. In addition, heavier oils are higher in molecular weight, have lower percentages of hydrogen and would, therefore, have a greater tendency to coke.

Residual oil typically has an ash content of 0.1 percent. The particulate emissions resulting from highly efficient combustion of residual oil are constituted almost entirely of inorganic ash which occurs as oxides, chlorides or sulfates. Residual oil combustion products, however, are more often found to contain about 50 percent by weight of sooty organic material. Frequently, this material consists of unburned carbonaceous solids which tend to be sticky and hygroscopic. The latter condition probably arises from the presence of calcination products and condensed sulfuric acid (Reference 3-19).

The effects of fuel grade on filterable and total particulate emissions are summarized in Figures 3-4 and 3-5 for all the commercial boilers tested. Ash content tends to be higher for fuels of low API gravity but is not sufficient to account for higher particulate levels with heavier fuels. The band of ash content for the fuels is shown in Figure 3-4. The 1 percent sulfur residual oil (LSR) was closer in performance to a No. 4 or No. 5 oil; it yielded filterable particulate levels about equal to those from No. 4 oil and only one third of those from the No. 6 oil. Low sulfur residuals tend to produce less particulate than straight residual oils, since they form less sulfates, are typically lower in ash content, and have a lower viscosity (thus, better atomization). However, no quantifiable relationship exists between fuel sulfur content and particulate emissions when a wide variety of fuels are considered (see below).

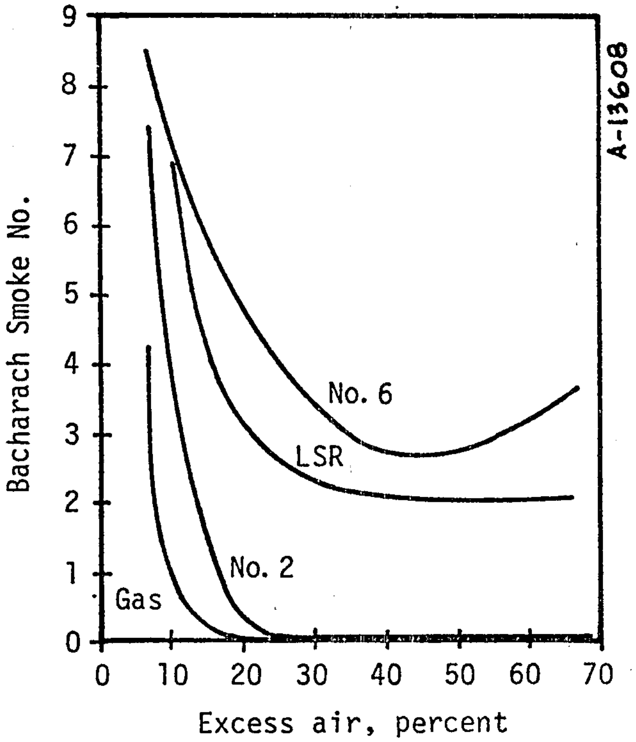

Figure 3-3. Typical characteristics of smoke versus air for an existing commercial boiler firing different fuels (Reference 3-6). New boilers emit less smoke.

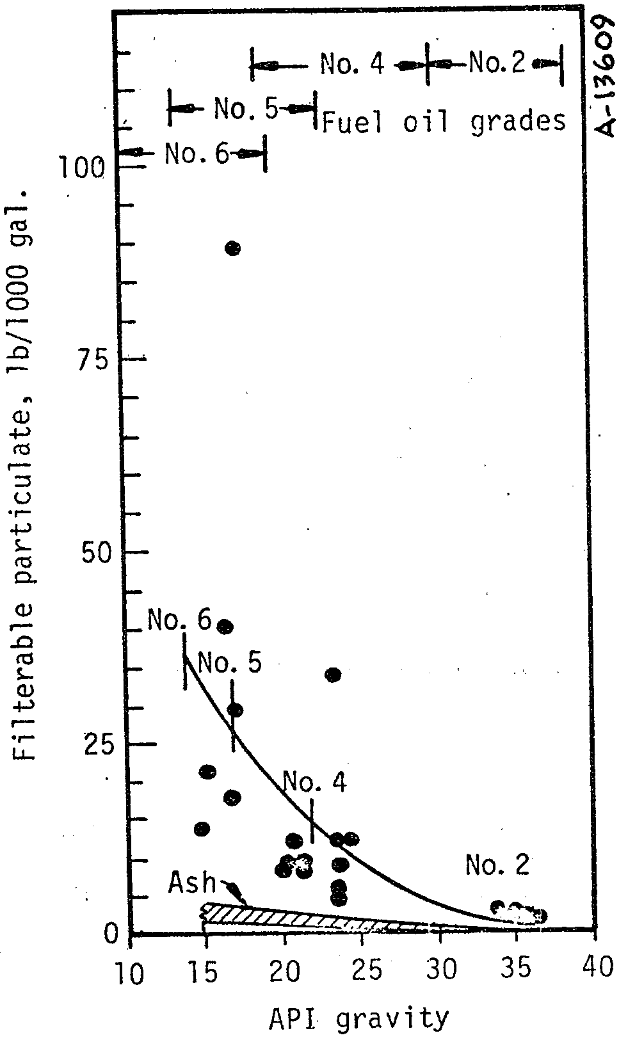

Figure 3-4. Relation of filterable particulate to API gravity for commercial boilers (Reference 3-6).

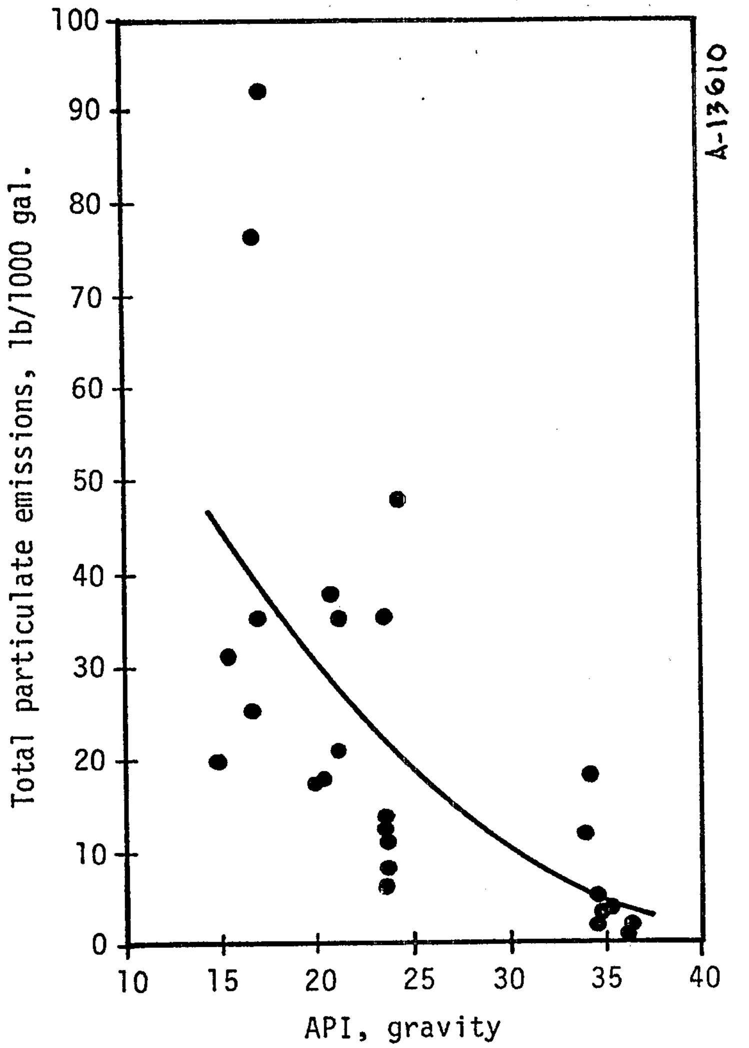

Figure 3-5. Relation of total particulate emissions to API gravity for commercial boilers (Reference 3-6).

A regression analysis performed in this study indicated that the single most important fuel property influencing filterable particulate was carbon residue.* API gravity also had a significant effect, but viscosity at firing temperature was relatively insignificant. An index combining carbon residue, viscosity at firing temperature, carbon content and API gravity yielded a good correlation with filterable particulate (see Reference 3-6). Since carbon residue cannot be reduced by filtering or centrifuging, the only method which can decrease the carbonaceous content of residual oils is mixing or blending with an oil which has a lower carbon residue.

A brief review of the No. 6 fuel oil analyses presented in Reference 3-25, however, shows that there is no direct relationship between sulfur content and carbon residue. Some low sulfur fuels have higher carbon residues than those with higher sulfur content; fuels with essentially the same sulfur content may vary widely in carbon residue, etc.

Desulfurization of a specific high sulfur fuel oil to a lower sulfur level will lower its carbon residue. However, it should be remembered that two high sulfur fuels (of the same sulfur content) will not necessarily have the same carbon residue and thus, even though they are desulfurized to the same sulfur level, there may be an appreciable difference in their final carbon residue contents (Reference 3-29).

Making a residual oil to a specified carbon residue would be unfeasible with current refining practices and equipment. Doing so would require the addition of another process (e.g., vacuum distillation, de-asphalting, etc.) and would result in a product much like a heavy No. 2 oil.

3.3.2 Impact of Fuel Oil Additives and Pretreatment on Particulate Emissions

"Fuel washing" has been suggested as a potential method of reducing particulate emissions from oil-fired furnaces and boilers (Reference 3-18). This process has been developed mainly to pretreat residual oils before firing them in gas turbines. As such it reduces turbine blade damage by removing ash and sediment in the oil (by approximately 70 percent in a typical one percent sulfur residual oil) without altering the viscosity or gravity. However, fuel washing does not remove carbon residue, which is the main source of particulate emissions from well maintained residual oil fired burners. Moreover there are no data (especially in stack emission test results)

*Carbon residue is the amount of carbonaceous residue left after burning a sample of oil in the absence of air (Conradson or Ramsbottom carbon test). The percentage carbon residue does not give an actual value for the formation of carbon or coke in actual practice, but only a relative value of this formation in an improperly designed or inefficiently operated oil burner installation. No trouble should be experienced if the correct grade of oil is used. However, if the oil is causing carbon trouble, this condition can be eliminated by decreasing the carbon residue with blending. Mixing and blending with a No. 2 oil, which has very little carbon residue, or with any oil that has less carbon residue than the troublesome fuel, will reduce the total carbon residue.

that demonstrate the effectiveness of the washing technique in reducing particulate stack emissions.

The effects of additives on smoke and particulate emissions from distillate oil-fired units were discussed in the section on residential boilers and furnaces. Additives for residual fuels also have been studied by a number of investigators (e.g., References 3-10, 3-12, 3-14, 3-17). One study found that chelates of iron and cobalt, and also hydrazine, reduced smoke in heavy fuel oils. The additives were used in rather high concentrations, ranging from 0.01 to 0.1 percent. Iron chelate was most effective. At a concentration of 0.01 percent it reduced Bacharach smoke number from 2.6 to 0.6. Other additives achieving varying degrees of smoke reduction were manganese compounds, copper, iron, and maganese inorganic salts, and organic compounds.

Fuel oil additives can produce additive-fuel interactions resulting in the formation of solids which could plug up the system. These interactions are so sensitive to the fuel properties that when one simply changes to a different refiner's product of the same grade or when different sources of crude are refined by the same refinery, these interaction problems can easily occur. It therefore seems necessary for the fuel supplier to demonstrate the compatibility of a particular additive with his fuel before adding the additive to the fuel.

A study on the effectiveness of additives in reducing particulate emissions from commercial boilers was recently performed by Battelle (Reference 3-30). It was observed that additives containing certain alkaline-earth and transition metals in concentrations in the range 20 to 50 ppm in residual oil were effective in reducing carbon particulate by as much as 90 percent. While similar low carbon particulate performance can be achieved with good burner design and adjustment, these results suggest that additives might be considered as a candidate control technique of the "insurance type" for the many commercial and small-industrial boilers operating in the field that are marginal in design or do not get the needed service adjustment. Thus, it may be possible for additives to give some tolerance to "sloppy adjustments."

Even though smoke-reducing additives may decrease visible emissions and, at the same time, not cause any adverse side effects on operation, environmental health considerations make the use of additives in commercial boilers questionable at this time. Further studies on these problems are needed and are currently underway. Thus, the use of these additive materials might create potentially harmful new emissions (even though total emissions might decrease); and therefore, none of the additives can be recommended as a means of controlling particulate emissions without further investigation.

In two recent studies by Hall (References 3-11 and 3-15), the effects of water/distillate and water/residual oil emulsions on pollutants from commercial heating systems were investigated. In general, both types of emulsions reduced smoke (see Figures 3-6 and 3-7) and total particulate from a packaged commercial boiler using (1) low pressure air atomization and an ultrasonic energy emulsifier and (2) high pressure mechanical atomization and a high pressure emulsifier. The energy requirements for emulsification are generally less than one percent of the energy content of the fuel to be emulsified.

In the distillate case, an emulsion with 25 percent water allowed the first unit to run with approximately 4 percent less excess air without increasing smoke emissions, but the resulting gain in thermal efficiency was offset by heat lost to vaporization of the water, water supply problems and emulsifier energy requirements. When firing residual oil, the emulsification results depended significantly on the emulsifier used, and baseline (oil only) results varied due to the different atomization technique used. Only the 25 percent emulsification test data reached as low a smoke level as Bacharach No. 3, and this only at about 40 percent excess air. The boiler's smoke intensity tends to stabilize at about Bacharach No. 6 beyond 40 percent excess air when firing only residual oil (no water); it could achieve the same smoke level with only 15 percent excess air if it burned a 25 percent emulsification. If the burner were operated on oil only at this last air-to-fuel ratio, its smoke level would be near Bacharach No. 8, which is marginally visible, depending upon the character of the plume. In conclusion, emulsification of a residual oil can enable a unit to achieve a significantly lower Bacharach No. than it could without emulsification, or to achieve an equivalent Bacharach No. with significantly less excess air.

3.4 INDUSTRIAL UNITS

Over 60 percent of the fuel oil used in industrial boilers is residual. Of the residual oils, No. 5 (light) usually does not need preheat, while No. 5 (heavy) and No. 6 do require it. Virtually all the distillate used in the industrial sector (see Table 3-5) is No. 2. The EPA particulate emission factors for industrial boilers are identical to those for commercial units and are given in Table 3-8.

3.4.1 Impact of Fuel Oil Properties on Particulate Emissions

The effects of fuel on particulate emissions from uncontrolled* oil-fired industrial boilers were investigated in a comprehensive field testing study (Reference 3-16). Industrial boilers firing

*No particulate control devices

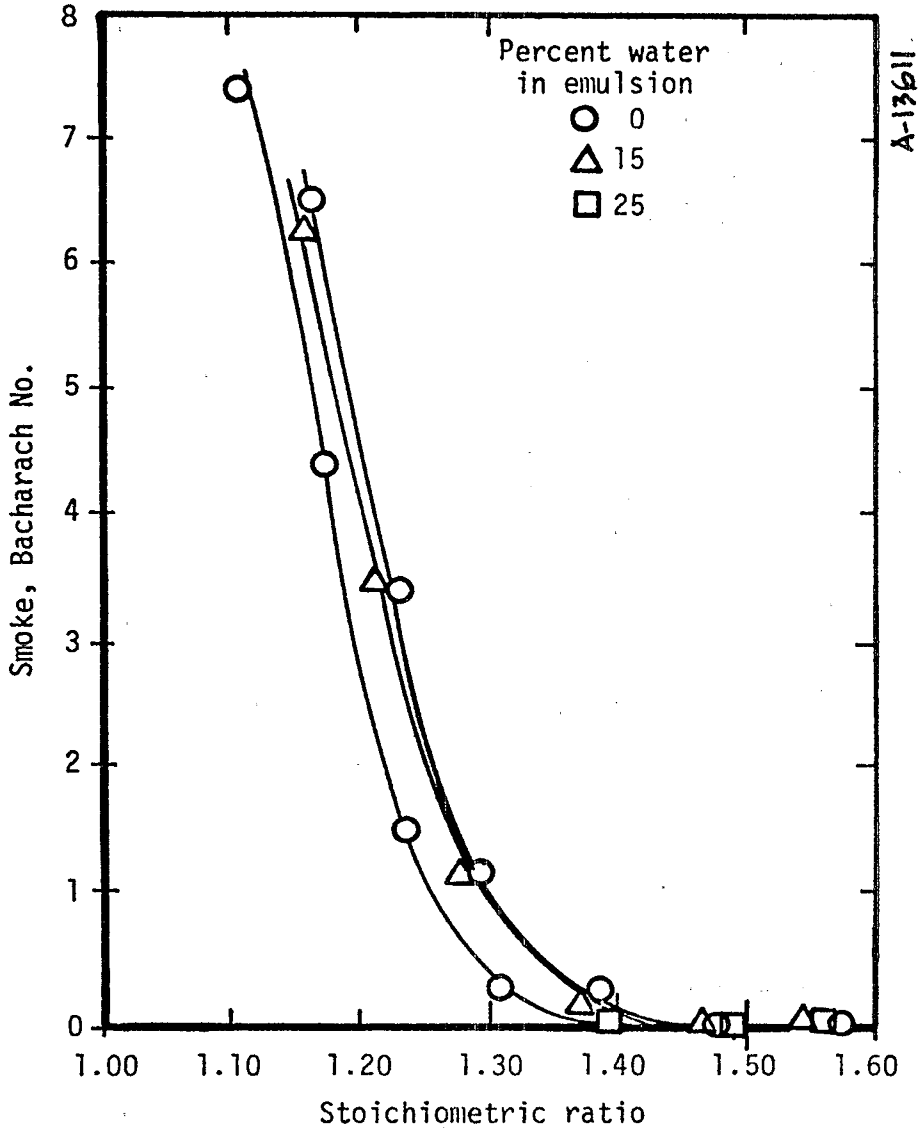

Figure 3-6. Smoke emissions versus stoichiometric ratio for water/distillate oil-fired commercial boiler (Reference 3-11).

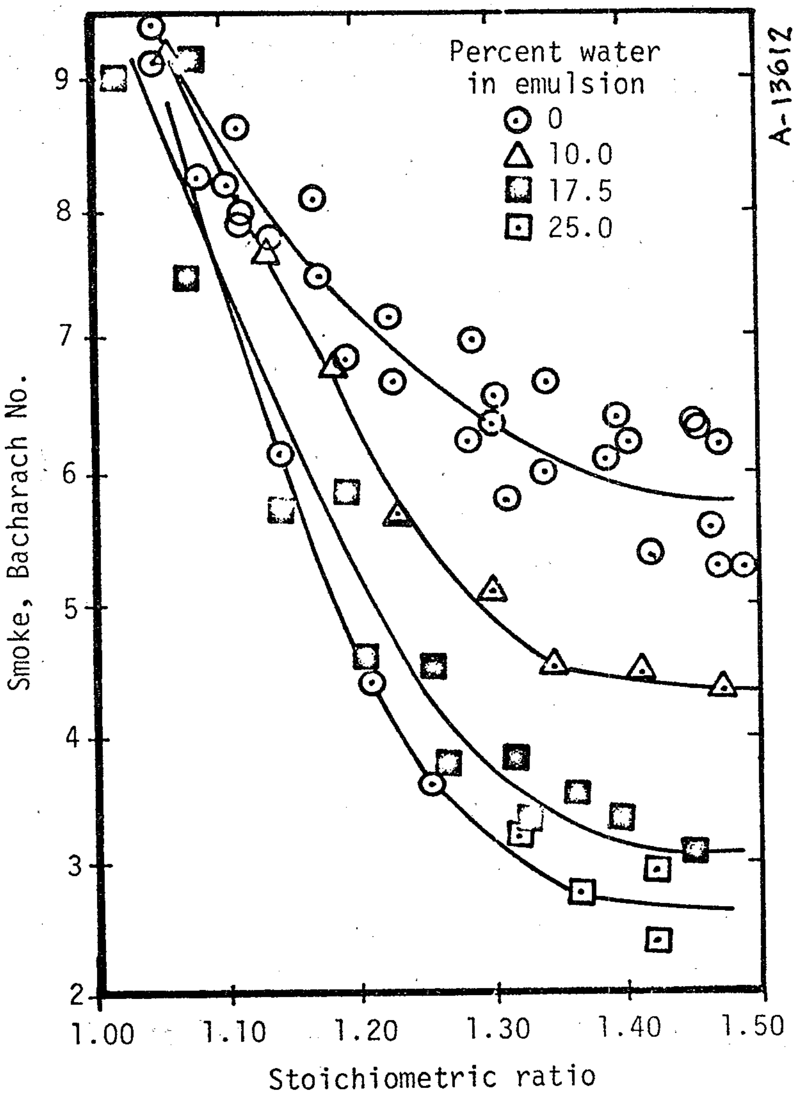

Figure 3-7. Smoke emissions versus stoichiometric ratio for water/residual oil-fired commercial boiler (Reference 3-15). Newer units emit less smoke.

a variety of Nos. 2, 5 and 6 fuel oils were included in the sample. The emission tests with No. 2 oil resulted in particulate levels of 0.02 to 0.04 lb/MBtu (8.6 to 17.2 ng/J), those with No. 5 oil 0.04 to 0.12 lb/MBtu (17.2 to 51.6 ng/J), and those with No. 6 oil 0.045 to 0.11 lb/MBtu (19.3 to 47.3 ng/J). Emission rates decreased with increasing size for steam atomized boilers fired with No. 6 oil (from about 0.1 lb/MBtu (43 ng/J) at 50 MBtu/hr (14.6 MW) to 0.05 lb/MBtu (21.5 ng/J) at 130 MBtu/hr (38.1 MW)). However, for units that burned No. 2 or No. 5 oil, the emission rates appeared to be more a function of atomizing type than of size. Particulate emissions were also found to increase as the carbon residue of the oil increases (see Figure 3-8).

A limited amount of particle size classification was also performed in these tests. For No. 6 fuel oil, over half the number of particles were less than 4 microns in diameter, and about 90 percent of the particles had diameters less than 6 microns. All particles were less than 50 microns. Thus, most of the particulate is in the respirable range, 0.5 to 5.0 microns.

3.4.2 Impact of Fuel Oil Additives and Pretreatment on Particulate Emissions

The impact of additives on particulate emissions from industrial boilers has been investigated only to the extent that other distillate and residual oil-fired units have been studied. Some of these studies were discussed in the two sections on residential and commercial units.

Magnesium oxide, manganese, and combinations of the two have been used as fuel oil additives to prevent corrosion and slagging in industrial and utility boilers. The specific choice of additive depends upon the needs of the particular boiler, as well as environmental considerations. These additives are used when required to control corrosion even though they generally cause total particulate emissions to increase.

Fuel washing may offer one possible solution to the problem of corrosion (thus, no metal containing additives would be necessary and no new emissions would be created). Vanadium, one of the primary substances in oil responsible for corrosion, is slightly water soluble. Thus, it may be possible to decrease the vanadium content of oils by fuel washing. This, of course, remains to be tested. Fuel washing was discussed in more detail in Section 3.3.2.

3.5 UTILITY UNITS

The major grade of fuel oil burned in utility boilers is No. 6, with lesser quantities of No. 5, No. 4 and No. 2 used (see Table 3-5). A few utility boilers today burn crude oil instead of the refined products.

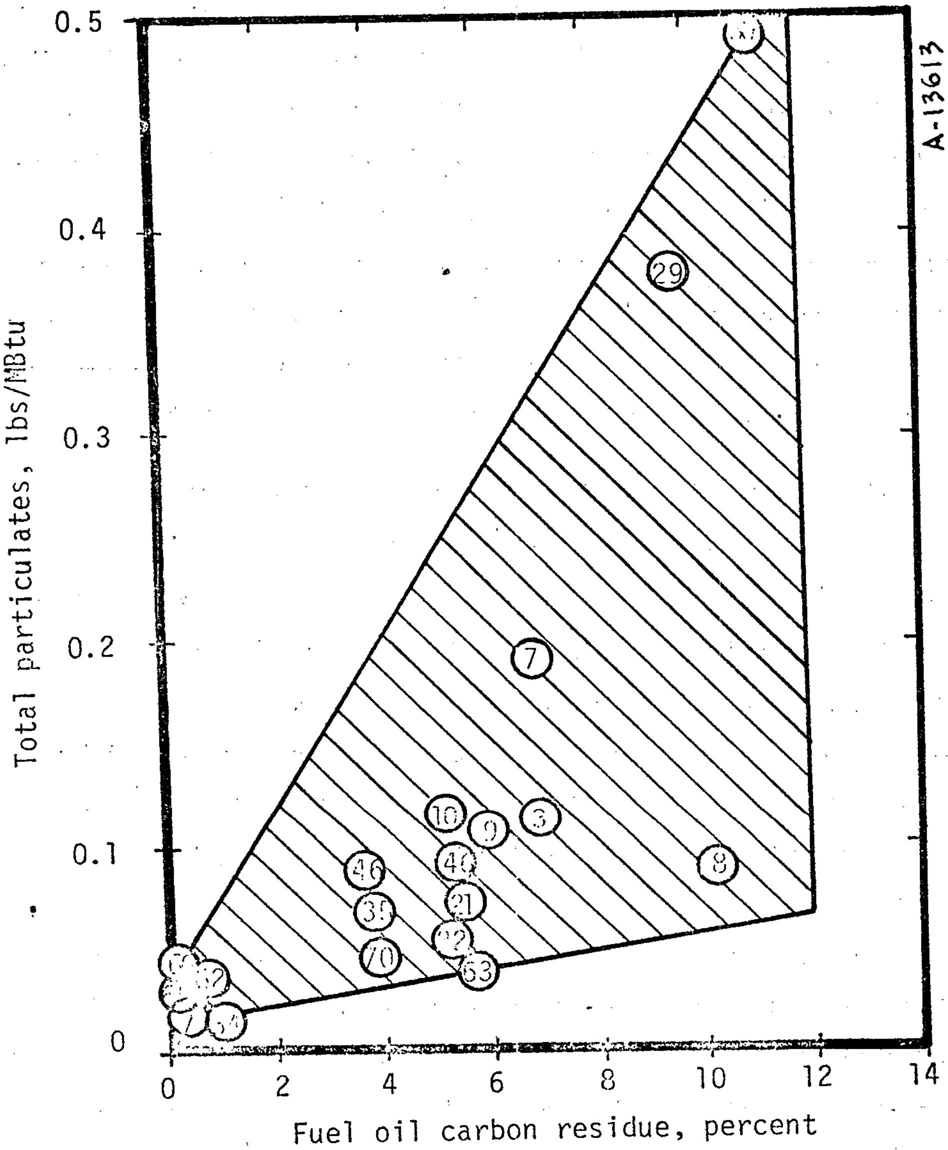

Figure 3-8. Effect of fuel oil carbon residue on particulate emissions from industrial boilers (Reference 3-16; numbers for identification in original test program).

Approximately 55 percent of the oil consumed by utility boilers is burned in units that are equipped with particulate control devices (Reference 3-19). The EPA particulate emission factors for utility boilers are identical to those for commercial systems, and are presented in Table 3-8. These, of course, are average uncontrolled emission rates that assume some mix of controlled and uncontrolled units; emission rates from controlled boilers will of course, be less.

3.5.1 Impact of Fuel Oil Properties on Particulate Emissions

Since the oils fired in utility boilers are the same as those fired in industrial boilers, one might to expect to find the same dependence of particulate emissions on API gravity as that discussed in Section 3.4. One recent study (Reference 3-19) investigated the effects of fuel ash and sulfur and fuel additives on particulate emissions from utility boilers. It has been postulated that increased sulfur in the fuel can lead to increased SO_3 adsorption, and hence, a greater mass accumulation on particulate sampling filters. The net result would appear as an increased solids emission rate. However, no positive correlation between sulfur content and particulate emissions was found in the data taken from both controlled and uncontrolled power plant boilers in the size range over 70 MW_e.* In addition, no correlation was found between fuel ash content and particulate emissions from controlled boilers. This was partly due to the fact that organic material (carbon residue) may have constituted a large fraction of the total emissions. As noted in subsection 3.3.1, unburned carbon from this residue can be an important constituent of particulate emissions.

3.5.2 Impact of Fuel Oil Additives and Pretreatment on Particulate Emissions

The effects of fuel oil additives on particulate emissions were also investigated in this study (Reference 3-19). Magnesium and calcium additives are commonly used to improve boiler heat transfer characteristics and reduce corrosion problems, especially when the fuel contains large concentrations of vanadium and sodium (References 3-20 and 3-21). In these cases, additives are the only known means of avoiding serious corrosion problems (other than switching to a lower vanadium fuel). Since desulfurization also reduces the vanadium concentration, low sulfur residual oils can usually be burned without additives. Also, it may be possible to decrease the vanadium concentration by fuel washing (see Section 3.4.2).

By virtue of the fact that they are ash-forming substances, these fuel additives were found to increase the solid particulate emissions from residual oil-fired utility boilers included in Reference 3-19. It was found that sulfates consituted approximately 35 percent of the filterable solids generated by the combustion of high sulfur (>2.5 percent) residual oil using MgO additives.

*A controlled boiler is used here to mean one having a particulate control device (e.g., ESP, scrubber, fabric filter, cyclone, etc.).

If no additive is used, the total sulfate decreases due to SO_3 penetrating the sampling filter, and the sulfate which is captured occurs as sulfuric acid. Figure 3-9 shows the amount of solid particulate as a function of boiler size for both controlled and uncontrolled systems. If one assumes that the efficiencies of the electrostatic precipitators used to control particulate emissions from oil-fired systems are essentially constant, the higher effluent concentrations shown in Figure 3-9 for systems using MgO additives are readily explained.

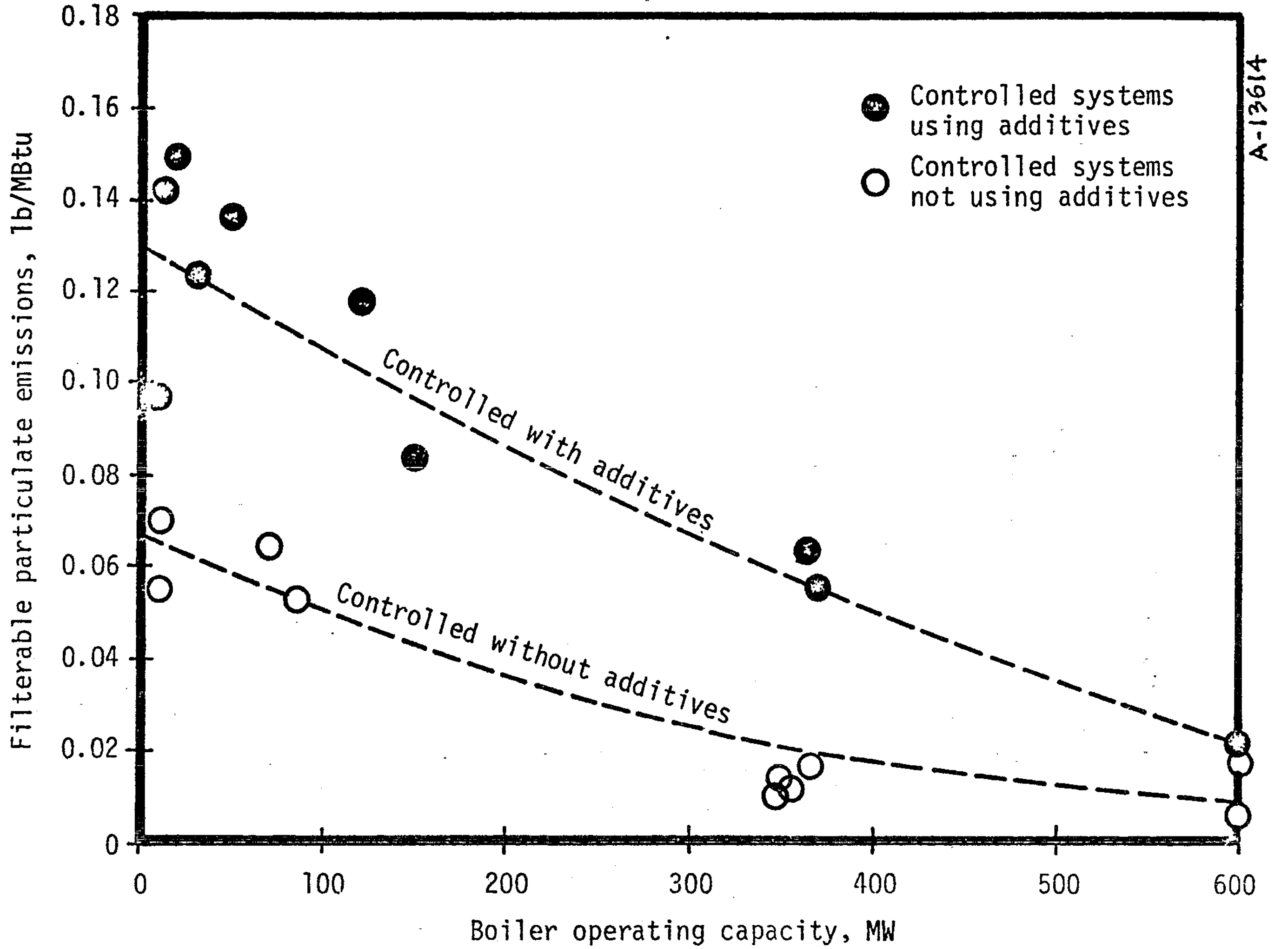

Figure 3-9. Particulate emissions from controlled (after ESP) residual oil-fired utility boilers with and without additives (Reference 3-19).

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SECTION 4

EXISTING CONTROL METHODS FOR PARTICULATE EMISSIONS

A variety of methods are known to reduce particulate emissions from oil-fired boilers and furnaces. For economic, technical, or institutional reasons some of these are not applicable to all the categories of users. For example, since fuel accounts for 80 to 90 percent of the annualized costs of owning and operating a boiler, these units are nearly always well-maintained in order to minimize the consumption of costly fuel. On the other hand, fuel costs may represent only 5 to 10 percent of a homeowner's living expenses (in a cold climate). Therefore, many individuals do not give high priority to activities such as maintenance, which may reduce this cost by 5 to 10 percent. Hence a mandatory periodic inspection and maintenance program could be an effective particulate control tactic if applied to residential, commerical, and small industrial units, but would be less effective for large industrial or utility boilers than are particulate collection devices.

The organization of this section takes these differences into account by discussing separately the controls that have been suggested for each user category. Because we feel that greater emphasis and interest will be placed on control of commercial systems than on residential units, and because the same control techniques are generally recommended for boilers and furnaces in both size categories, we have chosen to discuss particulate controls for commercial systems first. That discussion will be followed by a description of possible controls for residential units, with frequent reference being made to the material just presented for commercial systems. Then we will present a summary of potential control techniques for industrial and utility boilers. Since many of the same techniques are used in both categories, the discussion has been combined in one subsection.

The discussion of each control technique will start with a description of the system and its operating principles. We will then present its reported effectiveness. Any problems that may be associated with the use of this control system and the cost of owning and operating it will be summarized too.

The effectiveness and cost of many, but by far not all, of the control techniques discussed in the literature are well known. For example, some sources claim significant reductions in particulate emissions from specific control techniques, but they do not report emission levels, boiler types on which the unit has been tested, boiler types which cannot accommodate the system, etc. Therefore, we do not have sufficient data to recommend such systems as a particulate control technique. To clearly separate these potentially valuable systems from the currently demonstrated techniques, we include only demonstrated and thoroughly documented technologies in the first subsections under each user category (commercial, residential, and industrial/utility); the last subsection is then devoted to emerging technologies, which includes both these existing, but not fully tested, systems as well as ideas that are currently being developed.

4.1 COMMERCIAL FURNACES AND BOILERS

The most commonly proposed techniques for the control of particulates from commerical oil-fired furnaces and boilers are the widespread implementation of, and adherence to, proper operating and maintenance procedures and the use of new improved burner or combined burner/combustion chamber designs. In the following three subsections, therefore, we discuss the methods and results obtained with proper operation and maintenance procedures (Subsection 4.1.1), with the use of redesigned burners and/or combustion chambers (Subsection 4.1.2), and with dust collectors (Subsection 4.1.3). Subsection 4.1.4 deals with emerging technology. The effects of fuel oil grade variations on particulate emissions have already been discussed in Section 3.

4.1.1 Operation and Maintenance Procedures

Interest in proper operation and maintenance procedures as a particulate control strategy for commercial oil-fired units has received renewed emphasis as a result of recent surveys of the condition of these units in selected northeastern areas (New York — Reference 4-2; Maryland — Reference 4-1). These investigations concluded that many units were not maintained, but that those which were did not emit excessive quantities of particulate. The following three subsections describe the strategy of periodic inspection and proper maintenance as it relates first to the operation of the burner, then to the rest of the system (fuel handling as well as firebox), and finally to the administrative aspects of such a strategy.

4.1.1.1 Burner Tuning or Replacement

Smoking fires, or those with high smoke spot number in the absence of a visible plume, are usually caused by improper burner adjustment, dirty burner cups or nozzles, or damaged burner components (Table 4-1). Several studies have shown that smoke emissions can be reduced significantly by proper burner tuning and replacement of worn or damaged components.

In one of these studies (Reference 4-1) 400 tests were conducted on 310 burner units. Of these, 160 were in residential units that burned distillate, 48 were in commercial units fired with distillate, and the remaining 102 were in commercial units that used residual oil. Measurements were taken of smoke emissions (Bacharach Number), flue gas composition, and temperature before and after the burner units were adjusted. The adjustments included any of the following: replacement or repair of burner nozzle or cup, adjustment of primary or secondary air, repair or replacement of burner parts affecting oil distribution, and repair of the combustion chamber. Of these, nozzle replacement and air flow adjustment were found to have the greatest impact on smoke emissions.

According to this study, the service procedures described above reduced smoke emissions nearly 40 percent. The average Bacharach smoke number for all units was reported to be 2.8 before adjustment and 1.7 afterwards. This post-adjustment figure includes lower values for residential units, an average number of 2.2 for all commercial units (distillate and residual), and a mean reading of 2.6 for all residual fired commercial systems. As mentioned in Section 3, residual-fired units generally emit more particulate matter than do distillate fired burners because of the higher solid carbon content in the oil.

Thermal efficiencies were also determined for each burner unit before and after adjustment. The results from all the units showed that, on the average, only slight improvements were obtained (from 78.2 to 79.2 percent).

Another study (Reference 4-3), undertaken by the City of New York, found similar results. Twenty-seven residual oil burners were tested during this program, and all but three were able to attain stack thermal losses of less than 20 percent and a Bacharach Number no greater than 3 with only minor adjustment. The problems with the remaining three units were attributed mainly to design flaws, such as flame impingement on combustion chamber walls, overfiring of the boiler, or improper combustion chamber modifications.

The effect of excess air on smoke emissions from six commercial boilers was reported in another study (Reference 4-17). These results will be mentioned here briefly even though they come from units tested in the "as found" condition because adjustment of excess air is part of the tuning procedure. They show that all of the units could achieve a level of Bacharach No. 2 at an excess air setting of no more than 30 percent when burning No. 2 oil. Four of the six units could even achieve Bacharach No. 1 at excess air levels below 30 percent.

TABLE 4-1. COMMON OIL BURNER OPERATIONAL PROBLEMS IN COMMERCIAL AND RESIDENTIAL BOILERS AND FURNACES (Reference 4-54)

Burner Type	Oil Type Usually Used	Defects Which May Cause Odors and Smoke
Commercial & Industrial (steam boilers)	No. 4, 5	Oil preheat too low or too high; nozzle wear; nozzle partly clogged; impaired air supply; clogged flue gas passages; poor draft; overloading
Horizontal Rotary Cup	No. 4, 5, 6	Oil preheat too low or too high; burner partly clogged or dirty; impaired air supply; clogged flue gas passages; poor draft; overloading
Steam Atomizing	No. 5, 6	Oil preheat too low or too high; burner partly clogged or dirty; impaired air supply; clogged flue gas passages; poor draft; overloading; insufficient atomizing pressure
Air Atomizing	No. 5	Oil preheat too low or too high; burner partly clogged or dirty; impaired air supply; clogged flue gas passages; poor draft; overloading; insufficient atomizing pressure
Domestic (residential furnaces, water heaters)	No. 1 or 2	Viscosity of oil too high; nozzle wear; clogged flue gas passages or chimney; dirt clogging air inlet; oil rate in excess of design; loose or bad flue pipes; poor mixing of air & fuel; flame impinging on firebox or boiler surfaces; absence of, or faulty barometric damper
Rotary Cup	No. 1 or 2	Viscosity of oil too high; clogged nozzle or air supply; oil rate in excess of design
Vaporizing	No. 1	Fuel variations; clogged flue gas passages or chimney; clogged air supply

These studies, therefore, lead one to conclude that proper maintenance procedures can produce the following results:

1. A decrease in smoke emissions per unit of fuel consumed
2. An additional decrease in annual particulate emissions because of the lower fuel consumption that comes from improved efficiency
3. A consequent cost saving to the users by the slightly improved thermal efficiency

It is important to note that while it is desirable to keep the excess air to a minimum, the efficiency gained (only a few percent) is small compared to the efficiency (10-15 percent) that can be lost due to fouling of heat transfer surfaces by soot. Consequently after cleaning the CO_2 concentration should be set 1-2 percent lower than the minimum attainable from the burner to avoid sooting with time.

4.1.1.2 Additional Maintenance Requirement

There are other operation and/or maintenance practices that can reduce smoke emissions and increase thermal efficiency. These include:

1. Cleaning soot from the boiler tubes to improve heat transfer effectiveness (i.e., with vacuum cleaner)
2. Adjusting oil preheat system to give correct oil temperatures for optimum atomization
3. Ensuring that combustion chamber is in correct working condition; there should be no flame impingement or cold surfaces
4. Sealing all oil or air leaks
5. Ensuring that proper maintenance is performed on any dust collectors
6. Verifying that burner controls are providing correct primary air-to-fuel ratio with changing load
7. Cleaning sludge from oil storage tanks to reduce burner plugging, and, consequently, increased emissions from poor atomization

Negligence in some of these practices contributed to the failure of many burner units tested in the New York City study to meet the minimum thermal efficiency and maximum Bacharach Smoke Number criteria when tested in the "as found" condition.

The cost for proper burner maintenance is slight compared with the cost of annual fuel usage. Normally, this service requires 4 to 8 hours of labor at approximately $25 an hour.

4.1.1.3 Procedures and Training for Boiler Operators and Maintenance Personnel

The investigations discussed above have shown that significant reductions in particulate emissions can be obtained by sound maintenance practices. In order to realize this potential, proper training is essential for boiler operators and maintenance personnel.

The New York City Department of Air Resources, in 1971, developed an air pollution control guidebook for boiler and incinerator operators (Reference 4-4). This guidebook is used in classroom training for the boiler operators as well as in the field for day to day guidance. It clearly presents the precautions to be taken to prevent excessive smoke, and the steps to be taken when excessive smoke does occur.

The EPA currently is also developing guidelines for use by service technicians when maintaining and adjusting oil burners to minimize pollutant emissions, especially particulates. A separate guideline is being prepared by a contractor to the EPA for each user category, including commercial oil-fired boilers (Reference 4-5).

4.1.2 Burner and Combustion Chamber Redesign and Retrofit

Continuing research efforts into both the fundamentals of combustion and the operation of boilers and furnaces have uncovered the relationships between various combustion parameters and the emission of air pollutants. Of these parameters, oil atomization method, excess air, combustion chamber temperature, flue gas recirculation, residence time, and air-fuel mixing have been found to affect the formation of particulates. In addition, investigators have noted that some burners, such as the rotary cup, need to be maintained daily to operate at high efficiency and low smoke.

Therefore, the use in new installations of burners, combustion chambers, and/or associated systems which are designed on the basis of these recent findings could reduce particulate emissions. Retrofit with new burners of boilers or furnaces found to have high emissions could have an important impact also. New systems and retrofits are discussed separately in the next two subsections.

4.1.2.1 Burner and Combustion Chamber Redesign

In this subsection we describe the state-of-the-art in combustion system design practices for low emissions. Atomization and combustion chamber size are treated here, while a discussion of more recent innovations is deferred to Section 4.1.4.

Oil Atomization Methods

Proper oil atomization is essential for complete, smoke-free combustion of oil. The oil droplet resulting from atomization must be vaporized before the oil is burned. Since large droplets will not be completely vaporized by the time they have traveled through the flame, they will leave as intermediate products, such as coke particles. Very large oil droplets could even pass completely through the flame in the liquid stage and spatter on the relatively cool heat transfer surfaces causing smoke (Reference 4-7). Therefore, fine oil droplets from the atomization process are a prerequisite to smoke free combustion.

Conventional burners employ one of four different methods to produce fine oil droplets: high pressure air or steam atomization, low pressure air atomization, mechanical (or oil pressure) atomization or rotary cups. These methods are described in Sections 2.1.1.1 and 2.2.1.3.

Conventional atomizers can perform satisfactorily to give low smoke and high thermal efficiency. However, frequent maintenance is necessary to ensure this condition. New methods of atomization being developed to minimize the cost associated with these maintenance requirements should also be beneficial in limiting smoke emissions. Presumably, smoke emissions are reduced and high thermal efficiency is maintained by these new burners because they remain tuned longer. Several new successful methods of atomization are described in Section 4.1.4.

Combustion Chamber Size

Residence time also has been shown to affect the amount of pollutants emitted. Investigators (e.g., Reference 4-13) have found that the longer residence time obtained by increasing the size of a combustion chamber has resulted in lower particulate emissions. The effect of residence time on particulate and gaseous emissions from residential units will be discussed quantitatively in Subsection 4.2.2.1.

4.1.2.2 Retrofit of Existing Burners and Combustion Chambers

Improved burner maintenance has already been shown to be an effective particulate reduction technique (see Section 4.1.1). Retrofitting of existing units which are difficult to maintain or defective in design is another way to reduce the particulate emissions. Such retrofits usually consist of burner or control replacements, minor modifications to the combustion chamber, changes to the draft system, etc.

One commonly practiced retrofit is replacement of rotary cup burners with pressure or air atomizing units. Although the rotary cup burner can function well when it is properly maintained, experience has shown that this burner usually emits more particulates than other types, especially when burning residual oil (Reference 4-14). The burner is very sensitive to changes in viscosity and is difficult to adjust (Reference 4-15). When No. 6 oil is used, the rotary cup usually must be cleaned daily (Reference 4-16). Therefore, at least one regulatory agency (Maryland) has prohibited the use of these burners.

The cost to replace a rotary cup burner with an air atomizing type varies with burner size. A 10 gph (10.5 cm^3/sec) burner costs about \$1000, and the labor to install it adds approximately \$500. If such a unit consumes 10,000 gal/yr at 40¢ gal, and if fuel costs account for about 40 percent of the total annualized costs for the boiler (fuel, operating, maintenance, and amortization), these parts and labor charges amount to 15 percent of one year's total costs. In practice this cost impact will be less because many rotary cup users are now adjusting their boilers to high excess air settings in order to insure compliance with smoke limitations. It has been estimated that a 10 percent fuel saving could be realized by replacing the rotary cup, which would make it pay off in nearly 4 years at today's fuel prices (Reference 4-15). For a 50 gph (52.5 cm^3/sec) burner replacement costs are estimated to be \$4000 for parts and \$1200 for labor. If one uses the same assumptions as above and scales the fuel consumption directly on burner capacity, the cost of the new burner would equal 10 percent of one year's total costs and be repaid in less than three years. Since the replacement burners require less maintenance for smoke free operation than do rotary cup units, the savings in labor costs would further reduce the cost impact of the new burner.

As noted earlier, improperly designed combustion chambers can also contribute to particulate emissions. Reference 4-2 showed that the combustion chambers on the commercial units which exceeded the smoke limits (Bacharach No. 3) were improperly sized for the burner at the required oil delivery rate. This problem manifested itself either in the form of flame impingement accompanied by the deposition of carbonaceous matter on the walls and/or floor of the combustion chamber or in incomplete combustion as a result of the failure to provide the necessary reflected heat and/or heat release per unit furnace volume to vaporize the oil and combust it completely.

For example, in the case of one unit, an uncommon arrangement was encountered where the burner was placed in the back of (instead of in the front of) the boiler. Additional excess air was being provided so as to permit operation without smoke. In another unit, there was considerable deposition of carbonaceous matter on the combustion chamber floor. A new layer of refractory had been installed on top of what was previously the combustion chamber floor. This had effectively reduced the height of the burner above the combustion chamber resulting in flame impingement and deposition of carbonaceous matter. Therefore, retrofit or repair of improperly designed combustion chambers could frequently reduce particulate emission and increase thermal efficiency of otherwise well maintained units. Presumably, such alterations would bring the emissions and efficiency into line with those achieved by well designed existing boilers and furnaces.

4.1.3 Dust Collectors

Although dust collectors can be used in the exhaust system of commercial units, they are generally not used for this purpose because of their high cost relative to the rest of the system and their need for greater attention than the boiler usually receives. One study has shown that they can be effective in reducing emissions from some commercial boilers, but the investigation did not report on the condition of these burners, or on the attention paid by the operator to the collector (Reference 4-14). The same report suggests that dust collectors on commercial boilers and furnaces may be a liability rather than an asset in many cases because of insufficient or improper maintenance (collection bag or hopper not emptied and cyclone not washed).

The cost of a cyclone collector (see Subsection 4.3.1.2 for a description of a cyclone collector) is about $4000 installed for a 20 gph unit (about 3 MBtu/hr or 0.88 MW) and $5800 for an 80 gph one (10.4 MBtu/hr or 3.05 MW). These figures are for systems that are designed to collect 80 percent (by weight) of the particles over 10 microns. If one annualizes the cost of the collector by using a carrying charge of 20 percent (which might be appropriate to cover interest, maintenance, and related costs for an amortization over 10 years), and if one assumes that the 20 gph (0.88 MW) boiler consumes 20,000 gal/yr at $0.40/gal, then the cost of the collector represents about 10 percent of the annual fuel bill. Alternatively, the cyclone would add nearly 12 percent to the capital cost of the boiler (about $35,000, including installation, fuel supply systems, and controls, but excluding the building).

Electrostatic precipitators are not available in this size range, wet scrubbers have waste disposal problems that make them unsuitable for typical commercial boiler applications, and fabric filter baghouses have a tendency to become plugged or damaged by corrosion when used to capture particulate emissions from oil-fired boilers (all four kinds of particle collectors are discussed in greater detail in Subsection 4.3.1).

4.1.4 Emerging Technology

Several oil burners using improved atomization techniques or optimized flow patterns have recently been marketed. Some data are available for many of these, but not enough to determine their applicability to general service or their effectiveness if included in a regional control strategy.

4.1.4.1 Novel Atomization Techniques

One novel method of oil atomization makes use of pressure oscillations at ultrasonic frequency. Simple atomizers that are based on this principle have been developed by attaching ceramic piezoelectric crystals to a stepped horn amplifier containing a fuel feed tube which discharges at the tip of the horn. The unit is tuned to its resonant frequency with the vibration amplified by the horn. The liquid fuel at the tip then breaks into droplets. Extremely fine particles can be produced at ultrasonic frequencies with low-level power supplies. These designs use relatively large oil passages, even at low flows, which explains the improved maintenance characteristics shown in several long-term tests. The same approach has been applied to larger atomizers. Fuel rates up to approximately 20 gph (equivalent to approximately 3 MBtu/hr or 0.9 MW heat input) have thus far been attained (Reference 4-9).

Progress also has been made in the field of acoustic nozzles by units incorporating cavity resonators. Steam or air is used as the driving medium which, in conjunction with the resonant cavity, generates an intense sound field that shears the fuel into atomized particles. A wide range of spray patterns and flame types result, depending on the cavity and fuel-nozzle configuration. In several applications such nozzles have achieved rates in excess of 1000 gph (1050 cm^2/sec) with appreciable turndown. Manufacturers claim that, when compared to conventional nozzles, resonant-cavity nozzles permit the use of lower excess air, have reduced clogging tendencies, and can operate stably over a wider heat release range (Reference 4-9). One manufacturer claimed that solid particulate emissions were cut by 90 percent and combustion efficiencies raised to over 83 percent with the installation of an acoustic nozzle (Reference 4-8). Unfortunately, quantitative data on particulate mass emission rates or smoke spot numbers could not be obtained to substantiate this claim. The approximately 3000 units which have been sold to date, in the range of 50 to 1000 gph (52.5 - 1050 cm^3/sec) have been marketed on the basis of their higher thermal efficiency (83 to 87 percent) and reduced maintenance (one-third to one-half the effort required for normal burners) at "no smoke" conditions. These atomizers cost about $1400 for parts and labor when installed as a retrofit.

When considering any new nozzle, including a sonic one, care must be exercised to insure that the flame pattern produced by the nozzle does not cause flame impingement on the walls of the furnace and, therefore, poor combustion.

A third novel atomization technique is incorporated in an experimental burner, the Babington Burner, which is discussed in Section 4.2.3.

4.1.4.2 Combustion Aerodynamics

An important parameter in controlling particulates is the amount of swirling (circulatory) motion given the gases in the combustion region (Reference 2-7 to 2-10). In general, there is an optimum value of swirl which yields low particulate emission for a given combustion system, as shown in Figure 4-1. Swirl can also influence the particle size distribution in the following ways:

- Increasing swirl reduces the quantity of large particles
- Overswirling increases the production of submicron soot and reduces the burnout of the largest particles.

Other aerodynamic factors influencing particulate emission are recirculation in the gas flow and relative air/fuel droplet velocity. The combustion of an atomized liquid fuel occurs in the homogeneous mixture of fuel vapor and combustion air; however, partial combustion, or cracking of the liquid fuel droplets can also occur. Such droplet combustion results in soot production, but it can be avoided if the relative velocity between the air and the fuel droplets is above a threshold value known as the "extinction velocity." This threshold velocity increases with both increasing droplet diameter and oxygen concentration. Internal recirculation of the combustion gases reduces the local oxygen concentration and, consequently, the extinction velocity, and so promotes soot-free combustion.

The investigator who obtained the results that have been reproduced in Figure 4-1 also found that at optimum swirl the fuel spray angle had little effect on particulate emissions. The swirl is a part of the whole aerodynamic flow pattern of the burner/combustion chamber configuration and generates recirculation into the oil jet. As the swirl is increased both the internal and external entrainment to the jet increases. However, at excessive swirl the external recirculation between the jet and the wall of the furnace decreases (Reference 2-9) due to the influence of the wall, and soot production is increased.

While astute selection of the swirl rate in a burner (by the manufacturers) can result in low particulate emissions, increasing swirl in general causes a corresponding increase in NO_x. Therefore, this parameter must be determined with low total emissions in mind.

Optimization of combustion aerodynamics is considered by many experts in the field to be the best approach toward achieving the triple goals of low particulates, low NO_x, and high thermal efficiency. Such an optimization attempts to control mixture (i.e., flow patterns and turbulence levels) and residence time to achieve complete combustion at a temperature that, locally or globally,

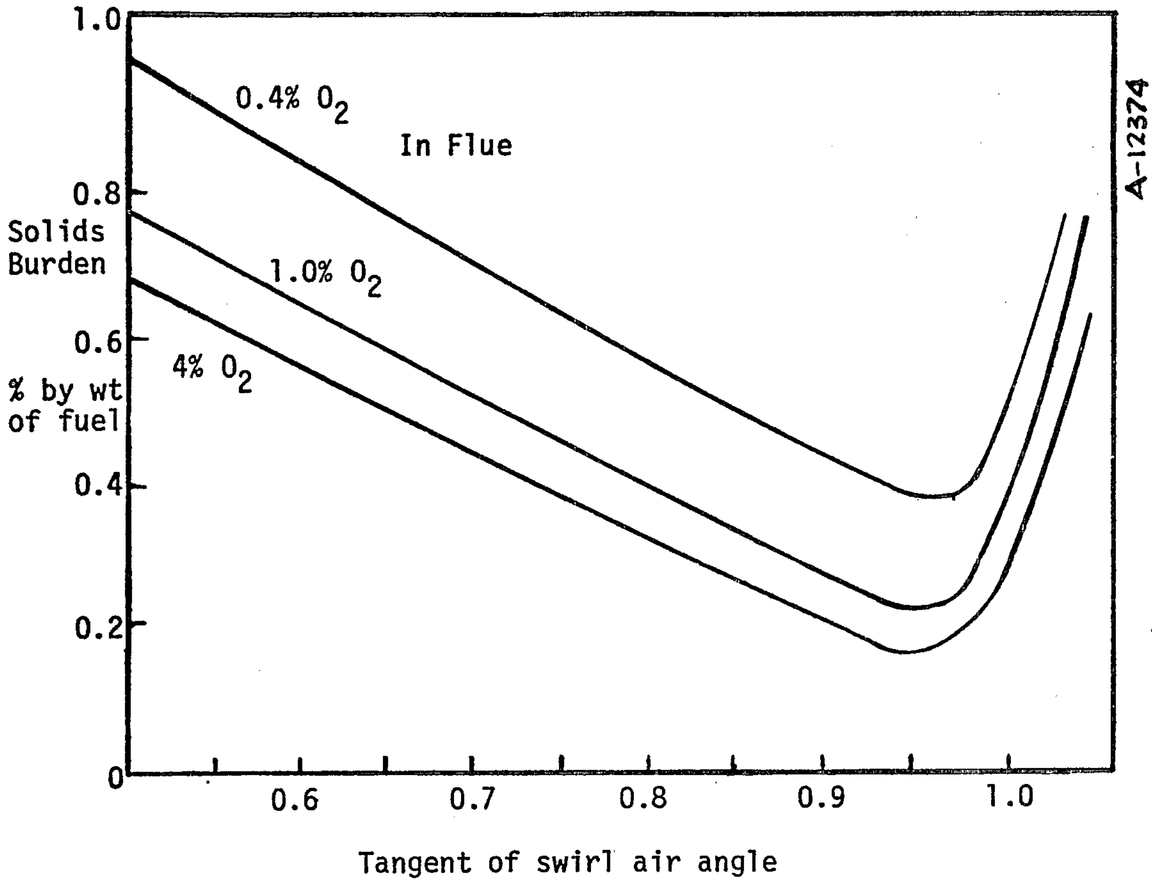


Figure 4-1. Effect of combustion air swirl on solid emission (Reference 2-8).

never falls below the level required to sustain combustion nor rises above the level at which NO_x formation becomes significant. Although most of the research in this area has been directed at NO_x reductions, with smoke merely a limiting factor, several investigators have been able to reduce smoke concurrently with lowered NO_x.

One such study began by investigating the pollution characteristics of high-pressure atomized distillate oil burners when fired coaxially into cylindrical combustion chambers (Reference 4-11). The results of these tests were analyzed and the findings used to design an "optimized" 9 gph (9.45 cm^3/sec) burner (approximately 1.3 MBtu/hr or 0.4 MW). The objective was to make minor changes in the burner blast tube end which would result in a reduction in emissions and improvement in efficiency. These changes were intended to be of a kind that could be retrofitted onto existing burners without requiring the use of new or special servicing requirements.

The resulting "optimized" burner employs peripheral swirl vanes oriented at 25° relative to the blast tube axis. This swirl vane angle gave the best compromise between smoke emissions and nitric oxide emissions. A flame retention device was not used because the pollution characterization tests had indicated that these devices promoted mixing and recirculation in the flame zone which was conducive to NO_x formation under efficient, near-stoichiometric combustion.

Nitric oxide emissions from this burner were found to be very low, at a level of about 0.6 mg NO/g fuel (approximately 35 ppm), compared to 1.2 mg NO/g fuel for similar sized representative commercial burners when fired into the same cool wall combustion chamber. The test burner also was found to be capable of operating smoke free at as low as 2 percent excess air, whereas the commercial burners required from 5 to 25 percent excess air to eliminate smoke. Simulated field testing of the burner for a total of 112 hours showed little variation in performance and no noticeable degradation in emissions. When the burner was fired into a hot wall (refractory lined) chamber, NO_x emissions rose to about 1.0 mg/g fuel during smoke free operation. Conventional burners generated over 1.5 mg NO/g fuel under similar conditions. This burner should be commercially available within 3 years.

The above burner was designed only for the lower size range of commercial boilers, which nearly all use distillate. However, another new burner has been developed for residual fired units. It uses both swirl and recirculation, as shown on Figure 4-2a. This burner has a multistage atomizer, utilizing shear forces in the first atomizing stage, and vibrational or acoustic energy in the final stage (see Figure 4-2b). Field performance has shown that the burners are able to operate over a wide range of oil viscosity and at excess air levels as low as 2.4 percent (for No. #6 oil).

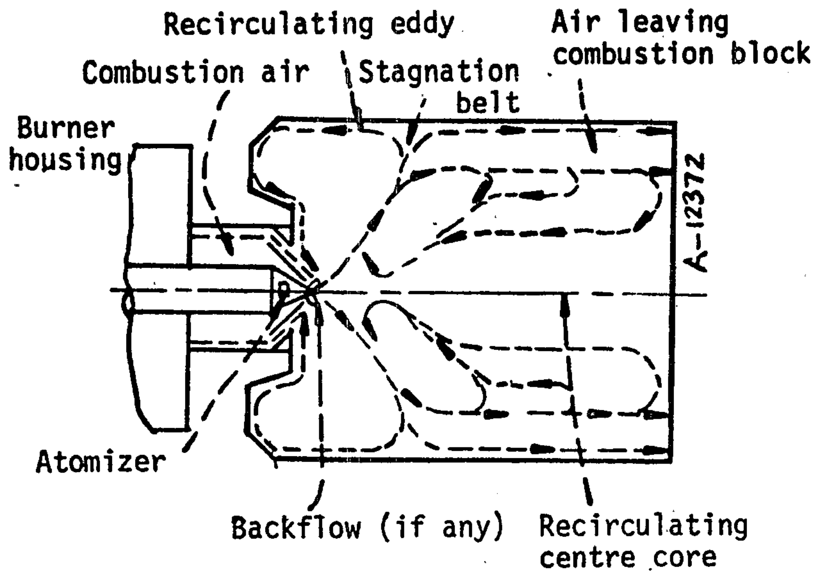


Figure 4-2(a). Typical flow patterns in vortometric burner (Reference 4-12).

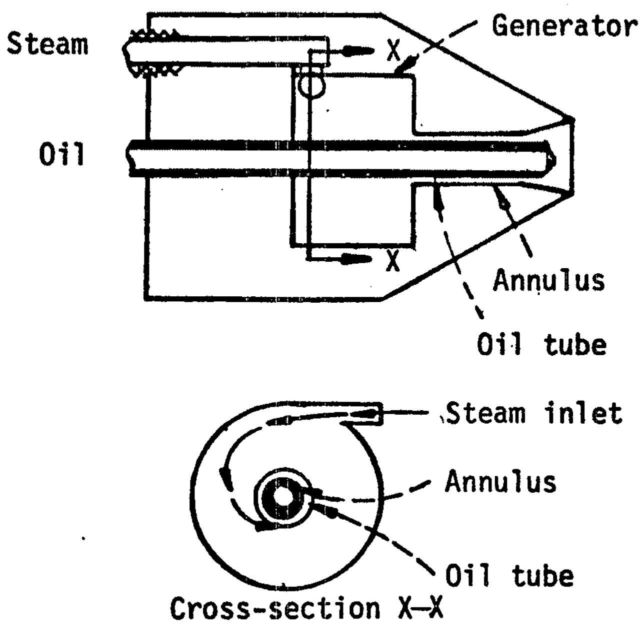


Figure 4-2(b). Atomizer is key component of vortometric burner (Reference 4-12).

The particulate emissions at full load were under 0.14 lb/MBtu (60.2 ng/J) for a 2 MBtu/hr (0.59 MW) unit, although the Bacharach Number was slightly above 4. At 85 percent load, the particulate loading was about 0.22 lb/MBtu (94.6 ng/J) while Bacharach Number was between 3 and 4 (Reference 4-12). Both these emission rates are slightly below the emission factor of 0.24 lb/MBtu (103 ng/J) proposed in Section 2.2.2 to describe existing commercial units fired on No. 5 oil. Thus the advantage of this burner is that it can achieve higher efficiencies than most other designs without increasing particulate emissions. It is also a relatively low NO_x emitter.

4.1.4.3 Modulation

A potential particulate control technique, which can be added to new units or retrofit to existing ones, is a modulating unit to eliminate cyclic on-and-off operation. It has been well documented that the transient nature of cyclic operation contributes to particulate emissions (e.g., Reference 4-17). When a burner is turned on, a few minutes are required for it to attain steady state conditions (see Section 4.2.2.1), and investigations have shown that particulate emissions, modulating burner control can be utilized. With modulating control, the burner is adjusted continuously to meet changing boiler or heat load requirements. The system never cools because the burner is always on. Thus, the modulating operation eliminates the peak particulate, smoke, HC, and CO emissions associated with on-and-off or step turn down controls and, coincidentally, prolongs system life. The effect on NO_x emissions is expected to be minimal. Unfortunately, no quantitative data are available on the difference in particulate mass emissions over an extended period of time (e.g., one day) between a standard unit and one equipped with a modulator.

Most new burners over 10 gph (10.5 cm^3/sec) can be ordered with modulating control. Therefore, when an existing burner needs to be replaced, a unit with modulating control should be considered. The cost involved is about $500 more per burner for the modulating unit. If the modulating unit is to be installed on an existing burner in the field, the extra labor charge is approximately $300 (i.e., total cost to retrofit is $800).

4.1.4.4 Retrofit Combustion Chamber Liners

Particulate emissions from some existing commercial and residential boilers can be reduced by placing a ceramic felt liner just inside the existing inner surface of the combustion chamber. This liner surrounds the combustion volume with a thin layer of insulation whose inner wall reaches temperature equilibrium with the combustion gases more rapidly than the older insulation, thereby reducing the particulate emissions during the start-up transient. However, the felt cannot withstand very high temperatures — i.e., those corresponding to combustion volume temperature above 2600°F (1427°C). Moreover, no specific data are available to show how much this retrofit reduces mass emissions.

4.2 RESIDENTIAL

The main fuel used in oil-fired residential heating units is No. 2 distillate oil. Since particulate emissions from the burning of this grade of oil are small compared to those from units fired with residual oil, high smoke readings are mostly due to improper air-to-fuel ratios, improper draft, worn-out burner components, or poor burner and combustion chamber design.

As with commercial units, an effective and practical technique to reduce particulate emissions from residential oil burners is to keep them well maintained. Procedures and programs directed toward this goal are discussed in Section 4.2.1, below. Significant improvements can also be obtained through the use of new, well designed burners and combustion chambers. These, and other potential control methods are discussed in subsequent sections.

4.2.1 Burner Maintenance

4.2.1.1 Burner Tuning or Replacement

Several investigators have shown that particulate emissions can be reduced significantly by adjusting, or tuning, existing burners and by replacing worn out components or the entire burner.*

One team of investigators studied the emissions from 33 residential units during the 1970 to 1972 heating seasons (Reference 4-17). Pollutant emissions were measured in the "as found" condition and then after proper tuning, which included:

- Cleaning and adjusting the ignitor electrodes
- Cleaning the blast tube and blower shell
- Cleaning or replacing the nozzle
- Cleaning or replacing the oil filter
- Sealing air leaks at the inspection door, around the blast tube, or at other easily accessible locations

*The relation between smoke level, gaseous pollutants and CO_2 concentration in the stack are shown in Figure 2-3. All these levels are affected by tuning.

Changing the draft regulator setting (replacing regulator if necessary)*

Three of the 33 units tested were found to be in such poor condition that they had to be replaced.

Table 4-2 summarizes the reduction in mean pollutant emissions that could be accomplished by the following steps (assuming a typical distribution of 3 units in poor condition out of each sample of 33 units):

1. Identifying and replacing the units obviously in poor condition

2. Completing Step 1 and, in addition, tuning the remaining units

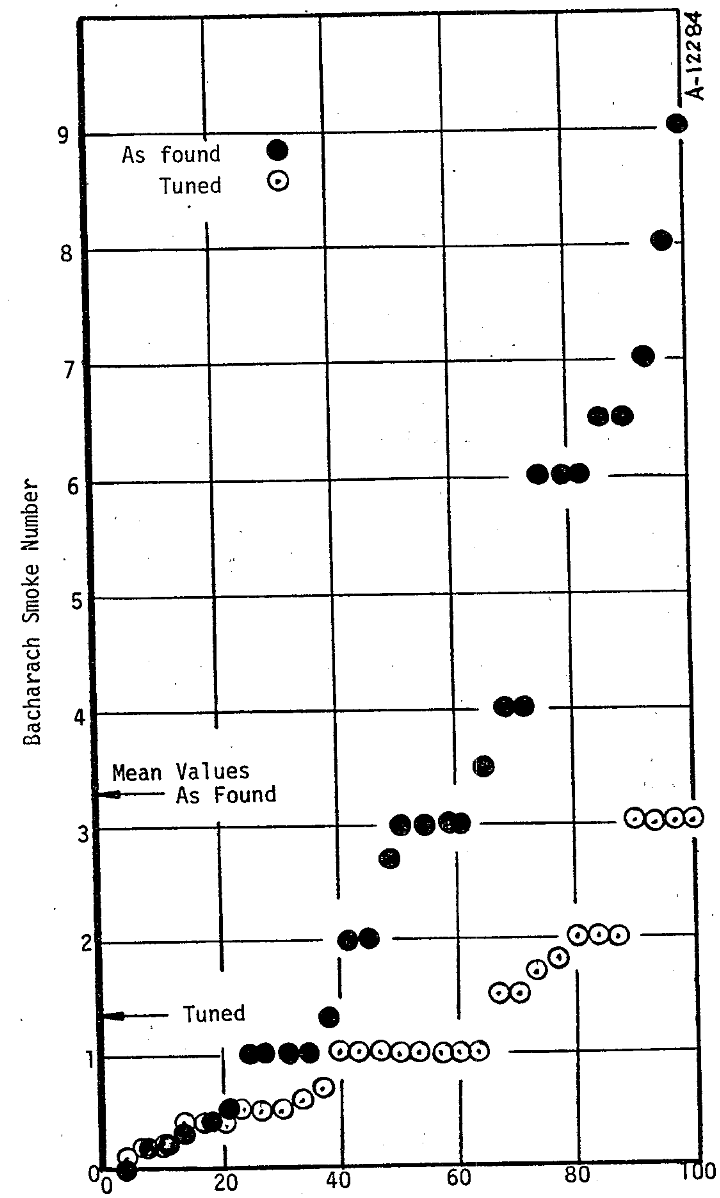
Tuning of the serviceable units reduced the mean values of Bacharach Number considerably as indicated by Figure 4-3. For the "as-found" condition, the mean Bacharach Number was 3.2. After tuning, this number was reduced to 1.3. Moreover, all of the serviceable units could have complied with a standard of Bacharach No. 3 and nearly 90 percent could have even complied with a level of 2. Tuning produced little change in NO_x, while filterable particulates and HC emissions decreased only slightly (see Table 4-2). The relationshop between smoke emissions and CO_2 concentration in the exhaust gas is shown in Figure 4-4. This plot shows that 11 of the 12 units tested could achieve a smoke level of Bacharach No. 2 with CO_2 concentration greater than 8 percent (Bacharach No. 2 is the Maryland regulation, and they recommend that it be achieved at CO_2 levels of 8 to 10 percent - see Chapter 6). Similarly, three-quarters of the units (9 out of 12) could achieve either a Bacharach No. 1 at 8 percent CO_2 or a No. 2 at 9 percent CO_2. Since thermal efficiency is directly related to excess air (and, hence, indirectly to CO_2) and stack temperature, the CO_2 concentrations can be viewed as a measure of efficiency if one assumes constant stack temperature. On this basis, 8 percent CO_2 represents about 77.5 percent efficiency and 9 percent, 79.1 percent for a typical stack temperature of 500°F (260°C).

Two other studies also concluded that burner tuning produced a marked reduction in smoke emissions (Reference 4-1, 4-18). In one of these studies, the mean Bacharach Number of 200 burners was reduced slightly more than 40 percent from above 2.0 before adjustment to 1.1 afterwards (Reference 4-1). Reference 4-17 also showed that tuning increased the overall thermal efficiency for 8 of the 13 units tested. The average increase for all 13 units was 1.7 percent. This average increase is similar to the one reported in Reference 4-1 (from 78.2 to 79.2 percent) and discussed earlier (Section 4.1).

*Periodic replacement of the filter for the air that is circulated through the house will affect particulate emissions indirectly by reducing the loss in furnace efficiency due to the restricted air flow.

TABLE 4-2. EFFECT ON MEAN EMISSION OF IDENTIFYING AND "REPLACING" RESIDENTIAL UNITS IN "POOR" CONDITION AND TUNING (Reference 4-17)

Pollutant	Reduction in Emissions, percent		
	Step 1	Step 2	Improvement Due only to Tuning
	Replacements of Poor Units	"Replacement" Plus Tuning	
Smoke	--	59	59
CO	>65	>81	16
HC	87	90	3
NO_x	No Change	No Change	0
Filterable Particulate	17	24	7



Percent of units having emissions less than or equal to stated value.
(Mean values exclude units in need of replacement)

Figure 4-3. Distribution of smoke emission for residential units (Reference 4-17).

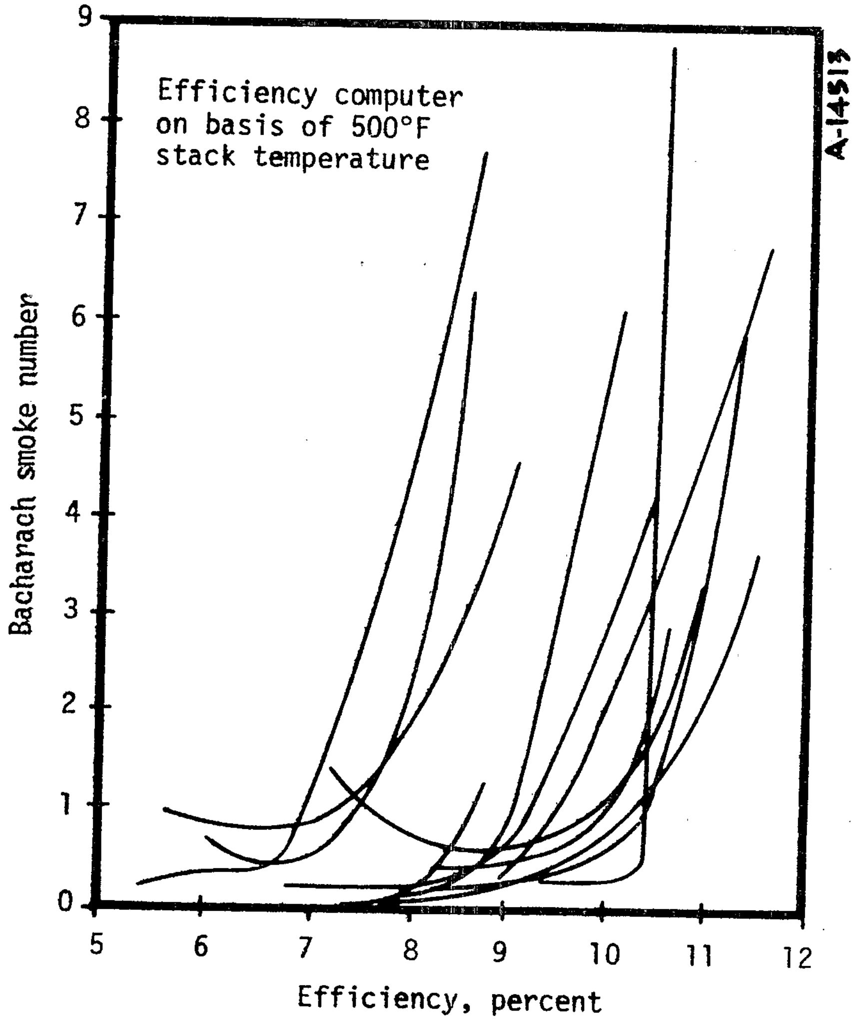


Figure 4-4. Composite of smoke emissions from tuned residential units as a function of efficiency and CO_2 in flue gas (Reference 4-17).

The value of a burner maintenance program is shown by the experience of the Maryland Bureau of Air Quality Control, which conducted a survey of over 400 residential burner units in the Baltimore and Washington Metropolitan Areas during 1972 to 1973 (Reference 4-10). They found that only 42 percent of the units had Bacharach Numbers less than 2 (the standard according to their regulations), and that the average thermal efficiency was about 70 percent. The poorest burners were only 54 percent efficient, whereas the best achieved 81 percent thermal conversion. However, investigators who studied the problem of particulate emissions in the Boston area concluded that most residential and commercial units in that area received good maintenance service (Reference 4-55). This conclusion was based on contacts with oil suppliers and burner servicing companies, who reported that most residential and commercial systems in the Boston area were serviced at least once each year (References 4-60 and 4-61). The adherence of a large number of home-owners and building landlords to a periodic service program is attributed to public relations compaigns by the oil suppliers that stressed burner maintenance for energy conservation. Since energy conservation was the criterion used to adjust the burners, some reductions in smoke emissions are still possible by requiring that boilers and furnaces be tuned to both a smoke spot number and a CO_2 concentration.

These results again show the value of proper maintenance both in directly reducing emissions and in indirectly reducing them as a by-product of decreased fuel consumption. In fact, since they showed that all properly operated and maintained units could achieve a Bacharach Number of 3, and nearly all could reach 2, these results imply that particulate emissions from residential sources could be reduced to an acceptable level in many regions by a control strategy that relies on maintenance procedures to identify units in need of replacement and on proper tuning for the remainder.

Usually burner maintenance service can be obtained from oil suppliers on a contractual basis. The cost for such services is approximately $30 to $35 per year.

In order to determine how rapidly burner performance deteriorated after a burner adjustment, follow-up measurements were made by the investigators who studied the 33 units described at the begining of this subsection (Reference 4-17). These later tests were performed twice during the heating season at 2-month intervals for four units. They showed that in only one unit did smoke, CO, and HC increase. In another unit, CO and HC increased, while the other pollutants remained constant. Emissions remained nearly constant for the other two units. However, results of tests in a laboratory burner unit (Reference 4-20) indicated that smoke emissions increased from a Bacharach Number of 1 to nearly 6 while NO_x, CO, and HC remained essentially constant over a 10-week period. The inconsistent results demonstrate the need for further study of the effects of time on emissions.

One other study (Reference 4-63) was conducted to determine how smoke and efficiency vary between burner servicings. Tuning resulted in an average reduction of smoke from Bacharach No. 1.9 to 0.9 and a 1.9 percent increase in efficiency. When the burners were next serviced, 3 months later, efficiency had not deteriorated, but the average smoke number had increased to 1.8.

The study just referenced above also concluded that the importance of annual maintenance is not so apparent if one only looks at emissions and efficiency of a well maintained burner before and after a given servicing. However if the unit is not serviced annually, the annual decrease in performance becomes additive until very poor operation is experienced. One reason is that smoke implies the presence of soot, some of which adheres to the heat transfer surface. After a boiler has operated for some time with even a moderately low level of smoke, the accumulation of soot will reduce its efficieny.

Periodic servicing is, therefore, a type of preventative maintenance that keeps the equipment operating near its optimal level and, hence, minimizes emissions. It also avoids system failures during the heating season.

4.2.1.2 Training of Servicemen

In light of the importance of proper burner maintenance in reducing air pollution in many areas, up-grading the competence of servicemen and supplying them with good diagnostic instruments can be considered a particulate control technique. Unfortunately it is difficult to assess the effectiveness of a program which requires that all oil burner servicemen receive a certain training and/or use specified instruments to adjust the burners. However, it is the uniform opinion of air pollution control authorities that the quality of service currently available varies from very good to very poor; therefore, they all believe such a control strategy would help. However, they consider it to be either unenforceable or not cost-effective, and none of them have instituted such a program.

Training programs for maintenance personnel are available in some localities where oil is in heavy use. These programs are usually offered in community colleges or trade schools. A few private or trade organizations in the United States also specialize in setting up training programs and preparing textbooks for oil burner servicemen. One such organization, the Petroleum marketing Education Foundation, based in South Carolina, conducts training programs throughout the United States. These programs are usually sponsored by trade organizations. Class durations run from two days to one week. Tuition is approximately $15 per day per student, including textbooks. The most popular program run by this organization is a 3-day course in which the servicemen are trained to adjust burners for high efficiency and low smoke.

The trainees in the above program are encouraged to utilize proper instruments when adjusting burners instead of merely "eyeballing the flame" (Reference 4-21). Instruments that can be used to measure CO_2, CO, Bacharach No., stack temperature, and draft pressure are available commercially at a cost of $300 to $500 for the set.

One of the documents in the burner maintenance and adjustment guideline series currently being developed by EPA is concerned with residential oil burners (Reference 4-29). This guideline is intended to be both a service guide and a training guide.

4.2.2 Burner and Combustion Chamber Redesign and Retrofit

Fundamental combustion research has stimulated new developments in small oil burning equipment, especially as applied to residential space heating using No. 2 distillate. Both the government and industry have sponsored programs to develop low pollution and high thermal efficiency residential oil burners. Some of the development efforts have resulted in commercially available units, while others are still in the experimental stage.

Improved systems designed for new installations will be described below; possible retrofits to existing systems will be discussed in the following subsection.

4.2.2.1 Burner and Combustion Chamber Redesign

New burner developments center mainly on the improvement of oil atomization and on the optimization of the combustion aerodynamics, particularly by adaptation of the flue gas recirculation concept.

Combustion Aerodynamics

Reductions in smoke and other pollutants have been achieved by improved design of the flow patterns in the burner and combustion chamber (see Section 4.1.4.2). Most of these systems rely on optimal choices for swirl air velocity to obtain the desired turbulence level and residence time. In addition, many use either internal or external flue gas recirculation (References 4-24 and 4-25).

One such development is now available commercially from the Blueray Company. This "blue flame burner" is sold in a warm air furnace in two firing ranges, 0.6 gph and 0.75 gph (0.63 - 0.79 cm^3/sec). Combustion gases amounting to 50 percent of the stoichiometric air requirement are recirculated internally to produce smoke-free, blue-flame combustion with essentially zero excess air. Most of the incandescent carbon particles are eliminated during the reburning. Because this burner has to be matched to the combustion volume to obtain the desired (internal) recirculation pattern, it comes only as a burner-furnace package.

About 300 units have been sold so far (Reference 4-26), but they are expected to be widely available by mid-1976. In laboratory tests, the thermal efficiency of the burner has been shown to be over 80 percent (Reference 4-27). A Bacharach Smoke Number close to zero, and NO_x emissions just over 20 ppm were achieved over a range of 11 to 14 percent CO_2. In addition it is purported to be quieter and smaller than comparable forced air heating systems.

The CO concentrations during ignition were 1200 to 1300 ppm (Reference 4-28). These high CO levels occur for about 3 to 4 seconds. After this initial ignition period, CO emissions drop down to about 30 ppm, which is normal for oil burners. Although these high peak CO emissions are not desirable, the benefits of reduced NO_x and particulates, increased efficiency, quieter operation, and reduced size far outweigh this disadvantage.

The cost for the burner package is about $550 excluding installation, or approximately 10 percent more than a conventional oil-powered warm-air furnace (Reference 4-27). This cost differential is quickly recovered through fuel savings and, in a new home, through lower costs for sound insulation and building space to house the unit.

The utilization of a flame retention device to create a more stable, compact, and intense flame is another area of development. Many such units are available currently. Studies have shown that most flame retention burners perform better — i.e., at higher efficiency with lower smoke and/or NO_x emissions — than do those with a conventional burner geometry. One of the flame retention units tested in Reference 4-20 emitted almost 60 percent less smoke than the conventional unit (average Bacharach No. of 1.2 for the retention head versus 2.9 for the others). In addition, thermal efficiency was higher for the retention head unit (83.0 percent versus 75.0 percent). A set of field test results (Reference 4-17) also showed that smoke, particulate, CO and HC emissions were lower for retention head burners than conventional ones, while NO_x emissions were essentially the same (see Table 4-3).

4.2.2.2 Retrofit of Existing Burners

Proper burner maintenance has already been shown to be effective in reducing particulate emissions from residential burners (see Section 4.2.1). As with the commercial sector (Section 4.1.2.2), the retrofitting of existing units which are difficult to maintain or defective in design is another method of reducing particulate emissions. These retrofits generally involve replacement of the burner units and controls at a cost of about $300, including parts and labor. However, sometimes commercially available combustion improving devices are added to the existing burners for the purpose of improving the mixture of air and fuel.

TABLE 4-3. EMISSIONS FROM BURNERS WITH VARIOUS COMBUSTION-HEAD DESIGNS IN CYCLIC OPERATION[a]

Combustion Head	Condition[b]	Number of Units in Sample	Bacharach Smoke No. at 5 Min	Emission Factors, lb/MBtu (ng/J)				
				Gaseous Emissions			Particulate Emissions[c]	
				CO	HC	NO_x (as NO_2)	Filterable	Total
Conventional	As Found	17	3.7	9.9	0.70	19.8	0.021(9.0)	0.048(20.6)
Shell	As Found	3	2.8	0.9	0.69	18.9	0.016(6.88)	0.039(16.8)
Flame retention	As Found	8	2.1	5.3	0.63	20.2	0.011(4.73)	0.035(15.1)
Conventional	Tuned	18	1.3	5.9	0.59	20.7	0.02(8.6)	0.048(20.6)
Shell	Tuned	3	1.7	0.9	0.60	18.3	0.009(3.87)	0.018(7.7)[d]
Flame Retention	Tuned	8	1.0	1.1	0.39	18.1	0.009(3.87)	0.028(12.0)
Conventional	Reference fuel	18	0.9	5.8	0.84	20.3	—	—
Shell	Reference fuel	3	1.0	1.6	0.81	19.2	—	—
Flame Retention	Reference fuel	8	0.8	1.1	0.54	18.8	—	—

[a]Source: Reference 4-17

[b]Excluding units in need of replacement. Reference fuel used to test all units on a common basis.

[c]Particulate by modified EPA procedure.

[d]Based on only one data point.

The ability of combustion-improving devices to reduce emissions and increase thermal efficiency has been investigated (Reference 4-20). When added to existing burners, these devices modify the combustion aerodynamics in the furnace. Of the five devices tested on a standard, high-pressure atomizing burner, only one, the flame retention head, was found to reduce smoke emissions significantly in comparison with the standard burner (see Figure 4-5). At a stoichiometric air-to-fuel ratio of 1.6 (minimum smoke for the retention head), the reduction was from slightly more than Bacharach No. 1 to almost 0, while the NO_x emissions were unchanged. More importantly, the retention head could achieve a smoke reading of No. 1 at an air-to-fuel ratio of less than 1.2 and No. 2 at 1.06, whereas the standard burner could only reach these levels at 1.64 and 1.5, respectively. Therefore, efficiency could be increased from 76.6 percent to 83.0 percent with this flame retention head. However, none of the other four devices gave the same encouraging results.

4.2.3 Emerging Technology

Current research directed toward reduction of particulate emissions from residential oil burners is aimed primarily at the following areas (excluding modifications to the fuel): improved atomization, optimization of the combustion aerodynamics, system use patterns, and modifications to the combustion chamber length and material. These are discussed below.

Improved Oil Atomizers

The high-pressure air atomizing gun-type burner is the most common one used for residential heating. Even though the basic principles and component functions have generally remained the same, marked advances have been made recently in gun burners. These improvements have resulted in more compact burners, having improved efficiency and flame stability. The improved efficiency reduces fuel consumption, which in turn, should reduce the total annual particulate emissions. The improved flame stability allows more uniform burning and, hence, fewer localized cold spots or temporary fuel rich zones where smoke or particulates are formed.

Ultrasonic and acoustic atomization, as discussed in Subsection 4.1.4.1, are two schemes presently under development. Another is the system used in the "Babington Burner" (Reference 4-62), financially backed in part by the National Oil Fuel Institute (NOFI), the trade association for home heating oil dealers. In this novel atomizer, liquid fuel washing over the outside surface of a small glass or plastic bulb forms a thin surface film. Air forced through one or more slots in the bulb breaks the liquid into a fine spray. Proponents of the burner claim uniformity of particle size, elimination of clogging, and ability to burn a variety of fuels (e.g.: diesel, distillate, kerosene, etc.) as advantages over conventional burners. Fifty of the units have been field tested and reportedly produced low smoke levels, but no numerical emission data are available.

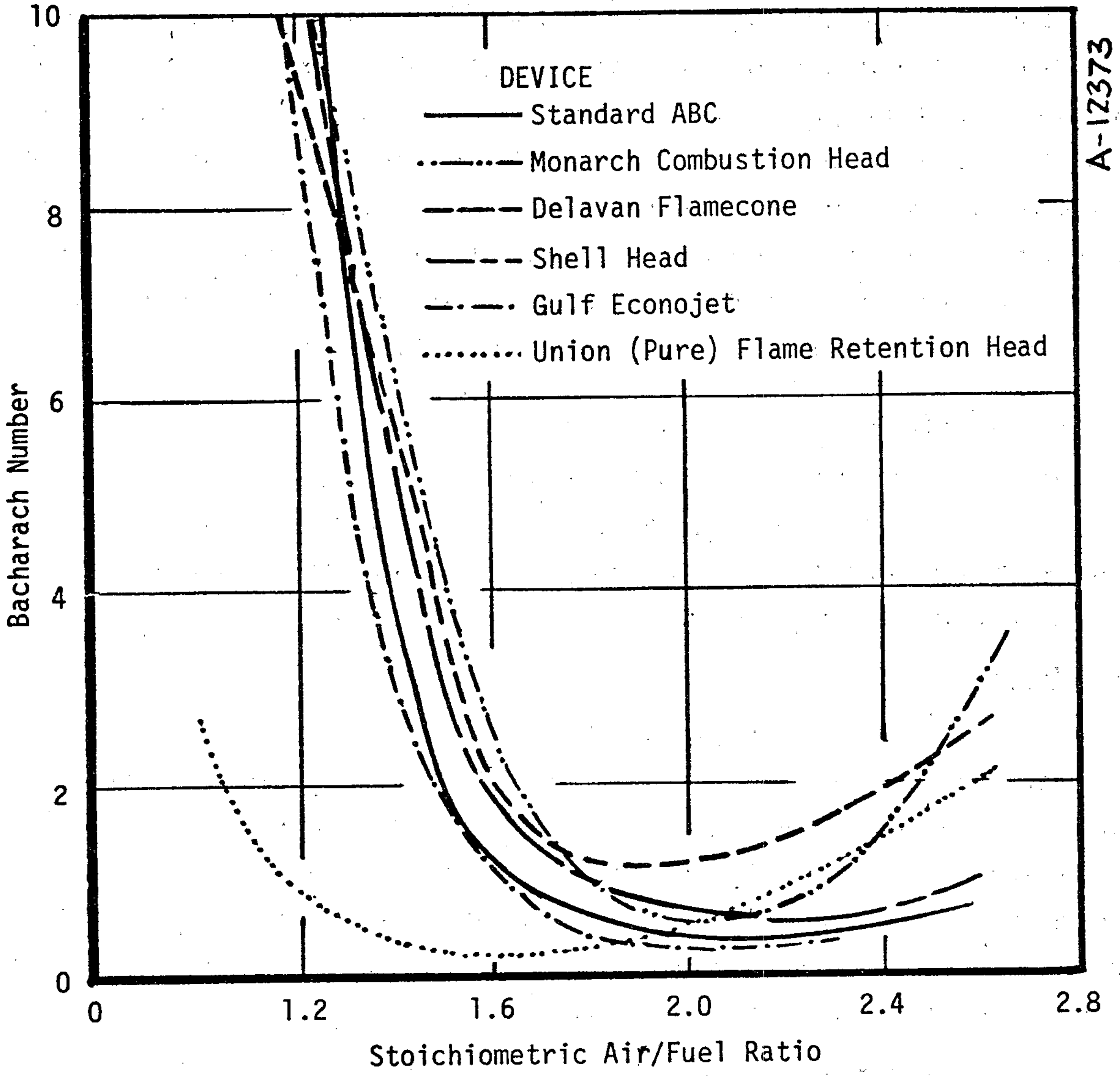


Figure 4-5. Average smoke emissions of combustion improving devices versus stoichiometric ratio (Reference 4-20).

Vaporizing Burners

Vaporizing burners have been used with kerosene and No. 1 heating oil for many years. However, with No. 2 oil vaporization may not be complete leaving oil deposits on the metal surfaces. The deposition rate can sometimes be as high as 200 grams of carbonaceous matter per cubic meter of oil consumed, and this material can later be emitted as particulate. A vaporizing burner for No. 2 oil that could overcome this problem would be of considerable interest because of its potential advantages: simplicity, quiet operation at low-capacity, low smoke, and high efficiency.

A prototype vaporizing burner for No. 2 distillate oil has been developed and tested (References 4-22, 4-23). Oil is introduced into a hot cast steel chamber where it vaporizes quickly. The vapor is then conducted to a combustion chamber, where it is mixed with air in a swirl-type burner. Such burners have performed satisfactorily on No. 2 oil for periods equivalent to a heating season, firing 0.5 gallon per hour (0.53 cm^3/sec) on an intermittent basis. Installed in a storage type water heater, one of these units logged over 1000 hours firing time, and gave satisfactory combustion performance of 12 percent CO_2 with 0 to 1 Bacharach Smoke Number.

Combustion Aerodynamics

An improved burner design for residential units evolved from the study discussed in Subsection 4.1.4.2 to design an optimum distillate oil burner for retrofit into existing warm air furnaces (Reference 4-10). In addition to the 9 gph (9.5 cm^3/sec) burner described there, a 1 gph (1.1 cm^3/sec) was also designed on the basis of the tests with existing units. The burner was fired in a refractory lined, coaxial combustion chamber. Smoke emissions were less than Bacharach No. 1 and only negligible quantities of unburned hydrocarbons and carbon monoxide were produced. Mass particulate emissions were not measured. Nitric oxide emissions were about 1 mg NO/g fuel burned (about 50 to 60 ppm), compared with nominal levels of 1.5 to 2 mg NO/g fuel from typical new commercial burners fired into the same combustion chamber. The NO emissions increased to 2.0 mg/g fuel at a smoke level of Bacharach No. 1 when the burner was positioned at right angles to the combustion chamber. This geometry is commonly found in residential furnaces. Other commercially available burners either smoked or emitted about 3 mg NO/g fuel when fired in the same facility. Additionally, the "optimum geometry" burner was capable of operating (in the laboratory) at only 5 to 10 percent excess air without smoke, whereas typical new commercial burners required up to 25 percent excess air to achieve smoke free operation.* Simulated field tests were conducted in a commercially available furnace for a total of 128 hours of cyclical on and off operation. The burner performed over the entire test period with

*Burners in the field usually need to be set at 10 to 20 percent more excess air than in the laboratory to avoid sooty operation due to dirt accumulation on air blower fans and the like. Nevertheless, the optimized burner can still run with less excess air than other currently available units, and these, in turn, are an improvement over the home heating systems that were installed in the past, which require up to 60 percent excess air for smoke free combustion.

little variation in performance and no noticeable degradation in emissions. The stoichiometric ratio was about 1.10, Bacharach No. 0, and NO_x emissions 0.95 mg/g fuel. This burner should be available commercially within 1 to 3 years.

Results from this study also suggested that an optimally designed burner which was specifically matched with a combustion chamber could achieve even lower NO_x levels at higher thermal efficiency with no increase in smoke. This new system is being designed with a sealed combustion air and draft control system that uses outside air instead of previously heated indoor air. The resulting conservation of heated indoor air should reduce fuel consumption. Work is currently underway to develop this matched system. Such a system may be commercially available within 6 years.

Burner Use Pattern

One of the major factors contributing to high particulate emission, particularly in domestic burners, is cycling. The on-off mode is a dominant characteristic of warm air furnaces, and its importance as a cause of increased emissions has been well documented (References 2-6 and 2-15).

A typical furnace cycle is shown in Figure 4-6. The burner is ignited at a point off the chart and after a minute or so, the blower starts circulating air over the heat exchanger. Four minutes later the burner is extinguished, and about 5 minutes after that the blower stops. Investigations on a model residential heating system indicated that the sizeable peak emissions measured during ignition and shutdown can account for most of the total emissions. Figure 4-7 shows qualitative emission traces from an oil burner during a typical cycle. CO and HC emissions peak at ignition and shutoff. HC concentration drops to insignificant levels between the peaks, while CO emissions tend to flatten out at a measurable level. Particulate emissions continuously taper off after the ignition-induced peak, whereas NO emissions first rise rapidly for a short period and then continue to rise at a more moderate rate as the combustion chamber temperature increases. The operating time of most domestic burners seemingly is not long enough for NO to reach equilibrium levels.

The transient emissions are caused mainly by variations in the combustion chamber temperature. At ignition, a cold refractory will not assist complete combustion and, therefore, peaks of CO, HC, and smoke can occur. In older units the oil nozzle tended to dribble during ignition and shutdown due to momentary low atomization pressure. This dribble is composed of large droplets which result in high particulate emissions. The problem has been minimized in new systems by the use of solenoid valves in the fuel tube (delayed on — instant off), the placement of this valve nearer to the burner tip, and the use of smaller diameter tubes.

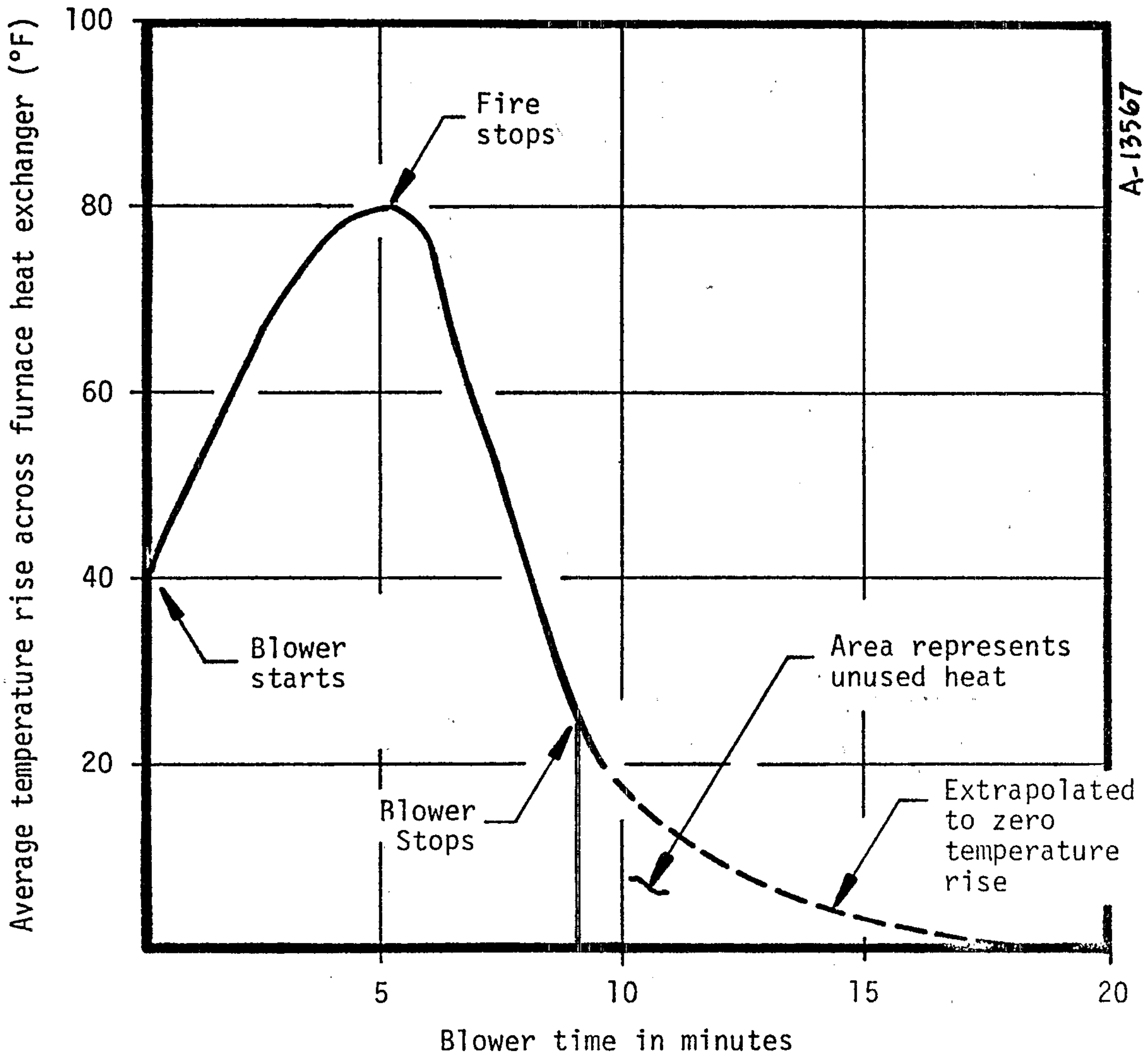


Figure 4-6. Temperature rise across an oil-fired warm air furnace heat exchanger during a typical cycle.

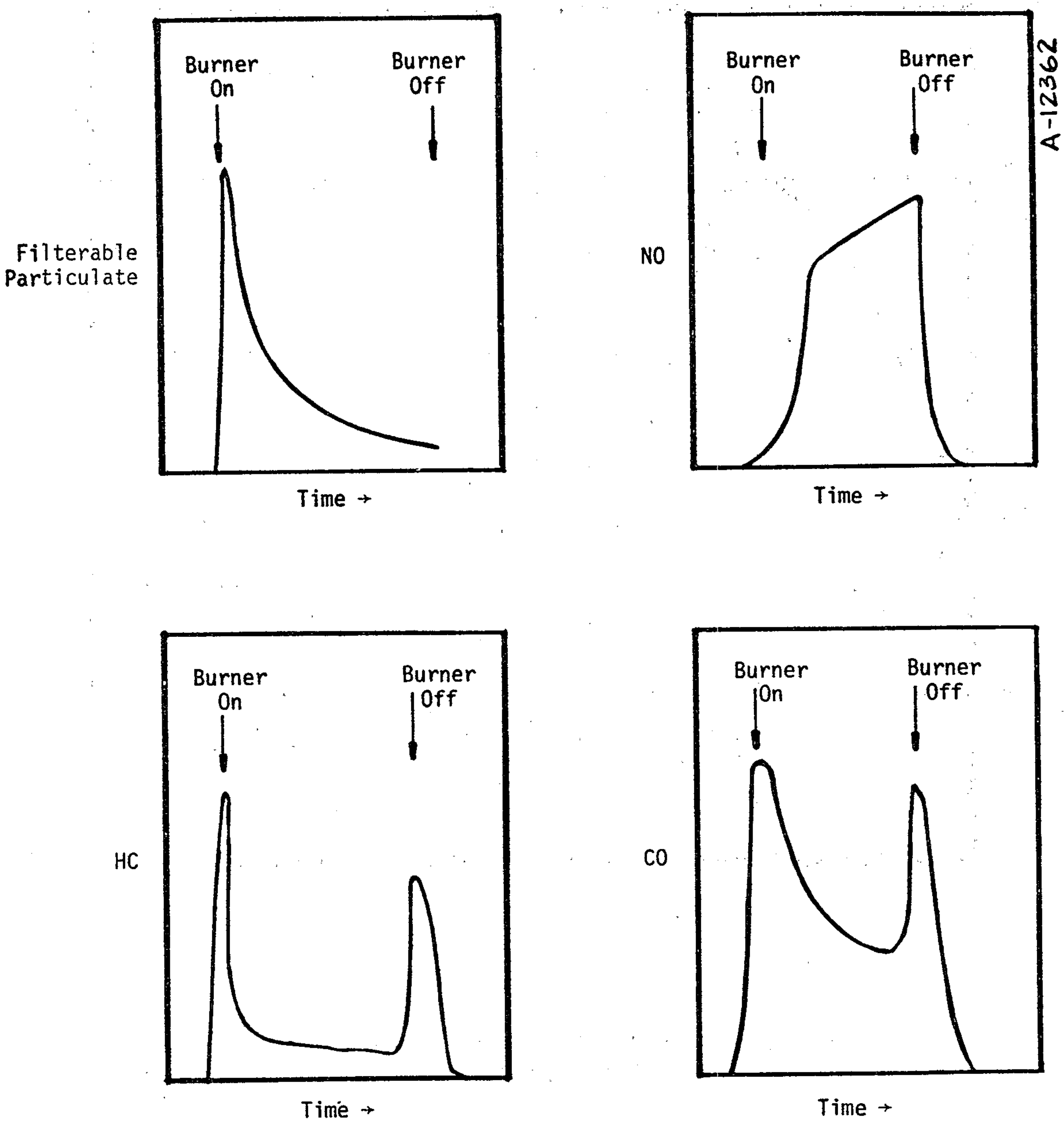


Figure 4-7. Characteristic emissions of oil burners during one complete cycle.

It should also be mentioned here that cycling has a deleterious effect on overall efficiency. As indicated in Figure 4-6, the fire is extinguished at the peak temperature rise across the furnace, and it is at this point that the maximum certified efficiency is probably achieved. For the remainder of the cycle the air blower remains on, but the flue gas temperature and flow rates through the burner have dropped to zero. Perhaps what is more important, and not shown on this curve, is that the burner has been firing for 1-3 minutes prior to blower start-up. Again, this means that there is a significant period of time when there is very little flow on the air side, implying ineffective heat exchange. Of course, some of this heat is stored in the furnace structure to be recovered eventually, but much of it escapes out the stack under inefficient conditions.

Peak smoke emissions resulting from the on and off cycle of boiler and furnace operations is a more serious problem for the residential sector than for other sectors (see also Subsection 4.1.2.2). Nevertheless, modulating burners are rarely used in residences because the peak oil consumption rate is usually less than 3 gph (3.15 cm^3/sec). To modulate these burners, they would have to perform effectively at the extremely low oil consumption rates characteristic of low load firing. Much more work would be needed to make burner modulation applicable to residential burners. Hopefully, the continuous development of the newer burners, such as the blue-flame (Reference 4-27) and optimum burners (Reference 4-10), could minimize the cyclic emission problem.

Combustion Chamber Size and Material

Residence time affects particulate and NO_x emissions from residential boilers and furnaces just as it does commercial units (see Subsection 4.1.2.1). Figure 4-8 shows particulate emissions as a function of excess air from two refractory-lined combustion chambers, one a 15-inch (380 mm) chamber and the other a 27-inch (680 mm) chamber. The longer chamber was created by adding a 12-inch (300 mm) refractory-lined section between the end of the 15-inch combustion chamber and the metal heat transfer surfaces. The increase in chamber size effectively increases the residence time. This figure shows that particulate emissions can be reduced substantially if a short residence time unit is enlarged. For example, at an air-to-fuel ratio of 1.6 the reduction is ten-fold, from 0.20 to 0.02 mg/g fuel. The emission rate from the long chamber is less than one-quarter the rate from a well maintained currently installed unit which has been retrofitted with a flame retention device to improve combustion and reduce particulate emissions (see discussion of flame retention devices above). The curves on Figure 4-8 also indicate that the particulate emissions from the long chamber at typical stoichiometric air-to-fuel ratios (i.e., between 1.45 and 1.85) are below the lowest levels attained by the short chamber, even when the latter is operated under very lean conditions.

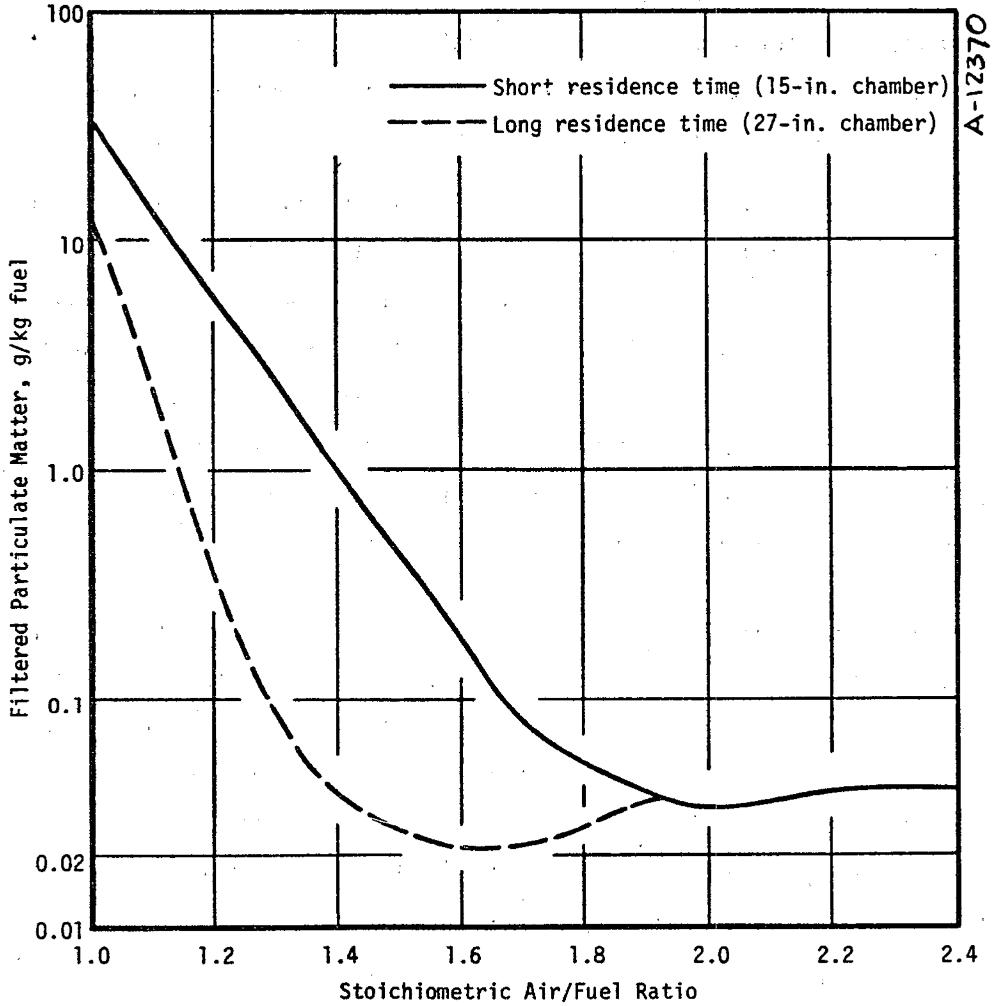


Figure 4-8. Effect of residence time on particulate emissions (Reference 4-20).

Figure 4-9 shows the NO_x emissions from the two chambers. At a stoichiometric air-to-fuel ratio of 1.6 (i.e., minimum smoke for the longer unit), the NO_x emissions are slightly higher for the larger chamber (1.25 mg/g fuel) than for the shorter one (1.1 mg/g fuel). Due to space limitations in homes, it may be difficult to apply this technique to commercially available systems. Moreover, data on emissions under cyclical operation are not available.

The material used in the combustion chamber has been shown to affect smoke emissions (Reference 4-20). When a burner was fired into two chambers which were similar except for liner material, the refractory-lined chamber gave lower smoke readings than the steel-lined one. It was assumed that the steel created a cold wall effect which quenched the flame before combustion was complete, thus producing excessive amounts of CO, HC, and smoke. Hence, refractory-lined combustion chambers are preferred for lower pollutant emissions, at least in steady-state operation. The potential use of ceramic liners as retrofits to existing units is discussed in the commercial section (4.1.2).

4.3 INDUSTRIAL AND UTILITY

In the industrial and utility sectors fuel accounts for 80 to 90 percent of the annual operating and maintenance costs. Therefore, the large boilers in these sectors are generally well-maintained to minimize fuel consumption, and state-of-the-art burner/combustion chamber design is used in new systems. Hence, particulate emissions from these sources are generally controlled by collection devices in the exhaust stream.

A recent study on particulate control strategies for the Boston area, however, has concluded that reductions of up to 30 percent could be achieved on industrial and utility boilers by more frequent inspection and improved maintenance procedures for boilers larger than 30 MBtu/hr (8.79 MW) (Reference 4-55). This strategy was chosen over fuel switching, fuel washing, and the purchase of steam from a central station for residential and commercial space heating on the basis of its technical feasibility, acceptable capital and operating cost increases, projected fuel availability, and enforcement requirements. The basis of this strategy is the set of procedures listed in Table 4-4. This table was an attachment to a compliance schedule submitted by the Boston Edison Company to the Metropolitan Boston Air Pollution Control District in support of their claim that their boilers were in compliance with particulate loading limitations.* The key, unique features of this program are their commitment to continuous sequential operation of soot blowers (Item IV) and their program to

*They stipulated frequent testing of the oxygen concentration in the flue gas rather than continuous monitoring (see Item I) because they felt the oxygen monitors which were available at that time were not reliable enough to use (Reference 4-57). Many large boilers, however, are equipped with automated air-to-fuel ratio controllers which respond to stack measurements of oxygen concentration and smoke.

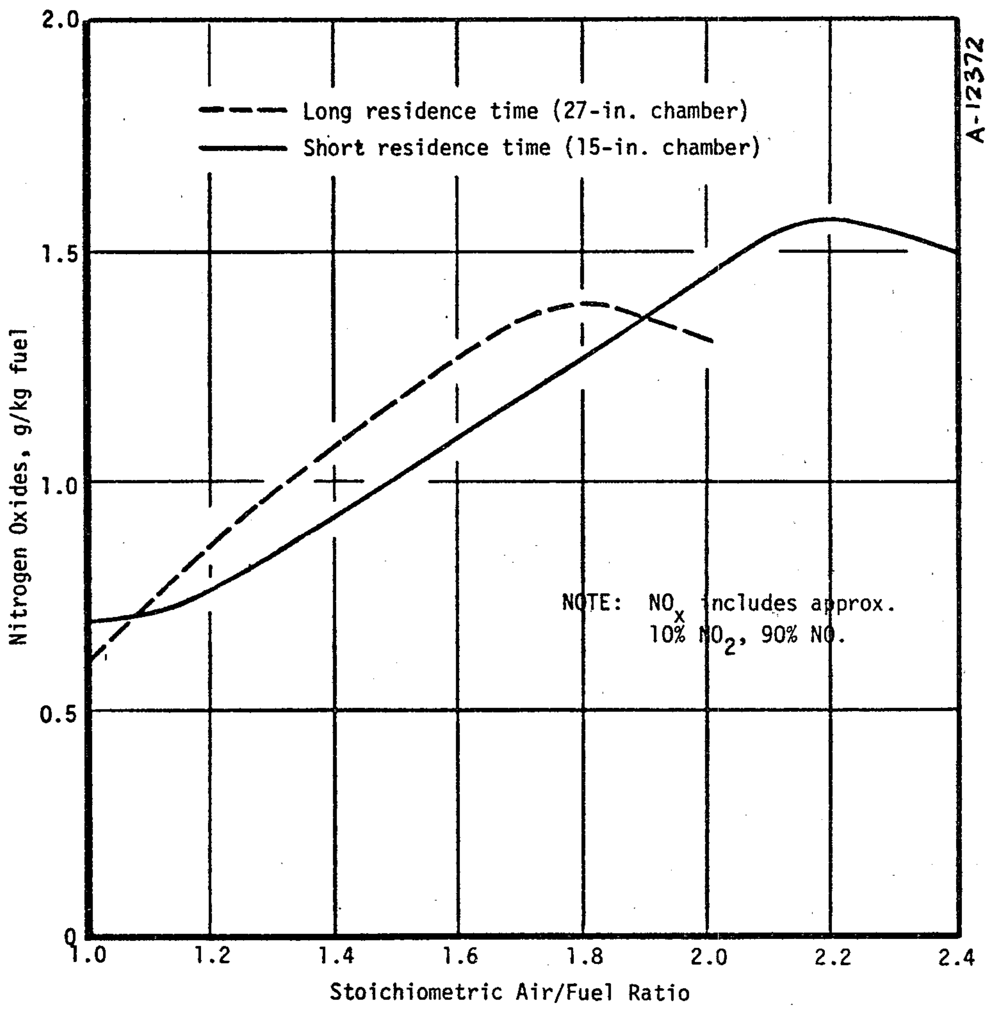


Figure 4-9. Effect of residence time on nitrogen oxides emissions. (Reference 4-20).

TABLE 4-4. PROCEDURES FOR CONTROL OF PARTICULATE EMISSIONS FROM THE STACKS OF THE BOSTON-EDISON COMPANY

I. Frequent testing to maintain proper fuel/air ratio for combustion.

II. Purge cleaning of fuel-oil burning guns at each shutdown.

   A. Routine disassembly and cleaning of fuel oil burning guns to determine possible plugging of orifices.

   B. Renew worn parts of fuel oil burning guns as soon as wear is noted.

III. Complete overhaul and repair of all fuel oil burning equipment and all flue gas passages of the boiler, during every annual outage for inspection.

IV. Continuous sequential operation of soot blowers.

V. Fire sides of boilers, boiler duct work and ash hoppers are to be cleaned at periodic intervals during the year.

   The frequency of cleaning will be determined by the results of the test program described in Item VI.

VI. A program of periodic testing of particulate emissions for representative Boston Edison boilers is under development. The object of this program is to determine the frequency of cleaning necessary to maintain particulate emissions in compliance with the Bureau of Air Quality Control's regulations.

develop a maintenance schedule designed to maintain all units in compliance (Item VI). Soot blowing is discussed in Subsection 4.3.2.1 below. Since the submission of this plan, they have adopted a schedule of boiler cleaning (especially Items II and V) every 3 months (Reference 4-56). This interval is based on tests of emissions versus time since the last cleaning. These measurements showed that the particulate emission rate increased with time and approached the regulatory limit about 3 months after the previous cleaning.

In general, some control over particulate is available by adjusting the air-to-fuel ratio, but other factors constrain the use of this technique. If low sulfur fuels are burned, the particulates consist mainly of ash (noncombustibles in the fuel) and smoke (partially burned fuel). Boilers which are fired with such a fuel are generally adjusted to the lowest air-to-fuel ratio at which no visible smoke is produced. This practice has the dual benefit of minimizing both fuel consumption and NO_x emissions. Although it is desirable to operate at an air-to-fuel ratio that represents about 3 percent excess air, many industrial and some utility boilers still require up to 15 percent excess air. New, better designed burners would have to be used in these boilers to permit the use of less air.

When high sulfur oil is used, the particulate can take on a different character with the presence of significant quantities of SO_3. These sulfates not only increase the rate of deposit accumulation on the heat transfer surfaces but also leave the stack as a visible plume (References 4-6 and 4-12). Virtually all the sulfur in the fuel is converted to SO_2 or SO_3, and the ratio of SO_3 to SO_2 increases with available oxygen. Therefore, low excess air firing is a necessity when high sulfur fuels are used. This requirement, more than the desire to reduce NO_x and increase thermal efficiency, was, in the past, responsible for the development of burners that could combust fuel with only 3 percent excess air.

Burners for packaged boilers have undergone almost continual refinement in the past 15 years to narrow the flame further for higher-capacity furnaces and to optimize efficiency and reliability. These burners now provide for complete burnout of combustibles with low excess air. (In addition to optimizing boiler performance, low-excess-air operation helps maintain emissions of nitrogen oxides at low levels.) However, high boiler efficiencies cannot be achieved without close control of the combustion process. Vendors generally recommend maintaining excess air in packaged oil-fired steam generators between 10 and 15 percent. Although efficiency can be increased by dropping excess air further, operation at lower levels requires extremely close attention on the part of operators to prevent incomplete combustion, and the release of substantial quantities of soot, during rapid changes in boiler load. Industry's drive to conserve fuel and minimize pollution control problems also has led to the development of burners that can handle a wide variety of waste fuels — tar, pitch, hydrogen, naphtha, coke-oven gas, carbon monoxide, sander dust, refinery gas, sewage sludge, etc. (Power Special Report, Power from waste, February 1975).

To summarize, when low sulfur oils are burned, excess air can be used to eliminate any visible emissions. However, this is not a useful approach because it also causes NO_x emissions and fuel consumption to increase. Moreover, when high sulfur fuel is used, low excess air combustion (e.g., 3-5 percent) is necessary to minimize particulate. Therefore, boilers should be equipped with burners that are capable of operating at low excess air to minimize simultaneously particulates and fuel consumption.

Since the smaller industrial units span the same size range as the larger commercial ones, they show many of the same operational characteristics. Therefore, control strategies suggested for the commercial units, such as improved maintenance procedures, could be applied to these industrial units. In the following subsections, only the control techniques for the larger boilers are discussed.

4.3.1 Particulate Collectors

Four basic types of particulate collectors are available for industry and utility applications: electrostatic precipitators, mechanical collectors, bag filterhouses, and wet scrubbers. Of these, the electrostatic precipitator and the multicyclone, which is one type of mechanical collector, are used in oil-fired facilities. Bag filterhouses and wet scrubbers are generally not used at this moment.

Particles that are emitted from large oil-fired units range in size from 0.1 to over 10 microns. If the burner is well maintained and properly adjusted, total particulate emissions should be low, but a substantial portion of those emitted will probably be less than 1 micron. However, it is common to find oil-fired sources which are not serviced frequently enough and whose emissions, therefore, are dominated by the larger particles. The plume from such a boiler would normally not be visible unless it was the discharge from a very large boiler with a correspondingly large diameter stack. Fine particles can cause the stack discharge to be visible because their size approaches the wavelength of visible light, and hence enables them to scatter light effectively. Particulate collectors have been used to minimize this problem (References 4-30 and 4-31).

Since particle size is an important factor in assessing the impact of emissions on various receptors, one needs to consider the relationship between collection efficiency and particle size when one discusses a control system. As shown on Figure 4-10, this efficiency decreases rapidly as the particle size approaches the submicron range.

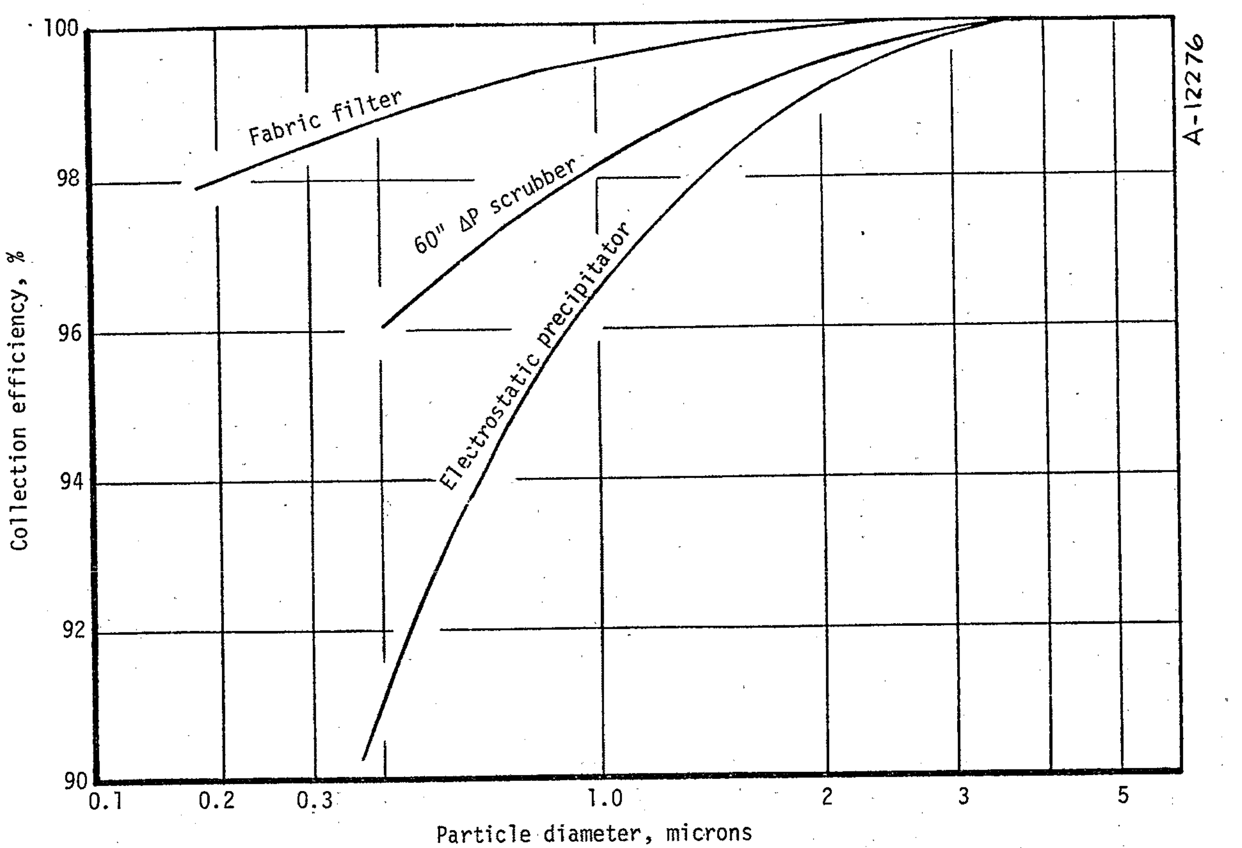


Figure 4-10. Collector efficiency as function of particle diameter for different collectors (Reference 4-52).

The following subsections describe each of these particulate, or dust, collection devices, give their control effectiveness, and present some cost information.

4.3.1.1 Electrostatic Precipitators

Electrostatic precipitators have been used by the electric power industry for coal flyash collection since 1923. Their use in this application has increased rapidly since 1950, from about 80×10^6 cfm (3.8×10^4 m^3/sec) installed capacity then to over 500×10^6 cfm (2.3×10^5 m^3/sec) in 1970 (Reference 4-35). Although they are now the most common collectors on oil-fired boilers, this application accounts for less than 10 percent of the total installed capacity.* Their predominance among control devices for oil-fired units can be attributed partly to the fact that many boilers which were at one time coal-fired have since converted to fuel oil. They originally were equipped with a precipitator to abate coal flyash and have kept it in operation after the conversion, with certain modifications to increase collection efficiency. In general, it is conceded that electrostatic precipitators are the most effective collectors in use today.

The operating principle consists of electrostatically charging the particulates by a corona discharge and then passing these charged particles through an electrical field which drives them to collecting plates. These plates are rapped periodically to dislodge the collected particulates, which then fall into a hopper.

The efficiency of electrostatic precipitators has been described quantitatively by simplified equations (Reference 4-30). These relationships are useful for preliminary design and systems analyses purposes, for they show the impact of the significant parameters. Among these, the most important are the effective collecting electrode area of the precipitator (A), the gas flow rate through the precipitator (Q), the strength of the two electric fields (charging and collecting), and the particle diameter. The A/Q ratio must be large for high collection efficiency; thus velocities should be low and collection plates large. In addition, the collection efficiency is proportional to the strength of the electric fields. However, experience has indicated that the effect on collection efficiency of particle size above the submicron range is small. Other factors that influence the precipitator performance are the gas viscosity, particle resistivity, sulfur content of the fuel, flue temperature, carbon content of the particulates, particulate loading and ability to get particles off collecting plates and into the hoppers (Reference 4-30).

*Based on Reference 4-35 for total installed capacity and Reference 4-36 for quantity of fuel burned annually in utility boilers that are equipped with precipitators.

For oil firing, field experience has shown that collection efficiencies between 50 and 95 percent by weight can be obtained. Normally, the precipitators are designed to remove about 90 percent of the particulate emitted (by weight) (References 4-31, 4-32, 4-33). However, it is not entirely meaningful to talk about efficiency alone because it is a function of particulate loading, increasing as the input particle concentration rises. Reference 4-31 claims that the outlet loading from a precipitator is nearly constant at 0.02 to 0.05 lb/MBtu (8.6 - 21.5 ng/J) independent of the inlet conditions (0.05 to 0.33 lb/MBtu (21.5 - 142 ng/J) in this case, including periods of soot blowing). One precipitator vendor states, further, that control performance is limited more by a lower bound of 0.005 gr/scf (0.009 - 0.011 lb/MBtu, depending on the excess air used) than it is by collection efficiency (Reference 4-68). For example, precipitators are in use which collect over 99 percent of the large amounts of flyash emitted by some coal-fired power plants; equivalent units designed for oil-fired units, whose uncontrolled emissions are much lower, can only achieve 90 to 95 percent collection. However, the outlet loading can be the same in both cases. At these typical efficiencies, well-maintained and correctly operated units should not emit a visible plume from the stack, given the ash and sulfur content of most oils. If one uses 0.01 to 0.26 lb/MBtu (4.3 - 112 ng/J) as representative data (Reference 4-36) for uncontrolled emissions from utility boilers and specifies a 90 percent efficient precipitator, then these boilers should emit less than 0.03 lb/MBtu (12.9 ng/J). The larger boilers (>300 MW) only emitted 0.04 to 0.06 lb/MBtu (17.2 - 25.8 ng/J) uncontrolled; therefore, they should be able to achieve the 0.01 lb/MBtu (4.3 ng/J) lower bound from precipitators.

Precipitators that are originally designed to collect coal flyash can experience a drop in efficiency down to 45 percent when used on oil. Apparently the changes in particle resistivity, size distribution, and surface properties are the primary reasons for this reduction. Therefore, units which were installed on coal-fired boilers should be modified if the plant is converted to oil. With proper modifications, efficiencies approaching 90 percent can be achieved. However, once a precipitator which was designed for coal has been used on an oil-fired source without modification, its efficiency is reduced even when switched back to coal (Reference 4-36).

Costs of precipitators in 1973 are shown on Figure 4-11(a). These figures are for new units to be used on oil-fired sources and for the modification to change from coal to oil firing. Erected costs are highly variable, especially on existing installations. For new installations, the erected, or installed, costs run about 1.7 times the FOB costs. Installed 1975 costs for both medium and high efficiency precipitators (all applications, not just oil-fired boilers) are shown in Figure 4-11(b). According to Figure 4-11(a), the purchase cost of ESP's designed for oil-fired

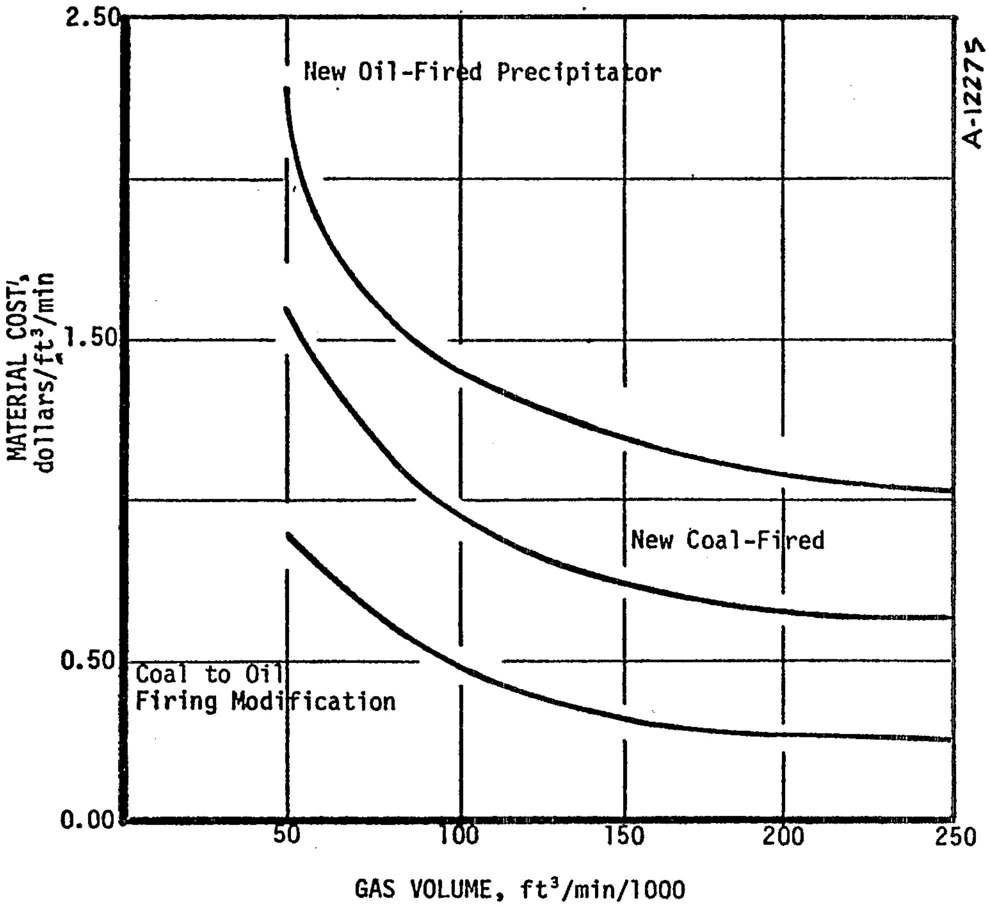


Figure 4-11(a). Electrostatic precipitator cost comparisons for 90 to 95 percent collection efficiency (1973 dollars — see Reference 4-31).

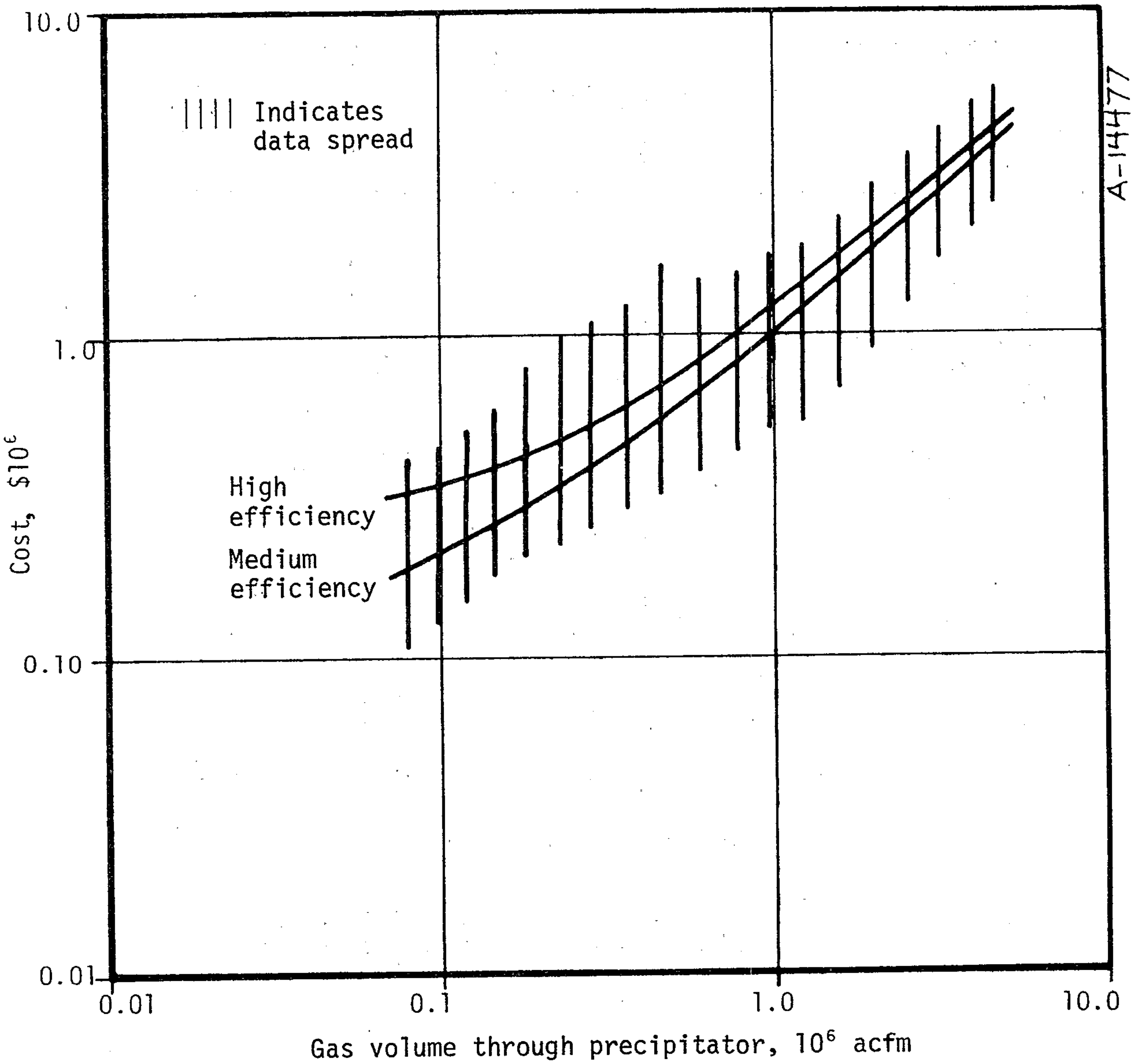


Figure 4-11(b). Electrostatic precipitator installed costs in 1975. Costs based on all units sold; ESP's for oil-fired boilers cost about 50 percent more (Reference 4-69).

units is about 50 percent more than that for ESP's used on coal units; hence the installed costs shown on Figure 4-11(b), which are heavily weighted by the preponderance of units sold to coal-fired boiler operators, should also be multiplied by 1.5 when used to calculate costs for oil-fired units. Operating cost is very low for electrostatic precipitators, amounting to about \$0.03 to 0.05/yr/cfm (Reference 4-31). Likewise, maintenance costs are about \$0.03/yr/cfm. Thus as shown by the calculations in Appendix D (page D-3), costs for high efficiency units are about \$0.8 x 10^{-4}/lb steam (\$1.8 x 10^{-4}/kg steam) for an industrial boiler with 125 MBtu/hr (36.6 MW) heat input (lower limit of data on Figure 4-11 and corresponding to about 100,000 lb steam/hr) and 0.008¢/kw-hr for a utility system.* Some recent data suggest that these costs may be as high as 0.02¢/kw-hr for large oil-fired boilers (see Appendix D). This means that the high efficiency precipitator cost represents nearly 2.5 percent of the fuel costs for the industrial boiler and 0.4 to 0.8 percent of the typical charge for electricity to a consumer (5¢/kw-hr). For a properly designed precipitator, only a very nominal draft loss of about 2 inches of water pressure is required (Reference 4-32). Precipitators require some ground space; therefore existing uncontrolled boilers would only be able to retrofit their boilers with such a device if they have the space available to expand.

Precipitators for oil-ash collection are faced with problems not normally encountered by precipitators for coal flyash collection. Some of the typical problems and solutions are noted below. None of them present insurmountable difficulties.

1. Oil ash contains a high percentage of unburned and uncombustible carbon (e.g., 50 percent). These particles have low electrical resistivity, especially when compared with most coal flyash. The low resistivity permits re-entrainment of the collected material. To solve this re-entrainment problem, the precipitators have to be enlarged, the electric controls have to be modified to increase power level, and the rapping frequencies have to be optimized.

2. Oil ash is hygroscopic. If this ash is allowed to cool, it would form a "cement." Therefore, the collector plates and hopper must be well insulated and heated to prevent this condition.

3. The whole system must be well insulated to prevent SO_3 condensation.

4.3.1.2 Mechanical Collectors

Mechanical collectors achieve particulate removal by means of centrifugal, inertial, and gravitational forces. These forces are developed in a vortex separator. The flue gas is admitted either

*See Appendix D for the method of computation. Based on 20 percent excess air for the industrial boiler and 3 percent for the utility system; cost increases by about 1 percent for each percent excess air.

tangentially or axially over swirl vanes (see Figure 4-12) thus creating a high velocity in the cylindrical portion of the device. Particulate matter, which is forced to the outer wall by the centrifugal forces, drops to the bottom of the cyclone and into the hopper. Axial collectors and centrifugal separators are both variations of mechanical cyclone collectors. These devices can also be built as multiple-cyclones, which consist of a number of small-diameter cyclones operating in parallel with a common gas inlet and outlet.

Typical efficiencies of the mechanical collectors are 75 to 85 percent by weight for particles 10 microns or larger (Reference 4-32). This efficiency is much lower for small particles. Therefore, the cyclones would be ineffective in oil burning installations if all burners were properly maintained and adjusted because small particles account for more than one-half of the particulate emissions by weight from such sources (References 4-30, 4-31, 4-37, and 4-38). However, if the burners receive only nominal attention, so that many larger particles are also emitted, or if the pollution problem is due to acid smut alone (typically large particles), and not opacity, a mechanical collector can provide adequate control. It is also useful in capturing the large particles that dominate the discharge during soot blowing.

The draft loss for mechanical collectors in normal boiler operation ranges from 2 to 5 inches of water. Capital, maintenance, and operation costs are approximately one-fifth of the corresponding costs for electrostatic precipitators (Reference 4-40).

Mechanical collectors have been used both before and after electrostatic precipitators. When installed ahead of the ESP, the purpose is to reduce the load on the precipitator, and when used afterwards, it is to catch re-entrained material that was dislodged from the collecting plates during rapping. Although these combinations are unnecessary with properly designed precipitators (References 4-32 and 4-41), they may be cost effective in certain instances.

4.3.1.3 Bag Filterhouses

In a bag filterhouse, the particle laden gas is filtered as it is forced through fabric tubes, or bags. The filtering is extremely efficient and normally results in better than 99 percent removal by weight of the entrained particles. The bags must be purged of the collected material periodically, and the method and frequency of cleaning characterize one type of filterhouse from another (e.g., mechanical shaker-type, reverse flow types, etc.). The pressure drop across the bags is usually greater than 6 inches of water.

This type of particulate collector has not been used in the control of particulate emissions from oil burning facilities. In fact, only one full-scale bag filterhouse is known to have ever been

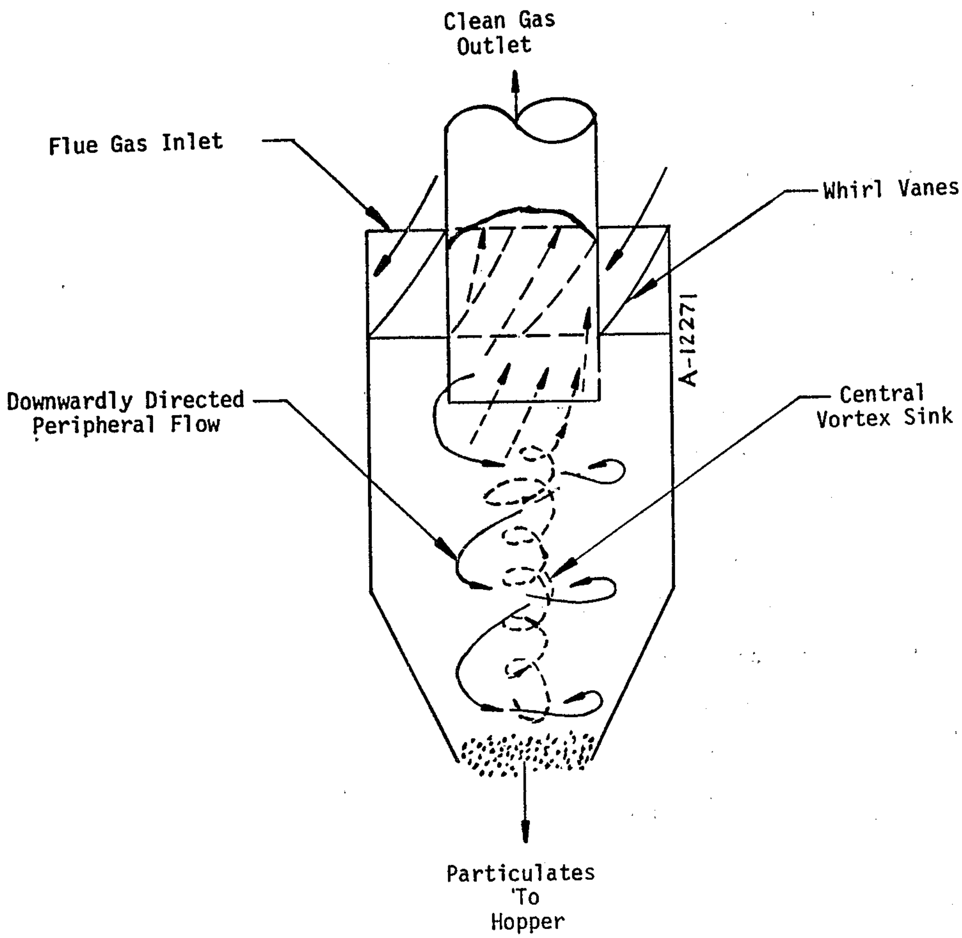


Figure 4-12. Principle of cyclone separator operation (Reference 4-30).

installed on an oil burning boiler. The purpose of that filterhouse was to eliminate a visible plume, and this requirement has now been eliminated by the availability of low sulfur, low ash oil. Therefore, the filterhouse has been removed from service (Reference 4-32). Many problems were encountered when the filterhouse was in service, the most prominent being the deterioration of the bags by the acidic oil and ash and the plugging of the bags due to the hygroscopic nature of the oil ash.

The costs of bag filterhouses vary appreciably depending upon the operating conditions for which they are designed. A fairly representative estimate for a typical installation, including amortized capital, installation, auxiliary power, operation, and maintenance costs is 2.2¢/MBtu input (2.1¢/GJ) (Reference 4-42). This cost is equivalent to $\$0.2 \times 10^{-4}$/lb raised (about $\$0.4 \times 10^{-4}$/kg steam), or about the same as the precipitator (see Subsection 4.3.1.1).

4.3.1.4 Wet Scrubbers

Wet scrubbers are employed by industrial and utility boiler operators mainly for sulfur oxide removal.* They are rarely used in oil burning facilities because of the relatively low sulfur content in most fuel oil.

Wet scrubbers can be used to remove particulates and/or sulfur oxides with high efficiencies. Particles are removed primarily by inertial impaction (e.g., impaction on spray droplets as the flue gas passes through fine sprays of scrubber solution), but other systems which rely more on interception, gravitational sedimentation, diffusion, and electrostatic forces are also used. Gaseous pollutants are generally removed from the exhaust stream by gas absorption in a selective liquid solvent.

Potentially, wet scrubbers can be utilized for the removal of fine particulates in conjunction with the removal of sulfur oxide. Considerable work has been done in this area (e.g., References 4-41, 4-42, and 4-44). Some of the wet scrubbers under development have shown particulate removal efficiency of greater than 99 percent by weight during pilot and prototype programs (Reference 4-41).

While wet scrubbers could be beneficial, some potential problems must be solved. These are as follows (References 4-32 and 4-36):

a. High draft loss — typically 10 inches of water (2.5 kPa) but extending up to 60 inches (15 kPa) for high collection efficiencies, resulting in high power requirement for operation

b. Cooled stack gas — resulting in reduced buoyancy at the stack exit

c. Moist exit gas — resulting in a visible vapor plume

d. Corrosive spent scrubber solution — resulting in a disposal problem.

*Their main use is to control particulates in industrial processes that emit large quantities of dust.

The capital cost of the wet scrubber is approximately one-quarter of that for an electrostatic precipitator. However, the operation and maintenance costs could be as high as five times that of the precipitator (Reference 4-40). On the basis of these figures the total annualized cost for the scrubber would be about 70 percent that of the precipitator before consideration of the differential power requirements to overcome the additional draft loss.

4.3.2 Operational Methods

4.3.2.1 Soot Blowing

Soot blowers are used in virtually all large industrial and utility boilers to remove ash and slag deposits from the heat transfer surfaces. These deposits come from both the noncombustibles in the fuel (especially the silica solids, sulfur, and vanadium) and the heavy hydrocarbon molecules that are difficult to burn (i.e., the carbon residue). Some lighter combustibles will also appear if the combustion is not controlled well. Moreover, the ratio between those particulates which leave the boiler directly and those which are first deposited on the heat transfer surfaces, and only leave when dislodged from these surfaces by the soot blowers, can depend upon the combustion characteristics, the configuration of the flow passages in the boiler, the shape of the heat exchangers, and the time since the last blow. Since soot blowers can do no more than remove material which has been deposited on the internal surfaces of the boiler, the major effect of varying soot blowing procedures is to change the manner in which particulates leave the boiler; little can be done directly with soot blowing to reduce the total mass of particulate created.

Specific soot blowing procedures can be used, however, to indirectly reduce total particulate emissions from a plant. The most important procedural change that impacts emissions is the interval between successive blows. Since soot blowing requires the use of either pressurized steam or air, both of which cost money and fuel to generate, the frequency of soot blowing has been dictated in the past by an economic trade-off analysis. The cost of blowing was balanced against the gains from improved heat transfer. On the basis of these guidelines, and also to minimize "hot spots" and buildup of corrosive deposits on the metal tubes, boiler operators generally established soot blowing programs with 4- to 8-hour intervals between blows on oil-fired boilers. One consequence of this approach was the periodic, short-duration discharge of a heavily dust-laden, visible plume. These emissions were probably dominated by large, heavy particulates that settled back to the ground near the plant and were a frequent source of complaints by neighbors. In an attempt to overcome these two problems (visible plumes and localized fallout), some utility and industrial owners of large boilers have adopted continuous, or continuous-sequential, soot blowing procedures. Boston Edison, for example, now blows each boiler in one of their plants in sequence (i.e., first one, then another, etc., and then returning to the first after the last of the boilers has been cleaned) rather than only two times per shift as they used to when guided only by boiler economics (Reference 4-56).

Although many blowers are manually operated, soot blowing manufacturers will now supply programmable blowers that can be controlled by a minicomputer to any desired schedule (e.g., one dictated by economics based on real-time analysis of the boiler performance, knowledge of the energy required to blow the surfaces, and the capacity of the particle collection equipment).

Unfortunately very little quantitative data are available on particulate emission rates or size distributions during soot blowing, and apparently none on total emissions during a complete cycle (the period between the start of two successive blows). One source reports that a particular residual oil fired utility boiler emitted between 0.05 and 0.08 lb/MBtu (21.5 - 34.4 ng/J) during normal operation and about 0.15 lb/MBtu (64.5 ng/J) during soot blowing (Reference 4-30). Since this boiler was equipped with an electrostatic precipitator, and since the collection efficiency of precipitators increases with increasing inlet loading and particle size (see Subsection 4.3.1.1), the emissions from the plant (i.e., downstream of the precipitator) were no higher during the soot blowing period than during the other times — about 0.02 to 0.05 lb/MBtu (8.6 - 21.5 ng/J). Apparently this precipitator was sized conservatively enough to handle the higher particulate loadings during the blow. In plants where this is not the case, alterations to the soot blowing frequency could reduce total emissions from the plant by insuring that the emission rates during a blow never exceed the capacity of the particle collection device.

If the plant has no collection device (recall from Subsection 2.4.3.3 that about one-half the residual oil consumed by utility boilers is burned in plants which do not have a particulate control device), then, as noted in the Boston Edison example cited above, the implementation of a reduced interval between successive blows changes the characteristics of the plume. It is possible that frequent soot blowing causes an increase in total suspended particles because it results in the frequent discharge of smaller particles rather than the occasional discharge of the larger particles which settle rapidly to the ground. Furthermore, the total mass emissions to the atmosphere probably do not change. Research is required to determine more clearly the relationship between soot blowing frequency and impact on total suspended particles in the ambient air.

Increased soot blowing frequency is the only variable that has been considered to date to alter particulate emissions. Spray angles, blower locations, fluid injection ratio, etc., are designed to remove deposits effectively and efficiently. Moreover, air and steam are considered to be equally effective when driven by the same power; the choice of which fluid to use is based strictly on individual plant economics (availability of steam at the desired pressure, need for compressed air elsewhere, etc.). Therefore, none of these parameters need to be considered when developing a particulate control program.

4.3.2.2 Low Load Versus High Load Operation

Industrial and utility boilers typically operate at between 60 and 100 percent of their design capacity, depending on the load requirement. However, information about the effect of boiler load on particulate emissions is scarce. Examples of the limited available data are presented in Figures 4-13 and 4-14 for two boilers, 250 MW and 600 MW, respectively (Reference 4-36). Both boilers employed fuel additives and operated with an electrostatic precipitator. If one ignores the scattered points at the 44 percent load level for the 250 MW unit and at full load for the 600 MW unit, then both plots show that particulate emissions increase with load.* These graphs suggest, for example, that a 40 percent reduction in particulate emissions can be realized by decreasing the boiler load from rated conditions to 50 or 60 percent of rated conditions. However, the capital expenditure penalties of such an approach are significant and most probably would not be acceptable, especially given current shortages in both capital and electric generation capacity.

4.3.2.3 Flue Gas Additives

Previous investigators have shown that SO_3 in the exhaust stream contributes significantly to the formation of visible plumes (Reference 4-45). Upon emerging from the stack the SO_3 forms a fine aerosol mist which increases the plume's opacity. One of the methods that can be used to reduce the amount of SO_3 emitted from the stack is to treat the flue gas with additives. This approach has been used primarily to reduce cold-end corrosion and smut deposits inside the furnace. The corrosion is caused by sulfuric acid, which is formed on these relatively cold surfaces by the condensation of SO_3 (claims of up to 50 percent reduction in SO_3 with use of flue gas additives appear in the literature — see Reference 4-49).

If the fuel contains high concentrations of vanadium and sodium, compounds of these metals will contribute significantly to the corrosion in utility boilers. These deposits generally cannot be removed from the heat transfer surfaces by soot blowers. Therefore additives must be used or a different fuel must be obtained.†

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*A similar result was obtained for commercial boilers that were fired on No. 6 oil (see Figure 2-7).

†In some cases the corrosion problem can be solved by reducing the superheater temperature from about 1000°F to 900°F (537 - 482°C). However, this causes a fuel penalty or decreased output of 2 to 4 percent and even then may not eliminate the problem (depending on fuel composition, superheater material, and boiler utilization).

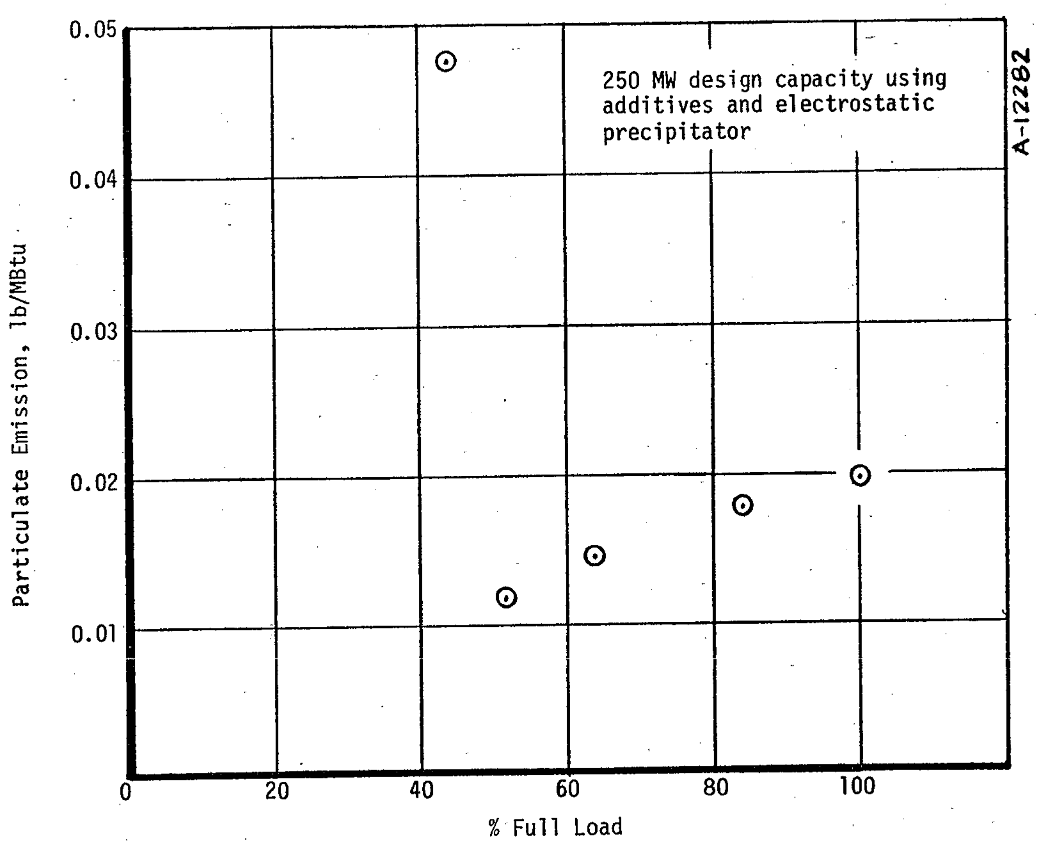

Figure 4-13. Particulate emission versus boiler load level for 250 MW unit (Reference 4-36).

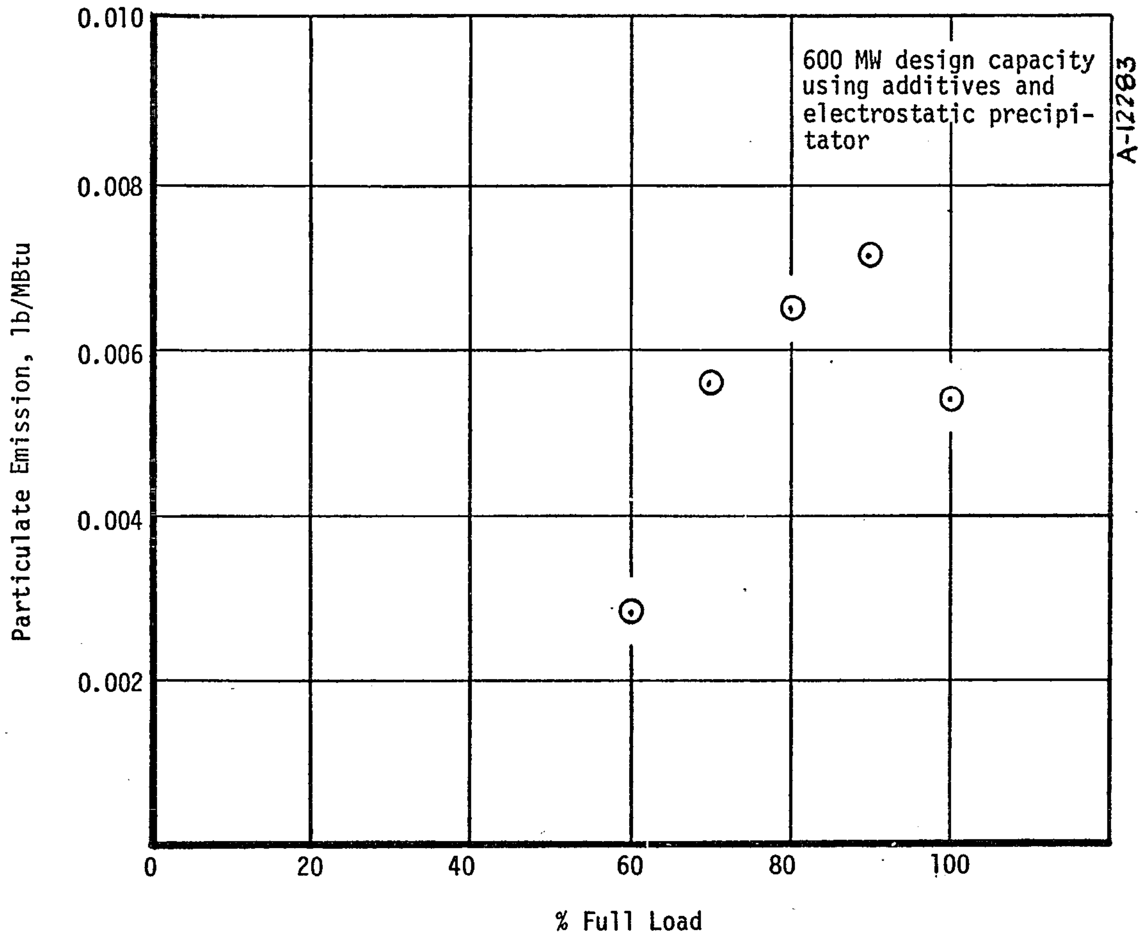

Figure 4-14. Particulate emission versus boiler load level for 600 MW unit (Reference 4-36).

Additives in dry powder, slurry, or gaseous form are injected into boiler installations either inside the firebox or the breeching. The most commonly used additives are limestone, dolomite, magnesium oxide, and ammonia. These additives react with the SO_3 to form solid sulfates (References 4-42 and 4-45) and, therefore, increase the emission of solid particulates. However, they turn the wet acid smut and sticky hygroscopic oil ash into a dry powder (References 4-42, 4-46, 4-47). Although precipitators and cyclones can collect a greater percentage of this dry powder than the acid smut or oil ash, the collection efficiency is not improved enough to offset the increased mass emissions. Therefore the total mass emissions are actually increased, even from boilers that are equipped with particulate control devices.

A coating of magnesium oxide on the superheater tubes has also been shown to effectively inhibit the conversion of SO_2 to SO_3. Apparently, the MgO coating prevents the vanadium deposits and the iron oxide from acting as catalysts for the SO_2 to SO_3 conversion (Reference 4-28).

From the cost-effectiveness standpoint, this approach probably should not be applied if the only concern is the reduction of plume visibility caused by SO_3. However, investigations have indicated that flue gas additives can be beneficial in reducing low temperature corrosion caused by the condensation of SO_3 and may be the only means available of burning residue with a high vanadium content.

4.3.2.4 Opacity Monitoring and Burner Controls

Instruments are available commercially for the continuous monitoring of stack opacity. In general these opacity monitors are connected to visible or audible alarm systems which give warnings should a preset level of opacity be reached. Many power plants and industrial operators of large boilers now use such a system, and some states require its use in residual-fired units or boilers larger than a certain size (see Table 6-5). These monitors are now also being connected to continuous recorders to provide a permanent record of boiler performance to both plant supervisory engineers and air pollution control authorities.

Until recently only one unit was available in the United States which satisfied EPA specifications for continuous opacity monitors on new steam generators >250 MBtu/hr (73.25 MW). These sources have to comply with a standard of performance which includes a continuous monitoring requirement. However, other transmissometers which will also satisfy these specifications (especially spectral response in the visible range and restricted divergence of the light beam) are now appearing on the market. The first unit mentioned above consists of a light source and photocell mounted on one side of the stack with a reflector mounted diametrically opposite. Since the light beam traverses the stack two times before it is received by the photocell, the sensitivity is twice what it would be if the photocell were directly opposite the light. Dust loading, or particulate density, is measured by the attenuation of the light beam as it traverses the stack. This attenuation is related logarithmically to the optical density, which, in turn, is related linearly to the dust loading, assuming a fixed particle size distribution and path length.* Therefore, once calibrated for a given source the instrument will read dust loading directly if the particulate characteristics do not change. As shown on Figure 4-15 for the emissions from a coal-fired utility boiler, the monitor's output can correlate well with outlet particle loading.

This particular system can be used in stacks whose diameter is between 1.2 and 60 feet (0.36 - 18.3 m). The monitor can be installed at a representative location of the exhaust system. If this location happens to be away from the stack exit, the output can be corrected to the stack exit conditions. Calibration is done remotely and, therefore, as often as one wants. The monitor costs about $8,800, including the unit startup, on-site calibration, alignment, repair kit, spare parts, and servicing for the first year of operation. The price does not include a recording device such as a strip chart recorder ($440). The newer units cost about one-third as much as this one, but they do not have as good a purge system as the more expensive monitor, and maintenance requirements for the system are somewhat greater. Ambient air is continuously blown across the optical surfaces to purge them. Maintenance after the first year includes cleansing of the optical surfaces, calibration, and troubleshooting. This is normally performed four times a year and takes 2 to 4 hours each time. The cost of this service is about $800 per year, including labor and spare parts (Reference 4-51).

In addition to these accurate, but expensive, monitors, there are also quite a few less costly units available. These systems sell for $600 to $1200. Although the lower cost ones usually do not meet EPA specifications for units less than 250 MBtu/hr (73.25 MW), the more expensive ones generally do satisfy these requirements (Reference 4-67). In some cases the main difference between a $600 and a $1200 unit is its linearity — the cheaper system is linear only up to about 80 percent opacity whereas the more expensive one is linear all the way to 100 percent opacity (as required by the EPA specification). Both respond to the obscurations in the spectral range specified in the Federal Register. Some of these units can be used only on stacks whose diameter is less than 10 ft (3 m) and are, therefore, not appropriate for large boilers. However, they can be particularly useful when installed on commercial or small industrial boilers to notify the operator (by an alarm) of a high smoke condition so that he can correct it immediately. The advantages of such a warning system in reducing localized

*According to the Beer-Lambert law, the transmittance, or fraction of the intensity of a light beam that passes through a particulate-laden flow, is given by $T = e^{-kcd}$, where k is a measure of the light absorbing capability of the particles, c = the concentration of particles (mass per unit volume), and d = the stack diameter. The optical density, D, is defined by the equation $D = - \log T$. By combining these two equations, one can show that $D = Kc$, where $K = kd/\ln(10)$ = constant for constant particle size distribution and light scattering characteristics.

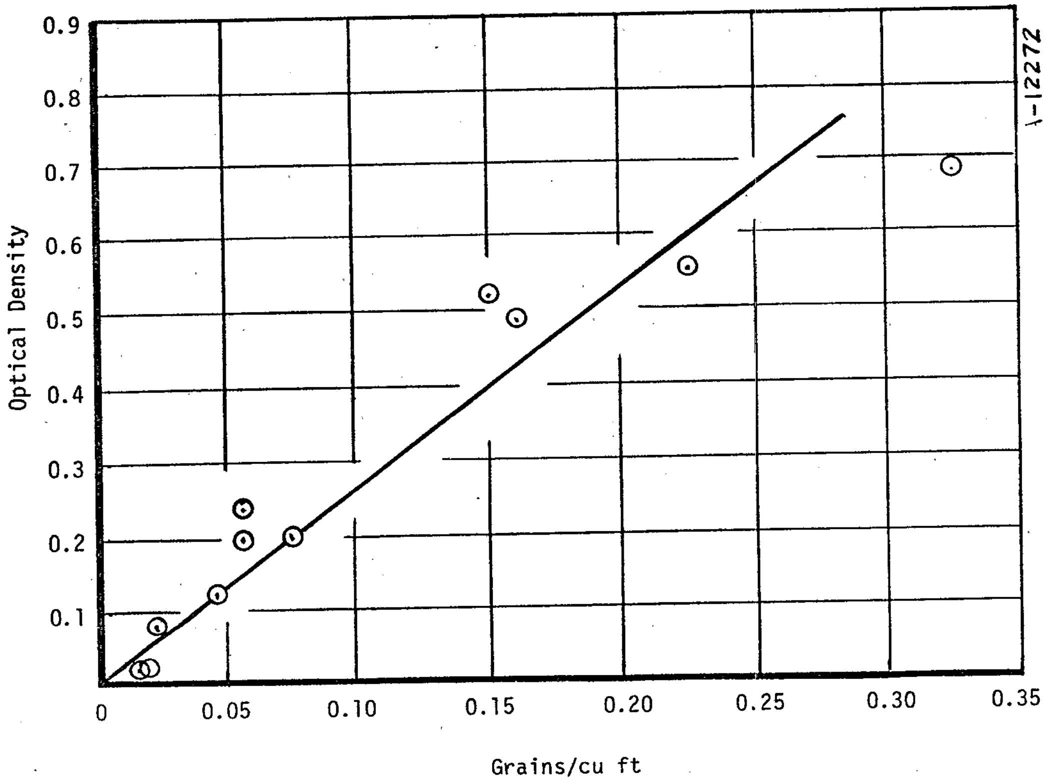

Figure 4-15. Optical density versus outlet grain loading from a coal-fired utility boiler (Reference 4-53).

pollution and saving fuel are obvious. These opacity monitors need frequent cleaning of the optical surfaces because they do not have an air purging system.

Certain opacity monitors can be connected to relays which shut off burners when excess smoke is encountered. However, boiler manufacturers and operators generally have not used this automated shutdown approach because they felt that the smoke meters have not been reliable enough (References 4-57 and 4-58). Moreover, high opacity readings in the stack can come from a variety of problems other than the burners themselves, such as failure of a particulate collection device or accidental shutting of an air damper. The temporary and occasional localized nuisance caused by the smoke during such malfunctions probably does not warrant a complete shutdown of a large, multiburner industrial or utility boiler.

Oxygen concentration in the exhaust gas is a better parameter to monitor than smoke for optimizing the combustion process. Typically a boiler can operate over a range of excess air levels without smoking, especially when it is on the lean side of the optimum oxygen concentration. Therefore, much more information about the combustion process is obtained from the exhaust gas oxygen concentration than from the plume opacity.

Most utilities now use automated controls to minimize operator error. The primary control parameters are load and oxygen content (as measured in the firebox), and the system is designed to ensure that sufficient oxygen is always present. As load increases, the automatic controls cause the air flow increase to lead the fuel flow rate increase; conversely, when power demand decreases, fuel reductions occur before air flow is decreased.

4.3.3 Emerging Technologies — Viscosity Control

Although the viscosity of the fuel at the burner head has been shown to affect particulate emission from commercial boilers (Reference 4-17), no data are available that demonstrate the effects of varying only viscosity. Nevertheless it has been suggested that improved viscosity control could reduce particulate emissions.

Oil-fired industrial and utility boilers, which generally burn residual oil, are equipped with fuel preheaters. These systems heat the fuel to reduce its viscosity to a level which is compatible with the burner nozzle. Most preheaters are controlled by the temperature of the heated oil, but a new device is now available which measures viscosity continuously, in real-time, with an accuracy of 1 percent (Reference 4-66). Output from the device can be used to regulate the preheat level. The value of this device is that it delivers the fuel at a specified viscosity independent of the fuel's viscosity-temperature relationship (which is generally different for each batch of fuel).

4.4 ENERGY CONSERVATION

Energy conservation is at once the most satisfying and the most difficult approach to reducing particulate emissions. Effective conservation practices would reduce the quantity of fuel burned and, hence, the generation of combustion derived pollutants. Unlike most other particulate control techniques, this one does not involve any trade-offs between particulates, fuel consumption and NO_x emissions; instead all are reduced simultaneously and proportionally.

Particulate emissions from industrial and utility boilers could be reduced by improved utilization of process steam, by the application of waste heat recovery systems to preheat combustion air or feedwater, by increased reliance on recycled materials, and by reduced consumption of electricity throughout industry, commercial or public buildings, and private homes. The high cost of energy is sufficient inducement for most industrial and commercial enterprises to introduce energy conservation procedures, and these vary considerably from one facility to another. In addition, many utilities have active information programs that describe techniques for conserving electricity to their residential customers. Therefore, these approaches will not be discussed further here.

In the residential sector a recent study (Reference 4-63) has shown that fuel consumption could be reduced by replacing existing fuel nozzles with properly sized ones. This conclusion is based on the observation that 97 percent of the units surveyed during the study were overfired — i.e., were equipped with a nozzle whose capacity is larger than necessary to heat the residence. When 27 of these units were fitted with smaller nozzles, their efficiency increased an average 1.6 percent. Unfortunately the average smoke number also increased, from Smoke Spot Number 0.8 to 1.2.

The most direct approach to energy conservation involves the design of new and more efficient heating equipment. In the past, the design of heat exchanges, for example, has been based on a compromise between cost and efficiency. However it is estimated (Reference 4-64) that improved designs could reduce energy demand by as much as 15 percent while maintaining a good cost/efficiency tradeoff.

Other examples (Reference 4-64) of new and improved equipment design include the use of automatic combustion air control (potential energy reduction 10 - 27 percent), modulating burners (10 percent) and oil heat pumps (50 percent). Of these, the heat pump and improved heat exchangers seem to have the best cost/efficiency trade-off and, therefore, have the highest potential for particulate reduction through conservation.

One area of energy conservation which has received considerable interest recently is building insulation. This practice is directly relevant to the current study because improved insulation reduces the load on oil-fired furnaces. Space heating accounts for about 80 percent of the consumption of energy for comfort heating and hot water in residences and about 86 percent in commercial buildings (Reference 4-57). It has frequently been stated that proper insulation could reduce the nation's energy consumption for residential and commercial space heating by 40 percent. If these figures apply to the large northeastern cities, and if a 40 percent reduction in energy consumption is equated to a 40 percent reduction in particulate emissions, then the immediate application of proper insulation would reduce the particulate emissions contribution from these sources by up to 5 percent of the total in these areas. Since immediate application of improved insulation to all buildings is unrealistic, the actual reductions in particulate emissions from an organized building insulation program will be less.

Several documents have been published recently by national agencies which describe how to reduce energy consumption for space heating and give the associated costs and benefits. These reports are listed in Table 4-5. Suggested energy reduction programs for winter heating are presented in Table 4-6. These approaches generally fall into three categories: life-style changes (e.g., lower thermostat settings), building improvements (insulation, weather stripping, storm windows), and proper maintenance of the heating equipment.

TABLE 4-5. SELECTED REPORTS ON ENERGY CONSERVATION

Technical Options for Energy Conservation in Buildings National Bureau of Standards Technical Note 789, July 1973. (Available from the Superintendent of Documents GPO, for $2.35.) Contains material distributed at the Joint Emergency Workshop on Energy Conservation in Buildings, June 19, 1973, under the sponsorship of the National Conference of States on Buildings Codes and Standards and of the National Bureau of Standards.
Energy Conservation Program Guide for Industry and Commerce National Bureau of Standards Handbook 115, September 1974. (Available from the Superintendent of Documents GPO, for $2.90.) Prepared in cooperation with the Federal Energy Administration/Conservation and Environment as an energy management tool for intermediate to small sized firms.
Potential for Energy Conservation in the United States: 1974-1978 National Petroleum Council (Committee on Energy Conservation), September 1974. Presents petroleum industry assessment of potential for energy reductions through conservation. Gives estimates of energy savings from a variety of conservation measures.
Mineral Resources and the Environment Committee on Mineral Resources and the Environment, Commission on Natural Resources, National Research Council, National Academy of Sciences, 1975. (Available from Printing and Publishing Offices, NAS, 2101 Constitution Avenue N.W., Washington, D.C. 20418.) Contains a section on material conservation.

TABLE 4-6. REDUCTION OF HEATING ENERGY CONSUMPTION

<u>Without Extra Cost</u>

- Set your thermostat lower
- Close off rooms not used and turn off heat
- Let the sunshine in on winter days; pull shades at night
- Reduce air leakage and ventilation
- Be careful about open windows and doors
- Reduce temperature in public spaces, lobbies, etc.
- Institute rigorous schedules for planned operation of ventilation
- Wear heavier clothing
- Maintain an efficient heating plant
- Turn off — turn down lights and electric appliances except when needed
- Concentrate evening work or meetings in a single heating zone

<u>With Extra Cost</u>

- Add a clock thermostat
- Add insulation, as much as feasible
- Add insulating glass or storm windows and doors
- Caulk and seal around windows, doors and other openings
- Insulate heating ducts and seal against air leakage into nonheated spaces (attics, crawl spaces)
- Maintain heating equipment — clean heat transfer surfaces, set flame and combustion air
- Install heat recovery and conservation devices
- Install automatic pilot light
- Adjust ventilation system
- Avoid use of portable electric heaters by improving main heating systems
- Replace defective or inefficient heating systems with systems of higher efficiency
- Modify systems for zone control using systems of higher efficiency
- Provide means to transfer heat from the core of a large building to the cool periphery needing heat
- Install automatic door closers

Source: Technical Options for Energy Conservation in Buildings, NBS Technical Note 789, 1973

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SECTION 5

INDUSTRY STANDARDS FOR CONSTRUCTION, SAFETY, AND PERFORMANCE OF BURNERS, BOILERS, AND FURNACES

As seen in Chapter 2, particulate emissions from an oil-fired furnace or boiler are a function of the design characteristics of the unit. This chapter gives an overview of the rules and guidelines used by the five principal private and trade organizations which set design standards for furnaces and boilers:

- American Boiler Manufacturers Association (ABMA)
- The Hydronics Institute (Formerly the Institute of Boiler and Radiator Manufacturers, or IBR).
- The American Society of Mechanical Engineers (ASME).
- The American National Standards Institute (ANSI).
- Underwriters Laboratories, Inc. (UL).

The ABMA is primarily concerned with providing a uniform method of testing commercial and industrial boilers to determine their rated capacity and efficiency (Reference 5-1). In order for a manufactured boiler to be listed with the ABMA, it must be capable of continuous operation at its stated capacity "without objectionable smoke as defined by existing smoke ordinances."* Consequently the ABMA serves an initial screening function against potentially large polluters. The boiler must also be in compliance with UL safety standards for construction.

The Hydronics Institute performs a function similar to the ABMA, but mainly for residential units. In order to be listed with the Institute a boiler must maintain a Bacharach smoke reading of less than No. 2 for distillate firing or No. 4 for residual oil firing (Reference 5-2). Consequently the Hydronics Institute also serves to screen out designs which are inherently heavy particulate emitters.

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*The manual did not specify whose smoke ordinances should be obeyed; presumably, they mean the regulations of the air pollution control district in which the boiler will be located although they could refer to those of the district in which the boiler manufacturer resides.

In addition to supplying a testing service and a boiler rating guide, the Institute publishes instructions for the operation and maintenance of large and small boilers. These manuals are generally educational and are written in non-technical language so as to be of use to operators of small boilers with little knowledge of boiler fundamentals.

The ASME publishes detailed recommended rules for the operation of both heating and power boilers (References 5-3 and 5-4). These rules include several practices which, if followed, would lead to reduced particulate emission levels. They are as noted below:

- A detailed maintenance procedure, including a list of boiler parts which typically require frequent inspection (e.g., nozzles and oil line strainers, both of which cause increased particulate emission when dirty).
- A detailed description of an annual combustion efficiency test, including measurements of draft, smoke, and CO_2. Although target CO_2 concentrations are suggested, no limitations are placed on Bacharach smoke numbers.
- General guidelines for soot-blower operation, which may reduce particulate emissions, or at least avoid the notorious short duration, high grain loading puffs.

The ASME also publishes many nationally recognized codes, such as the other sections of the pressure vessel code, which set design standards for the structural components of the system and operating specifications for the controls. These were developed to ensure the safety of such systems and are not affected by any proposed particulate control techniques.

The two organizations which exercise the most authority over furnace and boiler design standards are UL and ANSI, and their primary aim is toward consumer protection. Both organizations publish standards for construction and operation of furnaces and boilers. These deal mainly with structural, electrical, and control requirements. In the case of the UL standards, any references to combustion systems duplicate their standard No. 296 for oil burners (Reference 2-5). This standard, which is also approved as an ANSI standard, includes the following requirements that can impact particulate emissions:

- Emissions may not exceed a Bacharach smoke number of 2 if distillate is used or No. 4 if resid is used. These requirements must be met even if a burner is allowed to continue operation after failure of a forced draft fan.
- Ignition systems must activate before, or simultaneously with, main burner fuel delivery. This reduces "ignition puffs" to a minimum.

- Burner designs must include a self aligning feature so that replaced nozzles and firing assemblies will be automatically aligned to their correct position. This stipulation eliminates high particulate emissions caused by leaking nozzles, loose pump connections, etc.
- Burners must automatically shut off if a low atomizer pressure is detected. This requirement reduces dribble to a minimum. Additionally, the burner is tested over its entire range of operation under "worst case" conditions (for example, it is fired during testing with the heaviest recommended fuel oil), and it must perform satisfactorily under simulated emergency conditions.

A new ANSI standard, Z91.2 for automatic pressure atomizing oil burners of the mechanical draft type, has recently received mail ballot approval and will be published in early 1976. This standard is directed at residential units (<7 gph or about 0.3 Mw) and stipulates that they must be capable of producing and maintaining a CO_2 concentration in the exhaust of no less than 10 percent and a Smoke Spot Number of no greater than shade No. 1 during steady operation. These limits are considered to be a reasonable standard for the industry at this time, since they represent performance and emission levels that the products from many, but not all, manufacturers can meet now. Moreover, they are more demanding than the previous levels of 8 percent CO_2 and Smoke Spot Number 2.

In general, the rules, procedures and guidelines proposed by each of the above organizations seem to lead incidentally to reduced particulate emissions; no guideline was found that promoted increased emissions as a by-product of encouraging safety and standardized rating methods. These new equipment standards, though not required by pollution control regulations, appear to be beneficial in terms of limiting particulate emissions. In addition, the ASME boiler operating rules represent a basic standard of maintenance that should ensure minimal emissions from existing equipment.

REFERENCES FOR SECTION 5

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5-3. ASME Boiler and Pressure Vessel Code Section VI, Recommended Rules for the Care and Operation of Heating Boilers, The American Society of Mechanical Engineers, United Engineering Center, 345 East 47th Street, New York, N.Y. 10017, July 1, 1974.

5-4. ASME Boiler and Pressure Vessel Code, Section VII, Recommended Rules for Care of Power Boilers, The American Society of Mechanical Engineers, United Engineering Center, 345 East 47th Street, New York, N.Y. 10017, July 1, 1974.

5-5. Standard for Safety, Oil Burners, UL 296, Underwriters Laboratories, 1285 Walt Whitman Road, Melville, N.Y. 11746. Approved as American National Standard ANSI Z96.2-1974. September 19, 1974.

SECTION 6

SUMMARY OF EXISTING CONTROL PROGRAMS

6.1 INTRODUCTION

The major objective of this document is to propose model control programs that can serve as guides to State and local air pollution authorities when they prepare regulations for the control of particulates from oil-fired burners. Since any proposed control program should take advantage of the experiences gained with the existing control programs, we present here a summary and review of control programs that are currently in use for particulates from oil-fired equipment. This summary deals mainly with existing emission limits and enforcement procedures that are used by several control authorities. Unfortunately very little can be said about the effectiveness of these control programs, both because many of them are quite new and because the relationship between ambient air particulate concentrations and emissions from a given group of sources is not always clear. Occasionally we have received suggestions for additional or new control programs by staff members of various local and state control authorities, and these are included in our review.

Two approaches have been used to evaluate the existing control programs. The first consists of the review and compilation of regulations dealing with particulates. These regulations were obtained from the Environment Reporter - State Air Laws (Reference 6-1). Our review is restricted to those regulations which control particulate loadings and visible emissions from indirect heating oil-fired fuel combustion sources.

The other approach was to meet directly with the enforcement and engineering staff in nine State and local air pollution control agencies which are believed to have pursued active programs for the control of particulate matter from oil burner equipment. Four control agencies were contracted which had jurisdication over the entire State and five were contacted which had jurisdiction only over a metropolitan area (see Table 6-1). Los Angeles is included in the list of agencies contacted, despite the relatively low utilization of oil in the past, because of its history of leadership in control programs. The list of agencies contacted was purposely selected to include both State and metropolitan agencies. This was done to determine whether each one of these types of agencies had specific and unique control problems that the other agencies did not encounter.

TABLE 6-1. AIR POLLUTION REGULATORY AGENCIES VISITED DURING REPORT

States	Metropolitan Areas
Connecticut	Boston
Maryland	Erie County, New York
New Jersey	Los Angeles
Rhode Island	New York City
	Philadelphia

In the next section we present the review of the particulate and visible emission limits for all the states. The following section then looks in greater detail at the emission limits and enforcement procedures used in the nine selected control districts. Before proceding to these discussions of regulatory programs, we note that certain nonregulatory programs exist which aim to reduce particulate emissions. Chief among these are the various private, industry, and trace association sponsored training programs for burner servicemen and boiler operators/maintenance staff. Voluntary operational changes that result in energy conservation are indirect particulate control programs since they cause a reduction in fuel consumption. This category of activities includes the use of more building insulation, more attention to energy efficient operation, the installation of energy recovery devices such as waste heat recovery units, and a shift to greater recycling of metals, glass, and paper products. And, finally, information campaigns ("PR") can educate both the public and the owners of commercial or small industrial boilers about the value of proper, periodic maintenance programs. Such campaigns seem to be most effective if they stress the fuel savings that come from correct maintenance practices and only secondarily describe the consequent environmental benefits (see, for example, the discussion in subsection 4.2.1.1 about burner servicing in Boston).

6.2 PARTICULATE LOADING AND VISIBLE EMISSION LIMITS

Table 6-2 presents the particulate limits for each state for oil-fired indirect heating fuel burning sources. As mentioned earlier these limits were taken from the State Air Laws volume of a publication called the Environment Reporter (Reference 6-1). This multi-volume document is published in loose-leaf format and updated periodically. Other volumes report state laws for other media or federal regulations. Since this publication is directed in large part to environmental lawyers, it is frequently available at large law libraries. Most of the regulations are in terms of mass of pollutants per unit heat input (lb particulate/MBtu), but some are in terms of mass emissions per unit exhaust flow (grains particulate/standard cubic foot of exhaust). Whenever the

TABLE 6-2. STATE REGULATIONS FOR PARTICULATE EMISSIONS FROM OIL-FIRED INDIRECT HEATING SOURCES[a], lb/MBtu

	Footnotes[b]	Source Heat Input Rate, MBtu/hr																			
		<1	≤10	>10	20	50	100	≤200	>200	≤250	>250	≤500	>500	1000	2500	5000	7500	10000	>10000	50000	≥10[5]
Alabama	*			0.5						0.12											
Alaska	*	0.083																			
Arizona	*		0.6		0.51	0.4	0.35		0.30		0.28		0.243	0.21	0.17	0.13	0.11	0.09		0.036	0.025
Arkansas			0.25				0.15							0.10				0.025			
California	*	0.167																			
Colorado		0.5	0.21		0.23	0.18	0.15		0.13		0.12		0.1								
Connecticut	*	0.1																			
Delaware	*	0.3																			
D.C.	*		0.13				0.06							0.035				0.02			
Florida	*	0.1																			
Georgia	*		0.50								0.10										
Hawaii	*																				
Idaho	*		0.6				0.35							0.21				0.12			
Illinois		0.10																			
Indiana	*		0.6							0.1											
Iowa	*	0.6																			
Kansas			0.6		0.51	0.41	0.35		0.30		0.28	0.24		0.21	0.17	0.14	0.13	0.12			
Kentucky	*		0.56			0.38	0.33				0.10										
Louisiana		0.6																			
Maine	*		0.60					0.3													
Maryland	*		0.06	0.05		0.03			0.02												
Massachusetts	*		0.1								0.05										
Michigan							0.3														
Minnesota	*	0.4																			
Mississippi		0.6	0.6															0.19			
Missouri	*	0.6	0.6		0.56	0.46	0.4		0.375		0.36	0.30		0.26	0.23	0.2	0.19	0.18			
Montana	*		0.6				0.35							0.20				0.12			
Nebraska			0.6			0.41	0.35					0.24		0.21	0.17	0.14	0.13	0.12			
Nevada	*		0.6				0.35							0.20				0.09			0.02
New Hampshire	*		0.6			0.40	0.35				0.10										
New Jersey		0.6	0.6		0.4	0.22	0.15		0.1												
New Mexico	*		0.005																		
New York											0.1										
North Carolina	*	0.6	0.6				0.33							0.18				0.10			
North Dakota	*		0.6			0.486	0.443					0.359		0.328	0.291	0.266	0.252	0.242		0.197	0.180
Ohio	*		0.4											0.10							
Oklahoma	*		0.6				0.35							0.20				0.12			
Oregon	*	0.33																			
Pennsylvania	*		0.4			0.4							0.1								
Rhode Island			0.20								0.1										
South Carolina	*	0.60	0.60											0.60		0.2		0.12	0.1		
South Dakota		0.3																			
Tennessee	*		0.6		0.41	0.24	0.17				0.10										
Texas	*			0.1																	
Utah	*																				
Vermont	*		0.5									0.1		0.02							
Virginia	*	0.4			0.4													0.10			
Washington	*	0.33																			0.33
West Virginia			0.34		0.28		0.166									0.10					
Wisconsin	*	0.15								0.15	0.10										0.10
Wyoming	*	0.1																			
A. Samoa		0.1																			
Guam	*																				
Puerto Rico		0.3																			
Virgin Islands	*		0.6				0.352							0.207					0.09		

Footnotes follow. See Appendix C for conversion to SI units.

FOOTNOTES FOR TABLE 6-2

[a]Source: Environment Reporter: State Air Laws. Volume 2, Parts 1 and 2. A looseleaf document published and periodically updated by the Bureau of National Affairs Publishers, Washington, D.C., 20037. Based on update as of November 1975.

[b]Footnotes follow by states in alphabetical order for those with *. E = emission limits, lb/MBtu; H = input heat rate, MBtu/hr. Table contains limits for new units whenever there are different limits for new and existing sources. Limits for existing sources in the footnotes. ⟶ means constant emission limit from left end of line to tip of allow. – –→ means continuously decreasing limit between the values at each end of the dashed line (limits in state regulations either given as a graph or as an equation. See the footnotes by state below).

Alabama — Tabulated emissions are for Class 1 counties. For Class 2 counties $E = 3.109 H^{-0.589}$ for $10 \leq H \leq 250$ MBtu/hr.

Alaska — Based on regulation of 0.05 grains/scf flue gas @ standard conditions or 0.10 grains/scf for units operating prior to July 1, 1972.

Arizona — Based on 24 hour arithmetic average.

California — Based on grains/scf corrected to 12 percent CO_2. Valid for 14 counties. One additional county limited new sources to 0.167 lb/MBtu and existing sources to 0.333 lb/MBtu. Another county limited sources to 0.263 lb/MBtu and 12 counties limited sources to 0.5 lb/MBtu. In addition the South Coast Air Basin limits all new sources to 10 lb/hr.

Connecticut — 0.2 lb/MBtu for existing sources.

Delaware — No restrictions if heat input less than 1 MBtu/hr. Restrictions exclude start-ups and shutdown periods. Limits based on a 2 hour average.

D.C. — 0.13 lb/MBtu for units less than 3.5 MBtu/hr.

Florida — Based on a 2 hour average.

Georgia — For units in operation or under construction on or before January 1, 1972:

Less than 10 MBtu/hr	— 0.7 lb/MBtu
Greater than 10 but less than 20,000 MBtu/hr	— $E = 0.7\ (10/H)^{0.202}$
Greater than 2,000 MBtu/hr	— 0.24 lb/MBtu

Hawaii — No general regulation stated in final SIP.

Idaho — Sources less than 1 MBtu/hr are exempt; sources greater than 10 MBtu/hr and less than 10,000 MBtu/hr have allowable emission rate determined by $\text{Log } E = -0.233 \text{ Log } H + 1.0112$.

Indiana — For existing sources:

H MBtu/hr	E lb/MBtu
$H \leq 10$	0.6
$10 < H \leq 10{,}000$	$0.87H^{-0.16}$
$H > 10{,}000$	0.2

Iowa — 0.6/MBtu for any new source and any source in any standard metropolitan area; 0.8 lb/MBtu outside metropolitan area.

Kentucky — For existing sources the emissions are limited to:

MBtu/hr	Priority 1	2	3
≤ 10	0.56	0.75	0.80
50	0.38	0.52	0.57
100	0.33	0.44	0.49
250	0.26	0.35	0.40
500	0.22	0.30	0.34
1000	0.19	0.26	0.30
2500	0.15	0.21	0.24
5000	0.13	0.18	0.21
7500	0.12	0.16	0.19
10000	0.11	0.15	0.18

Maine — Based on 2 hour average

Maryland — Based on regulations in gr/scfd at 50 percent excess air for new units. Limits for existing residual-fired units greater than 200 MBtu/hr are 0.03 lb/MBtu. No mass limits on smaller existing units or on any sized distillate units.

Massachusetts — 0.15 lb/MBtu for existing sources greater than 3 MBtu/hr except 0.12 lb/MBtu in critical areas of concern (e.g., Boston). New units greater than 250 MBtu/hr can emit 0.10 lb/MBtu if also equipped with an SO_2 control device.

Minnesota — All old installations 0.6 lb/MBtu.

Missouri — For existing sources:

≤ 10 MBtu/hr — 0.6 lb/MBtu
100 MBtu/hr — 0.43 lb/MBtu
1000 MBtu/hr — 0.29 lb/MBtu
2000 MBtu/hr — 0.26 lb/MBtu
10000 MBtu/hr — 0.18 lb/MBtu

Montana — For existing sources:

≤ 10 MBtu/hr — 0.6 lb/MBtu
100 MBtu/hr — 0.40 lb/MBtu
1000 MBtu/hr — 0.28 lb/MBtu
> 10000 MBtu/hr — 0.19 lb/MBtu

Nevada — For 2.5 to 1000 kcal/hr, $E = 1.34H^{-0.231}(1.02H^{-0.231})kg/10^6$ kcal. For > 10^3 kcal/hr, $E = 13.9H^{-0.568}$ $(17.0H^{-0.568})$.

New Hampshire — For existing sources

Less or equal to 10 MBtu/hr — 0.6 lb/MBtu
50 MBtu/hr — 0.46 lb/MBtu
100 MBtu/hr — 0.40 lb/MBtu
500 MBtu/hr — 0.31 lb/MBtu
1000 MBtu/hr — 0.28 lb/MBtu
2500 MBtu/hr — 0.24 lb/MBtu
5000 MBtu/hr — 0.22 lb/MBtu
>7500 MBtu/hr — 0.20 lb/MBtu
≥10000 MBtu/hr — 0.19 lb/MBtu

FOOTNOTES FOR TABLE 6-2 (Concluded)

New Mexico — Based on operation greater than 8000 hours/year. Revision upward expected in 1976.

North Carolina — Use Figure 2 in state regulations for interpolating between given values.

North Dakota — For existing equipment $E = 0.80$ lb/MBtu

Ohio — $E = -0.15 \log H + 0.55$ for $10 \text{ MBtu} < H < 1000$ MBtu/hr.

Oklahoma — For old equipment less than 0.6 lb/MBtu.

Oregon — For old equipment less than 0.66 lb/MBtu.

Pennsylvania —

$2.5 \le H < 50$ MBtu/hr	$E = 0.4$ lb/MBtu
$50 \le H < 600$ MBtu/hr	$E = 3.6\ H^{-0.56}$
$H \ge 600$ MBtu/hr	$E = 0.1$

South Carolina — For all equipment emission limits depend upon stack height for heat inputs greater than 500 MBtu/hr. For units in use or under construction before February 11, 1971, limits are 0.8 lb/MBtu for those less than 10 MBtu/hr and the same as new units for those >10 MBtu/hr.

Tennessee — For existing sources built or under construction on or before July 1, 1975:

$H \le 10$ MBtu/hr	$E = 0.6$ lb/MBtu
$10 < H \le 250$ MBtu/hr	$E = 0.6\ (10/H)^{0.2594}$
$H > 10000$	$E = 0.1$

Texas — Federal regulation (0.1 lb/MBtu) extended to all oil-fired sources in the state unless sources are less than 500 HP. This regulation was obtained from phone conversations with Texas Air Control Board on December 3, 1975. For existing sources E (lb/hr) $= 0.048\ q^{0.62}$ for $H < 10000$ MBtu/hr where q is effluent flow rate in ACFM, and $E = 0.1$ lb/MBtu for $H > 10000$ MBtu/hr.

Utah — No limits.

Vermont — 0.10 lb/MBtu for $H > 300$ MBtu/hr. 0.020 lb/MBtu for sources constructed after July 1, 1971 and $H > 1000$ MBtu/hr.

Virginia — For heat inputs H, where $25 \le H \le 10000$ MBtu/hr, the emission of particulate is $E = 0.8425\ H^{-0.2314}$.

Washington — For all old equipment, limit is 0.66 lb/MBtu.

Wisconsin — Limit for units built or under construction on or before April 1, 1972 is 0.6 lb/MBtu except 0.3 lb/MBtu in Subregion 1 of Lake Michigan Interstate AQCR and 0.15 lb/MBtu for units greater than or equal to 250 MBtu/hr in Southeast Wisconsin Interstate AQCR.

Wyoming — For old sources $H \le 10$ MBtu/hr, $E = 0.6$ lb/MBtu.

Guam — No general regulation stated in final plan.

Virgin Islands — Regulation obtained from APTD-1334, "Analysis of Final State Implementation Plans — Rules and Regulations".

regulations were given in the later form, they were converted to a heat input basis by the following relationship:*

1 grain/scf = 1.67 lb/MBtu = 718.1 ng/J

Table 6-2 shows that there is considerable variation among the regulations from state to state. Some states do not place emission limitations on smaller units, and where all the states restrict emissions from a given size source, these restrictions can sometimes differ by an order of magnitude. Typically regulations range from about 0.6 lb/MBtu (258 ng/J) from units with a heat input of 10 MBtu/hr (in those states which regulate units of that size) to values of 0.1 to 0.2 lb/MBtu (43 - 86 ng/J) for the very large utility boilers.† Since the regulations differ so much from state to state, a condensed version of this large table has been prepared to facilitate comparisons among the states (Table 6-3). In this abbreviated version of the state regulations, each column approximately represents one of the four user categories discussed in this report. A quick review of this table shows, for example, that 29 states and territories (i.e., slightly more than half of the 55 states and territories included on the table) do not restrict particulate emissions from residential and commercial units smaller than 1 MBtu/hr (0.293 MW). Only three states or territories do not limit particulate emissions from units larger than 1 MBtu/hr (0.293 MW). The table also shows that the restrictions for industrial boilers of nominal 100 MBtu/hr (29.3 MW) capacity range from 0.04 to 0.6 lb/MBtu (17.2 - 258 ng/J) and those for utility boilers of nominal 1000 MBtu/hr (293 MW) capacity range from 0.02 to 0.6 lb/MBtu (8.6 - 258 ng/J) with the exception of New Mexico, which expects to reduce their limits.

Opacity limits are presented in Table 6-4 for fuel burning sources. Many states now limit opacity to 20 percent (Ringelmann #1), although some restrict visible emissions to 10 percent and three even permit no visible emissions. Frequently a more lenient limit is placed on existing

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*This conversion factor was used in "Analysis of Final State Implementation Plans" (Reference 6-9). It assumes 5-10 percent excess air as in large finely tuned boilers. At 50 percent excess air the converstion becomes 1 grain/scf = 2.2 lb/MBtu.

†For comparison, standards of performance for new boilers >250 MBtu/hr limit particulate emissions to 0.1 lb/MBtu (40 CFR 60.42). These standards also limit visible emissions to 20 percent opacity, except for a period of up to 2 minutes during each hour when they may discharge a plume with 40 percent opacity. It has been stated that any boiler which burns an oil whose ash content is less than 0.45 percent (by weight) should need no particulate control device to meet the gravimetric standard, and if it meets the gravimetric standard, it should also meet the opacity limit, except maybe during soot blowing (Reference 6-2). Moreover, many units have been shown to be capable of emitting less than 0.1 lb/MBtu (43 ng/J) as indicated in Sections 2.4.2, 4.3.1.1, and 4.3.2.1. These low emitters are primarily those boilers which are larger than 1000 MBtu/hr (293 MW). Hence, control technology exists to set limits which are lower than the standard of performance.

TABLE 6-3. PARTICULATE LIMITS AT SELECTED HEAT RATES[a], LB/MBTU

State	Source Input Heat Rate, MBtu/hr			
	<1	≤10	100	1000
Alabama	0.5	0.5	0.5	0.12
Alaska	0.083	0.083	0.083	0.083
Arizona		0.6	0.35	0.21
Arkansas		0.25	0.15	0.10
California	0.167	0.167	0.167	0.167
Colorado	0.5	0.21	0.15	0.10
Connecticut	0.1	0.1	0.1	0.1
Delaware	0.3	0.3	0.3	0.3
D.C.		0.13	0.06	0.035
Florida	0.1	0.1	0.1	0.1
Georgia		0.50	0.16	0.10
Hawaii[b]				
Idaho		0.6	0.35	0.21
Illinois	0.1	0.1	0.1	0.1
Indiana		0.6	0.6	0.1
Iowa	0.6	0.6	0.6	0.6
Kansas		0.6	0.35	0.21
Kentucky		0.56	0.33	0.10
Louisiana	0.6	0.6	0.6	0.6
Maine		0.6	0.32	0.3
Maryland		0.06	0.03	0.02
Massachusetts		0.1	0.1	0.05
Michigan		0.3	0.3	0.19
Minnesota	0.4	0.4	0.4	0.4
Mississippi	0.6	0.6	0.41	0.26
Missouri	0.6	0.6	0.28	0.14
Montana		0.6	0.35	0.2
Nebraska		0.6	0.35	0.21
Nevada		0.6	0.35	0.20
New Hampshire		0.6	0.35	0.10
New Jersey	0.6	0.6	0.15	0.10
New Mexico		0.005	0.005	0.005
New York				0.10
North Carolina	0.6	0.6	0.33	0.18
North Dakota		0.6	0.44	0.33
Ohio		0.4	0.2	0.1
Oklahoma		0.6	0.35	0.20
Oregon	0.33	0.33	0.33	0.33
Pennsylvania		0.4	0.27	0.1
Rhode Island		0.2	0.2	0.1
South Carolina	0.6	0.6	0.6	0.6
South Dakota	0.3	0.3	0.3	0.3
Tennessee		0.6	0.17	0.10
Texas		0.1	0.1	0.1
Utah[b]				
Vermont		0.5	0.1	0.02
Virginia	0.4	0.4	0.29	0.17
Washington	0.33	0.33	0.33	0.33
West Virginia		0.34	0.166	0.10
Wisconsin	0.15	0.15	0.15	0.15
Wyoming	0.10	0.10	0.10	0.10
Samoa	0.10	0.10	0.10	0.10
Guam[b]				
Puerto Rico	0.3	0.3	0.3	0.3
Virgin Islands		0.6	0.352	0.21

[a]Abstracted from Table 6-2. Limits are for new sources whenever a state has different regulations for new and existing sources. For further detail see Table 6-2 and accompanying footnotes.

[b]No limits on particulate emissions from oil fired sources in state regulations.

TABLE 6-4. VISIBLE EMISSION LIMITATIONS FOR OIL-FIRED INDIRECT HEATING SOURCES[a]

State	% Opacity	State	% Opacity
Alabama	20	Nevada	20
Alaska	20	New Hampshire	20[j]
Arizona	40	New Jersey	20
Arkansas	20[b]	New Mexico	20
California	20[c]	New York	20[k]
Colorado	20	North Carolina	20
Connecticut	20	North Dakota	20[l]
Delaware	20	Ohio	20
D.C.	0	Oklahoma	20
Florida	20[d]	Oregon	20[m]
Georgia	20[e]	Pennsylvania	20
Hawaii	20[f]	Rhode Island	0
Idaho	20[g]	South Carolina	20[n]
Illinois	30[h]	South Dakota	20
Indiana	40	Tennessee	20
Iowa	40	Texas	20
Kansas	20[i]	Utah	20[o]
Kentucky	20	Vermont	20[p]
Louisiana	20	Virginia	20
Maine	40	Washington	20[q]
Maryland	0	West Virginia	10
Massachusetts	20	Wisconsin	10[r]
Michigan	20	Wyoming	20[s]
Minnesota	20	A. Samoa	20
Mississippi	40	Guam	20
Missouri	20	Puerto Rico	20
Montana	20	Virgin Islands	20[t]
Nebraska	20		

Footnotes follow.

FOOTNOTES FOR TABLE 6-4

[a]From Environment Reporter: State Air Laws. Volume 2, Parts 1 and 2. A looseleaf document published and periodically updated by the Bureau of National Affairs Publishers, Washington, D.C., 20037. Based on update as of November 1975.

[b]Emission limitation is 40 percent opacity for existing equipment.

[c]Each APCD has own regulations. Limits are 20 percent opacity, except for 3 minutes in any hour, in South Coast Air Basin and San Francisco Bay Area Air Pollution Control District.

[d]20 percent limit also for existing units (built or in operation on or before July 1, 1975) larger than 250 MBtu/hr. Existing and new sources less than 250 MBtu/hr have 40 percent opacity limitation.

[e]Units in operation or under construction on or before January 1, 1972 are limited to 40 percent opacity, except 60 percent for a total aggregate time of 3 minutes/hour.

[f]Existing units have a limit of 40 percent.

[g]Existing units have a limit of 40 percent.

[h]New sources larger than 250 MBtu/hr have a 20 percent limitation except 40 percent for aggregate periods of 3 minutes during 60 continuous minutes, 3 times daily from one source location within 1000 feet radius from center point of any other stationary source.

[i]Units in operation or under construction on or before January 1, 1971 are limited to 40 percent.

[j]Existing units have a limit of 40 percent.

[k]Units in operation or under construction on or before February 1, 1975 are limited to 40 percent.

[l]Existing units have a limit of 40 percent.

[m]Units in operation or under construction on or before March 1, 1971 are limited to 40 percent.

[n]Existing units have a limit of 40 percent.

[o]Existing units have a limit of 40 percent.

[p]Units in operation or under construction on or before April 30, 1970 are limited to 40 percent.

[q]Existing units have a limit of 40 percent.

[r]Units in operation or under construction on or before April 1, 1972 are limited to 40 percent.

[s]Existing units have a limit of 40 percent.

[t]Existing units have a limit of 40 percent.

sources. In addition, sources are allowed to emit more than the limits shown on this table for short periods of time, e.g., 3 minutes during each 1-hour period. In some states there is no restriction on the opacity of the plume during these exception periods, whereas in other states the plume can obscure no more than 40 or 60 percent of the transmitted light. Some states apply these opacity limitations to all sources, irrespective of their size.

6.3 SUMMARY OF SELECTED REGULATIONS

The last three tables presented regulations for all the states and other governmental jurisdictions of the United States. The particulate loading and visible emission limitations represent only a portion of the particulate-related regulations for each state (or each local air pollution control authority, where the state was subdivided). More detailed information on the regulations and enforcement procedures used by local authorities was obtained by direct contact from personnel in nine agencies which were believed to have active control programs, as mentioned earlier. The quantitative information obtained from these visits is summarized in Table 6-5, which includes requirements for permits, continuous monitors, dust collectors, and specified fuels, in addition to the particulate and visible emission limitations.

The enforcement procedures in eight of the nine districts visited appeared to depend heavily on the use of construction and operation permits. These permits are used to identify sources of emissions. The applications for construction permits are generally reviewed by the engineering and/or enforcement staff in the control agency to determine whether the equipment and the proposed operating procedures will enable the source to comply with local regulations. After the new source has been installed, the control district inspects the facility to check its conformance with the application and to observe the procedures used by the operating personnel. If the inspector's report is favorable, an operating permit is then issued to the installation. Enforcement through the use of permits is generally supplemented by roaming inspectors who look for violations of the visible emission limits, by stack testing upon the request of the control district if a problem is suspected, by permanent installation of continuous opacity monitors in units which exceed a certain size or which use residual fuel, and, in the case of Connecticut, by annual stack tests for all units which emit more than 100 tons per year (TPY) total pollutants.

The regulations were generally stringent in these nine regions by comparison with many of the states (compare Table 6-5 with Tables 6-2 through 6-4). For example, two of the regions prohibited all visible emissions, and the other seven only allowed up to 20 percent obscuration, whereas several of the other states permitted plumes to have opacities as great as 40 percent (Ringelmann #2). With respect to particulate emissions the regulations were strict in that they

TABLE 6-5. SELECT PARTICULATE REGULATIONS FOR OIL-FIRED INDIRECT HEATING FUEL BURNING EQUIPMENT

Location	States				Metropolitan Areas				
	Connecticut	Maryland	New Jersey	Rhode Island	Boston	Erie County New York	Los Angeles	New York	Philadelphia
PERMIT REQUIRED[a] Construction	5 or emissions > 8 TPY total all pollutants	5[b]	1	1	3		All[c]	0.35 or 3 family home	All which may discharge particulates
Operation	5[d] or emissions > 8 TPY total all pollutants	50	1	1	3			0.35[e] or 3 family home	All
VISIBLE EMISSIONS[f] General	1	no visible emissions from any building or installation	1[g]	no visible emissions	1	1	1	1[h]	1
Exception (allowable duration)	2 (5)	2 (4)	unlimited 3 minutes per 1/2 hr	1 (3)	2 (6)	2 (3)	unlimited (3)	2 (3)	3 (3)
Continuous Monitor (fuel and/or min. size where required)	residual or 5 MBtu/hr			1 MBtu/hr[i]	10 MBtu/hr[j]	250 MBtu/hr		0.35 MBtu/hr[k]	

[a]Footnotes follow. See Appendix C for conversions to SI units.

TABLE 6-5. CONTINUED

Location	States				Metropolitan Areas				
	Connecticut	Maryland	New Jersey	Rhode Island	Boston	Erie County New York	Los Angeles	New York	Philadelphia
PARTICULATE LOADING (lb/MBtu)[1]									
Existing Units									
< 1 MBtu/hr	—		0.6	0.2	—		0.5[q]	0.4[p]	0.18[r]
≤ 10	0.2[m]		0.6	0.2	0.12[o]		0.5	0.4	0.18
100	0.2		0.15	0.2	0.12		0.5	0.25	0.18
1000	0.2	0.03[n]	0.1	0.1	0.12	0.1[p]	0.5	0.15	0.18
New Units									
< 1 MBtu/hr	—		0.6	0.2	—		0.5[q]	0.4[p]	0.10[r]
≤ 10	0.1[m]	0.06	0.6	0.2	0.1[o]		0.5	0.4	0.10
100	0.1	0.03	0.15	0.2	0.1		0.1	0.25	0.10
1000	0.1	0.02[n]	0.1	0.1	0.05[s]	0.1[p]	0.01	0.15	0.10
SULFUR RESTRICTIONS									
Minimum Size Allowed to Burn Residual		5 MBtu/hr[t]			3 MBtu/hr			1.5 MBtu/hr for No. 4 oil[u]; 3 MBtu/hr for No. 6 oil[u]	
Residual (% by weight)	0.5	0.5	0.3		1.0[v]	1.1	w	0.3	0.3
Distillate (% by weight)		0.3	0.2	0.55 lb/M Btu	0.3			0.2	0.2
Flue Cleaning Allowed in lieu of low S oil	0.55 $\frac{\text{lb } SO_2}{\text{MBtu}}$	yes	0.3 $\frac{\text{lb } SO_2}{\text{MBtu}}$	1.1 $\frac{\text{lb } SO_2}{\text{MBtu}}$	yes				0.3 $\frac{\text{lb } SO_2}{\text{MBtu}}$

Footnotes

[a]Minimum size (MBtu/hr) above which permit is required.

[b]Removal of rotary cup in sources >13 MBtu/hr by 1976. Also, no new rotary cups after July 1974 anywhere in the state.

[c]List of exemptions includes space heating furnaces and gass or LPG boilers <250 MBtu/hr.

[d]Also require source testing at least once every two years for all sources which emit more than 100 TPY total all pollutants.

[e]Renewed every three years if pass stack test.

[f]Limits in Ringelmann Number (U.S. Bureau of Mines Chart) unless otherwise stated. Most regulations allow the use of equivalent opacity. Time for exception is number of minutes exception is allowed during any consecutive 60 minute period.

[g]No visible emissions for sources <200 MBtu/hr or from stacks with internal cross-sectional dimension of less than 60 inches.

[h]Commercial boilers limited to Bacharach No. 3 at a maximum 20 percent thermal loss through stack.

[i]Photo-electric monitor with audible signal.

[j]Smoke meter with audible signal at Ringelmann Number 1.

[k]Unless only gas is burned.

[l]Most regulations also required the use of best available technology (control practices) to prevent fugitive dust (e.g., from collector solid discharge).

[m]For units larger than 5 MBtu/hr.

[n]Dust collectors also required for new residual fired units larger than 13 MBtu/hr and existing units larger than 200 MBtu/hr. Collection efficiency requirements specified (Table 1, Booklet 10.03.39). Users of residual fuel during gas interruptions only do not need dust collectors.

[o]For units larger than 3 MBtu/hr.

[p]A source is exempt if it can be proven that it will not exceed the established ambient air quality standards. Erie County limit of 0.1 lb/MBtu applies to all units >250 MBtu/hr.

[q]Based on regulations given in grains per cubic foot of gas (calculated to 12 percent CO_2 with assumption that fuel is $CH_{2.2}$) and 10 lb/hr limit independent of size.

[r]Based on regulations given in lb/1000 lb stack gas adjusted to 12 percent CO_2 and assumption that fuel is $CH_{2.2}$.

[s]0.10 lb/MBtu if SO_2 control device installed.

[t]In Baltimore and Washington, D.C. metropolitan area.

[u]Given as 10 gph for No. 4 and 20 gph for No. 6 oil.

TABLE 6-5. Concluded

Footnotes (concluded)

[v]Provided the service retains its capability to fire a lower sulfur content fuel, does not create a localized problem due to downwash, and is equipped with monitors. Relaxation from 0.5 to 1% sulfur content due to expire on July 1, 1977 unless extended.

[w]No source may discharge sulfur exceeding 0.2 percent by volume as SO_2 at the point of discharge.

imposed relatively low limits on all sources, and that limits were applied even to the smaller units in the district. Thus, in some regions all units had to conform with the particulate loading limits, irrespective of size. In all regions which were studied in detail, burners that were larger than 5 MBtu/hr (1.46 MW) had to comply. Some states still differentiate between new and existing sources, whereas others did for only the first few years after the enactment of the regulations. In these cases a compliance schedule was included in the regulations giving existing sources a fixed time to bring their units down to the same level as new sources.

Most of the regions contacted also had stringent restrictions on the allowable sulfur content of the fuel. Since desulfurization also results in the removal of some of the solid matter in the fuel, and in a decrease in weight (increase in API gravity) the sulfur restriction can have a beneficial side effect by reducing sources of particulate emissions.* Three of the nine control districts also prohibited the use of residual oil in small units. Combustion cannot be controlled as well in these small units as it can in the large ones, nor is the temperature in the combustion volume as high. Therefore, it is more difficult to obtain low particulate combustion in small burners using residual fuel. Thus, this restriction on the use of residual oil eliminates one potential source of large particulate emissions.

In the remainder of this section we discuss the regulations in these nine control districts as they affect each of the four user categories.

6.3.1 Residential Units

In general, the emission regulations in these nine districts did not apply to residential units. For example, permits were not required for units smaller than 1 MBtu/hr (.293 MW) in most districts: only New York City required them for units that were less than 1 MBtu/hr (.293 MW), and their minimum limit was .35 MBtu/hr (.10 MW). Thus, in New York City only the very largest of the units which have been classified as residential in this study would be subjected to the requirement for permit. However, if the unit was in a one or two-family home, the owner would still not have to obtain a permit for it, even if it exceeded the .35 MBtu/hr (.10 MW) limit.

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*As noted in Section 3, particulate emissions from correctly maintained and operated oil fired units depend largely on the carbon residue content of the fuel. Although desulfurization of a given oil will reduce its carbon content, the amount of carbon residue in any given oil depends more on the nature of its crude source than on the sulfur content of the refined product. There is no known relationship between sulfur and carbon residue content of crudes.

The exception to this general lack of regulations for residential units is in visible emission limits. Most air pollution control authorities include residential units in their opacity regulations (that is, they use such words as "no person" or "no building or installation" when they identify who must comply with the regulations). Maryland also limits smoke from residential units to a Smoke Spot Number of 2 or less. The other regulation that can apply to residential units is the fuel restriction. As mentioned earlier, several regions prohibit the use of residual oil in residential size units.

None of the air pollution control authorities contacted required mandatory service or maintenance procedures for residential units. However, several of the staff members in the control districts believe such a requirement would be a good one, especially if it were also combined with a mandatory licensing and certification program for servicemen. Both Boston and New York City would like to follow such an approach, but they cannot do it now because of a lack of funds. Their interest in this control strategy stems from their observations of existing service practices for residential units. According to staff members from several of the control districts, some servicemen provide good service, and some do not. Moreover most residential units are serviced only when the owners experience a problem with them. Such programs may be the next step which cities in the New Jersey, New York, Connecticut, Massachusetts area need to adopt. Although their current regulations for all other sources are generally considered to be quite stringent, many of the large cities in this area have not been able to meet the NAAQS for particulates. Space heating is believed to be one of the sources which could be controlled more efficiently.

6.3.2 Commercial Boilers and Furnaces

All the control districts contacted during this study had both opacity and particulate limits which applied to at least some boilers and furnaces in this user category. In a few regions units which were smaller than 1 to 5 MBtu/hr (.293 - 1.46 MW) were not subjected to the particulate loading regulations. New York City requires commercial boilers to pass a Bacharach smoke test with a reading of Number 3 or less and a stack loss no greater than 20 percent of the heat input. In addition, new units must show that they can achieve an overall thermal efficiency of at least 75 percent and a CO_2 reading of 12-1/2 percent without exceeding the Bacharach No. 3 limit. This joint stipulation of a smoke reading and a thermal efficiency is important because many people elsewhere satisfy smoke limits by the use of excess air. Such an approach reduces the thermal efficiency and hence increases fuel consumption. At best it leaves mass emissions unchanged, but it probably increases them as a result of the increased fuel consumption.* New York City also requires the use of a forced draft system and a continuous smoke monitor. By comparison Erie County, in New York, which follows the state regulations, has no smoke number or thermal efficiency limits, no requirement for forced draft fans, and only requires continuous monitors for boilers with capacity greater than 250 MBtu/hr (73.25 MW). As mentioned earlier most of the regions contacted in this study did have sulfur restrictions on the fuel that could be burned in their areas, and hence indirectly reduced the emission of particulate matter from oil burning equipment.

Maryland is the only region of the nine studied in detail which attempts to limit emissions by an equipment standard. They recently banned the installation of rotary burners in new units in the 1 to 13 MBtu/hr (.293 - 3.8 MW) size category, and required that all units throughout the state phase out rotary burners by 1976. This equipment standard was based on their observations that rotary burners require more maintenance to insure low particulate emissions than do other burners, and that the operators of commercial size boilers are not likely to give these units the required maintenance. Therefore, they decided to solve the problem by simply prohibiting the use of these burners.

New York City also requires that new and upgraded boilers meet performance specifications and be installed according to certain criteria (Reference 6-3). For example, all units must be able to demonstrate adequate draft over a range of outdoor air temperatures from 11 to 94°F (-12 to 34.2°C), and they may not be constructed with air-cooled walls. Moreover, if the boiler system is for an installation where the maximum load is going to be greater than 50 gph (52.5 cm^3/sec) and if the load will vary to less than 50 percent of the maximum, then multiple boilers must be used. Maximum and minimum heat release rates are stipulated by boiler type, and performance specifications are given for burner flow rate control, interlocks with the air fan, oil preheat equipment and temperatures, combustion air availability, and system controls, among others. These design criteria should insure that all newly installed units will meet the emission and thermal efficiency specifications (i.e., they should reduce the possibility that some units will fail to pass the Bacharach and stack loss tests when installed) and that they will be built in such a way as to improve the chance that they receive proper maintenance during the three years between permit renewals. In effect these criteria show in a published document what standards the Department of Air Resource engineers will use when they review an application for a construction or operation permit.

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*Although particulate loadings are generally corrected to a standard CO_2 concentration to overcome this problem of dilution, neither Bacharach readings nor opacity readings are corrected in this fashion. Quantitative opacity measurements could be corrected to a standard CO_2 or O_2 concentration if the concentration of CO_2 or O_2 in the exhaust is measured in addition to opacity.

The enforcement procedures used in these nine control districts for commercial boilers and furnaces varied from no activity after the granting of the permit to equipment restrictions to periodic inspections. For example, Maryland, as just mentioned, requires permits and prohibits rotary burners with the hope that by prohibiting hard-to-maintain units and reviewing all new installation designs they will reduce emissions as far as practical. However, they do admit concern about the effectiveness of their program due to their experience with boiler operators who do not service their units as often as they should. New York City, on the other hand, sets emissions standards, checks each unit when it grants the initial operation permit, and then checks it periodically again (every 3 years) to insure that the facility's operating procedures conform to the permit. These tests are in addition to their published engineering criteria. The other districts who use periodic inspections also restrict their review to operating procedures and equipment. They only resort to stack tests if they suspect a problem with the installation. During the inspection the enforcement officer observes the boiler operator to see if he is following the correct procedure; he also checks such operating parameters as stack and/or preheat temperature, draft pressures, functioning of the forced draft fan, if required, and flame color, instability, and impingement. In New York City each inspection also includes a test for Bacharach smoke reading and stack losses. Although several of the regions require the use of continuous smoke monitors, most of them need not be of the recording type and in any case these requirements are relatively new. Therefore it is too early to judge the effectiveness of this requirement.

In order to supplement the above mentioned enforcement procedure, which relies heavily on the skill of boiler operators, New York City offers a basic boiler operator course (see Reference 6-4 for the text). However, due to funding limitations, this is a very elementary course which only teaches the operators how to run the boilers and perform routine maintenance; it does not instruct them how to adjust or repair their burners. In a similar vein Erie County requires the operators of the boilers in the public school system to attend a class on the subject of boiler operations. In general the agencies feel that most commercial boilers and furnaces are in compliance with the regulations.

To summarize, most control districts enforce their regulations by a combination of permit reviews, a small group of roving inspectors who look for violations of visible emission standards, on-site inspections, and tests if they suspect a problem or have to respond to a complaint. The enforcement staff in the agencies contacted typically find 10 to 20 violations per month.

The differences among the control programs of the various regions seem to rest more on the emphasis given to commercial units versus industrial and utility boilers than on what regulations they use. For example, in Connecticut, where enforcement is a state function and is based on regulations that were passed in 1971, the approach chosen was to first address themselves to the largest individual emitters. By controlling these large sources, Connecticut officials felt they could obtain the greatest leverage in terms of potential emission reductions per man-hour of enforcement time spent. New York City, on the other hand, has an extensive program for the reduction of emissions from commercial boilers. They stress control of these units because they are used in the many apartment houses and office buildings within the densely populated city and, hence, contribute significantly to the total mass of particulates emitted into the city's air.

6.3.3 Industrial and Utility Boilers

These two user categories will be treated together because the regulations and enforcement procedures are virtually identical for both. The only significant difference is the quantitative emission limits that units in the two categories must attain. As shown on Tables 6-2 and 6-3 most air pollution control authorities impose lower limits on the larger units (based on lbs of emissions per unit input). Thus, typical values range from 0.06 to 0.6 lbs/MBtu (25.8 to 258 ng/J) for industrial size boilers and down to 0.02 lbs/MBtu (8.6 ng/J) for utility boilers larger than 10,000 MBtu/hr (2930 MW). Maryland also requires the use of a dust collector on all units greater than 13 MBtu/hr (3.8 MW) heat input and specifies the collection efficiency for the dust collector.

This requirement is based on the results of an evaluation they conducted of installed equipment (Reference 6-5). They measured the solid matter that had been collected by a dust collector on a sample of boilers in Maryland and found that these collectors were actually preventing the emission of up to 50 lb/1000 gal (143 ng/J) in commercial size units.*

Naturally, all boilers in this size group are allowed to burn residual oil, but the sulfur content in the fuel is generally restricted to less than 0.3 to 0.5 percent by weight. In Massachusetts the allowable limits are 0.5 percent in nonmetropolitan areas and 0.3 percent in metropolitan areas such as Boston. Four of the districts require the installation of continuous monitoring smoke meters in all boilers in these two categories, and one additional region requires it only for utility boilers. One state, New Jersey, prohibits any visible emissions from boilers with heat input less than 200 MBtu/hr (58.6 MW) or with a stack whose diameter is less than 60 inches (1.5 m) across.†

*For comparison the EPA emission factor for units burning No. 6 oil with 7 percent sulfur is 13 lb/1000 gal (37 ng/J), at 3 percent sulfur, it is 33 lb/1000 gal (94.6 ng/J).

†According to the Beer-Lambert law, opacity depends upon the concentration and the path length of the dust-laden air through which the light must pass (i.e., the diameter of the stack). Therefore, emissions at a given concentration are more visible in a large stack than in a small one.

The enforcement procedures for industrial and utility boilers were generally the same in all the regions contacted. Units in this size are the relatively few, easily identified ones. Moreover, due to their size, each source has a bigger impact on air quality than does the average commercial or residential unit and, hence, every region with a particular problem limits emissions from large oil fired boilers. Since the large boilers are usually operated and maintained as economically as possible by qualified, full-time staff, particulate emissions are usually not due to poor operation or maintenance procedures. Instead, if they exist, they are due to characteristics of the combustion process, itself, the ash or sulfur content of the fuel, or a lack of flue gas cleaning equipment. Any differences in enforcement procedures between the various regions are probably more subtle than in the other user groups because the practices used for these sources tend to depend mainly on the specific experiences gained by the enforcement staff in their dealings with industrial or utility boiler operators.

The development of sophisticated techniques to identify those sources which are contributing to high ambient particulate levels is also a distinguishing factor among the control districts. In this regard Erie County is probably the most advanced, using a network of 32 manned high volume samplers. The readings from each of these samplers are fed into a computer, which then generates a pollutant rose plot. Inspection of this plot enables the control district to rapidly identify large offenders. The ability of the system to discriminate among sources is limited more by their radial separation, relative to each ambient air sampling station, than by their size. That is, the network can only identify sources that are 30° to 40° apart when viewed from one station unless these sources happen to be located in a part of the region where they have a large number of stations. Then they can sometimes detect individual sources that are closer together by triangulation. In general, however, they could not detect an industrial sized oil-fired boiler which is located in the midst of a large manufacturing complex.

6.3.4 General Comments

It is difficult to evaluate the effectiveness of the particulate control programs described above for the nine selected regions for the following reasons:

- Oil burners are just one among many other sources in a given region. A variety of industrial processes (e.g., the iron and cement industries, transportation, fugitive dust from industrial activities, and agricultural and natural sources, etc.) all contribute to the ambient air concentration of particulates.
- Many of the particulate control programs are relatively new; therefore, they are not yet fully enforced and historical data are not available to separate the effects of the

control program from the other factors which cause ambient pollutant concentration levels to fluctuate from year to year.

- Particulate emissions from residential and commercial boilers and furnaces fluctuate significantly during the cycle of each unit. They are high at the start and stop of the cycle and lower inbetween. They are also non-uniform in larger units, being unusually high during soot blowing operations. Therefore, one cannot assess the effectiveness of the control program for oil-fired boilers and space heating furnaces on the basis of reductions achieved in steady state emissions.*

Different regions need different control strategies because of differences in the distribution of sources. As mentioned earlier New York City needs to stress emission reductions in commercial sized units as a result of the large number of apartment buildings in that area, whereas a less densely populated, more industrialized area would emphasize emissions from industrial and utility boilers.

One measure of the effectiveness of a control program is the stringency of emission limits that are set by the local regulations. Inspection of Tables 6-2 through 6-4 shows that many states do not impose as stringent emission limits on their fuel burning sources as do others. Therefore, if those states with the more lenient emission limits are not able to attain the national ambient air quality standards for particulates, they should at least consider the advisability of setting new standards which are as stringent as those used elsewhere.

Since the purpose of this report is to develop model control strategies, we asked the nine air pollution control authorities contacted during the course of this study whether they were contemplating new regulations in order to improve their own control programs. Our survey showed that this was generally not the case. Rhode Island had contemplated a regulation which required the installation of an electrostatic precipitator for oil-fired utilities. However, since most of these boilers are capable of firing either oil or coal, since they already have an ESP for coal operations, and since the same ESP cannot be used effectively for both oil and coal, it was decided not to impose the economic burden of requiring two electrostatic precipitators on these sources. Los Angeles

*The standard test procedure for residential and commercial units, which operate in cyclical fashion, is to measure the smoke emissions during the 10th minute of operation after startup. Thus, these measurements are made when the unit has reached a steady state operation and all the surfaces inside are warm.

is currently thinking of requiring utility boiler operators to install dust collectors if they are not, themselves, able to solve the fallout problem that currently exists when they fire oil.*

The major differences between the control programs in the metropolitan and in the state agencies visited during the course of this study appeared to be in the stringency of the limitations, especially those for sulfur in the fuel. As one would expect, the metropolitan regions, with their high concentration of sources and human receptors, generally placed tighter restrictions on the sulfur content of the fuel and lower emission limits on the sources than did the states. There was also a tendency within metropolitan control agencies to place greater emphasis on the control of emissions from commercial size units than was the case in the states. And finally the size of the enforcement staff in the metropolitan control districts was generally larger than it was in the state regions. For example, Philadelphia had approximately the same number of inspectors as did the State of Connecticut. Of course, the need for a large staff is a consequence of the need to control the many smaller units which exist in the metropolitan areas. Beyond these three areas, the major differences were individual and probably due to the approaches preferred by the people who establish the programs. That is the use of an equipment standard in Maryland and a performance standard in New York City is probably not at all related to the fact that one is a state and the other a metropolitan area.

The relationship between metropolitan and state control authorities also differ from state to state. Thus in Maryland and Massachusetts the state regulations include special provisions for the metropolitan districts. However, enforcement is frequently accomplished by local districts (e.g., Maryland and Erie County in New York) who accommodate local requirements by adapting their enforcement procedures to those requirements (e.g., by developing an effective, computerized monitoring system to identify problematic sources). On the other hand, New York City, Los Angeles, and Philadelphia all developed their own regulations for emission limits and enforcement practices themselves.† No attempt was made during the study to investigate the potentially sensitive area of the working relationship between metropolitan control districts and the state air pollution authorities, and particularly not the state agency's role as responsible body for the quality of the air within the state and as intermediary between the local air pollution authorities and the U.S. Environmental Protection Agency.

*Recall that Los Angeles has not had to deal with the problem of particulate emissions from oil-fired equipment until recently because most of their major sources used to burn the cleaner natural gas.

†Philadelphia actually enforces the State regulation whenever it is more stringent than the city's own laws.

This concludes our summary and review of existing control strategies for particulate emissions from oil-fired boilers and furnaces. In the next section we present possible control measures which draw from the experiences gained by agencies which have been most active in controlling particulate emissions as well as from the knowledge about the characteristics of equipment to be controlled (see Section 2), the fuel normally used by this equipment (Section 3), and the control techniques available for reducing particulate emissions from oil-fired boilers and furnaces (Section 4).

REFERENCES FOR SECTION 6

6-1. Source: Environment Reporter: State Air Laws. Volume 2, Parts 1 and 2. A looseleaf document published and periodically updated by the Bureau of National Affairs Publishers, Washington, D.C., 20037. Based on updatc as of November 1975.

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SECTION 7

POSSIBLE CONTROL MEASURES FOR FUEL OIL COMBUSTION

7.1 INTRODUCTION

This section presents control measures for fuel oil combustion which local or state air pollution control authorities can implement to help attain and maintain particulate national ambient air quality standards (NAAQS) in their region. These control measures for oil-fired boilers and furnaces are expected to be needed in major urban centers where particulate matter emissions from the use of oil are an important part of the total inventory. Continuing economic and demographic growth in all regions and the trend in some regions of the country from natural gas to oil will increase the impact on the ambient air due to oil burning installations, and, therefore, use of the control measures described herein will likely expand in the future.

Since the contribution of any source category to the total emissions in an area varies from region to region, and since the seriousness of the problem (e.g., the current and anticipated ambient air concentrations of particulate matter) also varies from region to region, control programs must be area specific. That is, each local or state control agency must evaluate its own situation (source and population distribution, ambient monitoring stations where NAAQS are being exceeded or are expected to do so in the future, characteristics of the particles captured by these samplers, standard that is exceeded (24-hour or annual), meteorology, topography, projected growth, etc.) to determine which user categories need to be controlled and the degree to which each of these needs to be controlled. Therefore, possible controls for each user category (residential, commercial/institutional, industrial, and utility) are presented separately. Within each category, the possible control measures are ranked in order of increasing effectiveness, taking into account the emphasis on future sources of emissions, cost, and public acceptance. This set of ranked control measures are intended to serve as guidelines to local and state regulatory agencies who must, however, evaluate, their applicability in light of the conditions in their own district.

Presentation of these control measures in the above format provides a control district with information that they can use in one of two ways. If they already know which user category they have to control and by how much (i.e., from analysis of Hi Vol catches, as noted above), they can use the information in the lists of possible control measures as input to a systems analysis and particulate dispersion model to determine the most cost-effective control program for their region, considering all sources of particulate emissions within the region, the current and projected ambient air concentrations, and the projected economic and population growth rates.

The possible control measures are presented in tabular form with text to explain and justify them. A separate table with accompanying text is used for each size category. For regulatory purposes the class of boilers and furnaces is divided into four categories based on size; the names residential, commercial, etc., are used here merely to facilitate references to a particular size category. Thus the controls which are applicable to boilers and furances in the 0.4 - 12.5 MBtu/hr (0.12 - 3.66 MW) category apply to any unit in this size, irrespective of whether it is located in a commercial or an industrial facility. This practice differs from the one used to classify boilers for the NEDS emission survey. That system attempts to categorize boilers on the basis of their application with no regard to size. However, a division according to size is more meaningful for regulatory purposes because emissions and emission control techniques depend more upon size than application. Moreover, a distinction by size facilitates the enforcement of regulations. The limitation of two-family homes for residential units is an exception to this general rule.

The control measures described in the following sections exclude most surveillance and enforcement procedures that are either not specific to particulate control (e.g., stack testing of large sources) or that are applicable to all size categories. In particular, they do not mention the use of visual observations of plume opacity by roving inspectors. These inspectors can be mobile, stationed on the top of large buildings, or airborne in light planes or helicopters, and they can be equipped with cameras for later analysis and use in notifications of violations.

The format of the tables which are used to present the potential control measures is shown and explained by Table 7-1. In most cases the intent is for the control measures to be applied cumulatively. That is, if a local air pollution control agency decides that measure No. 1 is not sufficiently effective to solve their ambient air problem, they should consider next the use of both measures No. 1 and 2. If these two still do not reduce emissions enough, they should then investigate the simultaneous implementation of measures Nos. 1, 2, and 3. Where measure No. 2 is simply a more stringent version of measure No. 1, the second one automatically includes the first one.

All the control measures discussed here are based on data that were presented in Sections 3 and 4.

TABLE 7-1. POSSIBLE PARTICULATE CONTROL MEASURES FOR BOILERS AND FURNACES: "SAMPLE FORMAT"[a]

Rank	Control Measure[b]	Policy Instrument	Effectiveness		Cost Impact[d]		Energy Impact,[e] %	Public Acceptance[f]
			Reduction per unit, %	Reduction Per Air Region[c]	User, %	APCD		
1	Abbreviated statement of control measure for implementation as first step to reduce particulate emissions from this source category.	Regulatory or political activities needed to give legal basis to control measure	Estimated average percent reduction in emission from each source affected by this control strategy.	Estimated impact on total emissions to the air basin from this source category — i.e., a measure of the fraction of this source category affected by the recommended control measure	Cost to each affected user (annual operating and initial, as appropriate).	Indication of enforcement effort required to police sources regulated by this control measure	Impact of this control on energy consumption by source (including indirect changes, such as energy consumed by refinery to desulfurize oil).	Judgemental estimate of general public reaction to the control measure. In all categories but residential, this reaction assumed to be conditioned by cost pass-through or publicity that arouses sympathy. Reaction labelled good if most people unaffected even if some people significantly impacted.
2	Abbreviated statement of control measure for implementation, in addition to 1, above, if 1 is not sufficient to meet the emission reductions goals of the region.		Impact of reduction due to this control measure					

[a]See Appendix C for conversion to SI unit.

[b]SSN = Smoke Spot Number

[c]Relative to area-wide emissions from all sources in this category only; impact on region depends on relative importance of this source category.

[d]Sample calculation of cost impact on annualized basis given in Appendix D.

[e](Increase) or decrease in efficiency.

[f]Judgement; no data to substantiate.

7.2 RECOMMENDED CONTROL STRATEGIES

7.2.1 Residential Boilers and Furnaces – 0 to 0.4 MBtu/hr (0 to 0.12 MW)

For the purposes of these recommended control strategies residential units will be defined as those hot water or steam boilers or space heating furnaces whose rated heat input is less than 0.4 MBtu/hr (0.12 MW) or which serve only one or two family residences. Nationwide, approximately one-quarter of all residential units are oil-fired, and this number will probably grow as gas becomes more scarce. The average age of the oil-fired units is about 15 years, and approximately one-quarter of these units have had their original burner replaced. Even though this source category does not now contribute significantly to the total particulate emissions in any ACQR (the largest contribution is 3.4 percent of the particulate emissions from all sources in one ACQR – see Table 1-1), they are concentrated in densely populated areas and are used mainly during the winter months of the year. Therefore, their impact is greater than the annual area-wide emission averages would indicate. They do pose an enforcement problem, however, since there are so many units, they are widely dispersed, and they are owned by people who are not generally knowledgeable about their operation or about the relationship between their operation and emissions.

For the above reasons, air pollution control authorities are encouraged, as a minimum, to engage in public information campaigns ("PR") which stress the value to the individual owner of having his burner serviced annually. Periodic burner servicing can be a useful way to reduce emissions because tuned and well maintained burners emit less particulates than those just left by themselves (see Subsection 4.2.1). This is especially true if burners which are found to be damaged or worn out are replaced. Despite the general awareness of increasing air pollution, individuals still seem to be reluctant to spend funds voluntarily to reduce their own contribution; therefore, programs which stress economic gains and treat pollution reductions as a side benefit will more likely be accepted than those which do not.

Since oil suppliers have ready access to individual homeowners (their customers), air pollution control authorities should make a special effort to induce these suppliers to develop similar information campaigns or to intensify existing ones. All publicity campaigns for improved burner maintenance should be accompanied by exhortations to conserve energy. These campaigns should remind the homeowner of the need to lower his thermostat setting in the winter, to use less electricity and hot water throughout his household, and to install or increase insulation of his home. Energy conservation is a valid air pollution control measure because particulate emission rates are generally a direct function of fuel consumption.

All regulatory programs have two parts to them — a standard and an enforcement procedure. Standards can be either an emission limit, a fuel specification, or an equipment standard, and each of these can be used in combination with one or both of the others. No equipment standard is yet workable for residential units because there does not appear to be any particular design feature or equipment type that stands out as being necessary to the attainment of low emissions. For example, as noted in Section 4.2, emissions from the integrated optimized burner/furnace combination are expected to be as low as those from the furnace with the blue flame burner. Moreover, the blue flame burner is a proprietary item and therefore could be produced by only one manufacturer. Hence, if an APCD requires the use of a furnace with a blue flame burner in new buildings, it would preclude installation of the integrated optimized burner/furnace, which is equally effective, and thereby prevent other manufacturers from entering this market. Even worse, such a specific equipment standard might inhibit the development of a better unit. Admittedly it is easier for a control district to plan and enforce an emissions reduction program if it can rely on equipment standards because then they do not have to test or analyze each different kind of unit. However it is felt that the other factors outweigh this advantage.

The potential control measures for residential furnaces and boilers are presented in Table 7-2. Although all reasonable control measures have been included for residential units on this table, there is serious doubt that any air pollution control agency will find it necessary or useful to implement the lower priority ones.

The first regulation which air pollution control authorities might implement to reduce particulate emissions from oil-fired residential units is one which sets stringent limits for new and replacement burners. This priority on new units is consistent with the basic philosophy of this whole document, which is to emphasize emission reductions from new sources to offset growth and allow an area to maintain the quality of its air. The control measure requires that smoke emissions be limited to no greater than a Smoke Spot Number 1, and that this level be attained simultaneously with a flue gas concentration of CO_2 that is at least 10 percent. This CO_2 concentration corresponds to an excess air setting of about 50 percent and prevents the inefficient use of additional dilution air to meet a smoke limit. At present these limits can be met by the furnace with the blue flame burner, by burners with flame retention devices, and by many other burners which are now commercially available. In the near future the integrated optimized burner/furnace combination will also be available and should be able to reach the same levels. Moreover, the ANSI standard Z91.2, which has recently been approved, also specifies these levels as an industry goal.

TABLE 7-2. POSSIBLE PARTICULATE CONTROL MEASURES FOR BOILERS AND FURNACES: 0 TO 0.4 MBTU/HR (0 TO 0.12 MW)[a]

Rank	Control Measure[b]	Policy Instrument	Effectiveness		Cost Impact[d]		Energy Impact[e] %	Public Acceptance[f]	Comments
			Reduction per unit, %	Reduction Per Air Region[c]	User, $	APCD			
1	Stringent limits for new and replacement burners — SSN 1, $CO_2 \geq 10\%$. Emission limit of 0.01 lb/MBtu suggested if certification agreement can be made with ANSI or UL. Regulation can be extended to sale of home.	Building codes, tax incentives, cooperation with standards laboratories, APCD regulations	50	Moderate (eventually)	30 to 100 less fuel savings	Low	(5 to 10)	Good	Should be acceptable due to fuel savings. Low cost impact based on flame retention retrofit. Impacts only small number of new units.
2	Moderate limits on existing units — SSN 2, $CO_2 \geq 8\%$, no visible emissions.	APCD regulations	10	Low	30/yr	Low	0	Fair	Approach is almost voluntary — too many sources to enforce. Probably ignored by worst offenders.
3	Moderate limits on existing units (as above) plus mandatory annual inspection/maintenance by licensed serviceman	APCD regulations, tax laws	20	Moderate	30/yr less fuel savings plus 0 to 300 once	Moderate	(1 to 2)	Fair	Impacts many units, especially on smoke. May force some users to replace burners.
4	Stringent limits on existing units plus inspection/maintenance (as above) — SSN 1, $\geq 8\%$ CO_2, 5% opacity	APCD regulations, tax laws	30	High	30/yr less fuel savings plus 0 to 300 once	High	(1 to 5)	Poor	Expect many users will have to replace burners. Could improve public acceptance with massive publicity campaign stressing energy conservation.
5	Fuel restricted to no heavier than No. 2 oil	APCD regulations	40	Low	0 to 300 + 10 to 15% of fuel costs	Low	(5 to 8)	Good	Does not affect many burners. May need to replace burner. Energy impact at refinery. Effectiveness assumes unit burned resid.
6	Combustion additives at optimized concentration to be added to fuel at suppliers distribution center	APCD regulations, coordination with nationally recognized standards	30 to 50	High	1 to 2% of fuel	Low	0	Poor	Supplier demonstrates that his concentration is optimum (see Figure 3-2), and additive is compatible with the fuel. Generalized use not recommended at this time because of possible toxic effects and interactions with fuel.

[a] See Appendix C for conversion of mass emission limits to SI units

[b] SSN = Smoke Spot Number

[c] Relative to area-wide emissions from all sources in this category only; impact on region depends on relative importance of this source category

[d] Sample calculation of cost impact on annualized basis given in Appendix D

[e] Unit (increase) or decrease in efficiency

[f] Judgement; no data to substantiate

A no-visible-emissions limit can be included for enforcement purposes. The appearance of smoke from a residential furnace or boiler indicates that the unit is malfunctioning and broadcasts this fact to anyone outside the house. A visible emissions limit gives APCD inspectors a firm legal basis for their actions when they advise a homeowner that his unit is malfunctioning and require that he correct the problem and show compliance.

If the regulatory agency (or the EPA) can obtain the cooperation of the American National Standards Institute (ANSI) or the Underwriters Laboratory (UL) in the form of an agreement to test prototypes of new units for their ability to comply with the limits stated above, then the regulation should include a requirement that all new or replacement burners carry a label from ANSI or UL which states that the unit belongs to a family of burners which has been certified by one of these labs as meeting the local emission limits. EPA is presently evaluating the practicality of such agreements. Such a cooperative effort would reduce the burden on both the local regulatory agency and the local burner suppliers. Moreover, if ANSI and/or UL are willing to measure particulate mass emissions during burner certification tests, the regulation should also include a mass emissions limit (given the difficulty and expense of mass emission measurement, it would be unrealistic to set such a limit unless coupled with a burner certification program). The value of 0.01 lb/MBtu fuel suggested in Table 7-2 is based on results with several retention heads.

Two methods are available to implement this regulation in addition to the cooperative effort with the standard setting laboratories. Since architectural drawings for all new buildings have to be approved by the city or county building department, performance standards for new burners could be written into the building codes and their installation policed by the building inspectors (after proper training). Replacement burners, however, are generally installed without the need to notify any governmental agency. Therefore, it is suggested that homeowners be induced to install these improved, low emission, high efficiency burners by means of a property tax reduction (which could be offset by an equivalent general tax increase). To obtain this reduction, which would be some fraction of the incremental cost of installing a low emission burner, the homeowner would have to obtain a form from the local APCD stating that his unit has been approved by these authorities. He could then include this form with his property tax payment to justify the reduction in taxes. Alternatively, the local air pollution control authorities could enforce the requirement that the replacement burners meet the stringent emission limits by spot-checking the parts storage facilities of the local burner suppliers. The purpose of these spot checks would be to insure that these burner suppliers stock only the approved kinds of burners. Similarly, the control agency could require service people to keep records of burner replacements and then spot-check them.

This control measure can be extended to cover more sources by requiring that the burners in all houses that are sold meet the stringent limits. Since the seller presumably has established a working relationship with his oil supplier or burner serviceman, the burden can be placed upon him to prove that his system complies with this regulation. Proof of compliance would be a prerequisite to recordation of the transfer of title. Such a regulation would be similar, for example, to one which pertains to automobiles in the State of California. In that case the seller of a car, if it is in a certain age group, must obtain a certificate stating that his automobile has been tested and found to comply with the air pollution control regulations before the Department of Motor Vehicles will issue a registration in the name of the new owner.

The maximum estimated unit effectiveness of 50 percent shown in Table 7-2 for this control measure is based on the assumption that a reduction from Smoke Spot No. 2 to Smoke Spot No. 1 is roughly equivalent to a 50 percent reduction in particulate mass emission rates. Virtually all currently available residential burners (distillate oil-fired) can achieve a Smoke Spot No. 2 and many can reach a level of 1. This proposed regulation, therefore, is intended to insure that all new units which are installed are of the lower emitting variety. Since this control measure only affects new and replacement units, its impact on the total emissions to the area will only be felt in the future. By the time it has a widespread impact, however, it should be a significant one, since the total emissions from the residential category would be reduced to half of its current level. Alternatively, the number of residential oil-fired units in a given region could double in the next 10 to 20 years, either because of population growth or conversions from electric or gas-fired units to oil, without increasing the total particulate emissions from residences.

The estimated cost impact shown in Table 7-2 for this first control strategy is based on the assumption that it will be achieved either by the use of the flame retention device or by the use of a new burner/furnace combination, such as the blue flame or the optimized units. These furnaces are estimated to cost up to $100 more than conventional furances. This extra initial cost would be recovered within 2 to 5 years, depending on fuel costs and annual usage, due to increased efficiency of the new burners. Since this control strategy relies heavily on cooperation with the standards laboratories, the use of the building permit system, tax reductions, and the city or county recorder or clerk, it should not impose a significant additional enforcement burden on the local air pollution control district.

In addition to reducing emissions by mandating the use of improved burners, this regulation should stimulate the conservation of petroleum because these new burners are 5 to 10 percent more efficient than the currently available ones. This improved efficiency also results in a secondary beneficial impact on particulate emissions through the reduction in fuel consumption. The public should be willing to accept this control strategy because the installation of a newer, more efficient burner results in a fuel savings and because the additional cost impact usually comes at a time when people are expecting to spend money and, hence, usually more willing to do so than normally. A distinction is being made here between a regulation that requires all units to convert to a lower polluting, more energy efficiency system by a certain date and the proposed one, which only affects new and replacement units. In the first case the people would not have factored this expense into their budget. Moreover, the cost impact to them would be the total cost of the burner, not just the differential cost between currently marketed units and the improved ones.

The next likely step for a control program of increasing stringency is to impose moderate emission limits on existing units. The possible limits are a Smoke Spot No. 2, a CO_2 concentration of at least 8 percent in the flue gas, and no visible emissions. Several investigators have demonstrated that existing units can meet these limits (see Section 4.2.1.1 and References 4-2, 4-17, 4-18). However, since the residential heating sector represents such a large number of widely distributed sources, it would be very difficult to enforce such a regulation. Therefore, as stated control measure No. 2 almost implies voluntary compliance. Consequently, both the reduction per unit burner and the impact on basin-wide emissions from this source category would probably be low. The cost impact has been estimated to be only $30 per year, which is the cost of an annual service and does not include a potential burner replacement. Although an annual inspection and servicing should improve the efficiency of the burner, we have assumed that the burners which would really benefit from such a program would not, in fact, be serviced. Therefore, zero energy impact is shown for this proposed regulation.

In order to overcome the shortcomings of this control measure, the third measure then combines the emission limits just proposed with a mandatory annual inspection and maintenance service by a licensed serviceman. The requirement for a mandatory annual service is intended to force each homeowner to bring his unit into compliance with the air pollution regulations at least once a year. By further requiring that this service be accomplished by a licensed serviceman, who has had to demonstrate competence as a burner serviceman (including the ability to work with CO_2, smoke, and similar test instrumentation) in order to obtain his license, the chances are greatly improved of actually attaining throughout the region the reductions that test programs have shown to be possible by periodic burner maintenance. Implementation of this control measure mainly ensures that burners are not allowed to deteriorate significantly. Although their performance usually does not change markedly during one heating season, they could rapidly become inefficient and high emitters if allowed to operate for several years without competent service.

There are several ways of enforcing such a regulation, and any of these could be used singularly, or in combination, with the others. The traditional approach would be for the air pollution control district to spot check a sample of the homes in the area. If they find burners which do not meet regulations, they could then fine the homeowner, or if he could prove his unit was misserviced within the last year by a licensed serviceman, they could fine or revoke the license of the serviceman. The effectiveness of this program would be enhanced by widely publicizing the enforcement activities and clearly identifying the inspector's cars. Another approach would be to lay the burden of compliance on the fuel oil suppliers (because they are fewer in number and supposedly more competent burner technicians than the homeowners) and require that they demonstrate annually, to the satisfaction of the air pollution control district that the burners of all the homes which they supply with fuel have been inspected and serviced. A third approach would be to induce the homeowner to retain a licensed serviceman for the annual inspection and maintenance of his unit by giving him a reduction in his property taxes if he can demonstrate that his unit has been serviced and complies with the district's emission limits. Such a demonstration would be in the form of a certificate provided by the serviceman on which he notes the service he conducted, his charge, and the performance of the burner after it had been serviced (i.e., emissions and thermal efficiency).

An annual inspection and maintenance program, in conjunction with the emission levels specified in the previous control measure, should reduce emissions from the average home furnace or boiler by the amount reported in the literature cited earlier. Since virtually all units in the region would be affected, the impact on the area-wide emissions from residential units should be approximately equal to the average reduction in emissions from each unit. The cost associated with this program is estimated to be about $30 per year for the annual service, plus up to $300 for the replacement of malfunctioning burners. A portion of these costs will be offset by fuel savings (nearly 2 percent, on the average, or about $8/yr). Investigation of a sample of residential units has indicated that approximately 10 percent of the units are in need of burner replacement, and that the replacement of these malfunctioning units can result in up to a 17 percent reduction in particulate emissions from residential burners.

APCD enforcement personnel will still have to conduct spot checks for this control measure and this will involve some costs. However, the total financial impact on the district could be reduced if it recovers the cost of training, licensing, and enforcing the servicemen from their license fees. Moreover, since both private agencies and public schools offer training programs for boiler and burner servicemen, the control district could identify those courses which are acceptable to it and require a certificate of completion from these courses as a criterion for obtaining a license. Such an arrangement would eliminate the need to conduct the courses themselves. It may also be advisable to require the servicemen to pass a test once every 1 to 2 years, and to certify to the district that they understand the regulations and the obligations imposed upon them by the regulation.

Most burners should gain a few percent in efficiency after the service, but as noted earlier, the reduced cost of the fuel does not offset the cost of the service itself (at least not at current fuel prices). For most people, however, the cost impact will not be terribly great and, therefore, it is expected that the public will accept this proposed control strategy, although possibly not with great enthusiasm.

If the ambient air in a given region exceeds the NAAQS for particulates by a large amount, and if residential units contribute significantly to the emissions in that region, then the control district could consider the stringent limits for existing units proposed in control measure No. 4. This strategy goes one step beyond the previous one by requiring that units emit no more than a Smoke Spot No. 1. It also includes the annual inspection and maintenance by licensed servicemen that was discussed in the previous control measure. Obviously, such a control measure should have a greater impact on the average particulate emission reductions per unit, on the total emissions from all residential units in the region, and on the costs to the air pollution control district. It should also have a greater impact on the users as a group, because more would have to replace their burners with new ones (the cost per burner replaced would be the same as in the previous control measure). Since more burners would be changed under this control measure and since they would be replaced by new, more efficient units, the average increase in thermal efficiency would be higher than in the previous measures. However, the cost of a new burner is a significant item for the typical homeowner, and the payback period from the reduced fuel consumption is probably too long to interest him; therefore, the public reaction may be poor, unless the implementation of this recommended control measure is accompanied by a massive publicity campaign which stresses its energy conservation aspects.

In some regions of the country, a slight additional reduction in emissions can be obtained by restricting all residential units to the use of No. 2 fuel oil. This recommendation is based on experimental results which show that burners fired on No. 2 oil emit less particulates than those fired on heavier fuels (see Figure 3-4). However, the impact of such a control strategy on an area-wide basis would probably be low because most residential units already use No. 2 oil. For those that do not, the owners would probably incur a cost of up to $300 for a new burner designed to operate on No. 2 oil, and they would have to use a fuel which is 10 to 15 percent more expensive than the heavier fuel they are now using. If this proposed control measure affects enough people that their voices are heard, public acceptance may be poor, despite the improvement in air quality.

Combustion improving additives at optimum concentrations have been shown to reduce emissions by 30 to 50 percent (see Section 3.1.3). Therefore, a requirement that they be added to home heating oil could be an effective particulate reduction measure. In order to insure a uniform and correct application, control measure No. 6 suggests that the chemicals be added by the fuel supplier at his distribution center. Since this control measure would reduce emissions from each unit significantly, and since it would impact all the units in the area, the total impact on emissions from all residential units in the area would be high. Furthermore, these reductions would be obtained without much additional effort by the enforcement personnel in the control district. However, the generalized use of combustion additives for residential burners is not recommended at this time because the metal compounds emitted from units which use metal based additives <u>may</u> be toxic or <u>may</u> react with substances which are already in the ambient air, such as POMS, to create a potential health hazard. Although some organic-based additives may not result in toxic emissions, they generally have to be added in relatively large doses (1 percent by weight of the fuel), and, hence, would be expensive. Moreover, some additives may interact with the fuel to increase deposits in oil lines, filters, or other burner parts. Therefore, this control measure would not likely be implemented until these issues have been resolved.

7.2.2 Commercial Boilers and Furnaces — 0.4 to 12.5 MBtu/hr (0.12 to 3.66 MW)

The commercial category of boilers and furnaces is very similar to the residential group in that it is comprised of systems which provide space heating and hot water for washing. Boilers and furnaces in this size category are found mainly in apartment houses, office buildings, shopping centers, and similar commercial or institutional facilities. They differ from residential units, however, because they are larger, they generally receive more maintenance, and they frequently burn residual oil. The first two factors tend to make them lower emitters than residential units, but that can be offset by the higher emissions due to the use of residual oil.

Particulate emissions from this category can account for as much as 9.5 percent of the total from all sources in an AQCR. Moreover, since commercial systems are larger than residential units, each individual source contributes more to the total particulate emissions in the region than does an individual residential heater. And, finally, since there are fewer commercial units than residential ones, the enforcement program can be more comprehensive. Therefore, the impact of a regulatory program for commercial boilers and furnaces should be more effective than one for residential units.

For the purposes of these potential control measures, the word "commercial" will be used as an abbreviation to describe those boilers whose rated heat input is between 0.4 and 12.5 MBtu/hr (0.12 - 3.66 MW), even though some boilers in this size range are used by industry to generate process hot water or steam. The control measures for this category are listed and ranked on Table 7-3.

The first measure that the control district might implement to reduce particulate emissions from commercial systems is a set of emission limits for both new and old systems. These emissions limits are noted under measure No. 1 in Table 7-3. They are stated in terms of Smoke Spot Number, with separate limits for new and old units, and within each of these categories, by fuel. Values for existing units correspond to typical levels reported by various investigators for well maintained systems (see Section 4.1.1 and References 4-2, 4-3, and 4-17). Those for new units are based on the lowest levels reported by any of these investigators and on the differences between old and new residential units. These limits should be accompanied by a requirement that they be satisfied at a minimum thermal efficiency with a CO_2 setting that allows for continued smoke-free operation until the next annual service — i.e., 1 - 2 percent lower than the value at which smoke-free operation can be achived immediately after servicing. This margin ought to ensure a sufficient supply of oxygen even after the eventual accumulation of dirt on the air supply system. The minimum CO_2 concentration of 12.5 percent specified in Table 7-3 is intended mainly for burner certification tests. As mentioned earlier during the discussion of residential units, an efficiency requirement prevents the owner or operator from engaging in the wasteful practice of using too much excess air to comply with the smoke limit. A "no-visible-emissions limit" is also appropriate to assist the enforcement activities.

Although it is not reasonable to expect each owner or operator of a commercial boiler or furnace to demonstrate compliance of his unit with a mass emissions limitation (as measured, for example, by EPA Method 5), an initial emission rate can be inferred for each new unit if the ABMA and the Hydronics Institute are willing to cooperate by including a measurement of mass emissions as part of their rating procedure. EPA is presently evaluating the practicality of such agreements. These organizations provide a rating service to boiler manufacturers. The particulate limit of 0.1 lbs/MBtu (43 ng/J) for new units larger than 5 MBtu/hr (1.47 MW) is equal to the most stringent limitation imposed by several states on this size category.

TABLE 7-3. POSSIBLE PARTICULATE CONTROL MEASURES FOR BOILERS AND FURNACES: 0.4 TO 12.5 MBTU/HR (0.12 to 3.66 MW)[a]

Rank	Control Measure[b]	Policy Instrument	Effectiveness		Cost Impact[d]		Energy Impact[e] %	Public Acceptance[f]	Comments
			Reduction per unit, %	Reduction Per Air Region[c]	User $	APCD			
1	Following smoke limits @ ≤20% stack loss (alternatively CO_2 ≥12.5%) and no visible emissions Fuel / SSN (new) / SSN (old) No. 6: 3 / 4 LSR (≤0.3%S): 2 / 3 No. 2: 1 / 2 For residual fired units >5 MBtu/hr suggest emission limit of 0.1 lb/MBtu if certification agreement can be made with ABMA or Hydronics Inst.	APCD regulations, building codes, tax incentives, cooperation with standards laboratory	10	Moderate	150/yr	Low	0	Good	Assumes new burners will cost no more than existing designs. Approach is almost voluntary for existing units – too many sources to enforce. Probably ignored by worst offenders. EPA presently considering certification agreement with ABMA or Hydronics Inst.
2	Installation and operating permit required. Renew every 3 years if pass emission test. Limits as per 1, above. Test program to determine need for design criteria.	APCD regulation, building codes, tax incentives, cooperation with standards laboratories	15	Low beyond impact from 1	165/yr less fuel savings 1500 (10 gph) 5200 (50 gph)	Moderate	(0 to 2)	Good	Most of cost born by user. First step to strengthen 1, above, without excessive enforcement costs
3	Prohibit rotary cup burners unless can prove compliance under typical operating conditions	APCD regulations	10 to 40	Low	1500 (10 gph) 5200 (50 gph) less 5% to 10% fuel savings	Low	(5 to 10)	Good	Has noticeable impact only in those regions with many rotary cup burners
4	No resid in units <5 MBtu/hr. (Residual oil defined as grades 5 and 6.)	APCD regulations	50	?	500 to 1500 (for 10 gph burner) + 15% of fuel cost	Low	5 to 8	Poor	Impact depends on current fuel usage pattern. Energy impact at refinery. High cost for cases where need new burner. Subject to availability of fuel.
5	Limits as per 1 above plus mandatory annual inspection/maintenance by licensed serviceman	APCD regulations, tax incentives	20	Moderate	150/yr less fuel savings also 1500 (10 gph) 5200 (50 gph)	Moderate	(1 to 2)	Good	Impacts many units. May force some to replace burner. States are encouraged to make reciprocal agreement for licensing servicemen.
6	No resid in any units (only No. 2 or 4 oil)	APCD regulations	75	High	500-1500 (10 gph) 1500-5200 (50 gph) + 15% of fuel	Low	5 to 8	Poor	Similar to above, but impacts more sources and will force more to change burners
7	All units limited to SSN 1 @ ≤20% stack loss (or CO_2 ≥12.5%), and no visible emissions	APCD regulations, building codes, tax incentives	50 to 90	High	1500 (10 gph) 5200 (60 gph) + 15% of fuel	High	5 to 8	Poor	Requires burner replacement in addition to above
8	Combustion additives at optimum concentration to be added to fuel at suppliers distribution center	APCD regulations, coordination with nationally recognized standards	50	High	1% to 2% of fuel	Low	0	Poor	Supplier demonstrates that his concentration is optimum and that additive is compatible with fuel. Generalized use not recommended at this time because of possible toxic effects and possible interaction with fuels.

[a] See Appendix C for conversion of mass emission limits to SI units
[b] SSN = Smoke Spot Number
[c] Relative to area-wide emissions from all sources in this category only; impact on region depends on relative importance of this source category
[d] Sample calculation of cost impact on annualized basis given in Appendix D
[e] Unit (increase) or decrease in efficiency
[f] Judgement; no data to substantiate

As with the equivalent control measures for residential units, measure No. 1 can be implemented by an APCD regulation. Its enforcement can rely in part on building codes, cooperation with the standard setting laboratories, and inducements for voluntary compliance through the use of tax incentives. The suggestion that a tax reduction inducement be incorporated into this control measure, the estimated effectiveness of only 10 percent emissions reduction per unit shown on Table 7-3, and the pessimistic tone of the comments for this control measure all stem from the belief that there may be too many commercial-sized installations in the highly urbanized northeastern cities for the APCD enforcement staff to monitor on their own now. The additional procedures to be described under control measure No. 2 below are intended to overcome this problem. Moreover, if controls are placed on new equipment, this enforcement problem will disappear eventually.

Most local or state air pollution control authorities who have an active program for the reduction of emissions in their region require an installation and operating permit for new sources above a certain size. Such a requirement assists the district staff to locate all new sources and enables them to provide a preconstruction review of the source. These early reviews lessen the chance that the source will exceed the local emission limits after it has been built and set into operation. By incorporating a requirement that the source owner renew his operating permit periodically (e.g., every 3 years as in New York City), and by further requiring that the renewal application include the results from a stack test to demonstrate compliance with the emission limits, the APCD can effectively enforce these limits at minimal additional cost and burden to itself. The fee for the renewal application should include charges not only to process the application, but also to cover the control district's cost of sending inspectors out occasionally to spot check emission tests.

The cost impact of control measure No. 1 in Table 7-3 is based on a typical annual service charge of approximately $150 for commercial-size units (including the cost of a smoke spot test) plus $15 to cover the cost of a permit application. This latter figure is based on New York City's projected triennial fee of $50.00, when distributed equally over a 3-year period for accounting purposes. Since some boilers and furnaces will need to replace their malfunctioning burners with new ones to comply with the emission limits, the cost of a new burner has also been included in the table.

If an air pollution control district feels that it needs to reduce particulate emissions from commercial units even further and faster, and if that region contains many systems whose burners are equipped with rotary cups, then the next step should be to prohibit the use of rotary cup burners.

This control measure is based on the findings by the Maryland Bureau of Air Quality Control that a large percentage of the units that fail to comply with their smoke limits are rotary cup burners. Moreover, many of those which do comply do so only by using too much excess air and, therefore, waste fuel. In order not to stifle the development and utilization of a rotary cup burner that can be maintained smoke-free under typical operating conditions, it is recommended that the regulations include a proviso which allows someone to use such an improved rotary cup burner if he can demonstrate compliance under typical operating and maintenance conditions. Such a demonstration would, of course, be at the expense of the proponent of the new system.

The impact on area-wide emissions of such a measure is expected to be relatively low because not too many burners are currently equipped with rotary cups (for example, in the Northeast, where they are most prevalent, they account for only 5 to 10 percent of the burners on existing furnaces and boilers). For this reason, and because the prohibition can be enforced by spot checking oil supplier records, it is estimated that the regulation will have only a minimal impact on the enforcement program of the APCD. The 5 to 10 percent gain of thermal efficiency shown on Table 7-3 for this control strategy is based on the observation of the Maryland Bureau of Air Quality Control that many owners of rotary cup burners now use large amounts of excess air to comply with the Smoke Spot Number limitations. Presumably they would not need to follow this wasteful practice with a new burner.

Particulate emissions are generally higher from units that burn a heavy grade of fuel, such as No. 6 oil, than they are from those which burn a lighter grade of fuel, such as No. 2 oil. The problem is generally considered to be worse in small units than in large units, because small units typically do not receive the service and maintenance attention that the larger units do, and because the temperature in the combustion volume of small units is not always high enough to completely oxidize all the fuel when it is a heavy oil. Therefore, several regions, such as Maryland and Boston, prohibit the use of residual oil in smaller units. Control Measure No. 4 is based on this practice. Before adopting this measure, the control agency should determine that local fuel suppliers can meet the increased demand for distillate fuel.

Since most burners and fuel handling systems are designed to operate with a fuel of a given specific gravity and viscosity, several components would have to be replaced or readjusted if the unit were changed from residual to distillate firing.* The cost of such a change is indicated in

*The changes include disconnection of the heating system for the fuel tank and air lines, flushing of the fuel systems and inspecting it for leaks, replacing the fuel filter and pump (or changing its speed, if that is possible), replacing the nozzle, and retuning the burner.

the cost impact column on Table 7-3. The lower estimate for smaller units is based on the assumption that this conversion would cost about three times as much as a typical annual service call (twice as much work plus parts). The corresponding figure for larger units comes from Reference 4-55. In both cases the upper cost impact is based on a complete burner replacement. It should be noted that there is a substantial cost saving if a new installation is initially designed to burn distillate rather than residual oil. The 15 percent fuel cost increase also noted on this table is based on the average price difference between distillate fuels and the higher sulfur residuals. The energy impact shown on the table for this control measure represents the energy requirement at the refinery to refine the crude into a distillate. Since the cost impact is significant, the public reaction may not be favorable.

Although boilers and furnaces which are located in commercial installations are frequently monitored and cleaned by a boiler operator, this person is usually responsible for many other aspects of the operation and maintenance of the building. The boiler is only a small portion of his job, and he may not even be trained for this task. Therefore, the additional requirement of a mandatory annual inspection and maintenance by a licensed serviceman, as included in control measure No. 5 should be an effective supplement to the previous control measures. Gains would come both from the use of specifically trained servicemen and from the guarantee that all units were serviced annually. This guarantee could be useful if permit renewal is required only once every 3 years, as included in control measure No. 2, because some boiler operators may call upon the services of a qualified maintenance person only before they are required to demonstrate compliance with the emission limits. The implementation and effectiveness of this control measure are similar to that described in the residential sector for the corresponding measure.

Control measure No. 6, which provides that no residual fuel be burned in any commercial boiler and furnace, is supported by the same reasoning as control measure No. 5, but simply goes one step further. Therefore, the impact on emissions to the ambient air will be greater, but so will the cost since the conversion charges will have to be born by more users.

In areas where the ambient air quality exceeds or is expected to exceed the NAAQS by a significant amount, and where commercial boilers and furnaces are major contributors to the total particulate emissions in that region, it may be necessary to go to control strategy No. 7 and apply stringent limitations on the smoke emissions from all units, both new and old. The indicated levels (Smoke Spot Number 1, minimum overall efficiency of 80 percent, or CO_2 flue gas concentrations of at least 12.5 percent for burner certification) presume that the user will have to install a new, well designed burner such as the optimized one that has been developed for residential and small commercial units. It also presumes that he will have to use distillate oil, at least until a low particulate and NO_2 emitting burner is developed for residual fired units. The estimated effectiveness of this control measure shown on Table 7-3 is based on several assumptions: (1) current units emit between 0.053 and 0.067 lb/MBtu particulate (22.8 - 28.9 ng/J) in accordance with the EPA emission factor for a unit using No. 6 oil with 0.5 to 0.7 percent sulfur content; (2) distillate fired units with Smoke Spot Number 1 would emit about 0.007 lb/MBtu particulate (3.0 ng/J) because current units are characterized by Smoke Spot Number 2 and are estimated to emit about 0.014 lb/MBtu (6.0 ng/J) (as per the EPA emission factor). That is, reductions from 0.014 to 0.007 lb/MBtu (6 to 3 ng/J) are envisioned for units which currently burn distillate oil and from about 0.067 to 0.007 lb/MBtu (28.8 to 3.0 ng/J) for those which now consume residual oil. The cost impact shown on Table 7-3 for this control measure is based on the need to replace the burner and on the price differential between No. 2 and high sulfur residual oils. The energy impact again represents the increased energy consumption at the refinery to refine the fuel. Although the use of building codes for new installations and tax reductions as inducements for existing installations are indicated as part of this control measure, the need to insure that all commercial boilers and furnaces burn only No. 2 oil and are equipped with burners which are designed specifically for that fuel would probably impose a significant burden on the enforcement staff of the control district.

Control measure No. 8 concerns the use of additives. Iron-based additives can reduce particulate emissions from commercial units by up to 50 percent, and some organic-based additives are equally effective. The impacts of such a control measure, both beneficial and adverse, are the same as those that were described under the residential sector. Implementation of this measure should be delayed until more information is available concerning toxicity of resulting emissions and possible adverse effects on fuel stability.

No control measure has been described that relies expressly on the use of emulsification. The available data come from only one set of tests on one boiler and are inconclusive. Of the two types of emulsifiers tested, one caused smoke emissions to increase when it was installed on the boiler and operated at zero or low water addition rates. Typical uncontrolled smoke levels were only reached when significant quantities of water were emulsified with the fuel. However, it was effective in reducing mass emissions. The other emulsifier did not affect smoke emissions significantly, but it increased mass emissions at zero or low water addition rates and never reduced them much below typical uncontrolled rates from standard systems. However, nothing in the control measures listed on Table 7-3 prevents an owner of a boiler or furnace from using emulsification to achieve specific emission limits if he feels that this technique is the most practical in his case.

7.2.3 Industrial Boilers – 12.5 to 250 MBtu/hr (3.66 to 73.2 MW)

Industrial boilers are generally used to provide process steam for washing, cooking, heating a substance to be dried, or heating a reaction vessel to provide the correct environment for a chemical process as well as space heating in conjunction with one of the above. They can account for as much as 9.5 percent of the particulate emissions from all sources in an AQCR. Some of the larger watertube boilers in this size category are also used to generate steam that drives a steam turbine which provides electricity to a plant (or a small utility). This size category of boilers is somewhat of an anomaly in that it straddles the regime between commercial boilers on the small size and utility boilers on the large size. The smaller industrial boilers generally have the same emission characteristics as the larger commercial units and frequently recieve the same kind of attention as do their commercial cousins. The large industrial boilers, on the other hand, are mostly of the watertube design, as in the utility sector, and are operated with the same care and professionalism received by boilers in central power stations. A concrete example of the transition that takes place in this size category is given by the application trends among soot blowers; units less than about 30 MBtu/hr (8.8 MW) usually are firetube boilers and are not equipped with soot blowers, whereas those which are larger than this size tend to watertube designs and are equipped with soot blowers. Maintenance practices vary widely in this size group and are frequently more a function of the size of the total facility rather than of an individual boiler. For example, some manufacturing facilities have several smaller boilers which each provide hot water or steam for one process. In such a case, these smaller boilers may receive the same kind of attention that a much larger boiler would normally receive.

The three major approaches to controlling particulates from boilers in this size category are as follows:

- Specific emission limitations
- Required installation of particulate collectors with specified collection efficiency
- Fuel restrictions

The first is used to insure that the burner is correctly designed to handle the fuel it receives given the combustion volume in which it is placed. From a control point of view this can be achieved by specifying emission limits for all boilers, and particularly all new ones. These limits could be set at levels which have been demonstrated by well designed units. Additional servicing and monitoring requirements can be placed on the owner of an industrial boiler to insure that his unit continues to emit no higher than its design levels. The second tactic can be invoked either directly by requiring the use of a particulate control device (usually an electrostatic precipitator or, in some cases, a multicyclone), or indirectly by specifying emission limits which are so low that they can only be met by the use of a control device, or by both approaches. Since the size, and hence the cost, of a precipitator are functions of the emissions reduction desired, successive control measures from among a prioritized list can mandate lower and lower emission limits at consequently increasing cost to the user (e.g., measure No. n could require 70 percent reduction, No. n+1, 90 percent, and No. n+2, 95 percent). The third approach, which is to place restrictions on the fuel used, attempts to insure that emissions will be reduced by removing the source of much of the particulate matter. One such restriction would be to limit the concentration of sulfur and vanadium in the fuel. The value of such a measure is that it eliminates the need for additives to reduce deposit accumulation and corrosion on the superheater tubes. These deposits tend to be more of a problem with utility boilers than with industrial units because the latter usually operate at steam temperatures which are low enough that corrosion is not significant. According to measurements taken on utility boilers, those which fired a fuel that required the use of additives emitted approximately twice as much particulate matter as those which burned a fuel that did not require additives.* The other fuel restriction that could be imposed would be a prohibition on the use of residual oil in any industrial boiler. As with the commercial units, distillate-fired industrial boilers emit less particulates than do residual-fired units.

Table 7-4 contains possible control measures for industrial (or small utility) boilers ranked in a suggested order of implementation. As before, the intent of this table is that control strategy No. 2 be applied only if control strategy No. 1 does not reduce particulate emissions from industrial boilers sufficiently. Similarly control strategy No. 3 would be implemented only if Nos. 1 and 2 together do not reduce particulate emissions far enough.

Control measure No. 1 contains two parts. The first is to require a construction and operating permit for all new or replacement boilers in this size category. Although most state and local air pollution control authorities already use a permit system, this measure is included for those which do not already have one. The significant part of this control measure, however, is the emission limits for new and replacement boilers or burners. The mass emission level indicated for

*These test results come from boilers which are equipped with particulate collection devices whose efficiency is approximately 50 percent.

TABLE 7-4. POSSIBLE PARTICULATE CONTROL MEASURES FOR BOILERS AND FURNACES: 12.5 TO 250 MBTU/HR (3.66 - 73.2 MW)[a]

Rank	Control Measure[b]	Policy Instrument	Effectiveness		Cost Impact[d]		Energy Impact,[e] %	Public Acceptance[f]	Comments
			Reduction per unit %	Reduction Per Air Region[c]	User $	APCD			
1	Require construction permits for all new or replacement units. Require operating permits (renewable annually) for all new or replacement units upon demonstration of compliance with following limits: Distillate SSN 2 Residual SSN 4 also 0.1 lb/MBtu Above limits to be achieved with 5% opacity.	APCD regulations, cooperation with standards laboratories	<40	Low–Moderate (eventually)	500-3000 yr	Low-High	(≥0)	Good	Need show compliance with mass emission limit only for first operating permit; renewal based on total engineering evaluation. Approval can be by model type. No cost impact assigned to this control for equipment because available systems can comply. Only cost impact for permit application (fee + engineers cost) and emissions test. For replacement assumes emissions due mainly to burner and not rest of boiler. Enforcement can be aided by a no-visible emission limit. Impact on APCD high if have no permit system.
2	Require operating permits for existing boilers, to be renewed annually if comply with following: Distillate SSN 2 Residual SSN 4	APCD regulations	≤30	Moderate	500 once plus 300 to 600/yr	Moderate	Positive	Good	Based on Maryland regulation as example. Presumes units now emit @ SSN 4 to 6 (barely visible). Cost for permit application.
3-A	Specify burner servicing and cleaning frequency: Units >30 MBtu/hr (10,000 lb steam/hr) on residual — 3 months All other units this category — 6 months Require operator and maintenance/servicemen to be licensed. Owner to advise APCD of service performed and post-service measurement of SSN and thermal efficiency (CO_2 and stack temperature).	APCD regulations, cooperation with trade or community-sponsored training program	<30	Moderate	6000/yr 1200/yr	Low	Positive	Good	States are encouraged to make reciprocal agreements for licensing servicemen. Whenever a source can show that a different burner servicing and cleaning frequency can maintain the same emissions, these provisions could be waived.
3-B	Require flue gas monitors: For units <30 MBtu/hr — Smoke detectors. Connected to audible alarm set for 15% opacity For units >30 MBtu/hr — Transmissometer that meets EPA specifications, connected to audible alarm set for 10 opacity and a continuous recorder Oxygen monitor connected to continuous recorder Size cut-off based on total heat input of all boilers that exhaust through the same stack (if more than one).	APCD regulations	?	?	500 to 600 plus 300/yr	Low	Positive	Good	Effectiveness unknown because of lack of data on incidence and duration of unnoticed upset conditions. Enforcement through operating permit renewal system. Oxygen meter used to insure efficient combustion. Many boilers already equipped with these monitors. Control district to issue a list of approved smoke detectors for use on units <30 MBtu/hr.

TABLE 7-4. Concluded[a]

Rank	Control Measure[b]	Policy Instrument	Effectiveness		Cost Impact[d]		Energy Impact[e]	Public Acceptance[f]	Comments
			Reduction Per Unit %	Reduction Per Air Region[c]	User $	APCD			
3-C	Require dust collectors on residual fired boilers >50 MBtu/hr with design collection efficiency >75% for particulate >10 μm.	APCD regulations	20	Low	0.2% of fuel	Low	0	Good	Low effectiveness based on assumption that many units well maintained and hence do not emit much large particulate. Helps more with local nuisances (especially during soot blowing) than TSP. Collection efficiency is design value.
4	Limit new residual units >50 MBtu to 0.04 lb/MBtu	APCD regulations	50 to 70	High	< 1.5% of fuel	Moderate	<2	Good	Based on Maryland regulation and use of multicyclones or ESPs with collection efficiencies of 50-70%. An excess air level ≤15% could also be imposed to retard SO_3 formation and conserve energy.
5	Limit existing residual units >50 MBtu to 0.05 lb/MBtu	APCD regulations	40 to 60	High	<1.5% of fuel	Moderate	<2	Good	Same comment as #4 above. ESPs are capable of efficiencies of >90% to ultimate emissions of approximately 0.01 lb/MBtu. Thus, if further reductions are necessary more stringent limits may be possible.
6	Prohibit use of anti-corrosion and anti-smut accumulation additives	APCD regulations	50	?	15% of fuel	Low	5 to 8	Poor	May indirectly prohibit use of fuels with high S and V. Cost based on use of LSR. Energy impact at refinery. Region-wide impact depends on fuel usage patterns. Unlikely that will need to implement this or succeeding measure in addition to all previous ones.
7	Prohibit use of residual fuel in all boilers	APCD regulations	70	High	15% of fuel	Low	5 to 8	Poor	Subject to availability of distillate fuel. Cost depends on current fuel and distillate as replacement
8	Combustion additives at optimum concentration to minimize emissions to be added to fuel	APCD regulations, coordination with nationally recognized standards	50	High	1% to 2% of fuel	Low	0	Poor	User and APCD need agree on enforceable system to ensure all fuel treated optimally. Generalized use not recommended at this time because of possible toxic effects and possible interaction with fuels.

[a] See Appendix C for conversion of mass emission limits to SI units

[b] SSN = Smoke Spot Number

[c] Relative to area-wide emissions from all sources in this category only; impact on region depends on relative importance of this source category

[d] Sample calculation of cost impact on annualized basis given in Appendix D

[e] Unit (increase) or decrease in efficiency

[f] Judgement; no data to substantiate

residual-fired units is based on the most stringent State regulations which do not envision add-on controls. Depending on design and fuel characteristics, some boilers can reach even lower emission levels. Thus, technically, this emission level may be revised downward if necessary.

An additional restriction is included in this control strategy by requiring that the plume not be visible. The 5 percent opacity limit is intended for those boilers which may be equipped with opacity monitors. A "no-visible-emissions" limit is also included for use by roving enforcement personnel. These two limits are essentially equivalent because plumes begin to be visible as their opacity approaches 5 percent. The Smoke Spot Number restrictions are the same as those given for new commercial boilers; their application to industrial boilers can be justified on the same grounds as the application of commercial mass emissions limits to industrial units. Although it is not common practice to measure Smoke Spot Numbers on units as large as the ones in this size category, enforcement personnel in Maryland use such tests to check for compliance with their regulations (which include Smoke Spot Number limits for all boilers). They feel that their measurements are meaningful as long as they insert the probe far enough into the stack to avoid wall effects.

This control measure recognizes the difficulty and expense of making mass emission measurements, particularly according to EPA Method 5. Hence, mass emission measurements are required only to obtain the original construction and operating permit for the boiler. A Smoke Spot Number reading would also be taken at this time at a representative location. The permit would be renewed each year after a total engineering evaluation by the control district, including review of smoke spot measurement operating parameters, condition of the equipment, etc. The use of smoke spot is based on the assumption that mass emissions at any future date will be no higher than they were during the original test if the Smoke Spot Number at the same sampling location is also no higher than it was during the original test (presuming the firing rate and air-to-fuel ratio are also the same). This assumption can be justified by data from residential and commercial units which show that, for any given unit, as the mass emissions increase so do the Smoke Spot Number readings, although not necessarily linearly. It is necessary to specify the sampling location as well as firing conditions because the flow is frequently nonuniform in the large stacks on these boilers. An additional flexibility is included in this control measure. If a manufacturer builds several boilers that are identical, he can ask the ABMA or Hydronics Institute to certify that this family meets the emission limits. New owners of one of these boilers can then use this certification in their permit application in lieu of another emission test.

The uppermost value of potential emission reductions reported for this control measure is based on the difference between the highest emissions levels reported for existing units of this size category and the indicated control levels.

The impact of this control measure on the area-wide emissions from all industrial boilers depends on the economic growth in the area and the future fuel usage patterns (particularly the degree to which coal replaces oil or oil replaces natural gas). Since the emission levels specified in this control measure are being achieved by existing units, no cost impact has been assigned to this control measure for the purchase or operation of new burners. Costs shown are for permit applications, including testing. The impact on energy consumption will be favorable if a unit that can run at less than 15 percent excess air is chosen as a result of this control measure rather than one which would have required more excess air.

Control measure No. 2 applies to existing boilers. It also introduces the requirement for an operating permit, which would be renewed annually, in the event that the control agency in question does not already use such a system. Since there are no data to substantiate mass emission limits for existing boilers on the basis of combustion modifications (such as was available for residential and commercial units from tests on the effects of tuning or the addition of a retention head), and since the cost to replace a burner with a new one that would meet the emissions limits specified in control measure No. 1 could be high, the first step indicated for existing units is to place a Smoke Spot Number limitation on them. As with measure No. 1, the limits shown here are based on the levels achieved by commercial units. They also conform to Maryland's regulations. The cost impact is based on the assumption that servicing and tuning industrial boilers takes about 2 to 4 times as long as it does for a commercial unit. The emission reduction of up to 30 percent that might be achieved by the implementation of this control measure is based on the assumption that existing industrial boilers are operating with a plume that is just below the visible limit. This limit corresponds to a Smoke Spot Number of 4 to 6, depending on the fuel and the combustion characteristics of the boiler. If the reduction from Smoke Spot Number 6 to Smoke Spot Number 4 corresponds to an equivalent reduction in particulate mass emissions, the upper limit of 30 percent reduction is justified.

The next control measure would be implemented if the air pollution control authorities predicted that they could not attain and maintain the NAAQS in their air basin despite the use of the first two control strategies, and if they thought that their inability to achieve these goals was due, in part, to the fact that many industrial boilers were not complying with the above regulations in between permit renewal periods. Thus, part A of control measure No. 3 specifically requires the owner of a boiler to perform frequent maintenance rather than leaving it up to his initiative to do so in order to comply with the emission limit. The 3-month interval between successive servicing and cleaning of the components that handle the fuel oil and combustion air is based on the experiences of the Boston Edison Company, as reported in the introduction to Section 4.3. This interval should be applied to residual-fired boilers that are larger than 30 MBtu/hr (8.8 MW). Smaller units, or larger ones that burn distillate oil, would only be required to service and clean their systems every 6 months. Although it is known that distillate oil does not create the same dirt problem that residual oil does, there are no quantitative data available to establish that 6 months is the optimum frequency between successive fuel system cleanings. Therefore, this control measure indicates the inclusion of an option which allows a boiler owner to demonstrate to the local air pollution control authorities that emissions from his unit will not increase substantially if it is cleaned less frequently. In order to insure that the boilers are cleaned by servicemen who are trained to optimize the performance of the boilers from both an energy and an emissions point of view, this control measure includes a requirement that both operators and maintenance/servicemen be licensed. Of course, the license would only be issued to people who could demonstrate that they had been appropriately trained and were competent in the field.

Part B of this control measure adds the requirement that boiler operators install flue gas monitors on the stacks of their boiler. These monitors would measure just smoke in the smaller systems and both smoke and oxygen in the larger ones. The reason for including oxygen monitoring on the larger boilers is to insure optimum combustion in those units. A distinction is made between the smaller and the larger boilers because the accurate transmissometers that meet EPA specifications are expensive.* The main purpose of these smoke meters is to notify the operator very rapidly if there is a malfunction in his boiler which causes smoke to be emitted. Such a condition could occur if a burner became plugged or if, for some reason, an air damper fell shut. Since smaller boilers emit less mass per unit time (i.e., g/s), then do larger ones, it seems reasonable to allow the smaller units to use a less accurate and hence cheaper smoke detector. The alarm level on such a unit should be set for about 15 percent opacity, or slightly higher than the level which would be set on the more accurate transmissometer that would be installed on a larger boiler. Unfortunately, data are not readily available in the open literature that document the frequency

*For units <250 MBtu/hr (73.2 MW), transmissometers that are purported to meet all EPA specifications (Federal Register, Vol. 39, No. 177, September 11, 1974) except linearity of response above 80 percent opacity are available for $500 - $600. Those which respond linearly up to 100 percent opacity cost about $1000 - $1500 (in early 1976).

and duration of typical upset conditions; therefore, one cannot estimate the effectiveness of this part of the control strategy.

Oil-fired boilers that are well maintained and tuned should not emit any significant quantity of large particulate matter (diameter greater than 10 microns). However, a survey by the Maryland Bureau of Air Quality Control has shown that some boilers apparently do not receive the attention they should because mechanical dust collectors in their exhaust do collect significant quantities of particulate matter (see Reference 4-14). Since these devices do not collect small particles efficiently one must assume that the exhaust from some boilers does contain significant quantities of large particulate. Therefore, part of the approach which should be taken to insure compliance with the control measures 1 and 2 is to require the use of mechanical dust collectors on all residual fired industrial boilers (except where a more efficient collector is used). Units are available which can collect up to 75 percent of the particulate matter greater than 10 microns (see Section 4.3.1.2). As noted on Table 7-4 in the comments for this control measure, collectors probably help more to alleviate local nusiance problems from the fall-out of large particulates than to reduce the quantity of total suspended particulates in the atmosphere. Compliance with the collection efficiency requirement can be demonstrated by proof that the collector is designed to capture 75 percent of the 10 μm particulates. This provision obviates the need for expensive EPA method 5 measurements.

The next two control measures listed on Table 7-4, Nos. 4 and 5, are stated in terms of mass emissions limits in order to allow the boiler owner maximum flexibility in meeting these limits. The limits in measure No. 4 are based on Maryland's regulations (0.02 gr/scf, or 0.04 lb/MBtu at typical excess air levels of 20-30 percent). It is recognized that this limit may implicitly require the use of a multicyclone or electrostatic precipitator (ESP) with collection efficiency of 50-70 percent. Depending on emission characteristics, ESP's are capable of efficiencies of greater than 90 percent to ultimate emissions of approximately 0.01 lb/MBtu. Thus, if a control agency determines that greater reductions are necessary to meet air quality standards, it may be possible to impose more stringent limits than those in Table 7-4. However, such parameters as cost, fuel characteristics, technical feasibility, etc., should be considered prior to imposition of more stringent limits. For example, a lack of adequate space for ESP around certain facilities in densely populated urban areas could contrain the use of this strategy.

The next two control measures listed on Table 7-4 (Nos. 6 and 7) deal with restrictions on fuel and fuel treatment. Both of these techniques are very expensive and may create economic dislocations if premium fuels become more scarce than residuals. It is unlikely that these strategies would have to be implemented because emission reductions of over 70 percent should have already been achieved by the use of the first five control measures.

Additives such as MgO are required in utility boilers if they are to burn fuel which has a high vanadium, sodium, and sulfur content because compounds of these elements would otherwise cause cold-end corrosion and acid smut accumulation on the heat transfer surfaces. Although industrial boilers generally operate at lower temperatures and, therefore, are not affected as much by these compounds, control measure No. 6, which prohibits the use of these additives, has been included to cover units which might use additives. Measurements on utility boilers have shown that those units which use additives emit twice as much particulate matter as those which do not. Boilers which are plagued by corrosion would have to switch to a lower sulfur, lower vanadium oil. Even greater particulate emission reductions could be achieved by switching all industrial boilers to distillate oil, providing the requisite fuels are available.

The final control measure is the possible use of combustion improving additives. The potential advantages and disadvantages associated with the use of additives are discussed under both residential and commercial systems.

7.2.4 Utility Boilers — Over 250 MBtu/hr (73.2 MW)

Oil-fired utility boilers account for up to 19 percent of the particulate emissions from all sources in an AQCR. Their impact is greatest in the urbanized northeastern areas of the country, where many power plants have been converted from coal to oil over the years to reduce sulfur and particulate emissions. They also are major contributors of particulate matter in the southern half of Florida, and moderately significant in a variety of other AQCRs throughout the country (see Table 1-1). Their impact in the future may depend more on the rate of oil to coal conversions in the eastern portion of the country and gas to oil conversions in the western portion than on the projected growth of electric power generation.

The same kinds of particulate controls can be used on utility as on large industrial units. Therefore, only a short discussion is required here in support of the control measure presented in Table 7-5. The major differences between the industrial and utility section are as follows:

- Utility boilers are generally operated and maintained by technicians who are specifically trained to optimize boiler performance. However, this does not always mean that they are trained to minimize emissions.
- Utility boilers show less variation in operating condition, maintenance practices, and quality of the staff than do industrial boilers.

TABLE 7-5. POSSIBLE PARTICULATE CONTROL MEASURES FOR BOILERS AND FURNACES: >250 MBTU/HR (73.2 MW)[a]

Rank	Control Measure[b]	Policy Instrument	Effectiveness		Cost Impact[d]		Energy Impact,[e] %	Public Acceptance[f]	Comments
			Reduction per unit, %	Reduction Per Air Region[c]	User, $	APCD			
1	Limit new units ≤550 MW according to capacity (in MW) as per: $FP(lb/MBtu) = 0.15 \times 10^{-6}(MW)^2 - .0.21 \times 10^{-3}(MW) + 0.09$ For units >550 MW, FP = 0.02 lb/MBtu. Limit to apply during soot blowing, too.	APCD regulation	50	Low	<1% of cost to customer	Low	<1	Good	Based on particulate collector with 50% collection efficiency during normal operation. Region-wide impact may be low because new oil-fired utility boilers may be rare. Cost impact will be diluted by lower cost electricity from existing power plants.
2	Specify 3 month interval between burner servicing and cleaning. Advise APCD of post-servicing opacity and O_2 (or CO_2)	APCD regulation	30	Moderate	26,000/yr	Low	Positive	Good	
3	Require continuous stack gas monitor for opacity and O_2 with recorders. Transmissometer to meet EPA specifications and be connected to alarm set for 5% opacity.	APCD regulation	?	?	5000 to 11000 plus 800/yr	Low	Positive	Good	Effectiveness unknown due to lack of data on incidence and duration of unnoticed upset conditions. Oxygen meter used to insure efficient combustion.
4	Limit new units to 50% of limits in control measure #1. (0.042 - 0.01 lb/MBtu). Limit existing units to same values in #1 (0.08-0.02 lb/MBtu)	APCD regulation	75 (new) 50 (existing)	Low	<1% of the cost to the consumer	Low	<1	Good	Based on ESP of 75 & 50% for new & existing units respectively. During soot blowing efficiency would be approximately 97.5 & 95% respectively.
5	Limit all new units to 0.01 lb/MBtu. Limit existing units to 50% of limits in control measures #1 (0.042-0.01 lb/MBtu).	APCD regulation	90-75 (new) 75 (existing)	Low	<1% of the cost to the consumer	Low	<1	Good	For new sources based on ESP of 90-75% efficiency for normal operations and approximately 99% during soot blowing. For existing sources, based on 75% efficiency normally and approximately 97.5% during soot blowing.
6	Prohibit use of anti-corrosion and anti-smut accumulation additives.	APCD regulation	50	?	15% of fuel	Low	3 to 10	Poor	May indirectly prohibit use of fuels with high S and V. Cost based on use of LSR. Energy impact at refinery. Region-wide impact depends on fuel usage patterns. Unlikely that will need to implement this strategy in addition to all previous ones.

[a] See Appendix C for conversion of mass emission limits to SI units

[b] SSN = Smoke Spot Number

[c] Relative to area-wide emissions from all sources in this category only; impact on region depends on relative importance of this source category

[d] Sample calculation of cost impact on annualized basis given in Appendix D

[e] Unit (increase) or decrease in efficiency

[f] Judgement; no data to substantiate

- Utility boilers are larger than industrial units and have a higher load factor than many of the latter system. Therefore, they have inherently lower particulate emissions and can better absorb the costs of control devices and increased maintenance efforts.
- Fuel costs account for a larger fraction of total operating costs in utility boilers than in most industrial units.
- Due to their size and continuous operation, each utility boiler has greater impact on the ambient air than a typical industrial boiler even though the unit emission rate (lb/MBtu) is generally lower for the utility.

Because of these differences, the control strategies in Table 7-5 place less emphasis on maintenance and operating personnel requirements and more on the use of high efficiency ESPs. Moreover, emission limits are specified in terms of a continous variation with size rather than in discrete groups.

The highest priority control measure is considered to be a low efficiency collector. Units with 50 percent collection efficiency would make a significant impact on the basin-wide emissions from the source category at a minimal cost. The control measure actually provides the boiler operator with some flexibilty in meeting the requirement because it is stated in terms of emission limits rather than equipment standards. Some boilers already emit at lower levels without controls (see Figure 7-1), either because of design features or the use of oil with low concentrations of ash, salts, and/or carbon residue. Boilers that do not comply with this limit without controls might use an existing ESP (e.g., one originally installed to reduce flyash emissions from a coal-fired boiler before it was converted to oil) or perhaps in some cases, a high efficiency multicyclone. The specified levels require a 50 percent reduction from the maximum emission rates reported for a sample of uncontrolled oil-fired utility boilers (see Figure 7-1, which shows the upper envelope of uncontrolled levels and curves which represents 50 and 75 percent control, respectively, from the upper envelope). Similarly, the levels in measures No. 4 and 5 are based on increasingly greater reduction from the curve of maximum emissions in Figure 7-1, with a lower bound at 0.01 lb/MBtu; precipitators generally cannot achieve lower levels (equivalent to 0.005 gr/scf at 3-5 percent excess air). The relationship and control measures in Table 7-5 correspond approximately to the following emission levels in lb/MBtu (ng/J).

	50 MW	200 MW	≤550 MW
Measures No. 1, 4 (50% collection)	0.08 (34.4)	0.05 (21.5)	0.02 (8.6)
Measures No. 4, 5 (75% collection)	0.04 (17.2)	0.03 (12.9)	0.01 (4.3)
Measure No. 5 (≤95% collection)	0.02 (8.6)	0.01 (4.3)	0.01 (4.3)

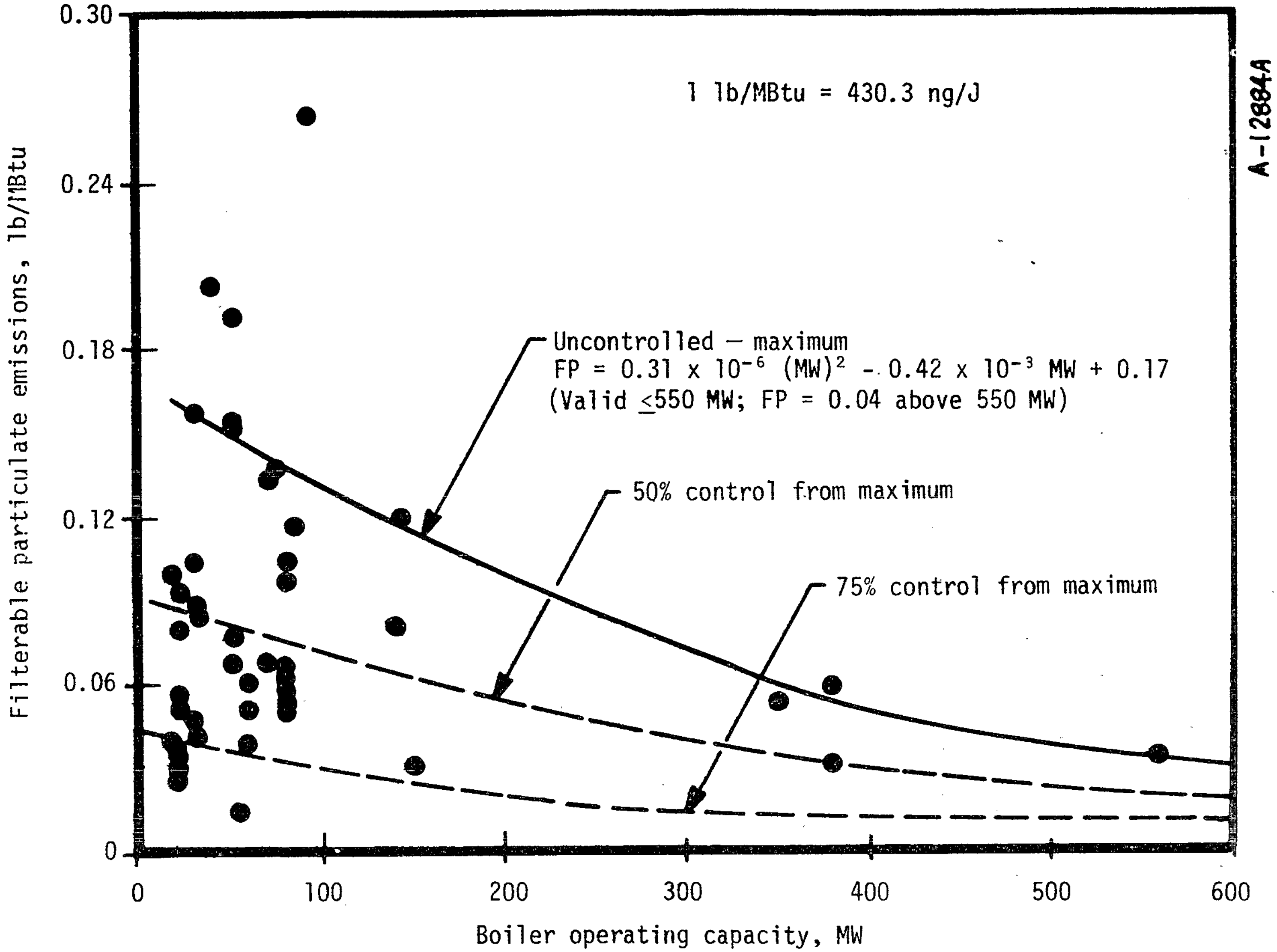

Figure 7-1. Emissions from uncontrolled electric utility boilers (no additives used) as a function of capacity and possible control levels (uncontrolled data from Reference 4-36).

It is indicated that the emission limits can apply during soot blowing as well as during nonsoot blowing as long as these limits do not require more than 99 percent control (from an assumed concentration level of 20 times the normal one for the soot blowing period). One source has stated that mass emissions during soot blowing can be as much as 20 times higher than they are during normal operation (see Section 4.3.2.1 and Reference 4-31). He has also shown that moderate and high efficiency ESP's allow no greater particulate mass to pass through during soot blowing than they do during the other operating periods. Therefore, the limit specified in control measures 1, 4, and 5 also apply to soot blowing periods. If emissions during soot blowing are truly 20 times higher than they are otherwise, the ESP would have to collect 98 percent of the emissions to comply with this limit. Commercially available units that are designed for oil-fired boilers can achieve this efficiency when the inlet grain loading is high (their major constraint is a minimum outlet loading of 0.005 gr/scf, or about 0.01 lb/MBtu).

Since these limits are based on reductions from the maximum reported levels and on the high multiplier of 20 for soot blowing, no power plant should have technical difficulties in complying with them. Although the limits in measures No. 4 and 5 appear to be very stringent, one should remember that the hourly emissions from a power plant are much higher than they are from boilers in the other source categories. For example, one 500 MW plant that is controlled to 0.01 lb/MBtu emits as much per hour as 12,000 homes with typical uncontrolled distillate-fueled furnaces. Since these home heaters do not operate continuously or year around, the annual emissions from a utility boiler are equivalent to those from nearly 100,000 homes.

For existing boilers it may be appropriate to consider the age of the unit when establishing emission limits. Utility boilers generally have a finite life (e.g., circa 40 years), and it may be most cost-effective for a region to spend more on controlling newer plants with many years left than on older ones which will soon be removed anyway. The applicability of a system of reduced control requirements for older sources is dependent on the severity of the local pollution problem and on the distribution of sources in that area. Such reduced control requirements should be negotiated on a case-by-case basis between the control agency and the source. Moreover, any regulation which takes account of plant age should, however, not discourage a source from delaying the replacement of an older, less efficient, higher emitting source with a new, controlled one. Therefore, consideration should be given to the use of variances, bonds (financial assurances that the old source will be removed or upgraded by a certain date), or substantial fines if the source is not removed or upgraded by a certain date.

The effectiveness of increased burner servicing (control measure No. 2) is given in terms of a maximum expected value because this figure is based on a projection that has not yet been substantiated. The requirement for continuous stack gas monitoring instrumentation on new units outlined in measure No. 3 is redundant because they are already equipped with these devices in compliance with NSPS. This control measure is included here in the event some control districts do not already require it on their existing sources. The last control measure has been discussed in the previous subsection on control of industrial systems.

7.3 ENFORCEMENT OF THE POSSIBLE CONTROL MEASURES

Before an agency decides what control measures to implement, it should investigate fully how it may utilize measures presently required. For example, revisions were made to 40 CFR 51 "Requirement for Submittal of Implementation Plans," and 40 CFR 60 "Standards for New Stationary Sources," October 6, 1975 (40 FR 4620) with regard to emission monitoring. These Federal regulations set forth minimum requirements for continuous emission monitoring and recording that each State Implementation Plan must include for specific existing source categories and that each source category covered by New Source Performance Standards must include. Existing fossil fuel steam generators are covered under 40 CFR 51, Appendix P for State Implementation Plans and new fossil fired steam generators are covered in 40 CFR 60.45 under New Source Performance Standards. The emission monitoring required by these regulations would satisfy the opacity monitoring requirements of control measure Nos. 2 and 3 in Table 7-5 for boilers and furnaces of greater than 250 MBtu/hr (73.2 MW). It should be possible for an APCD to obtain this information.

To judge the stringency of a regulation, Federal New Source Performance Standards (NSPS) can be used as a guide. These standards are based on best available control technology considering costs. However, state and local regulations can be more stringent than NSPS and should be for the case of fossil fired steam generators. This standard of 0.18 g/Mcal heat input (0.1 lb/MBtu or 43 ng/J) is meant for coal-fired generators, and much more stringent emission standards can obviously be met with oil-fired boilers.

APPENDIX A

POTENTIAL RESEARCH AND DEVELOPMENT TOPICS FOR PARTICULATE CONTROL FROM OIL-FIRED BURNERS AND BOILERS

Several areas of research into particulate emissions, their control, and their fate are currently being pursued. Successful conclusion of these research efforts will assist in the development of more refined control programs that should lead to significant and identifiable improvements in the air quality. The topics which are being considered fall into two broad categories — problem definition and control technology. In the first category the work that is underway and needs to be continued is directed at the following topic areas:

- The relationship between emission reductions from a given source category and consequent decreases in ambient air concentrations of particulate matter
- The relationship between particulate size, physical characteristics, and chemical composition on the one hand, and health hazard or welfare degradation, on the other
- The relationship between opacity, mass emissions, and smoke spot number
- The precursor/fate relationship for both primary and secondary particulates

Development of improved control technology is currently aimed at methods to collect fine particulates and changes to burners and/or burner/combustion chamber systems. This latter work has tended to stress smoke reductions (as measured by the Bacharach Smoke Spot Number) in residential and commercial sized units and NO_x reductions in the larger burners found in industrial and utility boilers. Since some combustion modifications for NO_x control can increase particulate emissions, additional research appears to be necessary to develop methods which can reduce both NO_x and smoke. In addition, studies are required to determine optimum maintenance practices (methods and frequency of maintenance) and soot blowing procedures for industrial and utility boilers. These subjects are discussed in somewhat greater detail below. It should be noted, however, the recommended R&D is not necessarily all-inclusive or presented in order of priority; it was not within the scope of this task to go beyond a simple identification of potentially fruitful R&D topics.

Fundamental burner design research has resulted in the development of an "optimum" oil burner for distillate-fired residential and commercial sized units (Section 4.2.3). These burners need to be field tested to verify the results obtained in laboratory experiments. A similar program is under way with residual oil-fired burners for commercial burners (under the auspices of G. B. Martin, Combustion Research Branch, Industrial Environmental Research Laboratory — RTP, EPA). Although the main purpose of this task is to develop a low NO_x burner, a secondary goal is to minimize particulate emission.

Several different atomization methods have been suggested for particulate reduction and/or improved fuel economy. These include the acoustic and ultrasonic schemes (Section 4.1.4.1) and the Babington burner (Section 4.2.3). Their capabilities should be evaluated by lab and field tests. Similarly, tests should be conducted on industrial and utility boilers to determine the potential for reducing particulate emission from residual oil-fired boilers when equipped with viscosity controlled preheaters.

As noted several times in Section 3, further R&D is required on the emission reduction, health impact, and potential operational problems of additives. This could be a very fruitful area of work because of the large emission reductions that may be achievable by cost-effective means that are relatively easy to implement and enforce. On the subject of fuel treatment, some work may be justified to further evaluate the value of fuel washing, especially as a means of eliminating the need for adding corrosion inhibiting MgO additives, which then become particulate emissions, themselves.

There appears to be little information on the effects of soot blowing on particulate emissions. In order to realistically evaluate the impact (if any) of various methods of blowing soot, measurements are needed of both particulate loading and size distribution in the stack during soot blowing and nonsoot blowing operation. A preliminary evaluation should be conducted of a number of boilers using different blowing procedures. More detailed measurements of emission characteristics as a function of blowing frequency may then be in order. The emission test results should then be related to control equipment capabilities and resulting ambient air levels (through the use of dispersion models) to determine the real impact of soot blowing procedures on the ambient particulate levels.

Electrostatic precipitators (ESPs) are the most commonly used particulate control devices for large boilers. Several operational problems were identified in Section 4.3 relative to the use of ESPs on oil-fired units. Development work may be appropriate to overcome these potential deficiencies and, thereby, add to the confidence that the ESP will perform continuously at its design efficiency. The discussion in Section 4.3 also pointed out that scrubbers and baghouses possibly could be used effectively on oil-fired units, but here too more R&D is required.

The difficulty in making accurate particulate emission measurements may prevent a control agency from adopting the most cost-effective control strategy. EPA Method 5 is expensive because it requires sophisticated sampling equipment and much time. Smoke spot methods, on the other hand, are fast and relatively simple, but they give no quantitative emission data (see Appendix B). Therefore, efforts should be made to develop a simpler mass emission sampler, or at least one which will give approximate data. For example, tests could be conducted on a variety of residential, commercial, and small utility systems to seek a "representative" sampling point that obviates the need for a stack traverse.

Several local agencies, as well as the EPA, have initiated programs to more clearly identify the causes of high ambient particulate levels. The microscopy studies mentioned in Section 1.1 are an example of such efforts. More work is required to establish more positively the relationship between specific source emissions (both individual point sources and distributed area sources) and ambient air quality. A typical question that needs to be answered is the relative impact of many small, low emission point sources (e.g., home heaters) as opposed to a few large, tall stack sources (e.g., power plants). Other questions deal with the relative importance of fugitive dust and natural sources of particulates, the generation of secondary particulate in the atmosphere, etc.

APPENDIX B

MEASUREMENT OF SMOKE AND PARTICULATE EMISSIONS

Several techniques are commonly used to obtain an indication of combustion generated particulate emissions. One approach is to determine the opacity of the plume, either by human observer or transmissometer. Another is to obtain a measure of the soiling capacity of the particulates in the exhaust by means of a Smoke Spot reading (e.g., Bacharach test). A direct measurement of the particulate loading is obtained by EPA Method 5. All three approaches actually measure different properties of the exhaust. Opacity describes the light obscuring ability of the particulates and is affected largely by the size of the particulates in the exhaust and their surface characteristics. EPA Method 5 measures mass emissions, but, unless the probe is fitted with additional equipment, it does not differentiate between heavy particles that might fall out in, or near, the private property surrounding the source and light particles which will remain suspended longer and contribute to the TSP. The Smoke Spot Number of a discharge gives a measure of the soiling characteristics of the particulate in the exhaust. Therefore, the reading obtained depends, in part, on the "stickiness" and the color of the particles. In addition, it is a very useful diagnostic for evaluating burner performance because it can measure the quality of the exhaust when the plume is invisible — the lower readings on the smoke spot scale (i.e., approximately 0 to 6 on a scale that goes from 0 through 9) are obtained in plumes which are not visible. Since EPA Method 5 and smoke spot are affected differently by the characteristics of the exhaust, we present below a brief comparison of the two techniques.

EPA Method 5 consists of isokinetically withdrawing a volume of effluent from the gas stream and collecting the particulate on a filter followed by a series of impingers (Federal Register, Vol. 36, No. 247). A cyclone may also be used at the front end of the sampling system to collect large particules which would otherwise clog the filter rapidly. The particulate loading for compliance purposes is determined by the weight added to the filter (after it is dried). The impinger is used for further characterizing emissions.

The accuracy of the method is dependent mainly upon the completeness of removal of the sample from the sampling system, especially for sources where emissions are relatively low. Battelle has recently used a modification of EPA 5 which includes more thorough washing of the probe and impingers (Reference B-1). This modification (subsequently referred to as MEPA-5) results in particulate measurements on residential units and commercial boilers which are approximately 1.7 times greater than those made by the standard method.

Due to the complex and time consuming nature of Method 5, several simpler (and necessarily more qualitative) measurement techniques are commonly used. The most important of these is measurement of the Smoke Spot Number. In this test (defined precisely in ASTM Procedure D2156-65) a sample of the effluent gas is withdrawn by means of a hand pump, and particulates are collected on a spot on filter paper. The amount of particulate collected is inferred visually from the darkening of the spot by comparison with a set of standard spots. The smoke concentration is then assigned a number based on the corresponding standard spot.

Several attempts have been made to relate particulate mass emissions to Smoke Number, but none have been very successful (see References B1 and B2). Data from one study (Reference B-1) shows widely different particulate levels even at equivalent smoke numbers. The most important reasons for this lack of correlation appears to be the dependence of Smoke Spot Number on particle size distribution and physical characteristics. In addition, EPA 5 measurements are often averaged over a long period of time (e.g., 10 minutes), while smoke spot determinations are essentially instantaneous in nature.

REFERENCES FOR APPENDIX B

B-1. Barrett, E. R., Miller, S. E., and Locklin, D. W., "Field Investigation of Emissions from Combustion Equipment for Space Heating," Battelle, Columbus Laboratories, EPA R2-73-084a, June 1973.

B-2. Levy, A., et al., "A Field Investigation of Emissions from Fuel Oil Combustion for Space Heating," Battelle, Columbus Laboratories, API Publication 4099, November 1, 1971.

APPENDIX C

UNIT CONVERSIONS

The following presents multiplication factors to be used in converting from engineering to SI units. This table is restricted to those physical quantities which are encountered frequently throughout the text and in the tables and figures of this document. Additional conversion factors can be obtained from "American National Standard E380-72, Metric Practice Guide."

To convert from	To	Multiply by
lb/MBtu	nanogram/Joule (ng/J)	430
MBtu	Giga Joule (GJ)	1.06
MBtu/hr	Megawatt (MW)	0.293
gph (gal/hr)	cubic meters/sec	1.05×10^{-6}
gr/SCF	g/m^3 (0°C, 1 atm)	2.42

The above conversion from MBtu/hr to MW is for thermal MW's — i.e., the burner input heat rate as expressed in SI units. Frequently it is desired to convert boiler heat input rate to an equivalent electrical output rate. This conversion is approximately 10 MBtu/hr per MW. The nuclear power industry generally uses the subscrips t and e to distinguish thermal (input) from electrical (output) power.

Other conversions within the engineering system of units are encountered often enough to be included here.

To convert from	To	Multiply by
1000 lb steam/hr	MBtu/hr	1
bhp (boiler hp)	MBtu/hr	0.0335
gph	MBtu/hr	0.140 (No. 2 oil)
gph	MBtu/hr	0.150 (No. 6 oil)
lb particulate/1000 gal	lb/MBtu	0.00714 (No. 2 oil)
lb particulate/1000 gal	lb/MBtu	0.00667 (No. 6 oil)
psi	Pascal (Pa) or Newton/m^2 (N/m^2)	6.895×10^3
In. W.G.	Pa	249
°F	°C	5/9 (°F-32)
inches	meters	2.54×10^{-2}
feet	meters	0.3048
kinematic viscosity in centistokes (cSt)	m^2/sec	10^{-6}

The conversions that depend upon the oil are based on 140,000 Btu/gal for No. 2 oil and 150,000 Btu/gal for No. 6 oil.

APPENDIX D

SAMPLE CALCULATIONS TO ANNUALIZE COSTS

One useful way of comparing the costs associated with a variety of emission control techniques, especially when they involve differing initial and continuing costs, is to annualize all the costs. We present here two examples of such a calculation, one using the costs associated with control measure No. 4 for residential units (see Table 7-2) and one with measure No. 5 for utility boilers (see Table 7-5).

Control measure No. 4 for existing residential boilers and furnaces specifies that they meet stringent emission limits, which means that many owners will need to purchase a new burner and have it serviced annually. A benefit of this control measure would be a cost saving due to the improved fuel consumption of new burners relative to the older ones they usually replace. Based on the figures shown on Table 7-2, the owner could, therefore, incur a one-time cost of about \$300 to purchase the burner and an annual cost of \$30 to service it. We will assume an intermediate value of 3 percent reduction in fuel consumption, an annual consumption of 1000 gallons (3.78 m^3), and a constant fuel cost of 40¢/gal. The initial cost is annualized using the capital recovery factor, CRF, with an interest rate of 10 percent (as in a home improvement loan) and a life of 10 years.* Then

$$\text{Annual costs (AC)} = \text{CRF} \times \text{Initial costs (I)} + \text{Annual service cost} - \text{Fuel savings}$$

$$= 0.163 \times 300 + 30 - 0.03 \times 1000 \times 0.40$$

or $$\text{AC} \simeq \$67$$

The cost calculation for the addition of an electrostatic precipitator to a utility boiler is more complicated because one must include at least depreciation and the tax reduction associated with the fact that normal expenses reduce the taxable income. For simplicity, we shall assume

---

*$\text{CRF} = \dfrac{i(1 + i)^n}{(1 + i)^n - 1}$, where i = interest rate (0.10 here) and n = number of years (10 here).

straight line depreciation, instead of an accelerated approach such as sum-of-the-years, and ignore any possible investment tax credit. We shall also use the same basic calculation procedure as in the residential example instead of a discounted net cash flow computation. These simplifications are acceptable for comparing area wide strategies, given the other uncertainties in the comparison, even though they should not be used by any individual firm when comparing two clearly defined alternative proposals. An interest rate of 10 percent will be used again, but the life of the system will be taken as 15 years, which is more representative of the life of large systems, at least for accounting purposes. The computation for a high efficiency unit with a capacity of 300,000 acfm (i.e., approximately 100 MW electric output) is then as follows (assuming a stack gas temperature of 350°F, 3 percent excess oxygen, and a plant thermal efficiency of 38 percent).

1. Installed cost (see Figure 4-11b) = \$825,000
2. Fixed cost = CRF x (1) = 0.131 x 975,000 = \$108,000
3. Operating costs = \$0.05/acfm x 300,000 acfm = \$ 15,000
4. Maintenance Cost = \$0.03/acfm x 300,000 acfm = \$ 9,000
5. Before tax costs = (2) + (3) + (4) = \$132,000
6. Operating tax credit = 0.5 x (5) = \$ 66,000
7. Net annual costs = AC = (5) - (6) = \$ 66,000

A similar calculation for a medium efficiency precipitator (installed cost = \$575,000, operating costs = \$0.03/acfm) yields AC = \$46,800. If these plants operate 8000 hours per year, the unit costs of the precipitators are:

AC/(100 MW x 8000 hr) = \$0.083/MW-hr = 0.008¢/kW-hr (high efficiency)

= \$0.059/MW-hr = 0.006¢/kW-hr (medium efficiency)

These are the kinds of cost data that should go into an area-wide model to compute the cost effectiveness of various possible control strategies. However, it may be more informative to relate the cost of the precipitator to the amount a utility charges its customers for electricity. The "before tax cost" (line 5, above) is the appropriate figure to use for this purpose. Since most oil-fired utilities are located in the northeastern states, precipitator costs should be compared to the 4-7¢/kW-hr charged in that region. On the basis of 5¢/kW-hr for electricity, a high efficiency precipitator would represent nearly 0.2 percent of the price of electricity. Similarly, a low efficiency unit would add a burden of less than 0.1 percent to a customer's electric bill.

One recent report suggests that ESP's designed for oil-fired boilers cost \$5 - \$8/acfm.* A value of \$3.3/acfm was used in the above calculation for high efficiency units. At \$8/acfm, the net annual cost of the precipitator would be 0.021¢/kW-hr, and the before tax costs would represent 0.4 percent of a 5¢/kW-hr charge for electricity.

The calculation for an industrial boiler follows the same procedure, but here it is most reasonable to relate the cost increase to the amount of steam produced. If one assumes 20 percent excess air, 350°F stack gas temperature, 80 percent thermal efficiency, and a 100,000 lb steam/hr industrial boiler, the exhaust flow is about 50,000 acfm. The cost calculation then proceeds as above, using the following costs.

Cost	High Efficiency	Medium Efficiency
Installed (\$)	430,000	200,000
Operating (\$/acfm/yr)	0.05	0.03
Maintenance (\$/acfm/yr)	0.03	0.03

The results of these calculations yield annual costs of \$30,200/yr and \$14,600/yr, respectively, for this 100,000 lb steam/hr boiler. Assuming that this boiler is used only 4000 hr/yr (i.e., two shifts of 5 days/week), the above costs become $\$0.37 \times 10^{-4}$/lb steam for the medium efficiency precipitator and $\$0.75 \times 10^{-4}$/lb steam for the high efficiency unit. Fuel costs of \$2.5/MBtu are equivalent to $\$31.3 \times 10^{-4}$/lb steam for an 80 percent efficient unit; therefore, the medium and high efficiency precipitator costs represent 1.2 percent and 2.4 percent of these fuel costs, respectively.

*"Partuculate Emission Control Systems for Oil-Fired Boilers," GCA Corporation, Prepared for U.S. EPA, Report No. EPA-450/3-74-063, December 1974. (Reference 4-36)

APPENDIX E

AD HOC ADVISORY COMMITTEE — PARTICULATE EMISSIONS FROM OIL BURNERS

Name	Affiliation	Specialty
Industry and Public Interest Groups		
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16. ABSTRACT

This report identifies possible control measures which Federal, State, or local control agencies might use to reduce particulate emissions in areas where the combustion of oil has a significant impact on air quality. To arrive at viable, effective controls, a comprehensive survey was conducted into such techniques as burner design changes, fuel restrictions, additives, mandatory periodic inspection/maintenance programs and particulate collection devices. Emerging technology that may assist boiler and furnaces operators to achieve lower particulate emissions was also identified. The experiences gained by agencies with active particulate control programs were evaluated, and their procedures included among the list of possible control measures where appropriate. These findings are summarized along with tabulations of possible control measures according to their stringency and applicability to residential, commercial, industrial, and utility boilers and space heating furnaces.

17. KEY WORDS AND DOCUMENT ANALYSIS

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