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PERFORMANCE OF EMISSION CONTROL DEVICES ON BOILERS FIRING MUNICIPAL SOLID WASTE AND OIL

Industrial Environmental Research Laboratory
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PERFORMANCE OF EMISSION CONTROL DEVICES ON BOILERS FIRING MUNICIPAL SOLID WASTE AND OIL

by

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ABSTRACT

Existing data on particulate emissions from oil-fired electric utility boilers and from waterwall (steam generating) incinerators firing either refuse or refuse-plus-coal/oil auxiliary fuel were used to estimate particulate flue gas loadings for combined firing of shredded municipal refuse (MSW) and oil. Estimates of control device performance were made for several planned oil-MSW resource recovery systems. On the basis of these estimates, installed particulate emission controls, designed for coal, are predicted to be significantly less efficient for control of particulate emissions from combined firing of oil-MSW. Anticipated control difficulties result mostly from relatively high particulate loadings, high flue gas volumes, fine particulates, relatively low particle density, and relatively high fractions of carbonaceous, low-resistivity particulate.

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SECTION 1

SUMMARY

Studies on the control of particulates from the combined boiler firing of oil and municipal solid wastes (MSW) were conducted for the Industrial Environmental Research Laboratory, Research Triangle Park (IERL-RTP). Objectives of this project were to develop quantitative emission forecasts and recommend control strategies for several planned oil-MSW combined firing tests. Oil-MSW tests included planned EPA demonstrations and industry tests which are to be carried out in utility boilers.

The program was divided into five major areas of activity: (a) an information search to acquire particulate emissions data for oil-fired utility boilers and municipal waterwall incinerators equipped with appropriate control devices; (b) development of correlations for fractional efficiency and control costs as functions of major design, control, and operating variables; (c) development of appropriate analytical models for control performance; (d) case studies to develop preliminary emission forecasts for plants where combined MSW-oil firing tests are planned; and (e) development of recommendations for future work.

INFORMATION ACQUISITION

Data acquisition included literature searches and contacts with government and private industry sources. Literature sources included: Air Pollution Abstracts, 1970 to 1974 (all entries); NAPCA Abstracts, 1970 to 1974 (all entries); Applied Science and Technology Index, 1958 to 1973 (all entries); and Engineering Index, 1965 to 1971. In addition to these sources, an APTIC Search was ordered and a key word index search was run on holdings in the Bay Area Air Pollution Library.

Data inventories were acquired for: (a) emissions from oil-fired electric utility boilers; (b) control device performance for oil-fired utility boilers; (c) emissions from waterwall incinerators; and (d) control device performance for waterwall incinerators.

CONTROL PERFORMANCE AND COST CORRELATIONS

Control system performance data were compiled for oil-fired utility boilers and for refuse firing systems (waterwall incinerators, refractory wall incinerators, and combined firing systems).

Data correlations for oil-fired boiler emissions were incorporated into a simplified model developed to predict uncontrolled particulate emissions as a function of percent fuel ash, percent fuel sulfur, fuel firing rate, percent excess oxygen (or air), and fuel heating value. A range of uncontrolled particulate emissions was defined on the basis of previous analyses of particulate levels generated in combined firing of coal and MSW. For a given boiler, refuse fuel, and method of firing, variations in total fly ash were interpreted in terms of a dimensionless "fuel characterization factor" comprised of heating values, ash contents, and fly ash-to-total ash ratios for both the conventional fuel and the auxiliary MSW fuel.

For ESP control, a modified form of the Deutsch equation was used to describe variations in collection efficiency resulting from changes in flue gas volume. The effect of particle size distribution was determined by calculating a separate collection efficiency for each discrete particle size range and by applying appropriate Cunningham "slip correction" factors. Empirical correlations were used to determine limitations in current density resulting from increased particle resistivity and/or increased flue gas temperature.

Installed cost data were acquired for new ESP installations, for retrofitting ESP units designed for coal, and for wet scrubbers. Detailed cost and design data were acquired for two new ESP units designed specifically for collection of refuse fly ash.

ANALYTICAL MODEL DEVELOPMENT

Analytical model development efforts included the development of predictive models for particle size, flue gas volume, total fly ash, and control device performance under combined firing conditions. Installed control systems on boilers in which combined firing tests were planned included ESP's and cyclones. A semiquantitative predictive model was developed for ESP control.

An analytical procedure was developed for calculating flue gas volumes as a function of MSW fraction, fuel moisture, fuel sulfur, higher heating values, and elemental compositions (C, O, H, N, and S). Calculations for representative oil and MSW fuels indicated a significant increase in flue gas volumes corresponding to increasing MSW heat input. For each percent of MSW heat input the calculations indicate approximately a 1% increase in flue gas volume. It is anticipated that this increase will have a significant effect on fractional control efficiencies.

Control performance evaluation methodology was developed for ESP control on the basis of previous performance studies. Use of the model was limited somewhat by the available data for refuse properties, particle size distribution, fly ash density, and resistivity for the MSW fuel. In general, however, the problem of fly ash collection when oil and MSW are fired in the same chamber does not appear to have any characteristics which have not previously been encountered in designing electrostatic precipitators for oil-fired units. On the basis of the present study, it is estimated that for most medium efficiency ESP units designed for coal fly ash (95.0 to 98.0% design efficiency) the efficiency is expected to drop to 60 to 70% for oil, 70 to 85% for oil plus refuse, depending on refuse composition and MSW heat input.

One multicyclone control system was evaluated in the study because of a planned oil-MSW combined firing test at Delmarva Power and Light Company's Edgemoor Station No. 3. It was found that for cyclone control, the theoretical basis for pressure drop and collection efficiency had not been well developed because of complexities of flow fields. Experimentally determined fractional efficiency data for cyclone control systems acquired in the literature study were used to adjust performance for changes in particle size distribution under combined firing conditions.

CASE STUDIES

Planned combined oil-MSW systems which were examined in detail included (a) District of Columbia, (b) Wilmington, Delaware (New Castle County), (c) New York City, and (d) Bridgeport, Connecticut. On the basis of control performance estimates, the performance of installed control systems designed for coal appears to be questionable for meeting applicable regulations for particulate emissions, except at very low MSW heat input and/or boiler load. For ESP control, major expected control difficulties result from: high flue gas dust loading and flue gas volume, low average particle density, fine particles, and large percentages of carbonaceous low resistivity particulate.

RECOMMENDATIONS

In view of the rapid projected growth rate of MSW fuel utilization in combustion systems and increasing public awareness of associated air emissions, in-depth evaluation of several existing and novel control systems appears justified.

The following recommendations are directed toward major deficiencies in the control technology defined in the present study.

Electrostatic precipitator control

In adapting existing theoretical studies to the development of a practical performance model to predict ESP performance for combined firing applications, there was found to be no quantitative information on the effects of:

1. Fly ash density;

2. Re-entrainment; and

3. Sneakage or bypassing.

Analysis of the effects of fly ash density, re-entrainment, bypassing, and other factors is recommended, based both on analysis and a survey of available data including contacts with equipment manufacturing firms.

Cyclone control

The theoretical prediction of cyclone pressure drop and collection efficiency is not possible because of complexities of flow fields. Other factors, such as the tendency of cyclone collectors to plug when in service on oil ash, and the performance decline in the corrosive atmosphere of incineration flue gases, need to be examined.

As in the case of ESP control, additional work on this type of control system specific to the application of combined fossil fuel-MSW combustion is recommended. This would include contacts with vendors, literature review, and analysis beyond the scope of the present study to develop guidelines for use in combined firing applications.

Novel Control Devices

High performance scrubbers and wet electrostatic precipitators have utility for collection of particulates, gaseous pollutants (SO_x, NO_x, and others) and potentially hazardous trace metals. There were no scrubber or wet ESP units installed on the boilers evaluated in the present study. An in-depth study of these control methods appears justified.

SECTION 2

INTRODUCTION

Resource recovery systems involving combined firing of shredded municipal solid wastes (MSW) with fossil fuels, such as oil or coal, are relatively new. Consequently, there is little available information from which to predict the performance of emission control systems. The present study was directed toward the analysis of control performance when oil and MSW are fired concurrently in a conventional electrical utility boiler.

The first demonstration plant to process raw municipal waste for use as a supplementary fuel in power plant boilers--the St. Louis-Union Electric Refuse Fuel System--is presently demonstrating the potential and problems of coal-MSW firing.

Oil-MSW firing is potentially more attractive in terms of long range fuel conservation, if a number of operating problems can be resolved, and if particulate emissions can be successfully controlled.

Oil-fired units have not utilized or needed very efficient control of particulates in the past. Particulate control from oil-fired steam generators normally involves using mechanical collectors which are used primarily during soot blowing. In combined firing, the resulting (controlled) particulate levels may be much higher than the existing standard for oil-fired boilers. In addition, the performance of those systems with high efficiency collection is in questions. It is not known precisely how the various high efficiency particulate control devices will behave for combined firing of refuse and oil.

The objective of the present study was to acquire the data base required for development of semiempirical control performance and cost models for the control of emissions from combined firing of oil and MSW and, using this information, to analyze the performance of installed control systems for planned oil-MSW combined firing systems.

SECTION 3

PARTICULATE EMISSION DATA ACQUISITION AND EVALUATION

A review of information pertinent to concurrent firing of oil and MSW was made using both literature searches and telephone contacts with private sources knowledgeable with (a) waterwall incinerators and emission controls, and (b) combined firing applications. The objective of this part of the study was (1) to determine the properties of particulate and flue gas from firing oil and refuse which are pertinent to emission control using cyclones, electrostatic precipitators, and high performance wet scrubbers, and (2) to estimate the composite fly ash and flue gas properties for combined firing. Pertinent variables for the control systems considered were determined to be:

1. Total fly ash per weight of fuel burned. Relative amounts of fly ash from burning oil and refuse fuels separately are needed to determine total fly ash emitted in combined firing and to estimate the physical properties of the composite fly ash which are needed for control device sizing (resistivity, bulk density, etc.).

2. Flue gas volumes per weight of fuel burned. Excess air levels and fuel composition data (moisture, ash, ultimate analysis) chiefly determine the flue gas volume.

3. Particulate density. Although fly-ash density has not been considered in previous combined firing studies, discussions with equipment vendors indicate that this may be an important factor in ESP sizing in that a decrease in density requires a proportional decrease in flue gas velocity through the precipitator. There is unfortunately no quantitative treatment available to describe the influence of reduced particle density on collection efficiency. On the basis of classical analysis, electrical or "capture" forces are independent of particle density, while aerodynamic or "drag" forces are inversely proportional to particle density for laminar flow. For particles of a

given diameter, the rate of acceleration away from the collection electrode during rapping cycles will also be inversely proportional to particle diameter. Other key design parameters (e.g., particle resistivity, dielectric constant, etc.) may also vary systematically with particle density.

4. Ash fusion temperature. This factor is important with regard to possible plugging of air passages and slagging of boiler tubes. It also indirectly influences excess air required.

5. Particulate size distribution. Particle size distribution data for each fuel burned separately are used, with the mass emissions data, to estimate the particle size distribution of the composite fly ash.

6. Particulate resistivity. Particulate resistivity depends on many factors including flue gas moisture level, fuel sulfur, fuel metals active as oxidation catalysts (principally vanadium), basic chemical constituents, and mass fraction of particulate from each fuel source. In firing of oil alone, high concentrations of metals active as oxidation catalysts, principally vanadium, are believed to be responsible for "acid smuts" which are agglomerates of oil ash and sulfuric acid. In combined firing of oil-MSW, it is anticipated that H_2SO_4 will be less of a problem than it sometimes is in oil-fired units. The higher particulate levels expected in combined firing should serve to collect most of the sulfates formed, resulting in a "well conditioned" fly ash with reduced resistivity. In the combined firing of oil with coal, none of the problems associated with firing of oil alone are encountered, indicating that the coal ash tends to adsorb excess moisture and sulfur compounds.1/

Data which were found for these properties for each fuel type, and methods of estimation of composite properties needed for control system sizing, cost, and performance estimation are described in the following subsections.

MASS EMISSIONS DATA

Data inventories were compiled for particulate emissions from oil-fired electric utility boilers and waterwall incinerators, as summarized in abbreviated form in Appendices A and B, respectively. The objective of the data acquisition was to use these data to estimate the range of particulate emissions which is probable when oil and MSW are fired concurrently in a utility boiler. More precise estimates of particulate emissions require detailed information about the fuel-oil ash content, refuse ash content, and type of boiler.

Uncontrolled Particulate Emissions from Oil-Fired Electric Utility Boilers

Particulate from oil firing (uncontrolled) was found to vary from 0.0055 to 0.87 $g/10^6$ joules of heat input (approximately 0.013 to 2.02 $lb/10^6$ Btu) with an average value for 29 electric utility boilers of 0.0632 $g/10^6$ joules (0.147 $lb/10^6$ Btu). In calculating the average, duplicate tests for the same boiler were averaged. A more representative value for uncontrolled particulate from oil firing is obtained by discarding extreme values. This yields a range of 0.01 to 0.154 $g/10^6$ joules (0.023 to 0.36 $lb/10^6$ Btu).

As indicated by the above range of values, uncontrolled particulate emissions from oil firing can vary considerably. The lower value is approximately equivalent to 0.0237% by weight of oil-fired, which is in the same range as the ash content of No. 6 residual oil (0.002 to 0.3% by weight).[2/] The upper value is approximately equivalent to 3.6% by weight of oil fired, or approximately one order-of-magnitude higher than the expected ash content. It has previously been noted that particulate fly ash from oil firing can range from approximately the ash content of the oil up to 10 to 15 times the ash content, the higher range of values being attributed to poor combustion.[2/] The combustible portion of fly ash normally ranges from 60 to 90%.[3/]

In order to determine the expected range of uncontrolled particulate for a given installation, the influence of several factors must be quantitatively defined. The quantity, type and size of uncontrolled particulate emissions from oil-fired combustion operations are thought to depend mainly upon the following factors:[2,4/]

Overall fuel consumption rate
Ash and sulfur content of fuel
Use of mineral fuel additives
Degree of atomization (type and oil viscosity)
Windbox air admittance
Burner tilt
Excess air
Boiler load
Flue gas recirculation
Age and condition of boiler

A review of the available literature indicated that in most cases, quantitative relationships describing the dependence of particulate emissions on these factors either did not exist or correlations developed were very uncertain. The reason for this is probably that the number of variables involved in a given plant are very large, and since these change from plant to plant, it is impractical to obtain sufficient data on the effect of a single variable while maintaining the others constant. Unfortunately, it is not always correct to assume that each factor exerts an independent influence on the measured emissions. It would be preferable to use statistical methods (e.g., linear regression analysis) to describe the influence of a single variable under conditions in which other variables are also changing, but unfortunately this has not been done.

As an illustration, consider the influence of excess air under variable boiler load. Some boilers are designed specifically for peak power generation and operation under variable load conditions. More frequently, when a convective superheater is used, decreasing the boiler load causes a decrease in steam temperature.[5/] Under conditions of reduced boiler load, increased excess air may be required to maintain both boiler stability and a constant steam temperature.[5,6/] An empirical equation has been developed by Maartman[7/] to describe these variations which also includes the variation in dust concentration with the sulfur content of the oil:

$$G \sim \frac{S^{\alpha}}{O_2^{\beta} \times Q^{\delta}} \qquad (1)$$

where G = dust concentration:mg/Nm^3

S = sulphur content of the oil:percent

O_2 = excess oxygen:percent

Q = capacity of the boiler:tons of steam per hour

Based on measurements made in England, Germany, and Sweden, it is thought that the values of the parameters α, β, and δ are:

$$0 \leq \alpha \leq 1 \qquad (2)$$

$$\beta = 1.0 \qquad (3)$$

$$0 \leq \delta \leq 1 \qquad (4)$$

The literature and data inventories compiled during this study suggest the following order-of-magnitude variations in uncontrolled particulate emissions with design and operating conditions:

Overall Fuel Consumption Rate: There is an apparent increase in particulate emissions (in grams per 10^6 joules of heat input) by a factor of two as capacity decreases from 600 to 100 MW.[4] The lower emissions for larger units probably result from better control, improved design, and better condition of the burners in the newer and larger oil-fired boilers.

Ash Content of Fuel: There is no quantitative information on the variation in particulate emissions with ash loading, although the average for No. 6 residual oil is estimated from available literature to be 0.1% by weight. The approximation made in this study is that greater or lesser concentrations of ash in the fuel oil will add or subtract from the total particulate in a 1:1 proportion.

Sulfur Content of Fuel: Sulfur content in No. 6 residual oil may between 0.3 and 4%.[2] A least squares linear curve fit of available data indicates that uncontrolled particulate emissions increase by about 25% over the range 1.0 to 2.5% sulfur by weight.[4] The scatter in the available data is again quite large, probably for reasons of nonlinear influence of design and operating conditions, as discussed previously.

Mineral Fuel Additives: The typical recommended application of fuel oil additives is in the proportion of 1 kg of additive per 1,000 kg of fuel oil.[8] The solid additive used is usually dispersed in slurry form in a light oil (e.g., No. 2 fuel oil) so the concentration of solids is usually less than 0.5 kg/1,000 kg of fuel oil, or 0.05% by weight. This is significant in comparison with normal fuel ash and should be included in calculating total fuel ash.

Degree of Atomization: The effectiveness of atomization is influenced mainly by the type of atomization (mechanical, steam, or air), the condition of the burners, and the viscosity of the fuel oil. The viscosity is determined by the intrinsic viscosity of the fuel and the temperature to which the oil is heated prior to atomization. Studies have been made to determine the effect of these variables on particulate emissions;[2] however, there are little data, and trends are insufficiently clear to permit a quantitative interpretation.

Windbox Air Admittance: Varying the settings on the main and auxiliary air dampers can cause pronounced effects on fly ash,[2] but there are insufficient data for a quantitative prediction.

Burner Tilt: There is evidence that burner tilt can influence fly ash loading under certain conditions.[2] There are not sufficient data to permit a quantitative prediction at this time.

Flue Gas Recirculation: Uncontrolled fly ash emission is believed to increase significantly when more flue gas is recirculated into the firebox.

This increase is believed to be due to a cooling of the flame and combustion gases.[2/] There are insufficient data for a quantitative correlation.

Excess Air and Boiler Load Level: These are most significant operating parameters, which can exert an order-of-magnitude influence on uncontrolled particulate emissions. As discussed previously, excess air is frequently increased with decreasing load level to maintain a constant steam temperature. At a constant load level, it was observed in one test that as the oxygen concentration in the stack gas decreased from 4 to 2% (corresponding to a decrease in excess air of approximately 22 to 10%) the particulate loading increased from 0.0086 to 0.060 g/10^6 joules.[2/]

On the basis of the preceding discussion, the following empirical relationship was developed to predict the variation in fly ash from firing No. 6 residual oil as a function of: excess air, expressed as percent oxygen; boiler load; fuel ash; fuel sulfur content; and fuel heating value.

$$g = \bar{g}\,\frac{(1 + A - \bar{A})(1 + C_M(M - \bar{M}))(1 + C_S(S - \bar{S}))\ H/\bar{H}}{O_2/\bar{O}_2} \qquad (5)$$

where g = uncontrolled particulate emissions, g/10^6 joules

$\bar{g}$ = mean (uncontrolled) particulate emissions for electric utility boilers firing No. 6 residual oil, g/10^6 joules

A = ash content of fuel, percent by weight

$\bar{A}$ = average ash content of No. 6 residual oil-fired, percent by weight

M = boiler load, MW

$\bar{M}$ = average load of boilers firing No. 6 residual oil, MW

S = sulfur content of fuel, percent by weight

$\bar{S}$ = average sulfur content of No. 6 residual oil-fired, percent by weight

H = higher heating value of fuel, joules/kg

$\bar{H}$ = average higher heating value of No. 6 residual oil-fired, joules/kg

O_2 = excess oxygen, percent by volume

$\overline{O}_2$ = average excess oxygen for boilers firing No. 6 residual oil, percent by volume

C_M, C_S = proportionality constants

The functional dependence of total particulates on excess air (percent oxygen) used in Eq. (5) is derived from the analysis of Maartmann[7] the results of which were presented in the preceding discussion as Eqs. (1) through (4). The linear variation between total particulates and boiler load is based on regression analysis (Eq. (1), Ref. 4). The linear variation between total particulates and fuel sulfur is also based on regression analysis (Figure 6, Ref. 4). The linear variation of total particulates with fuel ash (including additives) is an assumption, as stated in the preceding discussion. The inverse linear variation of total particulates with fuel heating value is presented without attempting to justify the approximation.

The overall range of validity of Eq. (5) for estimating oil emissions is unknown. For the purposes of the present study, this equation is considered to be sufficiently valid, if somewhat conservative. Comparisons between measured and predicted total particulate are presented in Figures 1, 2, and 3 as functions of percent oxygen, boiler load, and percent fuel sulfur, respectively. Several values of $\overline{g}$ were used in Figures 1 to 3 ranging from $\overline{g}$ = 0.0632 g/10^6 joules (average from the data inventory in Appendix A) to $\overline{g}$ = 0.00632 g/10^6 joules. Other numerical values used were as follows:

$\overline{A}$ = 0.1% by weight[2]

$C_M = 5.324 \times 10^{-4}$ (adapted from Ref. 4, Eq. (1))

$\overline{M}$ = 263.87 MW (calculated from the data inventory in Ref. 4)

C_S = 0.0670 (determined from Ref. 4, Figure 6)

$\overline{S}$ = 1.15% by weight (determined from Ref. 4, Figure 6)

$\overline{H} = 4.233 \times 10^7$ joules/kg[2]

$\overline{O}_2$ = 2.8942% by volume (calculated from an average excess air level of 15.0%[2])

In Figure 1, conversion of total particulate to milligrams per normal cubic meter was made by assuming an average heating value of 4.233×10^7 joules/kg and a volume equivalent of 13.4 Nm^3/kg of oil.

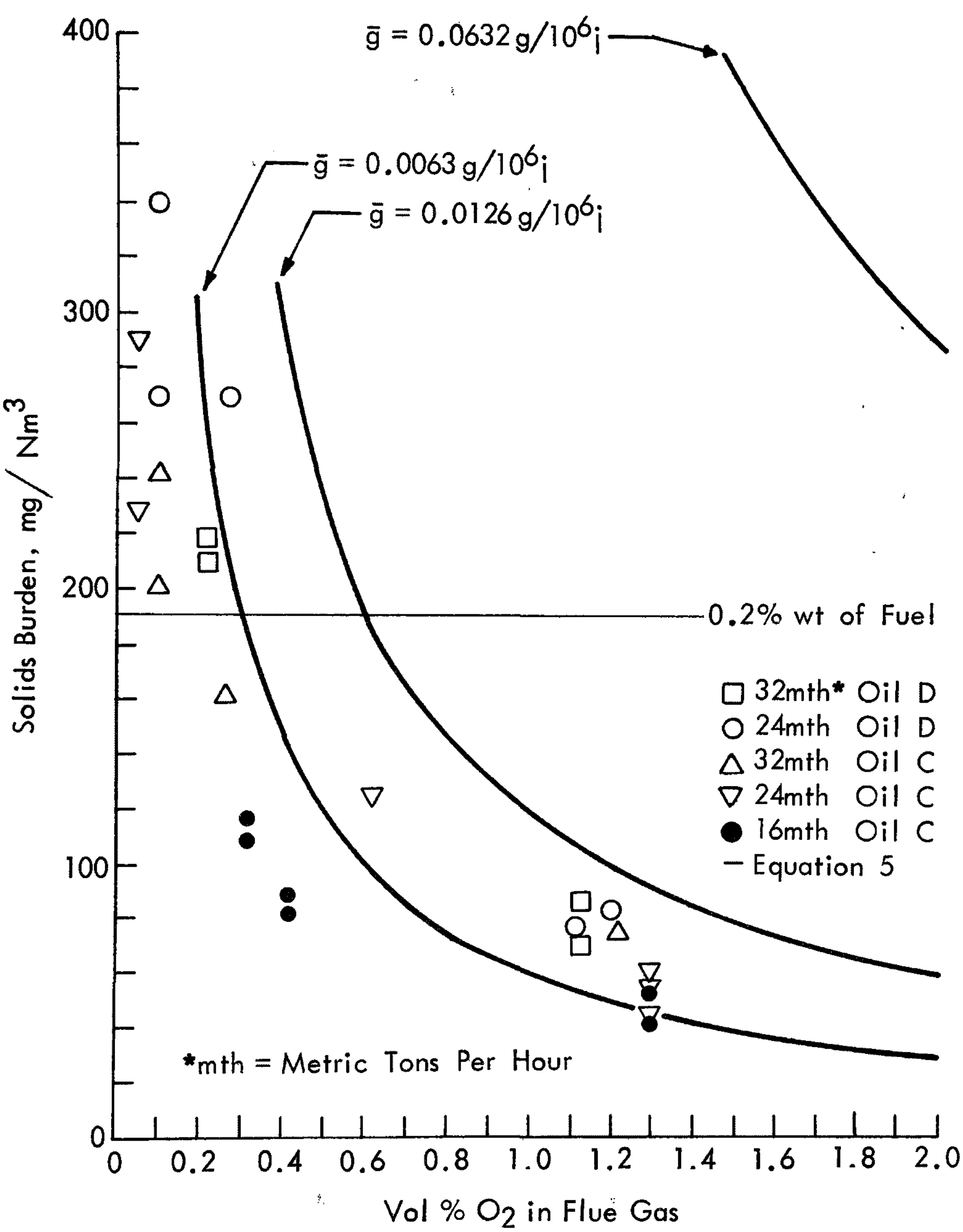


Figure 1. Solids burden plotted against excess oxygen for different boiler loads and fuel oil types.[9]

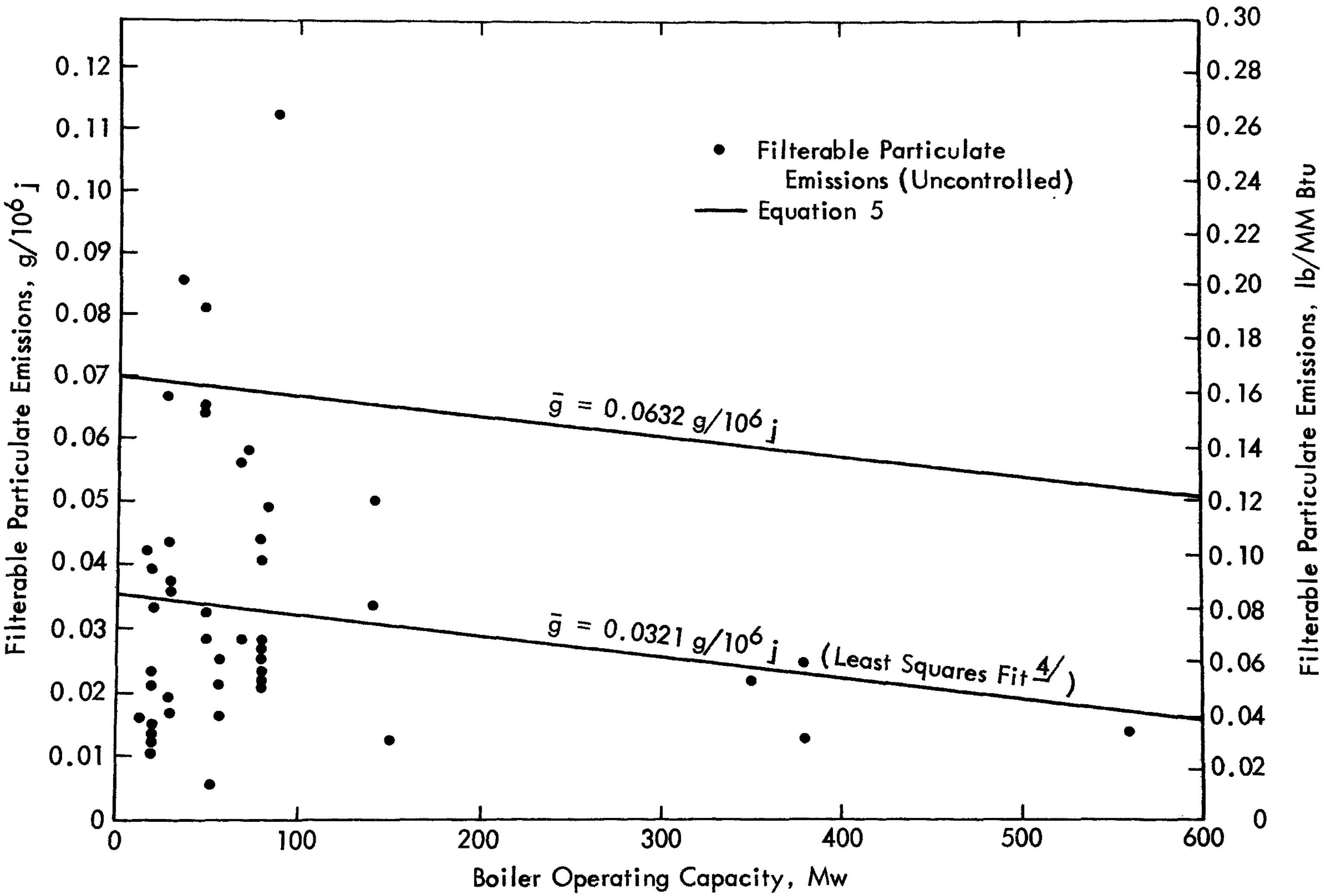


Figure 2. Uncontrolled electric utility emission versus capacity (no additives employed).[4/]

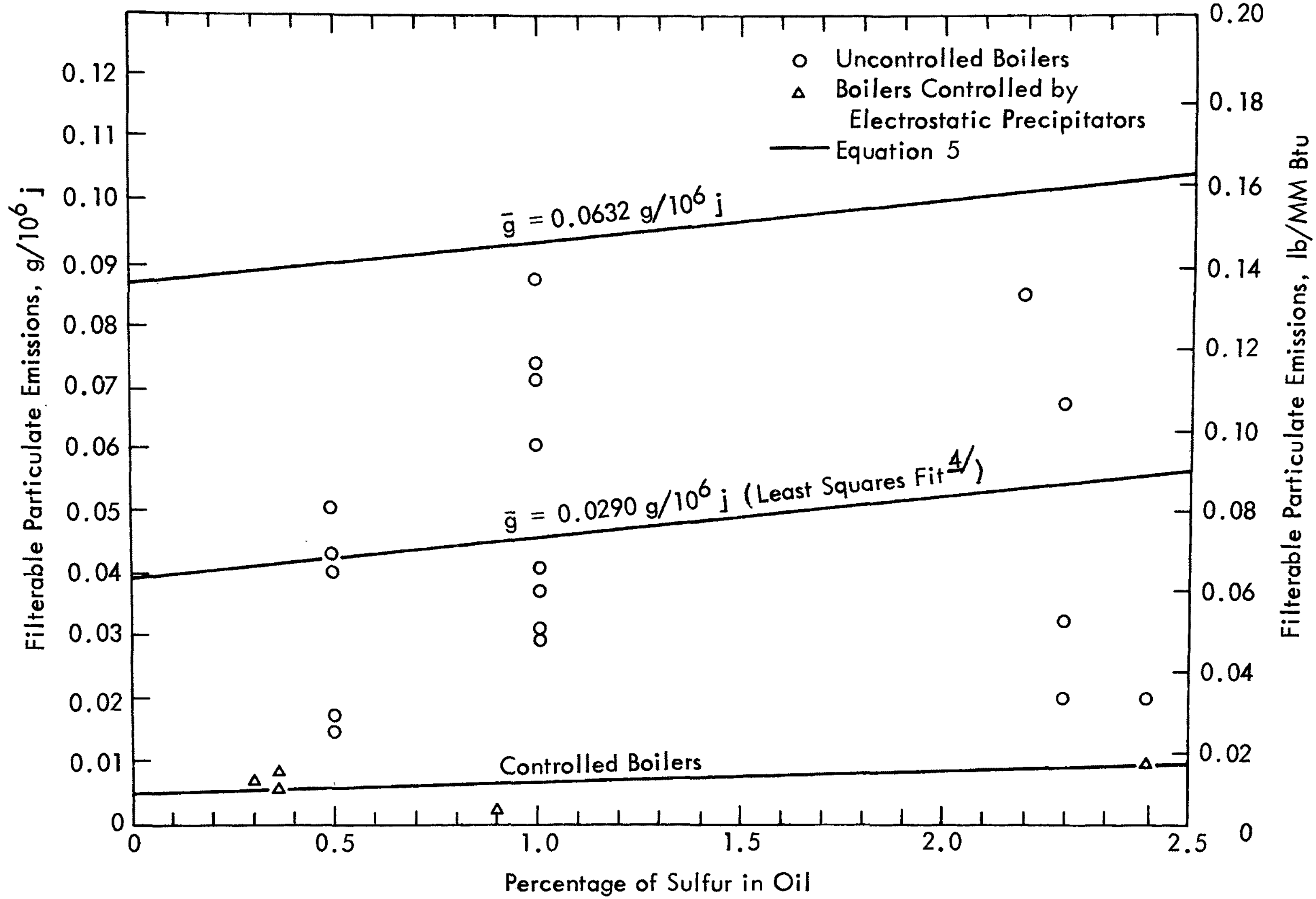


Figure 3. Controlled and uncontrolled particulate emissions for residual oil burning base loaded power plant boilers operating at ≥ 70 MW capacity (no additives employed).[4/]

Conversion of excess air to volume percent oxygen can be accomplished using standard procedures,[5] provided that the heating value is known. For a higher heating value of 4.233×10^7 joules/kg, the following expression is approximately correct for excess air levels between 0 and 40%.

$$O_2 \cong 0.2\ E_A - 3.1338 \times 10^{-5} E_A^{3} \qquad (6)$$

where E_A = excess air, percent by volume

O_2 = as previously defined.

It should be emphasized that there are expected to be rather wide variations in emissions from boilers firing No. 6 residual oil, as a result of factors not included in the data correlations, as previously discussed. Therefore, Eqs. (1) through (6) should be used only to give an order-of-magnitude estimate of the uncontrolled emissions.

Uncontrolled Particulate Emissions from Waterwall Incinerators

Uncontrolled particulate emissions from waterwall incinerators ranged from 0.95 to 9.64 $g/10^6$ joules (approximately 2.21 to 22.4 $lb/10^6$ Btu). The average value for seven boilers and 22 tests was 2.56 $g/10^6$ joules (5.95 lb/10^6 Btu). Stack test data for particulate emissions from several waterwall incinerator plants in the United States and West Germany were included, as tabulated in Appendix B.

In calculating the average, tests for the same boiler were not averaged, since tests were usually made under conditions of variable excess air, refuse heating value, ash and moisture content, and boiler load.

Possibly because of the limited data available at the time of this study, there are no clear trends in uncontrolled particulate emissions with refuse fuel heating value, ash content, or excess air level. Because of the limited data available, absence of clear trends, and the fact that the waterwall incinerator plants listed fired unshredded refuse, an empirically based representation of the available stack test data was not considered justified. At the time of the study, an in-depth investigation of emissions from waterwall incinerator plants was being conducted for EPA, Office of Solid Waste Management Programs,[10] and data from this study, when completed, should be used to supplement the data included in the present report.

Estimate of Refuse Fly Ash from Suspension Firing of MSW

There is no accepted design method for calculating particulate fly ash from combined suspension firing of refuse and conventional fuels. Control device sizing and performance evaluation is therefore somewhat a stochastic procedure. Estimates for the fraction of refuse ash which ultimately becomes fly ash (here denoted "f_r") range from about 0.13 up to 0.50, according to various sources. Estimates determined from the analysis of actual test data, described in this section, range from 0.13 to 0.35.

The approach for estimation of particulate loading favored by some investigators[6,10] is to use a ratio of fly ash to bottom ash characteristic of the fuel, the firing method, and the boiler system. This approach is of particular value to those concerned with MSW fuel preparation since it allows the fly ash to be related directly to MSW ash content and other fuel properties.

Assumptions implicitly made are that the refuse fly ash does not depend on the type of fuel fired, e.g., oil or coal, and that the presence of both fuels in the combustion chamber does not influence bottom ash or carbon burnout in the fly ash. This assumption implies that fly ash from the two fuels can be added in linear fashion to yield a total fly ash particulate:[11]

$$g = rg_1 + (1 - r)g_2 \qquad (7)$$

where g = total particulate, g/10^6 joules

r = fraction of MSW heat input

g_1 = observed fly ash particulate from refuse burning, g/10^6 joules

g_2 = observed fly ash particulate from burning No. 6 residual oil, g/10^6 joules.

If it is further assumed that the carbon content of fly ash is negligible by comparison with the total fly ash, Eq. (7) can be rewritten in terms of refuse fly ash fraction f_r and fuel properties in the following form:

$$g = 10^9 \left[\frac{X_{Ar} f_r r}{H_r} + \frac{X_{Ac} f_c (1 - r)}{H_c} \right] \qquad (8)$$

where g = grams of fly ash per 10^6 joules of composite fuel

H_r = average heating value of refuse, joules/kg

H_c = average heating value of auxiliary fuel, joules/kg

X_{Ar} = weight fraction of ash in refuse

X_{Ac} = weight fraction of ash in auxiliary fuel

f_r = fraction of refuse ash which becomes fly ash

f_c = fraction of ash in auxiliary fuel which becomes fly ash

r = fraction of refuse heat input

Equation (8) is used to estimate the total fly ash loading for a given boiler, firing method, and fuel properties. Rearranging Eq. (8), the following dimensionless equation results, which relates the fractional increase in fly ash particulate at a given refuse heat input (r) to a dimensionless ratio of fuel properties (c):

$$\varphi = r\ (C-1) \qquad (9)$$

where φ = fractional increase in particulate fly ash at fraction MSW heat input, r, dimensionless

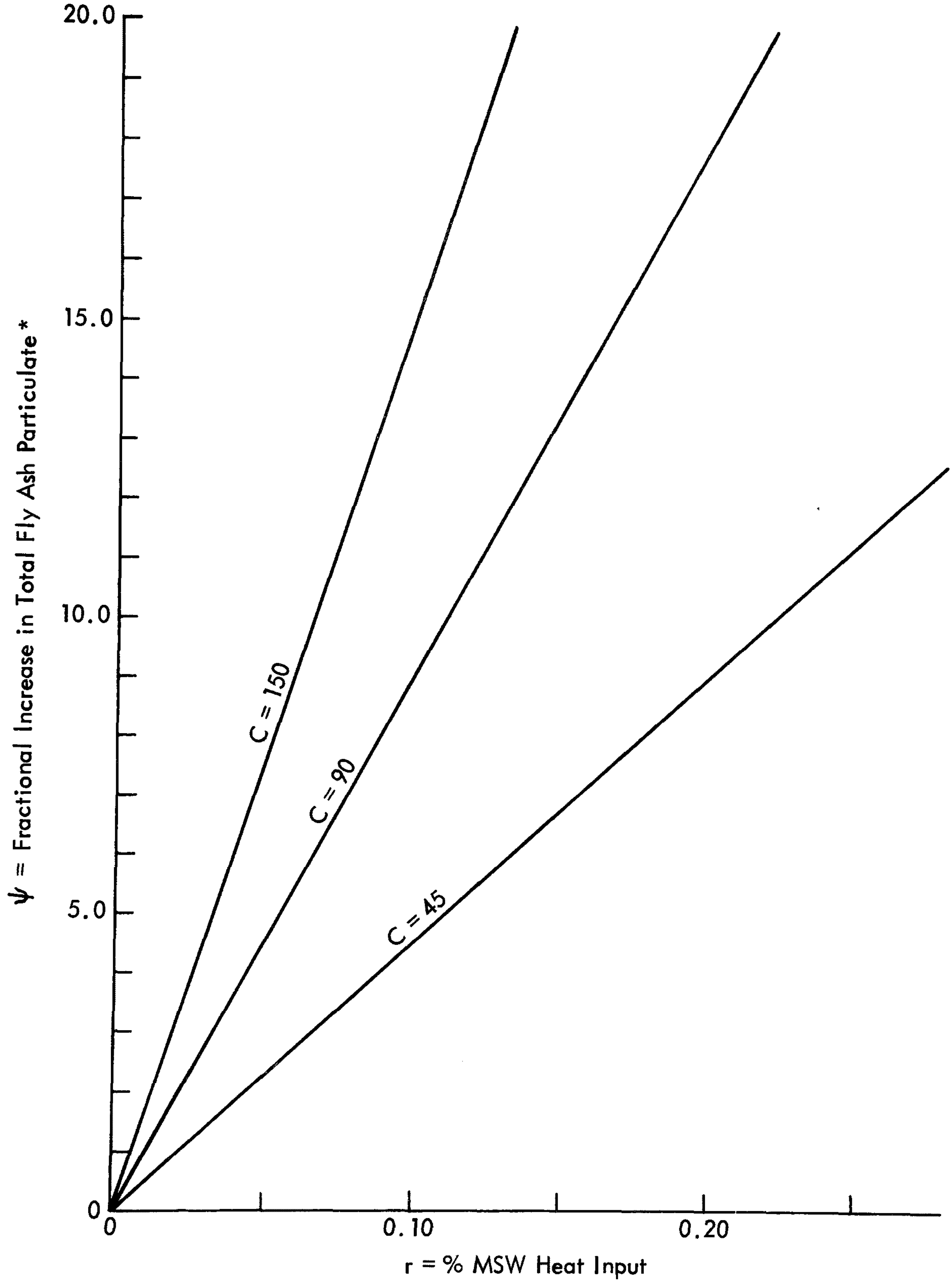
$$= \frac{g}{10^9\ X_{Ac}\ f_c/H_c^{-1}}$$

C = "fuel characterization factor," dimensionless

$$= \frac{X_{Ar} f_r H_c}{X_{Ac} f_c H_r}$$

r, g, X_{Ac}, f_c, H_c, X_{Ar}, f_r, H_r as previously defined.

The physical significance of the fuel characterization factor c, as defined by Eq. (9) is illustrated in Figure 4. The value C = 45 corresponds approximately to average fuel properties for refuse and oil for an assumed fly ash fraction of 0.15:



* See Equation 9 for Definition of ψ, C

Figure 4. Dimensionless plot showing fractional increase in total fly ash as a function of percent MSW for various values of fuel characterization parameter (C).

f_r = 0.15 (assumed)

X_{Ar} = 0.223[11]

H_r = 11,572,000 joules/kg[11]

f_c = 2.72 (assumed value, see p. 8)

X_{Ac} = 0.001[2]

H_c = 42,330,000 joules/kg[2]

For these fuel properties, C depends on the assumed fly ash fraction as follows:

f_c	C
0.15	45.9
0.30	91.8
0.50	153.1

Previous experience[12,13] indicates that variations primarily in MSW fuel properties may also cause variations in the ratios X_{Ar}/X_{Ac} and H_c/H_r. Changes in these ratios will also influence the rate of fly ash generation as described by Eq. (9).

Methods which have been used for estimating the fraction of refuse ash which ultimately becomes fly ash (f_r) are described in the following paragraphs.

Mass balance data: St. Louis/Union Electric refuse firing demonstration:[12,13] Analysis of recent mass balance data from the St. Louis/Union Electric refuse firing demonstration indicates that from 39.9 to 98.5% of the refuse ash was ultimately discharged from the boiler in the form of sluice solids (bottom ash). The average bottom ash fraction was 64.7% of the total refuse ash.[13] By difference, the average fly ash fraction from the St. Louis tests was equal to 35.3% of the total refuse ash.

The analysis based on bottom ash assumes that, in addition to the assumptions stated for Eqs. (7) and (8), a constant fraction (8.7%) of the ash present in the coal is collected in the sluice solids as bottom ash.

Particulate emissions data: National Center for Resource Recovery (NCCR) analysis of St. Louis/Union Electric refuse firing demonstration:[14,15] The NCRR method is based on analysis of the differences in fly ash emission rates when firing coal-plus-refuse and firing coal only. The assumption made is that the flue gas volume is constant at a given boiler load and is independent of the MSW fraction. This assumption is somewhat at odds with the overall conclusions of the St. Louis/Union Electric Air Pollution Test Report,[11] but is consistent with the test data chosen for the example calculation. Notation and dimensions used by NCRR have been altered as required for consistency.

Following Gershman, the particulate resulting from the MSW portion of the fuel in combined firing is given by:[14]

$$g'_r = g'_{r+c} - g'_c\ (1-r) \tag{10}$$

where g'_{r+c} = total fly ash from firing coal-plus-refuse, g/Nm^3

g'_r = fly ash from refuse portion of fuel, g/Nm^3

g'_c = fly ash from firing coal-only, g/Nm^3

The fraction of refuse ash which becomes fly ash (f_r) is determined from the following equation.[14]

$$f_r = \frac{g'_r \times 10^3 \times V}{X_{Ar}\ Wr} \tag{11}$$

where V = flue gas volumetric flow rate, Nm^3/min

Wr = MSW mass feed rate into the boiler, kg/min

f_r, g'_r, X_{Ar} as previously defined.

The NCRR methodology yields $f_r = 0.21$ for the data chosen:

$r = 0,\ 0.1$

$g'_{r+c} = 4.35\ Nm^3$ (1.9 gr/dscf) at 100 MW, $r = 0.1$

$g'_c = 3.84\ g/Nm^3$ (1.7 gr/dscf) at 100 MW, $r = 0$

$X_{Ar} = 0.21$

$Wr = 151.2$ kg/min (20,000 lb/hr)

$V = 7,702$ Nm^3/min (272,000 dscfm)

Calculated fly ash fraction (f_r) based on waterwall incinerator emissions data: The average value of 2.56 g/10^6 joules obtained from the survey of emissions data for waterwall incinerators (Appendix B) corresponds to a value of $f_r = 0.13$ for an average heating value H_r of 11,572,000 joules/kg (4,975 Btu/lb) and a total ash content of 22.3%.

Calculated fly ash fraction (f_r) based on St. Louis/Union Electric air emissions data at 140 MW, 10% MSW: On the basis of test data from the St. Louis/Union Electric refuse firing demonstration, in which shredded MSW was fired in suspension with coal, particulate loading increased with increasing MSW heat input in approximately the same ratio as increasing gas volumes.11/ That is, there was no apparent net increase in flue gas grain loading. At 10% MSW heat input and 140 MW, the theoretical increase in flue gas volume was approximately 5.2%. Using this information and average fuel properties, the value of f_r was determined from Eq. (8) to be 0.16. Average fuel properties used were as follows:11/

$X_{Ac} = 0.0703$

$H_c = 29,226,000$ joules/kg (12,565 Btu/lb)

$f_c = 0.85$

$X_{Ar} = 0.223$

$H_r = 11,572,000$ joules/kg (4,975 Btu/lb)

The value of $f_r = 0.16$ calculated from the St. Louis/Union Electric air pollution test results11/ agrees favorably with the average value for waterwall incinerators (0.13), when adjusted to a total ash content characteristic of shredded refuse.

Estimated Particulate Emissions from Combined Firing of Oil and Municipal Solid Wastes

The estimated range of uncontrolled particulate stack emissions from combinded firing of oil and MSW calculated from Eq. (8) are summarized in Table 1. An independent estimate of particulate, SO_x, and NO_x emissions made in

Table 1. ESTIMATED TOTAL PARTICULATE AND PERCENTAGE OF REFUSE FLY ASH IN FLY ASH COMPOSITE FROM COMBINED FIRING OF OIL AND MUNICIPAL SOLID WASTES (MSW)[a/]

% MSW heat input	Flue gas particulate ($g/10^6$ joules)				% Refuse fly ash			
	$f_r = 0.1$	$f_r = 0.15$	$f_r = 0.3$	$f_r = 0.5$	$f_r = 0.1$	$f_r = 0.15$	$f_r = 0.3$	$f_r = 0.5$
0.0	0.063	0.063	0.063	0.063	0.0	0.0	0.0	0.0
1.0	0.082	0.092	0.120	0.159	23.5	38.1	48.0	60.6
5.0	0.156	0.205	0.349	0.542	61.1	76.2	82.8	88.9
10.0	0.250	0.346	0.635	1.02	77.2	87.1	91.0	94.4
15.0	0.343	0.487	0.921	1.50	84.3	91.5	94.2	96.4
20.0	0.436	0.629	1.21	1.98	88.4	93.8	95.8	97.4
25.0	0.529	0.770	1.49	2.46	91.0	95.3	96.8	98.1

a/ Estimate of uncontrolled fly ash emissions made using Eq. (8). Estimate based on average emission rate for oil-fired boilers (Appendix A) and average MSW properties listed in Ref. 11: heating value (H_r) of 11,572,000 joules/kg; ash weight fraction (X_{Ar}) of 0.223; and various fly ash fractions (f_r) as shown.

an earlier study by another team of investigators at Battelle[16] predicted uncontrolled particulate from oil-refuse firing intermediate between values listed in Table 1 corresponding to $f_r = 0.15$ and $f_r = 0.30$. The results of this study are compared with the present estimates in Table 2. The Battelle emissions model for combined fuel firing was also based on an assumed linear addition of emissions from each fuel proportioned by relative heating value as described in Eq. (8).[17]

With regard to the physical properties of the fly ash particulate, it is evident from Table 1 that both oil and refuse particulate will have an influence on the physical properties of the composite fly ash. This conclusion is emphasized because it appears to be opposite to the general consensus of several EPA and design engineers.

FLUE GAS VOLUME

Flue gas volume for combined firing of different fuels depends on several factors, the most significant of which appear to be:

1. Boiler efficiency.

2. Excess air level.

3. Theoretical combustion air based on fuel composition and heating value.

Since the total volume of flue gas is of primary importance in predicting control device performance, a significant part of the present study was devoted to analysis of previous attempts to predict the flue gas volume for combined firing applications.

It is anticipated that boiler efficiency will decrease somewhat with increasing substitution of refuse derived fuel (for fuel oil). The estimated magnitude of major losses at 20% MSW heat input are summarized as follows:

1. Heating of additional excess air for combustion, 1.0%.

2. Incomplete fuel combustion, 2.0%.

3. Heating of additional fuel moisture (25% moisture in MSW), 4.0%.

4. Increased "dry" gas losses due to increased flue gas volume, 1.0%.

Table 2. CONTROLLED EMISSIONS FOR COMBINED FIRING OF REFUSE WITH OIL OR METHANE

Heat input from oil or methane (%)	Refuse heat input (%)	Particulates[a/] ($g/10^6$ joules) 95% Collection efficiency	99% Collection efficiency	Allowable sulfur content of oil for no SO_x control (%)[c/]	NO_x ($g/10^6$ joules)[d/]
90 (oil)	10	0.017(0.022)[b/]	0.003(0.004)[b/]	0.77[b/]	0.12[b/]
80 (oil)	20	0.031(0.044)[b/]	0.006(0.009)[b/]	0.84[b/]	0.12[b/]
70 (oil)	30	0.046(0.065)[b/]	0.009(0.013)[b/]	0.92[b/]	0.12[b/]
90 (methane)	10	- (0.022)[b/]	- (0.004)[b/]	-	0.099[b/]
80 (methane)	20	- (0.043)[b/]	- (0.009)[b/]	-	0.099[b/]
70 (methane)	30	- (0.065)[b/]	- (0.013)[b/]	-	0.009[b/]

a/ Values from Table 1 used in calculating uncontrolled particulate correspond to $f_r = 0.15$.
b/ Data from Ref. 16, Table 24.
c/ If the allowable SO_x emission is 0.344 $g/10^6$ joules (0.8 $lb/10^6$ Btu).
d/ Assuming a 60% reduction in NO_x by particulate control system (for nontangentially-fired units).

The above approximate values are estimates based on information in Refs. 12 and 18. A precise determination of combustion efficiency requires detailed information on refuse fuel composition, ash, moisture and heating value, and excess air level. The estimate for refuse fuel combustion efficiency (90% for MSW) is based on data for suspension firing of MSW and Illinois No. 6 coal in a tangentially fired boiler.[12] It is not documented at this point whether there is any improvement in combustion efficiency when the refuse fuel is shredded to a finer average particle size.[12] Union Electric engineers claim that fine shredding of refuse does result in better heat recovery. They interpret a higher heat recovery with refuse ground to less than 3.18 cm (1.25 in.) when compared to refuse less than 7.6 cm (3 in.) in size based upon MW generated per megagram of refuse. The St. Louis study, however, reports that the combustion efficiency did not improve with fine ground refuse when based on the two data points for fine-ground refuse.[12] Determination of improvements in combustion efficiency as a function of refuse fuel particle size requires additional study.

There is evidence that excess air may need to be higher when firing refuse with oil than when firing oil alone. The reasons for this are related to corrosion and "slagging," or deposition of fused ash on boiler tubes. Excess air levels used in waterwall incinerator plants are typically 70 to 100% where corrosion is a problem (see Appendix B). There does not appear to be any method for determining the excess air level a priori. There is some indication that an excess air level of 15% is sufficient for firing up to 10% refuse heat input[19-21] and that excess air should be increased to 25% for 20% MSW heat input.[6]

Theoretical air required for combustion was calculated from fuel composition and heating values using standard procedures (see Ref. 5, p. 4-10). Fuel nitrogen was assumed to be converted to nitric oxide (NO). When dealing with refuse derived fuels, it was found to be important to correct "dry basis" ultimate analyses for fuel moisture actually present. When refuse derived fuels are substituted for No. 6 residual oil, theoretical flue gas volumes will increase by as much as 1% for each 1% of MSW heat input <u>at the same excess air level</u>, depending on moisture, heating value, composition, and MSW substitution. Representative gas volumes for a 75 MW boiler are listed in Table 3. Variations due to MSW fuel moisture and refuse substitution rate are illustrated in Figure 5.

FLY ASH DENSITY

It is estimated that fly ash from combustion of municipal solid wastes will be comprised of a significant fraction of very light particles having a density on the order of half that of fly ash from pulverized coal.[22] The

Table 3. THEORETICAL GAS FLOW RATES FOR A 75 MW POWER PLANT AT 130°C, 1 ATM

Power output (MW)	Fuel moisture (% wt. wet)		Exhaust volume flow rates (m^3/min)[a/]			
	Oil	Refuse	Oil	5% R	10% R	20% R
40	0.354	10	3,445	3,804	3,892	4,145
	0.354	30	3,445	3,822	3,943	4,394
	0.354	50	3,445	3,858	4,071	b/
50	0.354	10	4,307	4,755	4,865	5,181
	0.354	30	4,307	4,777	4,929	5,493
	0.354	50	4,307	4,822	5,089	b/
60	0.354	10	5,168	5,706	5,838	6,217
	0.354	30	5,168	5,733	5,915	6,591
	0.354	50	5,168	5,787	6,107	b/
70	0.354	10	6,029	6,657	6,811	7,253
	0.354	30	6,029	6,688	6,901	7,690
	0.354	50	6,029	6,751	7,125	b/
80	0.354	10	6,891	7,608	7,784	8,289
	0.354	30	6,891	7,643	7,886	8,788
	0.354	50	6,891	7,716	8,143	b/

a/ Basis for calculation:

(1) Ideal combustion to CO_2, H_2O, NO, SO_2;
(2) 15% excess air for oil only; 25% excess air for oil plus MSW;
(3) Fuel properties used in the combustion calculations determined as follows: data for No. 6 residual oil from Ref. 20, using average values for refuse properties from Ref. 11.

b/ Refuse fraction exceeds limits for necessary boiler heat input.

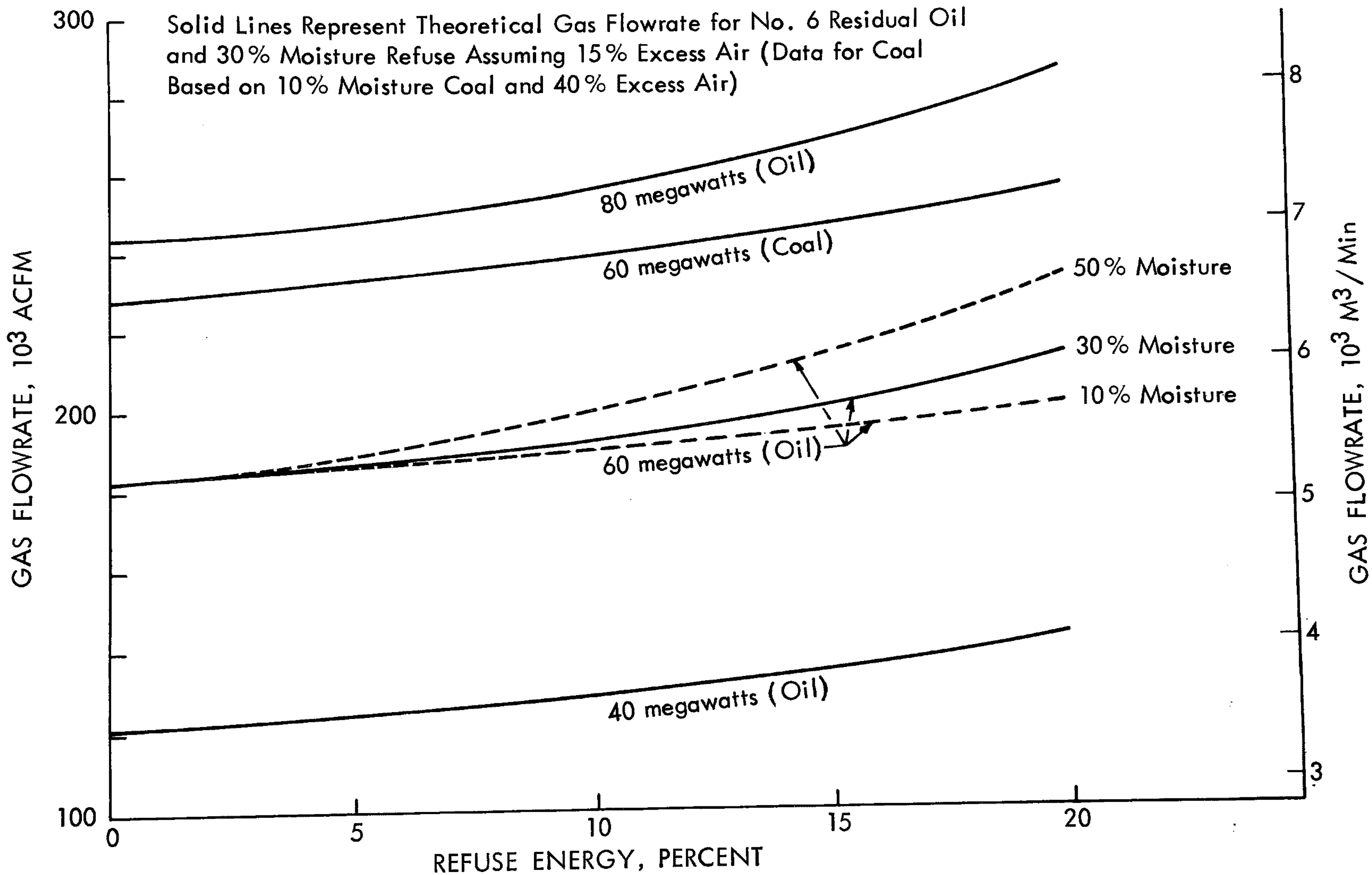


Figure 5. Theoretical gas flow rates for combined firing of oil and municipal solid waste (MSW) in a 75 MW power plant.

particle density overall ranges from 1.8 to 3.8 g/cc[23,24] compared to an average particle density of 2.3 g/cc for fly ash from coal fired boilers.[23]

The reason for the wide range in densities is that several mechanisms for particulate formation all contribute significantly to the total particulate formation. The combustible fraction consists of entrained char ("blackbirds"), soot produced by the thermal cracking of pyrolysis products, and "white smoke" which is produced by condensation of pyrolysis gases.[24] It is the low density, low resistivity carbonaceous particles which are the most troublesome to control, especially by electrostatic precipitation, since they tend to lose their charge on contact with the collection electrode and become reentrained.[25]

Particulate from fuel oil combustion also is not composed primarily of mineral particulate. The size distribution is characteristically bimodal, the larger particles being skeletons of burn-out fuel particles, called cenospheres, which are hollow, black, coke-like spherical particles. The smaller particles formed by the condensation of vapors are of regular shape and usually have a maximum dimension of about 1.0 µm. The average density is about 2.5 g/cc,[23] but densities as low as 1.22 g/cc have been reported.[26] In combined firing of oil and refuse, there will probably be a sufficiently large proportion of low density (~ 1.2 g/cc), low resistivity, predominately carbonaceous particulate that a major particulate control problem is expected.

FLY ASH FUSION TEMPERATURE

In previous studies of ash fusion levels, using both test coupons and tetrahedral cones, the minimum melting range for ash from refuse incineration was 454 to 1093°C (850 to 2000°F).[27] Higher levels of lead and zinc were found than had been anticipated, presumably from pigments, solders, and galvanized coatings. The melting range correlated with total concentration of basic oxides Na_2O and K_2O. The minimum range occurred at a level between 30 to 40% of the basic oxides by weight, excluding zinc, lead, and sulfur. Unfortunately, no relationship could be established between the presence of liquid state and chemical composition, a much more sophisticated procedure apparently being required. It is possible that small portions of a liquid phase could form at low temperature and remain undetected due to the wetting of the larger quantity of dry material.[27]

With few exceptions, the ingredients found in refuse deposits accelerate gas side corrosion above 510°C (950°F). In the presence of a reducing condition the threshold temperature could be reduced to as low as 315°C (600°F). In an oxidizing atmosphere containing HCl, it was found that corrosion could take place in a "dry" unfused, powdery ash.[27]

PARTICLE SIZE DISTRIBUTIONS

Particle size distribution data for particulate from firing No. 6 residual oil in electric utility boilers and from incineration of municipal solid wastes in waterwall and conventional incinerators is summarized in Tables 4 and 5, respectively.

It is widely believed that particulate from oil firing is extremely fine, with the usual estimate being 90% less than 1 µm. However, a search of available particle size data did not confirm this. The test data which showed the largest proportion of submicron particulate was for an air atomized, tangentially fired boiler which had originally been designed to fire coal and had been retrofitted for oil firing. Based on Andersen impactor data,[28] 13.3% of the fly ash by weight was determined to be less than 1 µm in diameter.

Because of the chemical nature of the oil ash, measurement of particle size is extremely difficult. Compared to coal ash, the solids emitted by fuel oil combustion are more hygroscopic.[4] When allowed to cool, the oil ash particles absorb moisture and tend to agglomerate into larger particles during storage, transportation, and handling. Therefore, _ex situ_ size determination methods such as Bahco and electron microscopy are subject to considerable error. _In situ_ measurements made using heated impactors are probably better, but here too, there is a chance for error resulting from inelastic collisions between particles and impactor walls. This could result in a distribution erroneously weighted toward the larger particle sizes.

Fly ash particulate from incineration of municipal solid wastes is typically about 10% smaller than 1 µm in diameter.[24] Andersen impactor data from Harrisburg Municipal (waterwall) Incinerator indicate that in some cases the particulate may be somewhat finer than this--about 20 to 30% less than 1 µm.[32] The latter size distribution was used in the present study for particulate from firing municipal solid wastes. Although use of the Harrisburg size distribution data seems conservative, it is considered representative by other investigators, based on analysis of stack test data from the St. Louis/Union Electric refuse firing demonstration.[33]

When firing oil with other fuels in the same combustion chamber, it is anticipated that the particle size distribution for the combined fuels will be determined by the fuel having the higher ash content. That is, in combined firing of oil and refuse, the assumption is made that the particle size distribution of particulate fly ash will be the same as the size distribution for firing refuse alone. This assumption is justified by: (a) the observed chemical nature of the oil ash, which tends to cause it to agglomerate with other ash particles in the flue gas, (b) the high percentage of refuse ash at MSW levels of 10 to 20% (Table 1), and (c) the observation that in combined

Table 4. PARTICLE SIZE DISTRIBUTION FOR OIL-FIRED BOILERS

Diameter (μm)	Wt % less than stated diameter Ref. 26[a]	Ref. 28[b]	Ref. 28[c]	Ref. 28[d]
1,000	100.0	-	-	-
250	97.8	-	-	-
150	92.7	-	-	-
45	50.0	-	-	-
30	39.6	65.3	77.8	73.0
9.2	13.2	52.3	55.6	46.0
5.5	6.8	38.3	25.7	26.3
3.3	3.2	29.0	10.5	15.9
2.0	1.4	21.6	6.6	9.0
1.0	0.3	13.3	1.3	5.7
0.3	0.0	4.9	0.65	2.3
0.1	-	-	-	-

a/ Bahco Data, specific gravity of oil ash = 1.22 (data interpolated graphically).

b/ Andersen impactor data, air atomizing burners on a tangentially fired boiler.

c/ Andersen impactor data, mechanically atomizing burners on a tangentially fired boiler.

d/ Andersen impactor data, steam atomizing burners on a tangentially fired boiler.

Table 5. PARTICLE SIZE DISTRIBUTION OF REFUSE FLY ASH

Diameter	Wt % less than stated diameter				
(μm)	Ref. 24[a/]	Ref. 29[b/]	Ref. 30[c/]	Ref. 31[d/]	Ref. 32[e/]
1,000	-	-	-	-	-
250	-	75	-	87	81
150	95	65	-	71	74
45	70	40	45	28	59
30	65	37	41	-	55
20	53	34	36	-	51
15	52	-	-	-	48
10	33	30	30	-	45
5	8	-	23	-	40
1	-	-	13	-	30

a/ Average of six recently reported studies (see Ref. 24, p. A-8).

b/ Taken from Ref. 29, Figure 2.

c/ Average of data for U.S. Incinerators. Taken from Ref. 30, Figure A-18.

d/ Based on sieve analysis of precipitator catch for tests of Harrisburg waterwall incinerator. Average of three runs with various heating values.

e/ Based on two-parameter Weibull distribution parametric representation of Andersen impactor data for Harrisburg Municipal Incinerator (average of six test measurements). Distribution of particulate larger than 14 μm was estimated graphically.

firing of coal and oil, none of the difficulties encountered in collecting fly ash from combustion of oil alone are observed.[1]

It is helpful to use analytical techniques in interpreting particle size data because of the need to interpolate between data points to provide narrow size increments for control device performance evaluation. In the present study, a two parameter Weibull distribution[33] was fitted, using a least squares technique, to the particle size data (Figure 6). Because of the different mechanisms operative for particulate formation, the portion of the size distribution less than 1 µm was curve fit separately. The Weibull parameter distribution can be expressed as follows:

$$F(R(j)) = 1 - e^{-\left(\frac{R(j)}{\theta}\right)^b} \qquad (12)$$

where $F(R(j))$ = the weight fraction of particulate having diameters less than $R(j)$

θ, b = independent parameters

Weibull parameters for the refuse portion of the fuel are as follows:

	θ (µm)	b
(< 1 µm)	1.48	2.91
(> 1 µm)	92.1	0.23

Incremental size data determined using Weibull parameters to fit selected size data for fly ash from pulverized coal, No. 6 residual oil, and MSW are shown for comparison purposes in Table 6. Note that for incineration of unshredded municipal solid wastes, a two parameter Weibull curve fit predicts that a significant fraction of the particulate will be larger than 1,000 µm. Approximately 20 to 30% of the fly ash is predicted to be less than 1.0 µm in diameter.

FLY ASH RESISTIVITY

Resistivity values for fly ash particulate from municipal solid waste incineration range from approximately 10^6 to 5×10^{12} ohm/cm. The resistivity maximum occurs between 149 and 204°C (300 to 400°F).[25] Bulk resistivity measurements were made of integrated hopper-catch samples from two German waterwall incinerators; the bulk resistivity of fly ash from firing refuse only at

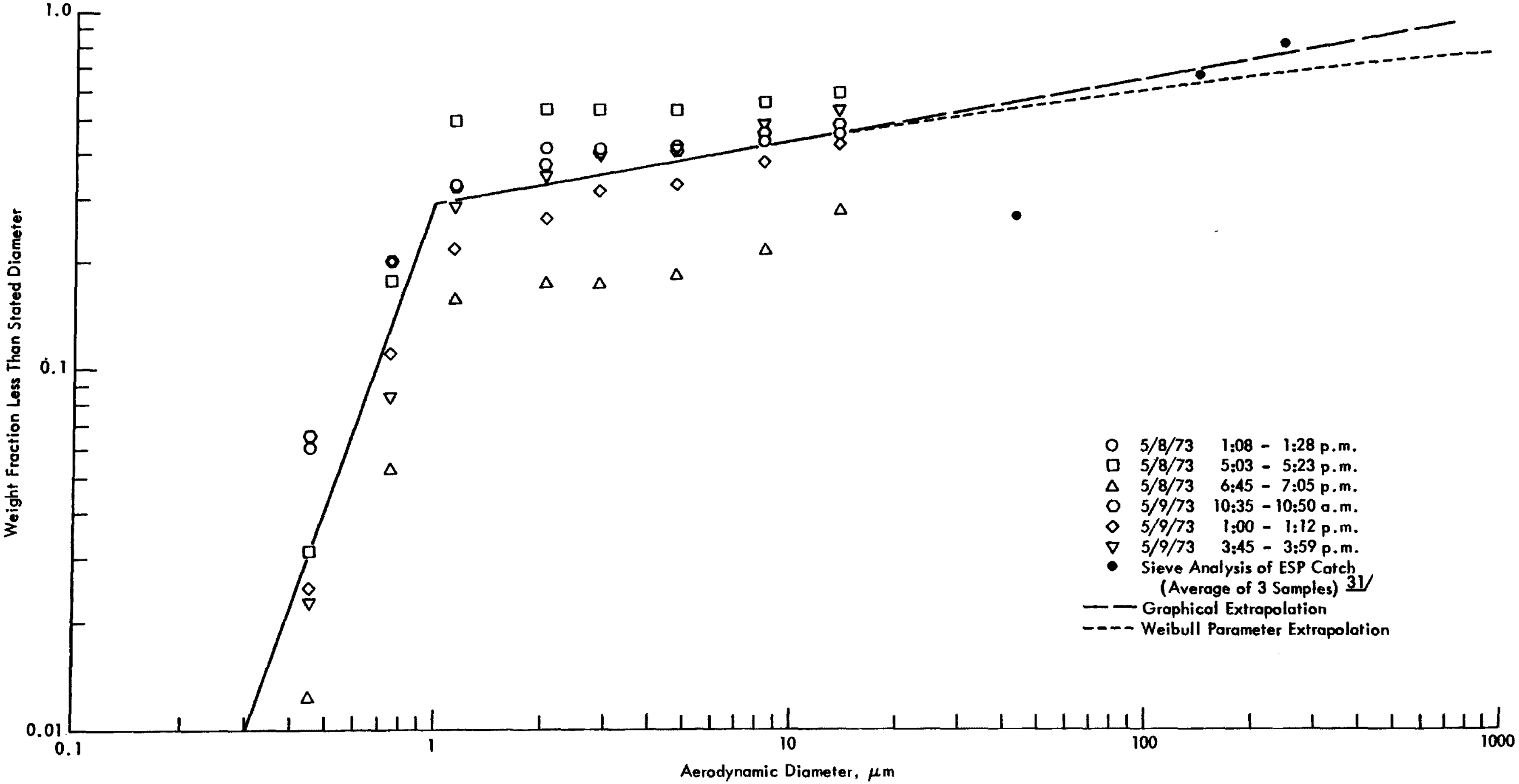


Figure 6. Weibull parameter interpolation of Andersen impactor data for Harrisburg Municipal Incinerator.[10,31,32]

Table 6. INCREMENTAL PARTICLE SIZE DATA FOR COAL, OIL, AND REFUSE FLY ASH DETERMINED USING TWO PARAMETER WEIBULL DISTRIBUTION

Diameter range (μm)	MMD[a/] (μm)	Selected size distribution used in analyses: Pulverized coal[b/]	No. 6 residual oil[c/]	Municipal solid wastes[d/]
100-1,000	316.2	-	0.0749	0.3150
12-100	34.6	0.6333	0.4115	0.2202
8-12	9.8	0.1000	0.0824	0.0307
4.5-8	6.0	0.0778	0.1024	0.0415
2.65-4.5	3.45	0.0622	0.0773	0.0358
0.975-2.65	1.61	0.0956	0.1212	0.0982
0.70-0.975	0.83	0.0144	0.0309	0.1508
0.27-0.70	0.43	0.0064	0.0546	0.1007
0.10-0.27	0.16	0.0102	0.0256	0.0067
0.01-0.10	0.03	0.0000	0.0166	0.0004
< 0.01	-	0.0000	0.0026	0.0000
		1.0000	1.0000	1.0000

a/ MMD $=\sqrt{D_1 D_2}$

b/ 10% ash, Illinois No. 6 coal; pulverized coal fired in tangentially fired boiler; Andersen Impactor data (see Ref. 34).

c/ Andersen Impactor data for No. 6 residual oil fired in a tangentially fired boiler with air atomization (see Ref. 28). Data interpolated using two parameter Weibull least squares fit (Ref. 33).

d/ Average of six tests using Andersen Mark III Impactor for particle size distribution of unshredded municipal solid wastes fired in Harrisburg Municipal Incinerator (Ref. 32). Data interpolated using two parameter Weibull least squares fit (Ref. 33). Distribution of particulate larger than 14 μm was estimated graphically (Figure 6).

Munich North Block 2 was 2 x 10^9 ohm/cm at 160°C (320°F).[27] Bulk resistivity of hopper ash from firing refuse at Dusseldorf was 6 x 10^7 ohm/cm at 222°C (432°F).[27] It is probable that these low values may have been influenced by the selective collection of low resistivity ash by the electrostatic precipitators. In situ resistivity measurements were attempted during acceptance tests of the Harrisburg Municipal (waterwall) Incinerator by Southern Research Institute. However, due to the high flue gas temperatures, in situ resistivity measurements could not be performed. Bulk samples were collected at the inlet and outlet of the precipitator using a coarse cyclone, fine cyclone and back-up filters in series. Three inlet samples and one outlet sample were collected. Resistivity measurements were performed according to the ASME Power Test Code No. 28 at a temperature of 218°C (425°F). The resistivity of the coarse material was 3 x 10^8 ohm/cm and the resistivity of the fine material was 5 x 10^6 ohm/cm.[32]

Because of higher flue gas temperatures characteristic of both conventional refractory and waterwalled incinerator plants, it is unfortunately not possible to compare ESP collection performance for these installations with performance of precipitators on electric utility boilers. Design methods also differ somewhat between these two types of installations, with precipitators of European design being used on all waterwall incinerators presently equipped with ESP control.[27] Data on the change in migration velocity with temperature indicate that the precipitation rate parameter decreases by about 25 to 50% as the flue gas temperature decreases from the range characteristic of waterwall incinerators (200 to 250°C) to the lower temperature range encountered in oil-fired electric utility boilers (150 to 200°C).[25,27]

Somewhat in contrast to U.S. manufactured equipment, the European precipitator design approach aims at a more conservative migration velocity by using somewhat lower field intensities. Thus, the size of the precipitator must be increased commensurately. As a result of this, lower gas velocities, 3 to 4 ft/sec, are employed in combined-fired applications. U.S. designers would typically specify gas velocities of 4 to 4-1/2 ft/sec for refractory walled incinerators.[27]

Gas velocity is selected for a discrete particle size distribution so that re-entrainment problems are minimized. For comparison, gas velocities used in design of coal fly ash precipitators are typically 6 to 8 ft/sec,[35] while lower velocities on the order of 4 to 5 ft/sec are recommended for oil ash.[4,35]

With respect to particulate emissions from oil-fired boilers, stack gas temperature and sulfur content of the oil affect the resistivity of the noncombustible portion of these solids; however, the balance of these solids are composed of highly conductive combustible carbonaceous solids. As a result of these carbonaceous solids, the resistivity of the particulate emissions is usually less than that for coal, 10^7 to 10^9 ohm/cm for oil versus 10^9 to 10^{13} ohm/cm for coal.[4/] Difficulties which have been reported in collection of oil ash result from the low concentration of fly ash having a relatively low bulk density and a relatively fine particle size. As in the collection of incinerator ash, there is frequently a high concentration of carbon in the oil ash, which sometimes causes a resistivity so low that ESP collection becomes difficult. In some cases, these solids are so conductive that they do not retain a charge and subsequently prevent the field from becoming saturated. Another problem that has been encountered is that these solids, upon deposition on collecting curtain surfaces, sometimes lose their charge to the curtain and become re-entrained in the gas stream.[4/] At least part of the difficulty with ESP collection of oil fly ash could also result from the breakup of agglomerates. Collection efficiency is improved through the employment of high voltage, large collection curtains, lower superficial gas velocity and high retention times. There is adequate evidence to indicate that, for an ESP unit suitably modified efficiencies of 90+% are possible for collection of oil ash. It is anticipated that high efficiencies should also be possible for refuse ash, with similar modifications as for oil fly ash.

SECTION 4

COST AND EFFECTIVENESS OF PARTICULATE EMISSION CONTROLS ON MSW-OIL FIRED BOILERS

This section includes a discussion of control performance (fractional efficiency) as well as cost data for estimation of control device cost and performance for meeting specific particulate emission levels when firing oil and municipal solid wastes (MSW) in a single combustion chamber. Control systems considered included cyclones, electrostatic precipitators, and high performance wet scrubbers.

INERTIAL COLLECTORS

The efficiency of a multicyclone is dependent upon the size and density of the particulates in the gas stream. On coal-fired cyclone furnaces the efficiency usually ranges from 30 to 40%, while on a pulverized unit it ranges from 65 to 75%.[4/] These differences can be attributed to the fact that the mean particle diameter of the emissions from a cyclone furnace is usually lower than that of the emissions from a pulverized unit. The estimated range of efficiency of cyclone collectors installed on oil-fired boilers is 82.5 to 90% as determined from a summary of National Emissions Inventory System data (NEDS) summarized in Table 7.

GCA[4/] estimates that a maximum efficiency of 40% might be obtained for small oil-fired boilers and that this efficiency would decrease as the boiler size increased. Though they are not efficient in the reduction of fine particulate emissions, mechanical collectors could help reduce acid smut emissions since smut is composed of agglomerated solids and is usually large in diameter.[4/]

The range of overall collection efficiences for oil-fired boilers, based on stack test data is 75 to 90%.[3,7,26,35/] Fractional efficiency data for coal fly ash and performance guarantees for oil ash are shown in Figure 7.

Table 7. SUMMARY OF EFFECTIVENESS OF VARIOUS CONTROL SYSTEMS IN USE ON OIL-FIRED ELECTRIC GENERATING PLANTS[a/]

Control method	No. installed	Range of efficiency (%)	Average efficiency (%)
Wet scrubber - low efficiency	1	-	80
Cyclone - medium efficiency	28	82.5-90	85.8
Cyclone - low efficiency	11	20-85	52.5
ESP - high efficiency[b/]	7	90-97	93.4
ESP - medium efficiency[b/]	11	35-97	68.1
ESP - low efficiency[b/]	28	30-95	62.0
Gravity collector - high efficiency	3	85.7-87.2	86.6
Cyclone (L)/gravity collector (L)[b/]	3	85	85
ESP (M)/cyclone (M)[b/]	2	95	95
Cyclone (M)/ESP (M)[b/]	6	96-98.5	96.5
Cyclone (L)/ESP (M)[b/]	2	93	93
Cyclone (M)/ESP (H)[b/]	4	99.2	99.2
Gravity collector (H)/ESP (L)[b/]	1	80	80

a/ Summarized from NEDS inventory listing, Ref. 4.

b/ Controls--ESP = electrostatic precipitator, M = medium efficiency, H - high efficiency, L = low efficiency.

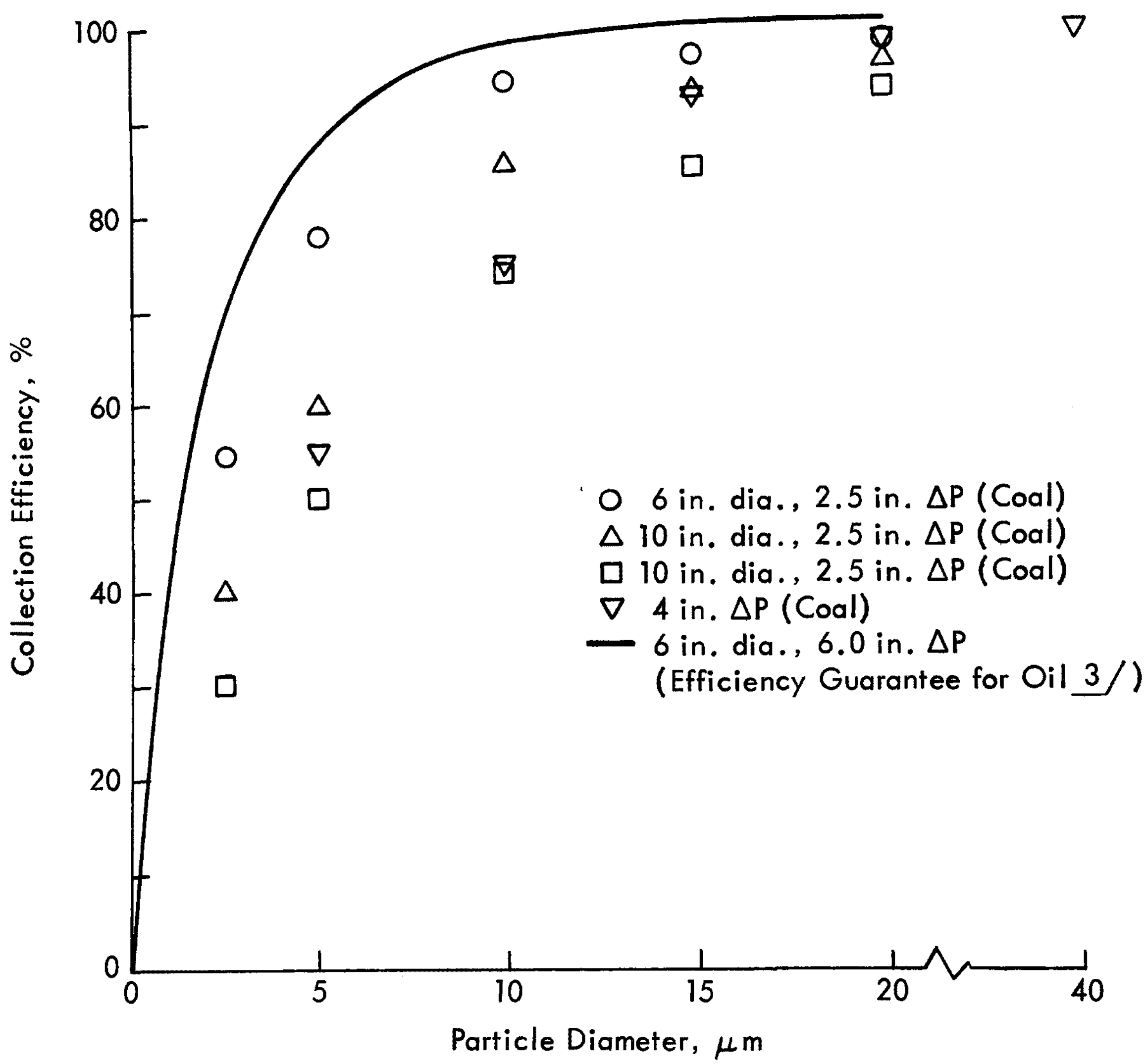


Figure 7. Fractional efficiency data for cyclone collection of fly ash from coal- and oil-fired electric utility boilers.

It should be emphasized that there are operating problems with the use of multicyclone collectors for control of oil-fired boilers. If the temperature of the combustion gas is below the SO_3 dew point, the hygroscopicity and corrosiveness of the oil ash can cause centrifugal collector operational and maintenance problems. Build up of cement-like ash on tube and hopper surfaces results in increased pressure drop as well as corrosion and cleaning problems.4/

There are several European waterwall incinerators equipped with cyclone control, but no fractional control efficiency data were found for these plants. The reported efficiency of a cyclone installed at Nashville Municipal (waterwall) Incinerator is 57.7%.36/ This unit is used as a precleaner for a scrubber. Collection efficiency of ash from refractory walled incinerators by cylones declines rapidly for dust smaller than 20 µm.24/ Theoretical performance models for cyclone collectors have been developed,37/ but the application of theory to practical design problems has not been achieved.

WET SCRUBBERS

When applied to 170 MW coal-fired boilers, high efficiency wet scrubbers have demonstrated an average 96% particulate removal efficiency at a pressure drop of 37.4 mm Hg (20 in. H_2O).4/ At Boston Edison's Mystic Station, a Chemico-Basic (Magnesia Slurry) scrubbing system installed on Boiler No. 6 (156 MW) has achieved particulate removal efficiencies as high as 69%.38/ The Chemico-Basic system employs a single stage Venturi scrubber. There have been operating problems with the system installed at Mystic No. 6. Collection efficiency decreases rapidly with decreasing particle size. Negative efficiencies were observed at the Mystic MgOx system for particle diameters below 1.5 µm, presumably resulting from entrainment of scrubber solids.39/ The lower stages of the impactor at the scrubber outlet were also found to be wet, indicating poor performance of the mist eliminators.39/

The estimated average efficiencies of scrubbers installed on oil-fired electric generating stations (medium efficiency scrubbers) is 85.8% (Table 7). The only waterwall incinerator plant presently equipped with a scrubber for particulate control is Nashville's (Nashville Thermal Transfer Corporation) Riverside No. 2 Unit. A low energy wet scrubber with a Venturi rod insert is used to reduce particulate emissions from 2.31 g/Nm^3 (1.01 gr/dscf at 12% CO_2) to 0.39 g/Nm^3 (0.169 gr/dscf at 12% CO_2).36/ (This emission level is in violation of New Source Performance Standards for Incinerators.) Also at NTTS, there are plans for installation of a high energy two-phase scrubber designed by Chemico-Aronetics.36/ This scrubber is similar in design to the Chemico-Aronetics "Adtec" Scrubber.40/ Based on the pilot plant studies, estimated particulate emission levels are 0.049 g/Nm^3 (0.0214 gr/dscf at 12% CO_2).36/ This corresponds to an overall efficiency for particulate removal of 98.0%. There are no cost-performance data available at this time from Chemico. Reasons given were that (a) present data are based only on a pilot plant installation, and (b) there are not enough data available at this time to determine whether conventional construction materials will be sufficient to withstand the corrosive incinerator flue gas.[41]

The cost and performance of Venturi scrubbers is highly dependent upon allowable pressure drop and economic tradeoffs between installed and operating costs. Typical installed costs (1975 basis) for high energy Venturi scrubbers for fly ash removal are \$48 to \$96/m^3 (\$1.35 to \$2.70/acfm).[42] The variation in installed cost with gas volume and efficiency is shown in Figure 8.

ELECTROSTATIC PRECIPITATORS

When applied to cyclone-fired, coal-burning boilers, electrostatic precipitators have demonstrated particulate collection efficiencies ranging from 65 to 99.5%. On general pulverized coal boilers, control efficiencies are usually between 80 and 99.5%.[4] As discussed, there are several difficulties in adapting fly ash precipitator designed for coal-fired boilers to handle fly ash from firing oil. For control purposes, major differences are: (a) lower ash density, (b) a higher concentration of carbonaceous, low resistivity particulate, (c) a higher percentage of submicron particulate, (d) a hygroscopic fly ash which tends to agglomerate, and (e) a reduced volumetric ash loading. As a result of these factors, when a coal-fired boiler with an electrostatic precipitator is converted to oil with the precipitator unmodified, particulate control efficiency is usually reduced. A typical collection efficiency for an unmodified unit is reportedly about 45%.[4] If the precipitator is modified, however, control efficiencies approaching 90% can be realized.[4]

Enlargement of collection electrodes can be used to minimize re-entrainment of low density, low resistivity fly ash[4] which tends to easily lose its charge when it comes into contact with the collection electrode. Reduction in gas velocity, increased rapping intensity, and decreased frequency are also recommended to minimize re-entrainment.[4] Because the average particle size is smaller, a lower operating voltage, higher current, and longer gas treatment path are recommended.[4] Other modifications are required because of ash handling problems. The hygroscopicity of the particulate matter causes a solids buildup on high tension electrodes, insulators, and collection curtains. When allowed to cool, these solids absorb moisture, become difficult to remove and cause arcing and shorts. By locating the precipitator on the hot side of the air preheater, solids accumulation is reduced on high tension wires and collection curtains. Build up on insulator bushings can be prevented by using hot air ventilation. Hopper plugging can be avoided by either heating the hopper or employing a wet bottom system.[4]

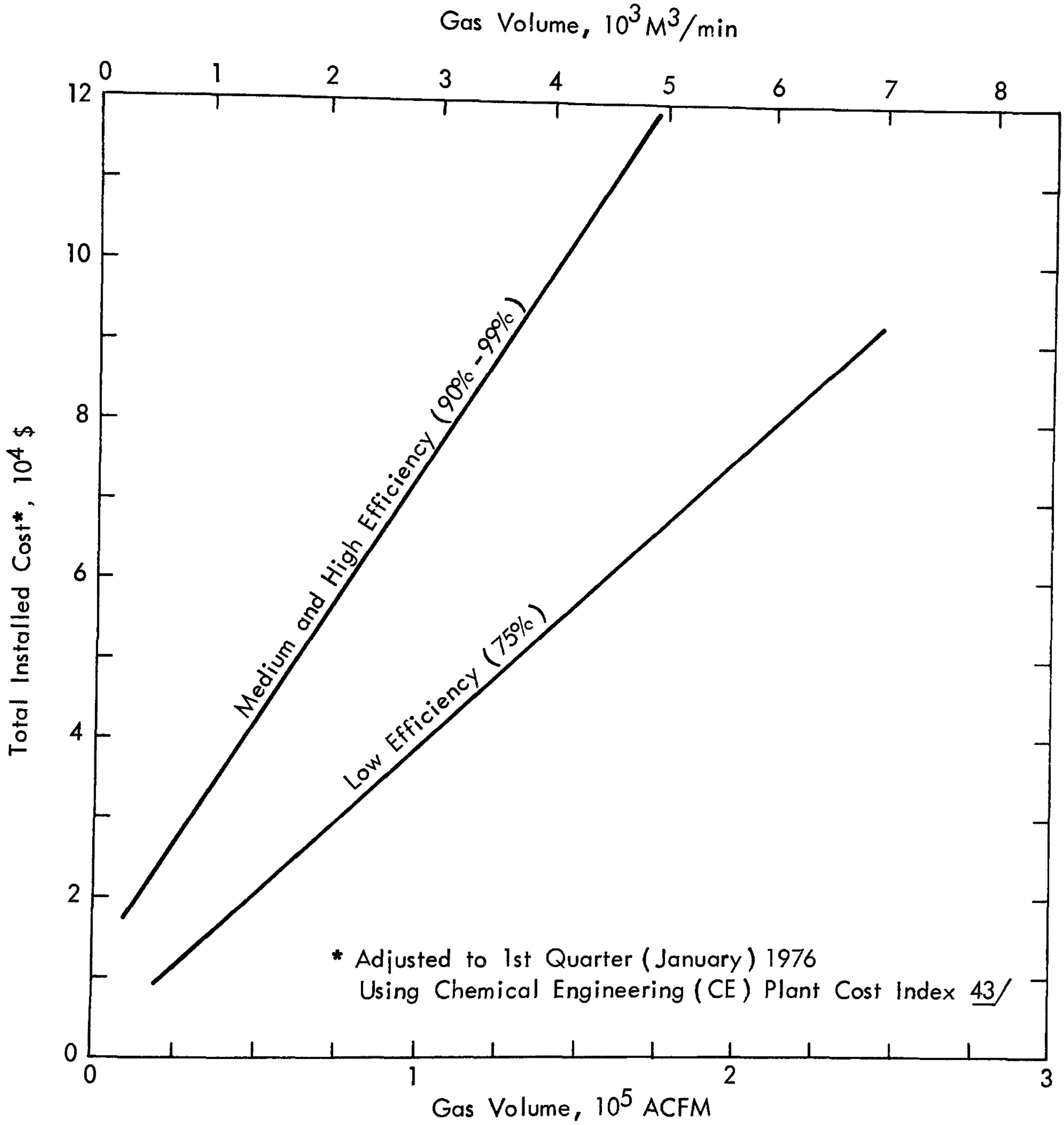


Figure 8. Total installed cost of wet scrubbers.27/

The average collection efficiency for high efficiency electrostatic precipitators on oil ash is estimated, based on NEDS inventory data (Table 7) to be 93.4%. The average collection efficiency of ESP installions on waterwall incinerators is approximately 95% (see Appendix B).

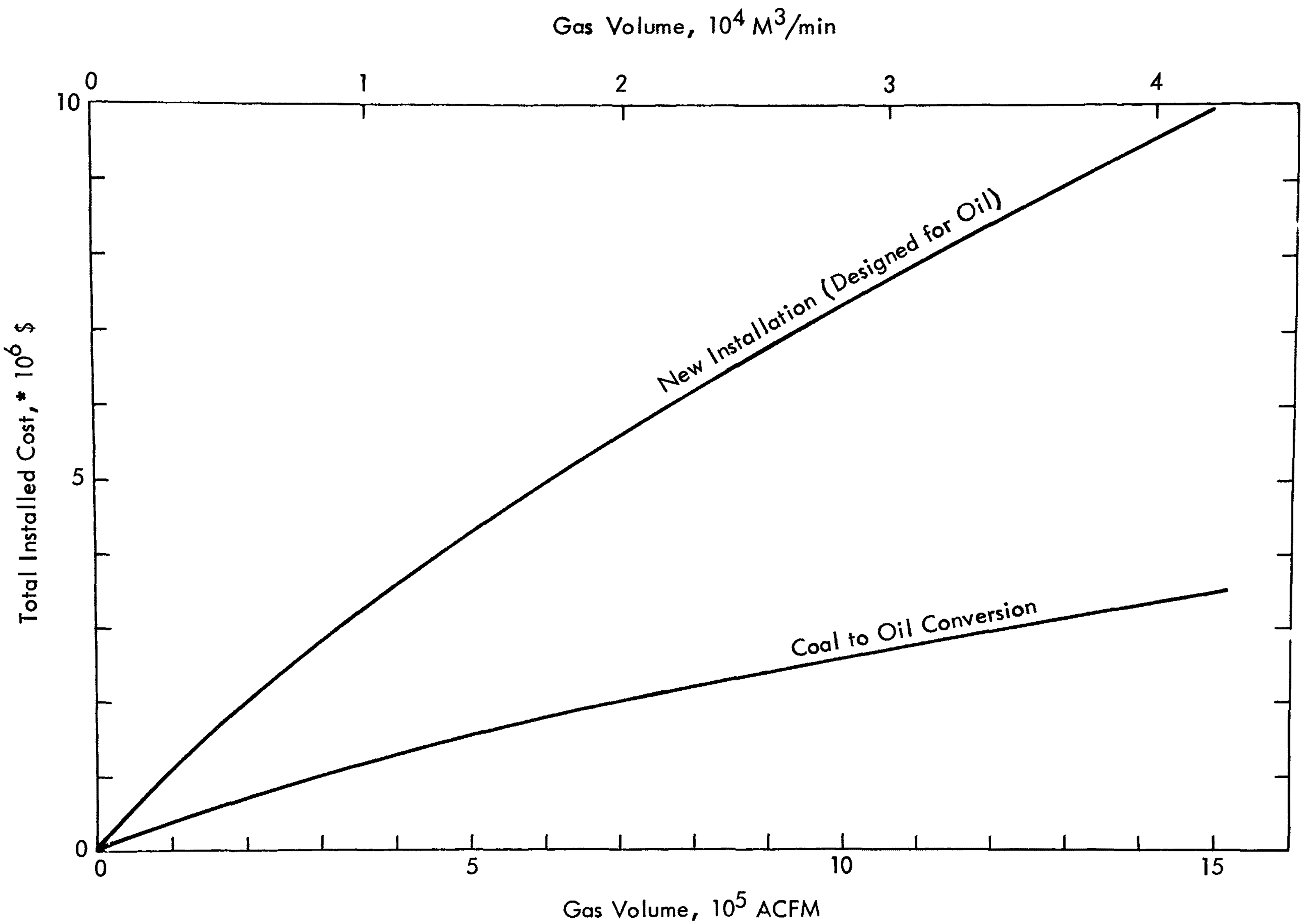
Control Costs for Electrostatic Precipitator Control

Installed control costs for new high efficiency, multiple field electrostatic precipitators typically range from \$26.5 to \$123.6/m^3 (\$0.75 to \$3.50/ACFM), based on data for 1975.[42] Retrofitting for collection of oil fly ash costs an additional \$87 to \$131/m^3 (\$2.50 to \$3.75/acfm) (see Figure 9); a new installation designed for oil costs \$218 to \$350/m^3 (\$6.25 to \$10/acfm).[4]

An alternative approach would be to install ESP collectors specifically designed for refuse fly ash. This approach would be applicable for new installations, but would probably not be suitable for existing units which may need to be converted back to coal at some later date. Installed cost and design data for ESP units installed on existing waterwall incinerators are summarized in Table 8.

Electrostatic Precipitator Performance Model

As previously discussed, combined firing of oil and MSW will cause departures from fly ash properties and ESP operating conditions. Specifically, changes may occur in dust loading, flue gas volume, particulate density, size and resistivity. Because ESP controls are installed on most units planned for combined oil-MSW firing studies, a considerable effort in the study was directed toward adaptation of available information to develop an analytical model for prediction of ESP performance. The model, which is intended to provide the capability for rapidly estimating ESP performance for combined-firing conditions, is described in detail in Appendix C.



* Adjusted to 1st Quarter (January) 1976 Using Chemical Engineering (CE) Plant Cost Index.[43]

Figure 9. Total installed cost for electrostatic precipitators.[4]

Table 8. DESIGN AND COST DATA FOR ELECTROSTATIC PRECIPITATORS DESIGNED FOR COLLECTION OF WATERWALL INCINERATOR FLY ASH

Installation A - 150 TPD Incinerator

A. Sizing and performance data

Gas volume	= 1,130 m^3/min (40,000 ACFM)
Temperature	= 290°C (560°F)
Efficiency	= 97.5% by weight
Inlet loading	= 4.6 g/Nm^3 (2.0 gr/scf) at 12% CO_2
Residual	= 0.1 g/Nm^3 (0.05 gr/scf) at 12% CO_2 (Mass. Code)
Maximum excess air	= 100%
Migration velocity (W)	= 9.03 cm/sec
Gas velocity	= 1.10 m/sec (maximum) (3.70 fps)

Precipitator size - One (1) precipitator
14 Gas passages Two (2) fields
4.6 m (15 ft) field height 25 cm (10 in.) passage spacing
Field length = 2.85 m (9.36 ft) x 2 = 5.70 m (18.72 ft)

Precipitator will remove 97.5% by weight of the incoming dry solid particulate provided the inlet dust is at least 4.6 g/Nm^3 (2.0 gr/scf) at 12% CO_2. If the inlet dust load is less than 4.6 g/Nm^3 (2.0 gr/scf) at 12% CO_2, the unit is guaranteed to have a maximum outlet emission of 0.1 g/Nm^3 (0.05 gr/scf) at 12% CO_2.

B. Prices (budgetary)

1. Basic E/P with electrics, support steel, access and dust valves		$253,460
2. Thermal insulation for entire precipitator including installation		$ 34,125
3. Erection of E/P and auxiliaries excluding L.V. wiring		$ 93,160
	Total	$380,745

Table 8. (Concluded)

Installation B - 750 TPD Incinerator

A. Sizing and performance data

Gas volume	= 5,660 m^3/min (200,000 acfm)
Temperature	= 220°C (428°F)
Inlet loading	= 4.6 g/Nm^3 (2.0 gr/scf) at 12% CO_2
Residual	= 0.1 g/Nm^3 (0.05 gr/scf) at 12% CO_2
Efficiency	= 97.5% by weight
Maximum excess air	= 100%
Migration velocity (W)	= ~~9.0 cm/sec~~
Gas velocity	= 0.15 m/sec (4.25 fps) (maximum)

Precipitator size - One (1) precipitator
37 Gas passages — Two (2) fields
7.6 m (25 ft) Field height — 25 cm (10 in.) Gas passage spacing
Field length = 3.328 m (10.92 ft) x 2 = 6.657 m (21.84 ft)

Precipitator will remove 97.5% by weight of the incoming dry solid particulate provided the inlet dust is at least 4.6 g/Nm^3 (2.0 gr/scf) at 12% CO_2. If the inlet dust load is less than 4.6 g/Nm^3 (2.0 gr/scf) at 12% CO_2, the unit is guaranteed to have a maximum outlet emission of 0.1 g/Nm^3 (0.05 gr/scf) at 12% CO_2.

B. Prices (budgetary)

1. Basic E/P with electrics, support steel, access and dust valves		$420,130
2. Thermal insulation for entire precipitator including installation		$ 93,225
3. Erection of E/P and auxiliaries excluding L.V. wiring		$258,990
	Total	$772,345

Source: Wheelabrator Frye, Inc., Air Pollution Control Division, September 26, 1975.

SECTION 5

CASE STUDIES

DISTRICT OF COLUMBIA

The Department of Environmental Services, District of Columbia, recently initiated a combined-firing test program originally planned as an EPA resource recovery demonstration program which would have involved concurrent firing of oil and coal with shredded municipal solid wastes (MSW). The planned test boiler was the Potomac Electric Power Company (Pepco) Benning Station Boiler No. 26. The planned refuse processing capacity was 22.7 MT/hr of raw refuse, or approximately 16.3 MT/hr of refuse derived fuel (RDF) at a 75/25 air classifier cut; considered sufficient to remove 90 to 95% of the aluminum cans for aluminum recovery in the heavy fraction, and also yield a fuel of lower ash and higher burn-out than was prepared in St. Louis (see Tables 9 and 10). This refuse capacity is equivalent to 20 to 25% of the heat input to Benning Station No. 26 (75 MW) at 100% load. The actual steady-state refuse capacity when firing oil would have been determined in the test. Three tests each on coal only and oil only were planned to establish steady-state baseline conditions. Following these preliminary tests, one to three steady-state tests each with oil-plus-refuse and coal-plus-refuse were planned. Benning Station Boiler No. 26 is equipped with ESP control; emission tests on Benning Station No. 26 (firing oil) have recently been performed by York Research Corporation.[44]

Notable characteristics of the planned combined firing tests at Pepco were: (a) the refuse preparation facility would have employed primary and secondary shredders, and it was planned to test the combustion characteristics of a wide range of particle sizes; and (b) air emissions monitoring of NO_x, SO_x, Hg, HCl, and particulates were to have been supplemented by an extensive program, conducted by a separate subcontractor, to determine air emissions of trace heavy metals, POM's, PCB's, and small organic moieties. Statistical methods were to have been used for refuse sampling. Refuse analyses would have been done by the same laboratory as for the St. Louis/Union Electric test program. Corrosion would have been monitored by probes, waste measurements, and test specimens

Table 9. ESTIMATED MATERIALS BALANCE*

Operations	Paper	Glass	Non-Fe	Fe	Al	Yard Waste	Food Waste	Rags & Wood	Ash Rock	Total (tons/hr)
Estimated % Composition	43.0	10.0	0.5	7.0	1.0	14.0	12.0	5.0	7.5	100
Receiving	10.75	2.50	.13	1.75	.25	3.50	3.00	1.25	1.87	25
Shredder	10.75	2.50	.13	1.75	.25	3.50	3.00	1.25	1.87	25
Air Classifier	10.75	2.50	.13	1.75	.25	3.50	3.00	1.25	1.87	25
Lights	9.93	.49	.01	.03	.04	2.89	1.98	.50	1.07	16.94
Heavies	.82	2.01	.13	1.72	.21	.61	1.02	.75	.80	7.87
Dust (Loss)			-	-	-					0.16
Pneumatic Feeder	9.93	.49	.01	.03	.04	2.89	1.98	.50	1.07	17.13

*Table based on feed rate of 25 tons per hour

Source: Department of Environmental Services of the District of Columbia, "Utilization of a Refuse-Derived Fuel as Supplementary Fuel in an Oil and Coal Fired Electric Utility Boiler", Proposed to U.S. Environmental Protection Agency for a Research, Development and Demonstration Grant, April 1, 1975.

Table 10. TARGET ANALYSIS OF REFUSE DERIVED FUEL AT SWRC-1 (Washington, D.C.)[a/]

Higher heating value	12,800-14,000 joules/g (11,600)[b/] (5,500-6,000 Btu/lb)
Moisture	20-25% (30%)[b/]
Ash	15-20% (30%)[b/]
Sulfur	0.3% (0.4%)[b/]
Chlorine	0.6% (1.0%)[b/]
Particle size	≤ 3.8 cm[c/] (≤ 1.5 in.)
Bulk density	32-116 kg/m^3[d/] (2-11 lb/ft^3)

a/ Dry weight basis.
b/ Extreme value for acceptance by Pepco.
c/ The maximum specified dimension of each particle is 95%/weight less than 10 cm.
d/ The pneumatic delivery system as designed by Rader Pneumatics can deliver RDF as low as 32 kg/m^3 (2 lb/ft^3) only at the highest flow rate of 400 m^3/hr (14,000 CFH).

to determine any incremental effects from burning RDF compared to the conventional fuel. Slagging effects would have been monitored both visually and during operations, by monitoring manometers indicating draft loss. The combined firing test program and estimated emissions are described in detail in the following subsections.

Program Status

The District of Columbia Department of Environmental Service submitted a joint proposal with Pepco and National Center for Resource Recovery (NCRR) to EPA, Office of Solid Waste Management Programs on April 1, 1975. The program is now inactive as an EPA resource recovery demonstration program.

Refuse Derived Fuel (RDF) Preparation and Facilities

Shredding of MSW--

The DES Solid Waste Reduction Center No. 1 (SWRC-1) is equipped with a tipping floor and steel pan pit conveyor feeding a Williams 780, 2.684×10^9 joules/hr (1,000 hp) horizontal hammermill. Discharge is onto a Jeffrey vibrating oscillating pan feeder conveyor and then to a rubber belt conveyor. Full rated capacity of the shredder system is 25 tons/hr; the limitation of capacity is the design of the conveying system, which was originally for oversized bulky wastes (OBW), and not any limitation of the shredder. The feeder was to have been modified for larger capacity.

Air Classification--

Modifications were planned to install a 25 ton/hr Triple/S "Vibrolutriator" air classifier to SWRC-1. This classifier is the same as specified in Ames and Chicago. A 75/25 split was expected in the air classifier between light and heavy fractions, giving a maximum delivery of approximately 16.3 MT/hr of fuel. The objective for the split was to recover from 90 to 95% of the aluminum cans while also dropping items such as wood, textiles, and heavy food wastes. Achieving these objectives would have yielded RDF of lower ash and higher burn-out than was prepared in St. Louis.

Secondary Shredding--

Detailed engineering plans were approved by the district government for the installation of a cyclone and associated blower and rotary valve (all owned by NCRR) as the arrangement for de-entrainment of the air classifier light fraction. The plans called for the cyclone to discharge through a rotary valve which, in turn, would have discharged to either a positive displacement feeder or to the second shredder.

The secondary shredder proposed for this work was a verticle type, such as the Heil 42F. The proposed arrangement (Figure 10) was such that the

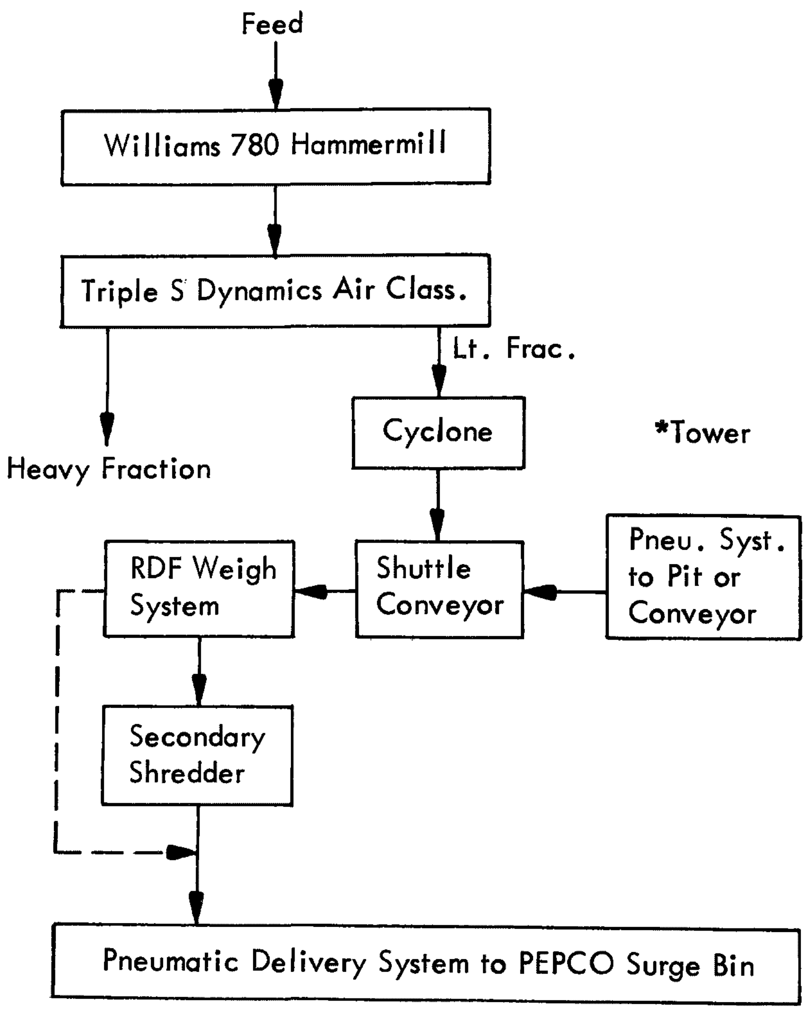


Figure 10. Process flow for preparation of RDF at District of Columbia.

secondary shredder could have been by-passed, or not, to deliver RDF to the boiler. This arrangement would have permitted testing of a wide range of particle sizes of RDF. It was considered impractical to obtain all sizes using the secondary shredder only. A second planned method for achieving variable particle size was to change the grate of the Williamson 780 shredder. A combination of both methods would have extended the particle size range from 95% minus 10 cm to something under 5 cm. Particles smaller than this would have been produced in the second shredder.

Characteristics of Test Boiler

Benning Station Boiler No. 26 is a tangentially fired boiler designed by Combustion Engineering for a nominal capacity of 75 MW. The boiler system is broadly similar to that used in St. Louis except with a smaller capacity. Another difference is that this is a dry ash handling system as contrasted to the Union Electric wet system. Boiler ratings for firing coal and oil are listed in Table 11.

Boiler No. 26 was designed to burn either 100% coal or oil at the maximum capacity rating (MCR). However, it may have been necessary to remove one level of oil guns to accommodate RDF burners, which would have reduced capability to 67%.

The boiler modification to accept RDF would have consisted of removing one level of oil guns and replacing them with (two) locally controlled, tiltable refuse burners. If two-corner burning were found unacceptable, the system would have been modified to permit burning at four corners. Combustion Engineering has also investigated the possiblity of locating the refuse nozzles in the windbox without removing one level of oil firing to allow refuse-oil firing at the MCR.

Installed Air Pollution Control Equipment

Boiler No. 26 employs a mechanical-electrical precipitator system which was initially installed by Aerotec Corporation. The electrical section was restored in 1968 by Research-Cottrell to original Aerotec specifications.[46] Design specifications are 99% for both collectors in series when burning 1% sulfur coal at a flue gas volume of 9,344 m^3/min (330,000 acfm), 165° C (330° F).[46] When firing oil in Boiler No. 26, the mechanical collector, which has a tendency to plug under these conditions, is normally bypassed. When the mechanical collector is bypassed, the design efficiency, under conditions just described (i.e., for 1% sulfur coal) drops to 90.8%.[46] Design parameters for the electrostatic precipitator are summarized in Table 12.

Table 11. PEPCO BENNING STATION BOILER NO. 26 DESIGN RATINGS[45]

Boiler rating

Steam: 306,000 kg/hr
(675,000 lb/hr)

Temperature: 538°C
(1,000°F)

Pressure: 1,062 newtons/cm^2
(1,525 psig)

Coal firing

Heat in: 8.5565×10^{11} joules/hr
(811,000,000 Btu/hr)

Boiler efficiency: 89%

Heat out: 7.6153×10^{11} joules/hr
(721,790,000 Btu/hr)

Oil firing

Heat in: 8.6933×10^{11} joules/hr
(823,961,180 Btu/hr)

Boiler efficiency: 87.6%

Heat out: 7.6153×10^{11} joules/hr
(721,790,000 Btu/hr)

Table 12. CHARACTERISTICS OF ELECTROSTATIC PRECIPITATOR

Plate area--1,235.6 m^2 (13,300 ft^2)/section

Plate-to-plate spacing
  (a) Inlet[a/]
  (b) Outlet[a/]

Corona wire diameter[b/]

Specific collection area--264.5 $m^2/10^3\ m^3\text{-min}^{-1}$
(80.6 ft^2/1,000 acfm)

Migration velocity--15.0 cm/sec
(29.6 ft/min)

Design voltage--45 kv

Current density--16.8 nanoamps/cm^2[c/]

Electrical sets--two in parallel

Design efficiency--90.8% burning coal with 1% sulfur at approximately 75 MW and 9,344 m^3/min (330,000 acfm) into the precipitator 165°C (with mechanical collector bypassed)

a/ Data not available; assumed value was 25.4 cm (10 in.).
b/ Data not available.
c/ Average for particulate emission tests made when firing No. 6 residual oil.[46/]

The electrostatic precipitator is not presently expected to meet design specification when firing coal. Therefore, the above specifications must be used with caution. Efficiency measurements with coal and using both the mechanical and electrical sections have been made and indicate an average efficiency of only 96.5%.[46/] Recent efficiency tests with No. 6 residual oil reflect an efficiency of roughly 60%.[44/] When burning coal, flue gas temperature is typically 204° C (400° F, which is higher than that for which the ESP unit was designed. Increasing temperature increases flue gas volume and frequently decreases ESP collection efficiency for this temperature range.

District of Columbia Emission Regulations

Administering Agency:

Bureau of Air and Water Quality Control
Department of Environmental Services
25 K Street, N.E.
Washington, D.C. 20002

Fuel-Burning Particulate Emission:

For installations using more than 3,500,000 Btu/hr total input, the particulate emission limitation shall decrease as the rate of heat input increases as summarized below:

H (10^6 Btu/hr)	E (lb/10^6 Btu)
3.5	0.13
10	0.101
100	0.059
1,000	0.034
≥ 10,000	0.02

H = total heat input in millions of Btu/hr

E = maximum emission in pounds of particulate matter per million Btu heat input

$H \leq 3.5$; $E = 0.13$; $3.5 < H < 10{,}000$; $E = 0.17455\ H^{-0.23522}$ $H \geq 10{,}000$; $E = 0.02$

Sulfur Oxides:

No person shall purchase, sell, offer for sale, store, transport, use, cause the use of, or permit the use of, fuel oil which contains more than 1% sulfur by weight in the District, if such fuel oil is to be burned in the District.

On and after July 1, 1975, the sulfur content of such fuel oil shall not exceed 0.5% by weight.

Nitrogen Oxides:

Emission limits for nitrogen oxide in fossil fuel fired steam generating units of more than 100,000,000 Btu/hr heat input are as follows:

1. 0.20 lb per million Btu heat input (0.36 g per million cal.), maximum 2 hr average, expressed as NO_2,,when gaseous fossil fuel is burned.

2. 0.30 lb per million Btu heat input (0.54 g per million cal.), maximum 2 hr average, expressed as NO_2,,when liquid fossil fuel is burned.

3. 0.70 lb per million Btu heat input (1.26 g per million cal.), maximum 20 hr average, expressed as NO_2, when solid fossil fuel (except lignite) is burned.

4. When different fossil fuels are burned simultaneously in any combination the applicable standard (lb NO_x per 10^6 Btu) shall be determined by proration, according to the following fomula:

$$\frac{x\ (0.20) + y\ (0.30) + z\ (0.70)}{x + y + z} \tag{13}$$

where x = the percent of total heat input derived from gaseous fossil fuel

y = the percent of total heat input derived from liquid fossil fuel

z = the percent of total heat input derived from solid fossil fuel

Estimated Performance of Installed Air Pollution Control Equipment

On the basis of information related to the planned test program, the performance of the installed electrostatic precipitator was calculated for the tests which would have involved combined firing of oil and MSW. ESP design and performance data used in the calculation were summarized in Table 12. The target composition data for the RDF fuel in Table 10 were used; actual composition data were not available. The ESP analytical model is described in Appendix C. Dust loadings were estimated using Eq. (8). An average value of 0.0632 $g/10^6$ joules was used for total particulate from the oil portion of the fuel based on data in Appendix A. The predicted variation in flue gas dust loading with RDF heat input is shown in Figure 11, in comparison with an earlier estimate by another group of investigators.[16]

The predicted dust loading shown in Figure 11, for $f_r = 0.15$ corresponds approximately to average emission value for oil fired boilers, and combined suspension firing of MSW with coal. The curve for $f_r = 0.50$ corresponds approximately to the highest estimate for the refuse fly ash fraction.[6]

The calculated electrostatic precipitator performance is shown in Figure 12. Efficiencies range between 77 and 86%, depending on boiler load and percentage of refuse fired. In making the calculation it was assumed:

1. The ESP unit would be put into proper operating condition.

2. The cyclone precleaner would be bypassed, as is done for oil firing.

On the basis of data for flue gas dust loading and ESP performance, in Figures 11 and 12, the particulate emissions under two different boiler loads and with varying refuse heat input fraction were calculated. These results are shown in Figure 13. As is evident from Figure 13, it is predicted that particulate emissions will exceed New Source Performance Standards for Fossil Fuel-Fired Steam Generators, except at low MSW and/or low boiler load. Referring to District of Columbia Emission Regulations, the particulate emission standards for the District of Columbia are lower than new source standards decreasing with fuel consumption rate. At the MCR, the District of Columbia standard is 0.0161 $g/10^6$ joules (0.037 $lb/10^6$ Btu), about one-third the federal new source standard.

Cost of Air Pollution Control

The cost of new or modified control systems to meet existing particulate emission standards when Benning Station No. 26 is burning oil and MSW was not determined.

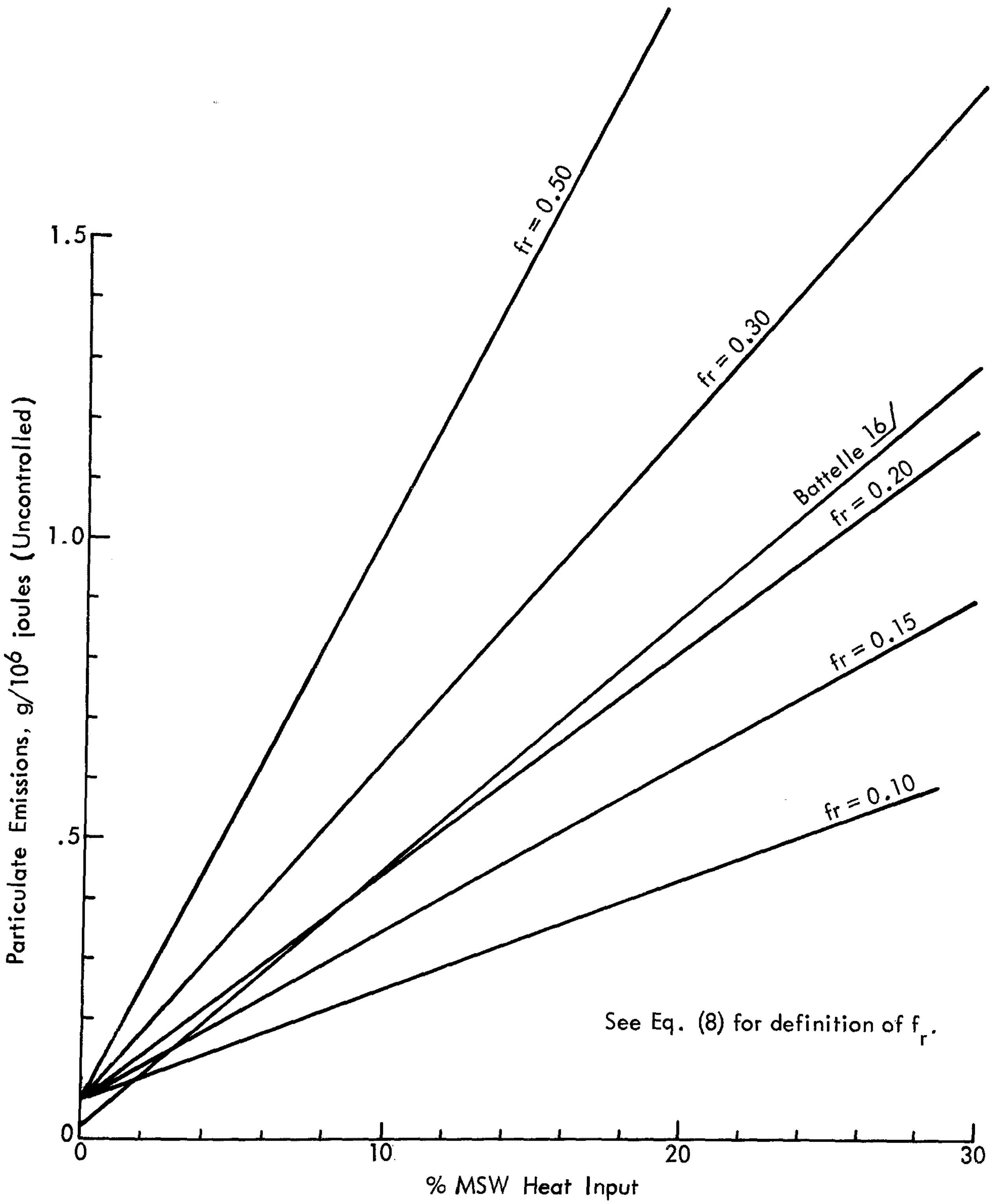


Figure 11. Effect of MSW fly ash fraction (f_r) on calculated particulate emissions (uncontrolled) from combined firing of MSW and No. 6 residual oil (from Tables 1 and 2).

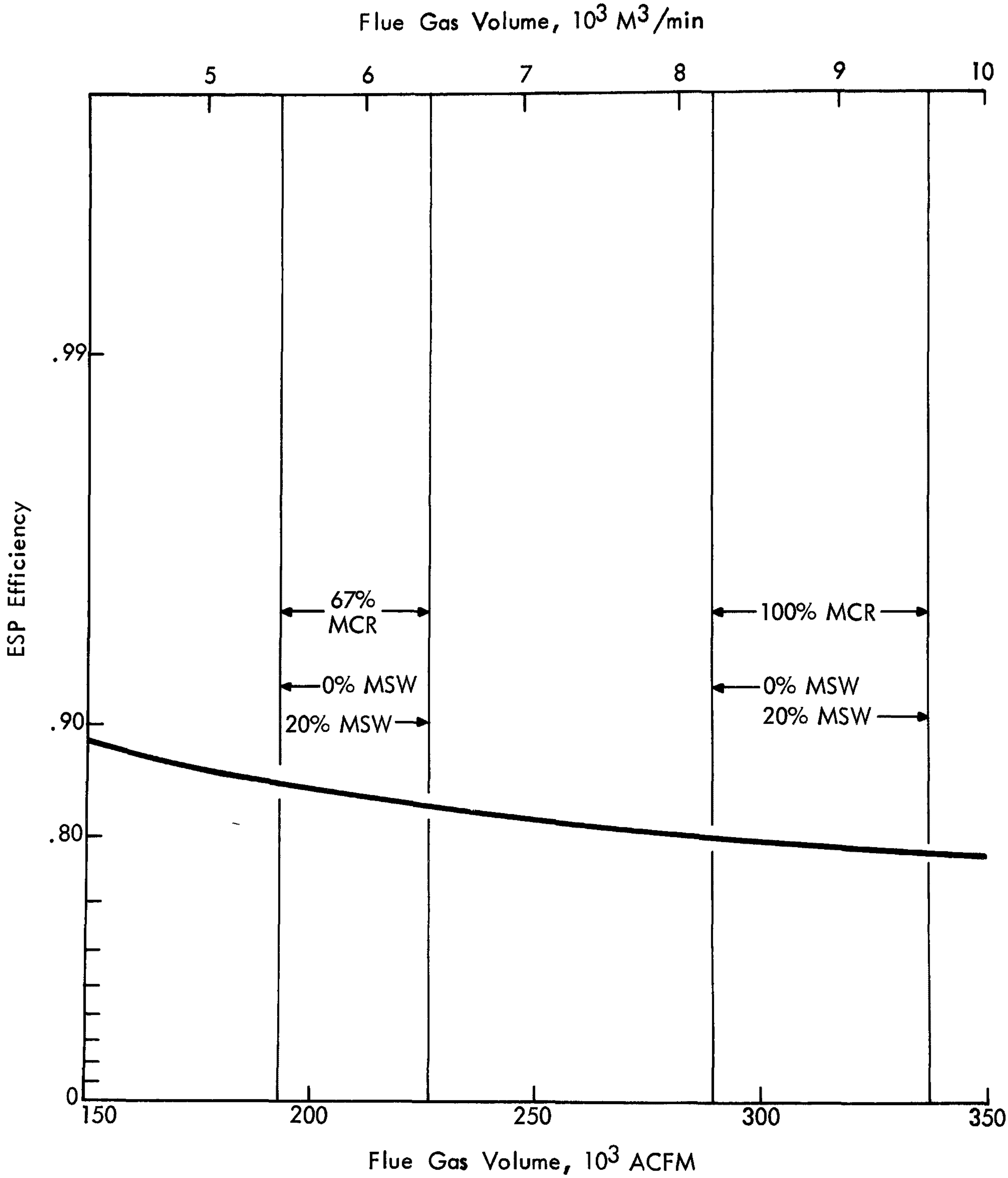


Figure 12. ESP efficiency (predicted) for combined firing of oil and MSW at Pepco Benning Station No. 26.

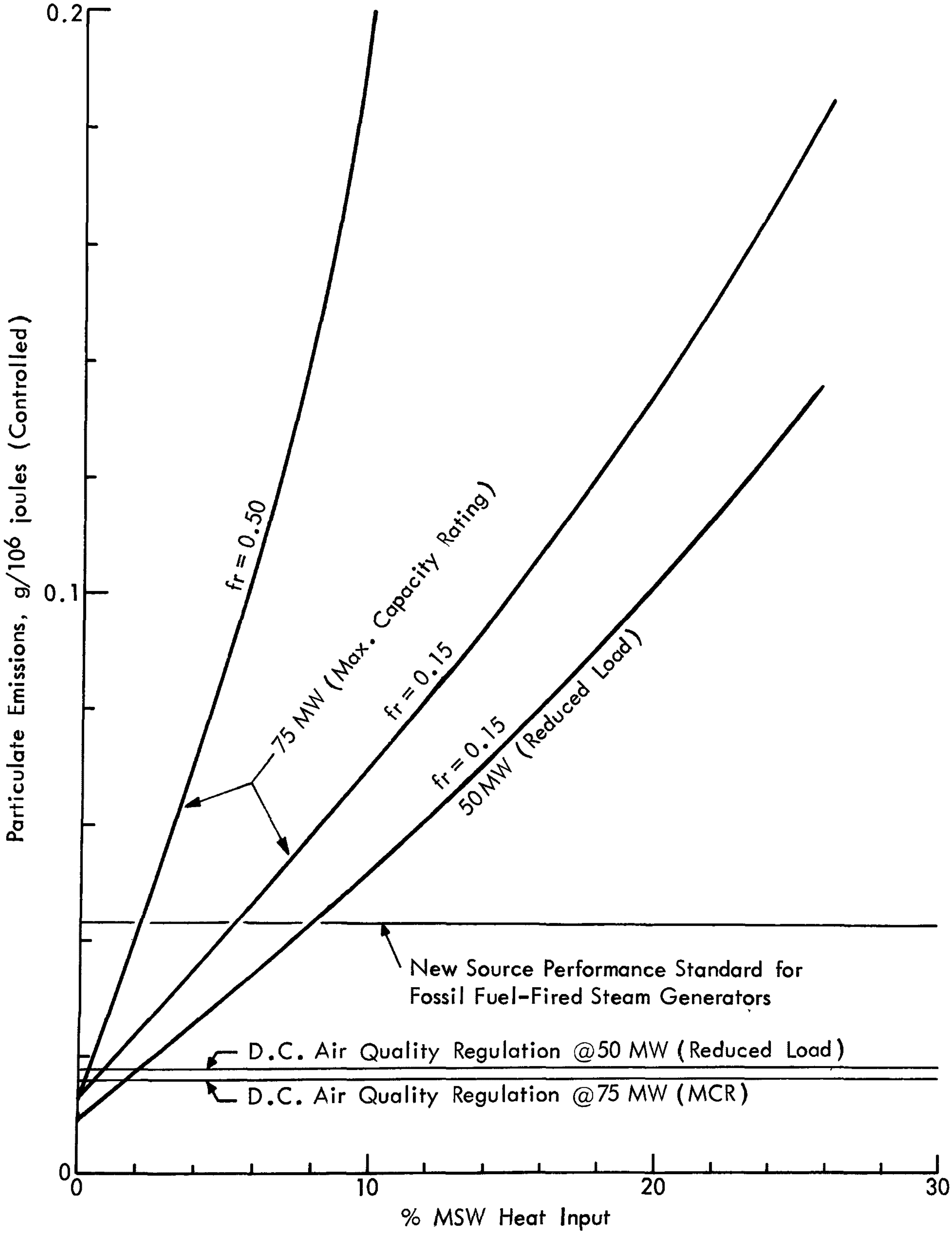


Figure 13. Estimated particulate emissions (controlled) for combined firing of oil and MSW at Pepco Benning Station No. 26.

Pepco estimated the required control efficiency to be 99% when firing oil and refuse at 10% MSW, based on 1.16 x 10^7 joules/kg, 7,936 kg/hr (5,000 Btu/lb, 8.75 tons/hr).[44/] Based on a lower assumed inlet loading corresponding to $f_r = 0.15$ in Figures 11 and 13, the required control efficiency at 10% MSW is 95.3%.

WILMINGTON, DELAWARE (New Castle County)

The State of Delaware, Division of Natural Resources, was awarded a $9 million resource recovery demonstration grant from EPA in October 1972.[49/] Delmarva Power and Light Company has agreed to participate in the program, and will modify either Edgemoor Station Units 3 or 4 to fire refuse. Delaware Division of Natural Resource will construct a new processing plant in New Castle County. There are few details available with regard to test schedule and emission tests because these plans have not yet been finalized between the State of Delaware and Delmarva Power and Light Company. If Edgemoor Station Boiler 4 (160 MW) is the test boiler the Demarva plan is to fire 5% MSW with oil at 242 ton/day of MSW.[50/]

Project Status

A feasibility study was completed by Combustion Engineering in May 1974.[20/] Delaware plans to issue an RFP for boiler modifications within FY 76. Delmarva estimates it will require approximately 1 year to make boiler modifications; the Delaware schedule is presently to begin tests by 1979.[51/]

Refuse Derived Fuel Preparation and Facilities

Presently, the State of Delaware is operating the 500 ton/day facility shown schematically in Figure 14 in New Castle County. The process uses air classification, magnetic separation, screening, rising current, heavy media, and electrostatic separation as well as optical methods for separating municipal solid waste into paper, ferrous and nonferrous metals, glass, and organic fractions.[52/] Regular markets have already been developed for glass, paper, and metals.[52/] Typical analytical properties of the refuse fuel are listed in Table 13.

Characteristics of Test Boilers

Edgemoor Station Boiler No. 3 is a tangentially fired boiler with a nominal rating of 75 MW. Edgemoor Station Boiler No. 4 is a tangentially fired boiler of the same design, except with a capacity of 160 MW. Both boilers are designed for firing either fuel oil (No. 2 or No. 6 - residual) or pulverized coal. Both boilers are equipped for flue gas recirculation. The only modification required

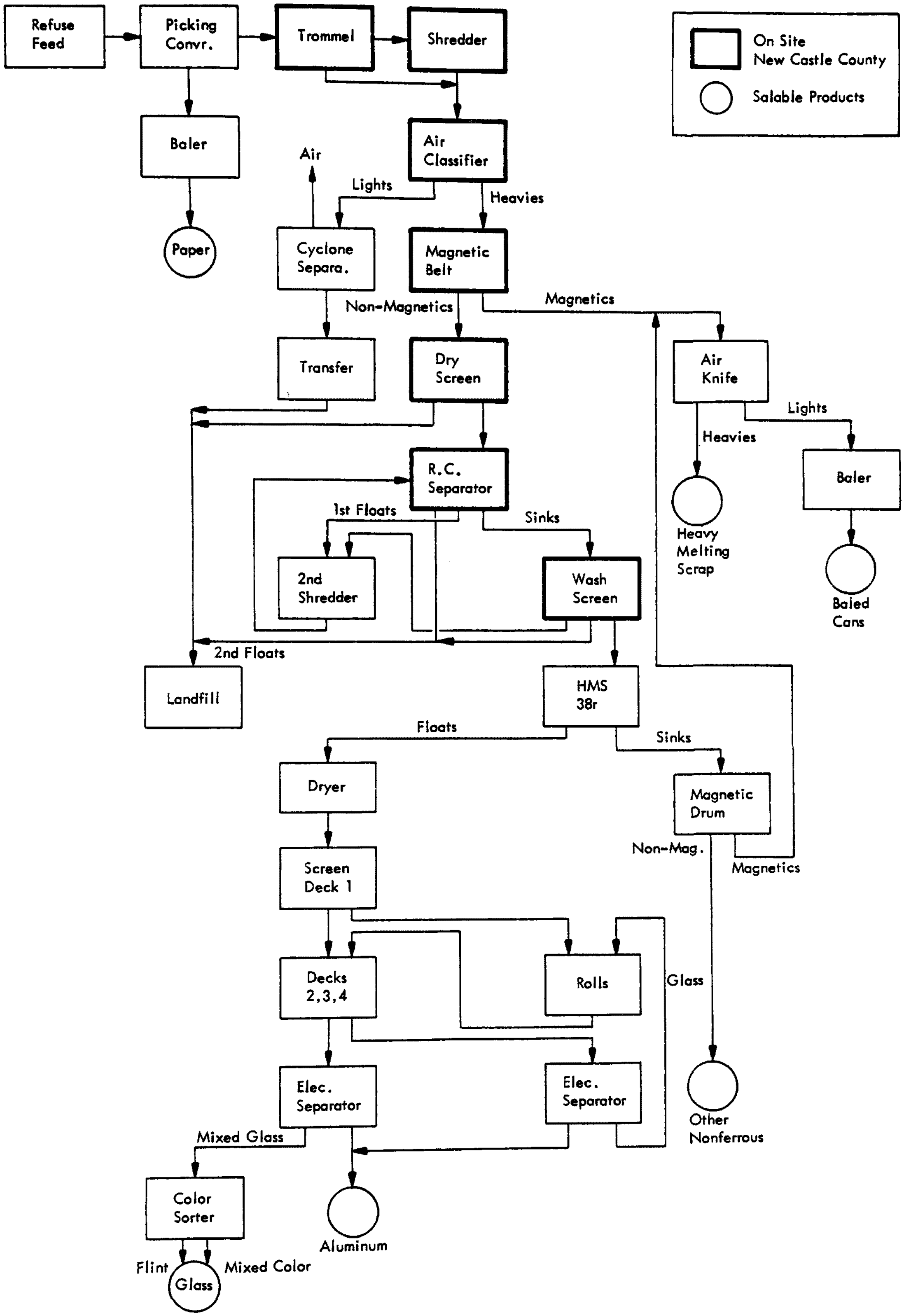


Figure 14. Schematic representation of materials recovery process, New Castle, Delaware.52/

Table 13. PROJECTED ANALYSIS OF REFUSE FUEL--
NEW CASTLE COUNTY, DELAWARE[20]

	(As fired - percent by weight)
Moisture	25.0
Ash	15.0
Sulfur	0.15
Chlorine	0.40
High heating value	
joules/kg	1.314×10^7
(Btu/lb)	(5,650)
High heating value (Dry, ash free)	
joules/kg	2.093×10^7
(Btu/lb)	(9,000)
Bulk density	
kg/m^3	64-176
(lb/ft^3)	(4-11)
Ultimate	(As fired - percent by weight)
Carbon	31.90
Hydrogen	4.70
Nitrogen	0.40
Oxygen	22.85
Sulfur	0.15
Moisture	25.00
Ash	15.00
Total	100.00

for firing MSW will be to add one new nozzle in each corner for firing refuse. Design ratings for Edgemoor Station Boilers Nos. 3 and 4 are summarized in Table 14.

Installed Air Pollution Control Equipment

Edgemoor Station Boiler No. 3 is equipped with a multicyclone collector with conventional reverse flow, designed by Western Precipitator. The design efficiency is 83% at 7,044.6 m^3/min and 149°C (248,775 acfm and 300°F). Design ratings are summarized in Table 15.

Edgemoor Station Boiler No. 4 is equipped with a two stage ESP collector designed by Research-Cottrell. The design efficiency (for coal or oil) is 95.0% at 12,560 m^3/min and 135°C (440,000 acfm and 275°F). Design ratings are summarized in Table 16.

Delaware Emission Regulations[20/]

Administering Agency:

Department of Natural Resources and Environmental Control
Air Resources Section
Tatnall Building
Dover, Delaware 19901

Particulates:

Emissions from any fuel-burning equipment shall not exceed 0.3 lb/10^6 Btu heat input.

Sulfur Oxides:

Sulfur content of distillate oil used in fuel-burning equipment is limited to 0.3% by weight. Sulfur content of other fuels used in fuel-burning equipment is limited to 1.0% by weight in New Castle County and to 2% in Kent and Sussex counties. However, if between July 1, 1973 and October 1, 1974 the national secondary ambient air-quality standard for the Metropolitan Philadelphia Interstate AQCR is exceeded due to an air-containment source located in New Castle County, then the enforcement agency may, after January 1, 1975, reduce the maximum allowable sulfur content of fuel to a level not lower than 0.3% by weight. High-sulfur fuel can be used if a state-approved SO_2-removal system is employed.

Table 14. DELMARVA EDGEMOOR STATION BOILER DESIGN RATINGS

	Unit 3	Unit 4
Boiler manufacturer[a]	C-E	C-E
Type of firing[a]	Tangential	Tangential
Turbo generator size[a]	75 MW	150 MW
Design fuel consumption[a]	20.4 m^3/hr (128.34 Bbls(oil)/hr)	40.5 m^3/hr (254.53 Bbls(oil)/hr)
Steam flow, kg/hr (coal)[b]	260,800	484,765
Steam pressure, newtons/m^2[b]	1.04×10^7 (1,500 psig)	1.29×10^7 (1,850 psig)
Steam temperature, °C[b]	538 (1000° F)	538 (1000° F)
Furnace volume, m^3[b]	1,319 (46,600 ft^3)	2,574 (90,885 ft^3)
Efficiency, % (pulverized coal)[b]	89.33	89.99
Flue gas flow rate (100% MCR)[a]	7,045 m^3/min (248,775 acfm)	12,805 m^3/min (452,187 acfm)
Exit gas temperature[a]	149° C (300° F)	135° C (275° F)
Flue gas cleaning equipment[a,c]	MCAX	E

a/ Information furnished by Delmarva Power and Light Company, December 30, 1975.
b/ Information taken from C-E Power Systems Study.[20]
c/ MCAX = multiple cyclones-conventional reverse flow with axial inlet;
E = electrostatic precipitator.

Table 15. DESIGN DATA FOR CYCLONE COLLECTOR/DELMARVA EDGEMOOR NO. 3[a/]

Manufacturer/Model No.--Western Precipitator/P37754A

Description--Multiple cyclones--conventional reverse flow; axial inlet

No. of sections
  (a) Series--1
  (b) Parallel--6

Tube arrangement--14 x 20.3 cm (8 in.)

Pressure drop--4.95 mm Hg (2.65 in H_2O)

Design efficiency--83% at 7,044.6 m^3/min and 149°C (248,775 acfm and 300°F)

a/ Source: D. B. McClenathan, Delmarva Power and Light Company (Ref. 51).

Table 16. CHARACTERISTICS OF ELECTROSTATIC PRECIPITATOR ON DELMARVA EDGEMOOR UNIT NO. 4[a/]

Plate area--2,274.3 m^2 (24,480 ft^2)

Plate-to-plate spacing
(a) Inlet--22.86 cm (9 in.)
(b) Outlet--22.86 cm (9 in.)

Corona wire diameter--0.28 cm (0.109 in.)

Specific collection area--182.6 $m^2/10^3\ m^3\text{-min}^{-1}$ (55.7 ft^2/1,000 acfm)

Migration velocity--14.92 cm/sec (29.4 ft/min)

Operating voltage--45 kv avg., 70 kv peak

Current density--70 nanoamps/cm^2[b/]

Electrical sets--two in parallel and two in series

Design efficiency--95.0% burning either coal or oil, with 2.7% sulfur coal, at approximately 150 MW, flue gas volume of 12,459.5 m^3/min (440,000 acfm) at 135°C (275°F)

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a/ Data from Ref. 51.
b/ Data from Appendix C, Figure C-3.

Nitrogen Oxides:

After Janaury 1, 1975, emissions from fuel-burning equipment in New Castle County rated 500 x 10^6 Btu/hr fuel input and greater will be limited to 0.2 (gas fuels) or 0.3 (other fuel) pound NO_x (calculated as NO_2)/10^6 Btu heat input.

However, NO_x laws do not apply to fuel-burning equipment when the heat produced in the equipment is used for some purpose other than steam production.

Estimated Performance of Air Pollution Control Equipment

Edgemoor Station No. 3--

The C-E Power Systems estimate for 10% MSW heat input is based on a collection efficiency of 70% with an inlet dust loading of 0.275 g/10^6 joules (0.64 lb/10^6 Btu).[50] This yields a net discharge rate of 0.0825 g/10^6 joules, which is nearly twice the New Source Performance Standard for Fossil Fuel-Fired Steam Generators, but within the Delaware emission regulation for fuel burning equipment. MRI estimates a net discharge rate of 0.0939 g/10^6 joules, which is only slightly higher than C-E, based on an efficiency of 70% and an inlet dust loading shown in Figure 11. At 5% MSW, MRI estimates a net discharge rate of 0.0564 g/10^6 joules, about 30% above the New Source Standard.

As discussed previously, there is not presently an adequate method for modeling the performance of the multicyclone collector. However, the design efficiency of 83% corrected for particle size (Table 6) yields an efficiency of 67.5% based on the fractional efficiency curve in Figure 7. This is within 10% of the C-E estimate.[20]

Edgemoor Station No. 4--

Estimated ESP performance for the unit on Edgemoor No. 4 is shown in Figure 15 as a function of flue gas volume. The estimate is based on the particle size for refuse (Table 6) and the fuel properties listed in Table 13. The ESP performance model is described in Appendix C.

On the basis of calculations made, the estimated range of emissions at 5% MSW is 0.034 to 0.077 g/10^6 joules, which is within the Delaware Emission Regulation for Fuel Burning Equipment. The predicted emissions for Edgemoor Station Boiler No. 4 are shown in Figure 16 as a function of percent MSW heat input and refuse fly ash fraction f_r at the MCR of 150 MW.

Cost of Air Pollution Control

On the basis of calculations made in this report, it is unlikely that particulate emissions when Delmarva Edgemoor Station No. 4 is burning No. 6

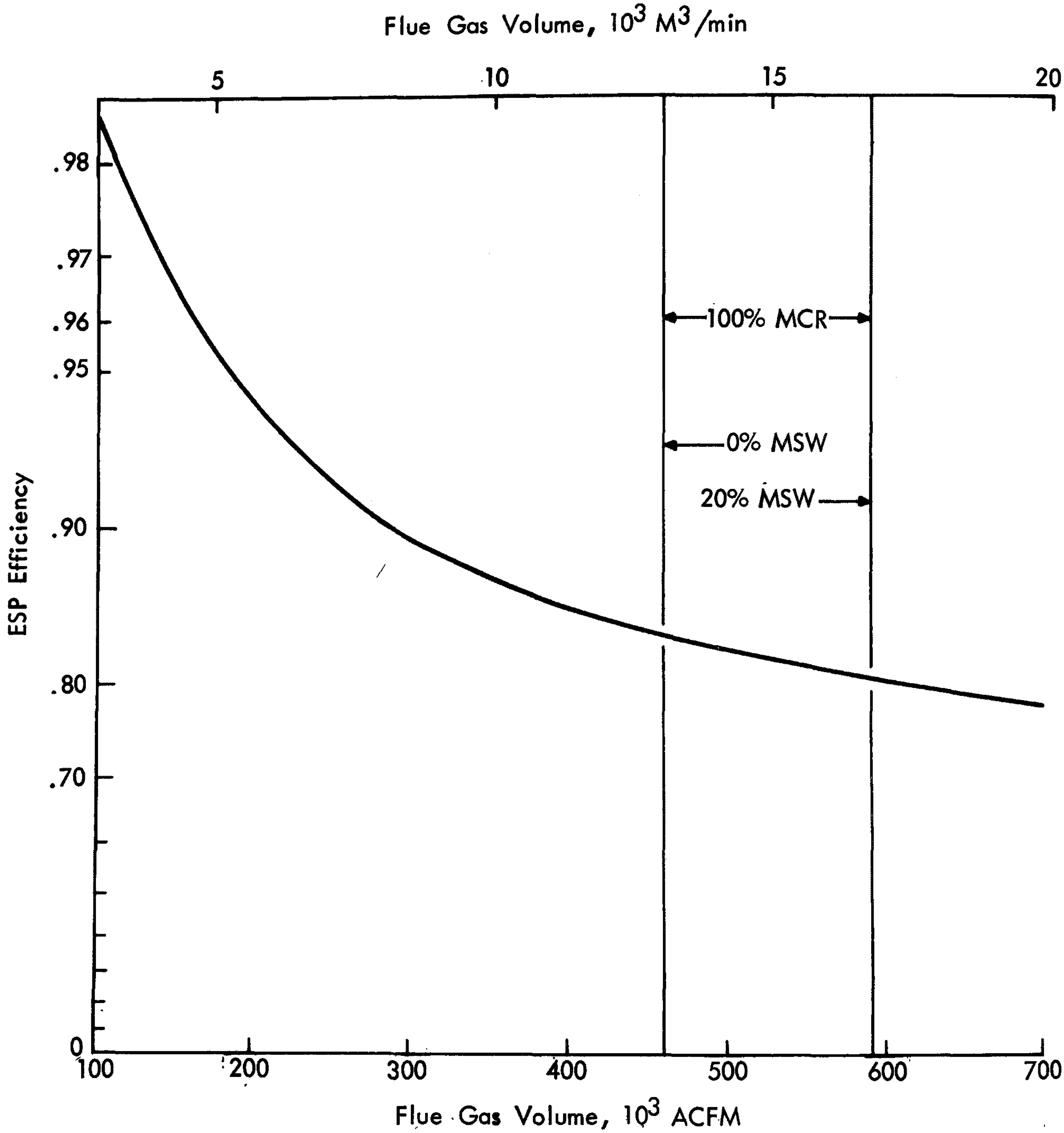

Figure 15. ESP efficiency (predicted) for combined firing of oil and MSW at Delmarva Edgemoor Station No. 4 (150 MW).

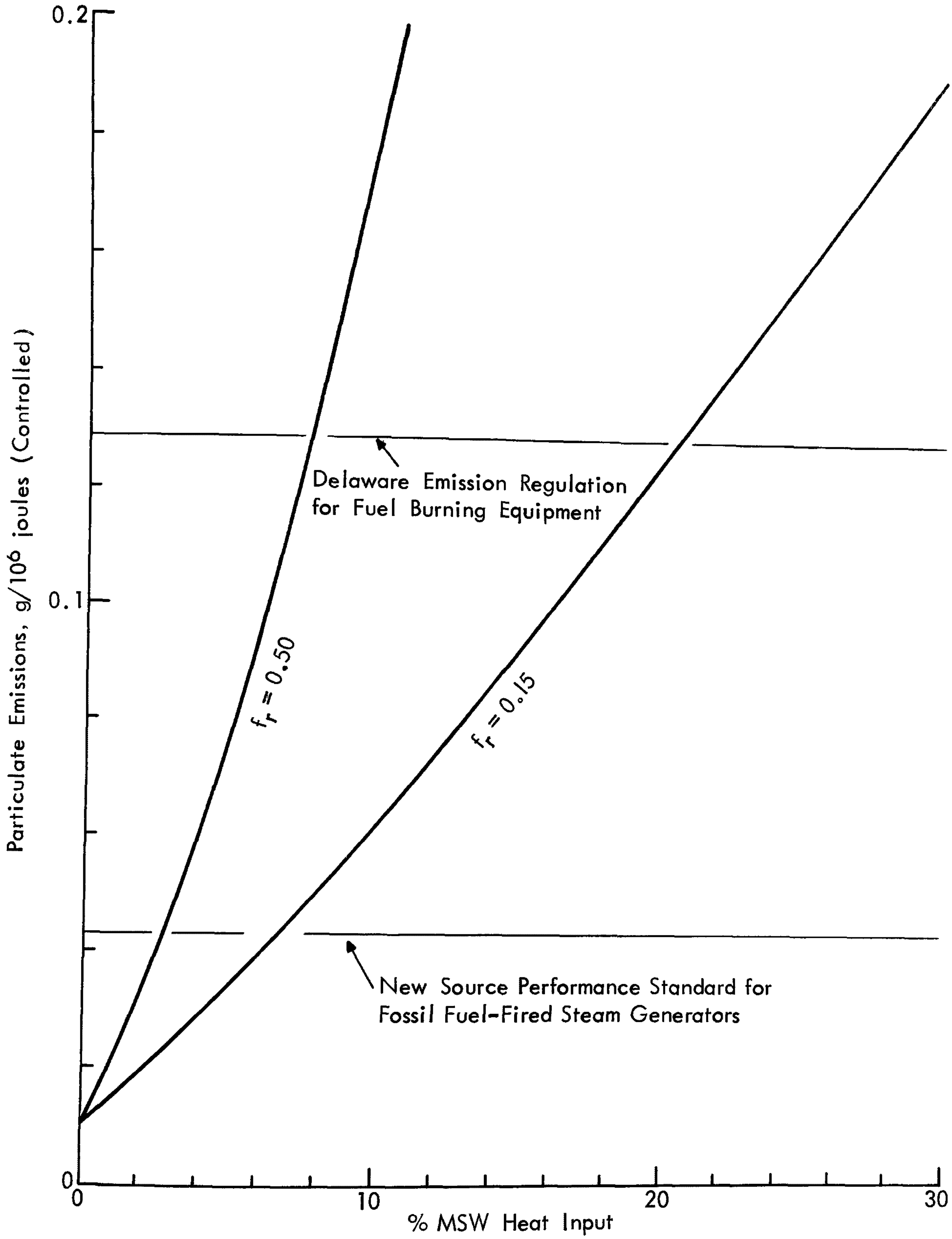

Figure 16. Estimated particulate emissions (controlled) for combined firing of oil and MSW at Delmarva Edgemoor Station No. 4.

residual oil and 5% MSW will exceed applicable Delaware standards. Therefore, no control modifications are indicated, provided MSW specifications are met.

Estimated emissions from Edgemoor No. 3 will probably exceed the Delaware standard of 0.129 g/10^6 joules (0.3 lb/10^6 Btu) at 5% MSW unless control modifications are made. The cost of such control modifications has not been determined.

NEW YORK CITY

On March 6, 1975, the City's Board of Estimate awarded a $340,000 feasibility and preliminary design contract for the firing of 1,000 tons/day of solid RDF with oil in the Consolidated Edison No. 20 boiler at Arthur Kill in Staten Island to Horner and Shifrin of St. Louis and Laramore, Douglass, and Popham Engineering Consultants of New York City. They will also devise an equitable formula for apportioning capital costs and determining the dollar value of refuse to Con Ed, which is also a party to the contract.53/

Originally the City assumed the cost of the contract. But a $50,000 federal grant was awarded for the project, signifying recognition of refuse derived energy in the Project Independence strategy. Con Ed purchases most of its oil from foreign sources. Firing of RDF in this pilot project will cut this dependence by approximately 1,400 barrels of oil per day.53/

A notable characteristic of this program is its size; Arthur Kill No. 20 has a net generating capacity of 325 MW and planned MSW heat input is 20%.54/ The Arthur Kill project will be the first of approximately 10 to 20 resource recovery projects in New York City.53/ A master plan, due in December 1975, will recommend a construction timetable for specific processes at specific sites.53/ Arthur Kill No. 30 (500 MW, tangentially fired) is also included in the master plan and will also fire MSW with No. 6 residual oil.6/

Project Status

The Arthur Kill No. 20 project feasibility study was originally due to be completed by Laramore, Douglass, and Popham Engineering Consultants (New York City) by September 1, 1975. New York City granted an extension for completion by December 1. The major difficulties apparently result from the inadequacies of existing air pollution control systems. The electrostatic precipitator installed on Arthur Kill No. 20 is not presently operational, and the electrostatic precipitator on Arthur Kill No. 30 has never met design specifications when firing No. 6 residual oil.55/

Refuse Fuel Preparation Facilities

Detailed plans for the refuse shredding system are not available at this time. A new installation will be built at an estimated cost of $12 million.[55]

Boiler System Descriptions

Arthur Kill No. 20 is a front-wall fired boiler designed by Foster Wheeler for a net generating capacity of 325 MW. This unit was originally designed for coal and was retrofitted to fire oil.[54] Modifications to fire MSW include additional burners for firing refuse and installation of a flue gas recirculation system.[54]

Arthur Kill No. 30 is a tangentially fired boiler designed by Combustion Engineering for a nominal capacity of 500+ MW.[6] This unit will also be converted for flue gas recirculation.

Installed Air Pollution Control Equipment

Both Arthur Kills Nos. 20 and 30 are presently equipped with Research-Cottrell ESP systems. However, the ESP on Arthur Kill No. 20 is not operational and the ESP on Arthur Kill No. 30 has not met design specifications when firing No. 6 oil.[55] There is no test data available for either unit when firing No. 6 oil.

New York City Particulate Air Emission Regulations

Total air emissions are rigidly controlled by a total allocation which regulates air emissions from a given piece of fuel burning equipment to present levels.[55] A proposed emission standard for particulate is 0.043 $g/10^6$ joules (0.1 $lb/10^6$ Btu) for fuel oil or refuse and fuel oil.[55]

Estimated Performance of Installed Air Pollution Controls

Since the ESP unit on Arthur Kill No. 20 is not presently in operating condition, the control efficiency is zero. New York City officials are apparently aware of deficiencies in existing control systems for both Arthur Kills Nos. 20 and 30. Because of the present early status of the Arthur Kill No. 30 project, estimation of control efficiency for combined firing is not considered justified until city officials decide on which control system will actually be used when oil and MSW are fired concurrently in either boiler.

Cost of Emission Control

Laramore, Douglass, and Popham Engineering Consultants, estimate the installed (erected) cost of a new ESP control system with 99% efficiency for

Arthur Kill No. 20 to be $12 million.[6] There is apparently some difficulty in getting the control manufacturer to guarantee efficiency for this application, however.[6] There is no cost estimate available for Arthur Kill No. 30.

STATE OF CONNECTICUT (Bridgeport)

The Connecticut Resource Recovery Authority (CRRA) is currently planning three resource recovery systems within the state. CRRA was formed following a study sponsored by the State of Connecticut Department of Environmental Protection. Funding is obtained both from the State and outside agencies.

Three programs presently planned include Bridgeport (United Illuminating Company, Bridgeport Harbor Stations Nos. 1 and 2), Central Connecticut (Devon Station), and South Central Connecticut.[56] The South Central Connecticut program will involve construction of boilers designed specifically for combined firing of refuse and oil.[56]

The Bridgeport project will be the first CRRA project undertaken. Original plans called for a pilot scale test, with oil and MSW fired in Bridgeport Harbor No. 1 (82 MW), for a period of about 2 months, followed by modification of Bridgeport Harbor No. 2 (160 MW) to fire refuse. The objective of the pilot scale test is to determine required modifications to the larger unit.

Notable aspects of these planned tests are that Bridgeport Harbor Nos. 1 and 2 are both pressurized, cyclone-fired boilers. If this type of system can be successfully used to burn refuse, flue gas dust loading can be reduced by about 50% of that for front-wall and tangentially-fired suspension boilers.

Project Status

Engineering feasibility studies have been completed by Gibbs and Hill and C-E Power Systems.[57] A contract was signed with Garrett Research Corporation (now Occidental Research) to supply the refuse fuel. Site preparation began in the fall of 1975. Construction was planned to begin in the spring of 1976.[57] Design changes are still being made.[57] Because of a recently formed joint venture between Occidental Petroleum and Combustion Equipment Associates,[58] there is some consideration being given to use of the CEA Ecco II process.[59]

The pilot scale oil-MSW combined firing test was originally planned to begin in January 1976,[56] but this test was recently delayed because of difficulties in locating a source of refuse fuel and difficulties in funding.[59] CRRA has recently applied for a $900,000 ERDA grant.[59]

Boiler System Descriptions

Bridgeport Harbor No. 1 is a pressurized, cyclone-fired boiler designed by Babcock and Wilcox for a net output of 82 MW. The unit has two cyclone burners.

Bridgeport Harbor No. 2 is a pressurized, cyclone-fired boiler designed by Babcock and Wilcox for a net output of 170 MW, of similar design to Bridgeport No. 1, except with five cyclone burners.

Refuse Preparation Facilities

The design of the refuse preparation facility has not yet been finalized.

Installed Air Pollution Control Equipment

Both Bridgeport Harbors Nos. 1 and 2 are equipped with electrostatic precipitators designed by Research-Cottrell.

Connecticut Air Emission Regulations

Administering Agency:

Department of Environmental Protection
State Office Building
Hartford, Connecticut 06115

Existing and new fuel burning equipment must comply with the following regulations

Particulates:

Emissions are restricted to 0.1 $lb/10^6$ Btu heat input. The heat-input value is the equipment manufacturer or designer's guaranteed maximum input, whichever is greater.

Sulfur Oxides:

Fuels are restricted to a maximum sulfur content of 0.5% by weight (dry basis). Under fuel-shortage conditions, variances can be obtained for burning higher sulfur fuels on a temporary basis. High sulfur fuels also can be burned if state-approved stack-gas cleaning equipment is capable of limiting total sulfur-compound emissions to the ambient air to 0.55 lb SO_2 (equivalent)/10^6 Btu gross heat input, and if waste discharges from the stack gas cleaning system into State waters are approved by State authorities.

Nitrogen oxides:

Emissions from fuel burning equipment rated above 250 x 10^6 Btu/hr heat input are limited to 0.2 (gas), 0.3 (oil), or 0.7 (coal) pound NO_x (expressed as NO_2)/10^6 Btu heat input.

Estimated Performance of Air Pollution Control Equipment

The Connecticut Resource Recovery Authority is not optimistic about the performance of ESP units on either boiler. As with most units designed for coal, the efficiency is expected to drop to 60 to 70% for oil, 70 to 85% for oil plus refuse, depending on refuse composition and MSW heat input.

Cost of Emission Control

Because the test program is not yet final, and refuse fuel characteristics and heat input are not known, it is not possible to make significant estimates of emissions at this time. However, we do know that CRRA and United Illuminating Company are not presently planning replacement or modification of either ESP unit. At 70% efficiency, particulate emissions could well be as high as 0.052 g/10^6 joules (0.121 lb/10^6 Btu), at 10% MSW heat input, even allowing for a 50% reduction in fly ash because of cyclone burner characteristics. This would exceed state regulations of 0.043 g/10^6 joules (0.1 lb/10^6 Btu) applicable to new and existing fuel burning equipment.

SECTION 6

RECOMMENDATIONS

Since the present study has emphasized the application of existing air pollution control methodology for particulate air pollutants from power boilers firing municipal solid wastes and auxiliary fuel oil, it seems appropriate to point out some deficiencies in the control technology, as applied to this aspect of resource recovery. An attempt should be made to resolve these difficulties in future studies. Difficulties encountered in the present study are discussed according to the general types of control systems considered.

ELECTROSTATIC PRECIPITATOR CONTROL

In adopting existing theoretical studies to the development of a practical performance model to predict ESP performance for combined firing applications, there was found to be no quantitative information on the effects of:

1. Fly ash density;

2. Re-entrainment; and

3. Sneakage or bypassing.

This is somewhat surprising, in consideration of the influence of these effects both on equipment cost and collection efficiency. For example, one source recommended a reduction in flow velocity directly proportional to a decrease in fly ash density.[22] Referring to Figure 8, this would increase installed cost of a new ESP unit in approximately the same proportion as the decrease in flow velocity. There are sufficient data on the resistivity of oil ash and refuse fly ash, both of which are relatively high in carbon compared to coal fly ash, to conclude that a significant proportion of the ash will be low in resistivity compared to the average. In other words, there is probably a much larger resistivity range for oil and/or refuse firing than for a given coal. The low resistivity fraction is comprised primarily of carbon. Such low resistivity particulate tends to lose its charge easily on contact with the collection electrode, and be re-entrained. In the case of oil ash, a modification of the shape of the collecting electrodes is recommended to prevent re-entrainment. However, there is no method available to quantatively relate the fraction re-entrained with ash properties (resistivity, shape, and density) and system parameters (velocity and electrode geometry). There has been some work done on bypassing, or sneakage, but this effect has not yet been quantitatively defined in terms of system variables.

What is needed is an order-of-magnitude analysis of the effects of fly ash density, re-entrainment, and bypassing based on both approximate analysis and a survey of available data including contacts with equipment manufacturing firms. None of the above effects were included in the model used to estimate ESP performance in the present study. This is not too important in terms of the present objectives, since these effects result in a control performance which is lower than predicted. However, in consideration of the preceding discussion, it is perhaps not too surprising that one source[6/] who attempted to acquire cost and performance information for a new ESP unit for combined oil-MSW firing was unable to obtain a performance guarantee.

CYCLONE CONTROL

Because of the relatively low cost of cyclone control, this type of system would seem to be useful, in conjunction with ESP control, to collect low density, weakly charged particulate <u>if placed after the ESP</u>. The function of the cyclone used in this fashion would be to collect the coarse fraction of ESP re-entrainment losses. There is at least one such intallation on an oil-fired boiler.[4/]

The theoretical prediction of cyclone pressure drop and collection efficiency still is not possible because of complexities of flow fields. Other factors, such as the tendency of cyclone collectors to plug when in service on oil ash, and the performance decline in the corrosive atmosphere of incineration flue gases, need to be examined.

As in the case of ESP control, there needs to be additional work done on this type of control system specific to the application of combined fossil fuel-MSW combustion. This would include contacts with vendors, literature review, and analysis beyond the scope of the present study to develop guidelines for use in combined firing applications.

SCRUBBER CONTROL

High performance scrubbers and possibly wet electrostatic precipitators have utility for collection of particulates, gaseous pollutants (SO_x, NO_x, and others) and potentially hazardous trace metals. There were no scrubber or wet ESP units installed on the boilers evaluated in the present study.

However, there is at least one high performance Chemico Arotec scrubber planned for installation at Nashville.36/ The manufacturer was contacted regarding the feasibility of using scrubbers for emission control on boilers where MSW and fossil fuels are being fired. At the time the contact was made, Chemico was very cautious about this application, saying that some reports based on pilot plant data may have been premature. There is a general reluctance on the part of the gas cleaning industry to recommend scrubbers for service on incinerator flue gases. The problem, as in cyclone control, is with corrosivity. One other equipment vendor was contacted regarding the possible application of wet electrostatic precipitators for combined MSW-fossil fuel firing. The manufacturer was optimistic regarding this application, but cost and design data have not been received.

Both wet scrubbers and a wet ESP unit have recently been evaluated on a pilot plant scale as part of the evaluation of EPA's "Landgard" Demonstration Project in Baltimore, Maryland. The Landgard system is a pyrolysis reactor which fires approximately 7.1 gal. of No. 2 fuel oil per ton of MSW. Maryland particulate emission regulations for this facility are 0.013 g/Nm^3 (0.03 gr/dscf). Particulate emissions measured in shakedown runs in the spring of 1975 reportedly were in the vicinity of 0.069 g/Nm^3 (0.2 gr/dscf).60/ In the summer of 1975, two Teller Crossflow Nucleating scrubbers were evaluated adiabatically and in condensing modes. These systems could not achieve state standards but could achieve the federal standards of 0.18 g/Nm^3 (0.08 gr/dscf).60/ A Micropuls wet ESP test could meet the state code; however, tests were not conclusive.60/ An expanded control evaluation program is now planned which will include several other control systems.60/

Because of the increasing public awareness of problems resulting from gaseous and trace metal pollutants, an in-depth study of these control methods appears justified.

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APPENDIX A

PARTICULATE EMISSIONS FROM OIL-FIRED ELECTRIC UTILITY BOILERS

PARTICULATE EMISSIONS FROM OIL-FIRED BOILERS

Boiler Identification	Description	% Load	% Excess air	Particulate loading ($g/10^6$ joules) Inlet	Outlet	Control method[a]	Reference
Undisclosed	C-E tangentially fired, 250 MW	100[b]	15.8	-	0.0085	ESP	61
		84[b]	15.5	-	0.0076		
		64[b]	20.8	-	0.0061		
		52[b]	27.3	-	0.0052		
		44[b]	38.2	-	0.0210		
Franklin Station, Rochester, Minn.	C-E Type VP-14-W	100	15.4	0.1033	0.0133	M	62
		100[b]	18.5	0.1256	0.0172		
		100[b]	24.0	0.2327	0.0331		
Boston Ed., Mystic No. 6	C-E tangentially fired, 156 MW	94	-	0.1015	0.0310	V	37
		92	-	0.0727	0.0361		
		97	-	0.1269	0.0478		
		95	-	0.0538	0.0293		
Boston Ed., Mystic No. 6	C-E tangentially fired, 156 MW	80	-	0.4010[c]	0.0501[c]	V	38
		80	-	0.7622[c]	0.0752[c]		
		80	-	0.8676[c]	0.0633[c]		
		51	-	0.6752[c]	0.0482[c]		
		51	-	0.4115[c]	0.0418[c]		
Hartford Elect., Middletown No. 3	B and W 5 cyclone universal pressure unit, 240 MW	100[b,d]	-	0.0820[c]	0.0104[c]	ESP	63
		100[b]	-	0.0361[c]	0.0127[c]		
		67[b]	-	0.0293[c]	0.0086[c]		
Boston Ed., Mystic No. 3[e]		-[b]	-	0.0784	0.0486	ESP	4 (Table 2)
		-	-	0.15	0.0645		
		-[b]	-	0.0490	0.0142		
		-	-	0.0965	0.0637		
		-[b]	-	-	0.1050		
		-[b]	-	-	0.0663		
		-	-	-	0.0663		

Boiler Identification	Description	% Load	% Excess air	Particulate loading (g/10^6 joules) Inlet	Outlet	Control method[a]	Reference
Consolidated Edison, Ravenswood No. 30[d]		-	-	0.0087	0.0073	ESP	4 (Table 2)
Consolidated Ed. Astoria, No. 50[d]		-	-	0.0070	0.0034	ESP	4 (Table 2)
		-	-	0.0095	0.0052		
No. 40[d]		-	-	0.010	0.0052	ESP	4 (Table 2)
No. 30[d]		-	-	0.011	0.0052	ESP	4 (Table 2)
L. I. Lighting Company Northport, Suffolk County Unit No. 3	375 MW	98.1	11	-	0.0044	ESP	64
		98.1	11	-	0.0049[d]		
		98.1	11	-	0.0150[d]		
		98.1	11	-	0.0085[d]		
		96.8	8.7	-	0.0057		
		96.8	8.5	-	0.0042		
L. I. Lighting Company Port Jefferson, Suffolk County Unit No. 3	C-E type RR1564[e]	-	31.1	-	0.0116	ESP	64
		-	33.6	-	0.0120		
		-	30.4	-	0.0125		
L. I. Lighting Company Barrett Station No. 2 Island Park, Nassau County	C-E tangentially fired boiler	-	42.7	-	0.0198	M	64
		-	41.5	-	0.0261		
		-	41.6	-	0.0207		
		-	39.7	-	0.0197		

Boiler Identification	Description	% Load	% Excess air	Particulate loading (g/10^6 joules) Inlet	Outlet	Control method[a]	Reference
Niagara Mohawk Power Corporation Albany Steam Station, Glenmont, New York	G-E tangentially fired boiler					M	64
No. 1[b] (1974 test series)	↓	-	-	-	0.0619 0.0821[d]	↓	↓
No. 2[b] (1974 test series)	↓	-	-	-	0.0576 0.0791[d]	↓	↓
No. 3[b] (1974 test series)	↓	-	-	-	0.0662 0.0765[d]	↓	↓
No. 4[b] (1974 test series)	↓	-	-	-	0.0464 0.0692[d]	↓	↓
No. 1[b] (1973 test series)	↓	-	-	-	0.0367	↓	↓
No. 2[b] (1973 test series)	↓	-	-	-	0.0367	↓	↓
No. 3[b] (1973 test series)	↓	-	-	-	0.0411	↓	↓
No. 4[b] (1973 test series)	↓	-	-	-	0.0355	↓	↓
Boston Edison Company New Boston Station, Unit No. 1		87	31.9	-	0.0103[d]	Unknown[g]	65
Boston Edison Company Edgar Station, No. 10		96 95	104 128	- -	0.0318 0.0460[d]	Unknown[g]	65

Boiler Identification	Description	% Load	% Excess air	Particulate loading (g/10^6 joules) Inlet	Outlet	Control method[a]	Reference
Boston Edison, Edgar Station, Unit No. 9		95	112	-	0.0219	Unknown[g]	65
		95	122	-	0.0275[d]		
Boston Edison Company L-Street, Unit No. 76		96	304	-	0.0189[d]	Unknown[g]	65
Boston Edison Company Kneeland Street, Unit No. 2		96	181	-	0.0241	Unknown[g]	65
		98	206	-	0.0813[d]		
Boston Edison Company Mystic Station, Unit No. 5		87	75	-	0.0529	Unknown[g]	65
		85	77	-	0.0641[d]		
Undisclosed[b,e]		-	-	-	0.0585	ESP	4 (Table 2)
		-	-	-	0.0641		
		-	-	-	0.0370		
		-	-	-	0.0568		
		-	-	-	0.0404		
		-	-	-	0.0809		
		-	-	-	0.0559		
		-	-	-	0.0568		
		-	-	-	0.0336		
		-	-	-	0.0426		
		-	-	-	0.0757		
		-	-	-	0.0805		
		-	-	-	0.0676		
		-	-	-	0.0688		
		-	-	-	0.0318		
		-	-	-	0.0611		
		-	-	-	0.0645		
		-	-	-	0.0417		
		-	-	-	0.0602		
		-	-	-	0.0413		
		-	-	-	0.0426		

Boiler Identification	Description	% Load	% Excess air	Particulate loading (g/10^6 joules) Inlet	Outlet	Control method[a]	Reference
Undisclosed[c]		-	-	-	0.0090	ESP	4 (Table 2)
Undisclosed		-	-	-	0.0275	C	4 (Table 2)
		-	-	-	0.0288		
Hartford Elect., Middletown No. 2[b]		-	-	-	0.0301	ESP	4
		-	-	-	0.0245		
		-	-	-	0.0288		
Undisclosed[b,e]		-	-	0.0965	0.0357	ESP+C	4 (Table 2)
		-	-	0.0954	0.0267		
		-	-	0.1507	0.0211		
Undisclosed		-	-	0.0650[b]	0.0065	ESP[f]	4 (Table 2)
		-	-	0.0352[b]	0.0095		
		-	-	-	0.0043		
		-	-	-	0.0047		
		-	-	-	0.0151		
		-	-	-	0.0086		
		-	-	-	0.0056		
		-	-	-	0.0043		
Undisclosed[b]		-	-	0.0489	0.0396	C	4 (Table 2)
		-	-	0.0393	0.0366		
		-	-	0.0623	0.0181		
		-	-	0.0522	0.0146		
		-	-	-	0.0207		
		-	-	-	0.0198		
		-	-	-	0.0224		
		-	-	-	0.0344		

Boiler Identification	Description	% Load	% Excess air	Particulate loading ($g/10^6$ joules) Inlet	Outlet	Control method[a]	Reference
Undisclosed		-	-	-	0.0026	ESP	4 (Table 2)
		-	-	-	0.0013		
		-	-	-	0.0026		
		-	-	-	0.0026		
Boston Edison L. Street, No. 68		-	-	0.0168	0.0168	None	4 (Table 12)
No. 74		-	-	0.0827	0.0827	None	4 (Table 12)
No. 75		-	-	0.0290	0.0290	None	4 (Table 12)
		-	-	0.0665	0.0665		
No. 76		-	-	0.0654	0.0654	None	4 (Table 12)
Boston Edison N. Boston, No. 1		-	-	0.0228	0.0228	None	4 (Table 12)
		-	-	0.0281	0.0281		
No. 2		-	-	0.0137	0.0137	None	4 (Table 12)
		-	-	0.0133	0.0133		
Boston Edison Kneeland Street, No. 1		-	-	0.0258	0.0258	None	4 (Table 12)
No. 2		-	-	0.0211	0.0211	None	4 (Table 12)
No. 4		-	-	0.0055	0.0055	None	4 (Table 12)
		-	-	0.0166	0.0166		
		-	-	0.0052	0.0052		

Boiler Identification	Description	% Load	% Excess air	Particulate loading ($g/10^6$ joules)		Control method[a]	Reference
				Inlet	Outlet		
Boston Edison Minot Street, No. 6		-	-	0.0094	0.0094	None	4 (Table 12)
No. 7		-	-	0.0110	0.0110	None	4 (Table 12)
		-	-	0.0258	0.0258		
Boston Edison No. 9 Edgar Station		-	-	0.0564	0.0564	None	4 (Table 12)
		-	-	0.0585	0.0585		
		-	-	0.0254	0.0254		
		-	-	0.0416	0.0416		
		-	-	0.0375	0.0375		
		-	-	0.0355	0.0355		
		-	-	0.0400	0.0400		
		-	-	0.0331	0.0331		
		-	-	0.0272	0.0272		
		-	-	0.0185	0.0185		
		-	-	0.0222	0.0222		
		-	-	0.0223	0.0223		
		-	-	0.0238	0.0238		
No. 10		-	-	0.0217	0.0217	None	4 (Table 12)
		-	-	0.0495	0.0495		
		-	-	0.0204	0.0204		
		-	-	0.0170	0.0170		
		-	-	0.0293	0.0293		
		-	-	0.0356	0.0356		
		-	-	0.0290	0.0290		
		-	-	0.0244	0.0244		
		-	-	0.0336	0.0336		
		-	-	0.0296	0.0296		
		-	-	0.0244	0.0244		
		-	-	0.0302	0.0302		
		-	-	0.0176	0.0176		
		-	-	0.0271	0.0271		
		-	-	0.0213	0.0213		

Boiler Identification	Description	% Load	% Excess air	Particulate loading ($g/10^6$ joules) Inlet	Outlet	Control method[a]	Reference
No. 11		-	-	0.1149	0.1149	None	4 (Table 12)
		-	-	0.0478	0.0478		
		-	-	0.0430	0.0430		
		-	-	0.0209	0.0209		
Boston Edison Company Mystic Station No. 3		-	-	0.0719	0.0719	None	4 (Table 12)
		-	-	0.1050	0.1050		
		-	-	0.0200	0.0200		
		-	-	0.0455	0.0455		
		-	-	0.1484	0.1484[b]		4 (Table 13)
		-	-	0.1024	0.1024[b]		
		-	-	0.0784	0.0784[b]		
		-	-	0.0490	0.0490[b]		
No. 5		-	-	0.0113	0.0113	None	4 (Table 12)
		-	-	0.0402	0.0402		
		-	-	0.0278	0.0278		
		-	-	0.0175	0.0175		
		-	-	0.0527	0.0527		
Boston Edison Company Mystic No. 6		-	-	0.0564	0.0564	None	4 (Table 12) (Table 13)
		-	-	0.0456	0.0456		
		-	-	0.1196	0.1196[b]		
		-	-	0.0739	0.0739[b]		
		-	-	0.1213	0.1213[b]		
		-	-	0.0468	0.0468[b]		
Braintree Elect. Potter Station No. 1		-	-	0.0234	0.0234[b]	None	4 (Table 13)
		-	-	0.0321	0.0321[b]		
		-	-	0.0306	0.0306[b]		
No. 2		-	-	0.0988	0.0988[b]	None	4 (Table 13)
		-	-	0.0398	0.0398[b]		
		-	-	0.0524	0.0524[b]		

Boiler Identification	Description	% Load	% Excess air	Particulate loading ($g/10^6$ joules) Inlet	Outlet	Control method[a]	Reference
No. 4		-	-	0.0434	0.0434[b]	None	4
		-	-	0.0565	0.0565[b]		(Table 13)
		-	-	0.0608	0.0608[b]		

a/ ESP = electrostatic precipitator, C = cyclone, M = multicyclone, V = venturi scrubber.

b/ Fuel Additives: First Test Series (Undisclosed Boiler), MgO in liquid carrier used to control SO_4 emissions and maintain a soft tube scale. Fuel-to-additive ratio was 2,300:1. Franklin Station, Calgon Velvamag (No. 2 fuel oil containing 8.6 lb MgO/gal.). One gallon (14.3 lb/gal) used per 4,000 gal. No. 6 oil). Middleton No. 3, CH-22 Fuel Oil Additive (additives not specified for other tests).

c/ Grain loading in grams per million joules recalculated from values reported in gr/scf assuming a ratio of 9,917 million joules/MW-Hr (9.40 million Btu/MW-Hr).

d/ Test measurements made during soot blowing.

e/ Boiler originally designed for coal; retrofitted to fire oil.

f/ Control system designed for oil.

g/ Control system not described.

APPENDIX B

PARTICULATE EMISSIONS DATA FOR WATERWALL INCINERATORS

HARRISBURG MUNICIPAL INCINERATOR
(tests made May 1973)[31]

	Unit No. 1							
Test No.	11	12	13	14	15	16	17	18
Refuse								
metric tons/hr[a]	15.69	15.69	15.88	15.88	14.61	14.61	12.97	12.97
% ash[a,b]	58.0	58.0	54.2	54.2	54.2	54.2	35.9	35.9
HHV, joules/kg x 10^6 [a,b]	8.70	8.70	9.30	9.30	9.30	9.30	15.10	15.10
% moisture[a,b]	26.7	26.7	25.1	25.1	25.1	25.1	15.30	15.30
Auxiliary fuel, kg/hr	-	-	-	-	-	-	-	-
Steam, 10^3 kg/hr	37.10	37.10	48.94	48.94	40.87	40.87	51.71	51.71
Fly ash, kg/hr								
ESP inlet	259.91	339.11	172.50	183.75	308.04	240.63	265.67	-
ESP outlet	5.40	8.16	7.30	10.07	5.67	7.98	14.11	-
% control efficiency	97.68	97.59	95.77	94.52	98.16	96.68	94.69	-
Residue, metric tons/hr[a,c]	3.29	3.29	4.28	4.28	3.59	3.59	3.48	3.48
Ratio: fly ash/residue[c]	0.079	0.103	0.040	0.043	0.086	0.067	0.076	-
Excess air, %	153.8	94.8	93.0	71.5	71.5	73.0	76.2	-
Flue gas temp., °C[d]	225.0	225.0	207.8	207.8	203.9	203.9	227.8	227.8
Fly ash								
kg/metric ton[f]	16.57	21.61	10.86	11.57	21.00	16.47	20.48	-
g/10^6 joules[f]	1.90	2.42	1.17	1.24	2.26	1.77	1.37	-

HARRISBURG MUNICIPAL INCINERATOR
(tests made May 1973)[31]

Test No.	Unit No. 2 1	2	3	4	5	6	7	8
Refuse								
metric tons/hr[a]	13.88	13.88	14.06	14.06	14.70	14.70	11.97	11.97
% ash[a,b]	58.0	58.0	54.2	54.2	54.2	54.2	35.9	35.9
HHV, joules/kg x 10^6[a,b]	8.70	8.70	9.30	9.30	9.30	9.30	15.10	15.10
% moisture[a,b]	26.7	26.7	25.1	25.1	25.1	25.1	15.30	15.30
Auxiliary fuel, kg/hr	-	-	-	-	-	-	-	-
Steam, 10^3 kg/hr	38.42	38.42	48.63	48.63	44.82	44.82	49.62	49.62
Fly ash, kg/hr								
ESP inlet	203.12	170.28	200.81	252.88	195.77	288.40	174.09	185.43
ESP outlet	9.12	8.62	10.84	10.25	8.66	10.16	10.80	12.70
% control efficiency	95.51	94.94	94.60	95.95	95.58	96.48	93.80	93.15
Residue, metric tons/hr[a,c]	2.29	2.29	3.16	3.16	4.33	4.33	2.51	2.51
Ratio: fly ash/residue[c]	0.089	0.074	0.064	0.080	0.045	0.067	0.069	0.074
Excess air, %	52.3	131.1	109.8	83.5	74.2	74.5	119.5	87.0
Flue gas temp., °C[d]	221.7	221.7	209.4	209.4	225.0	225.0	235.6	235.6
Fly ash								
kg/metric ton[f]	14.63	12.27	14.28	17.99	13.28	19.62	14.54	15.49
g/10^6 joules[f]	1.69	1.41	1.54	1.93	1.43	2.11	0.95	1.03

CHICAGO NORTHWEST INCINERATOR TESTS MAY 1971[66]

Test No.	PE-X	PE-1	PE-2/PD-2	PE-3/PD-3	PE-4/PD-4
Refuse					
metric tons/hr	-	-	-	-	-
% ash	-	-	-	-	-
HHV, 10^6 joules/kg	-	-	-	-	-
% moisture	-	-	-	-	-
Auxiliary fuel, kg/hr	-	-	-	-	-
Steam, 10^9 joules/hr	-	-	-	-	-
Fly ash, kg/hr					
ESP inlet	-	-	92.99	226.80	215.46
ESP outlet	-	-	10.61	8.21	7.03
% efficiency	-	-	88.6	96.4	96.7
Residue, metric tons/hr	-	-	-	-	-
Ratio: fly ash/residue	-	-	-	-	-
Excess air, %	136	136	130	78.1	78.1
Flue gas temp., °C	252.2	225.6	179.4	181.1	180.0
Fly ash					
kg/metric ton[f]	-	-	-	-	-
g/10^6 joules[f]	-	-	-	-	-

STUTTGART (W. GERMANY) WATERWALL INCINERATOR[27]

	Stuttgart Unit 28		Stuttgart Unit 29	
Test No.	4	5	4	5
Refuse				
metric tons/hr	24.10	21.04	22.33	21.54
% ash	25.9	28.5	31.3	30.6
% moisture	30.5	41.0	38.4	37.6
HHV, 10^6 joules/kg[e]	7.624	6.780	6.836	6.918
Auxiliary fuel, kg/hr (oil)	5,484	2,951	6,108	2,774
Steam, 10^9 joules/hr	342.1	209.1	331.9	203.3
Fly ash, kg/hr				
ESP inlet	532.1	294.4	681.3	686.8
ESP outlet	-	-	-	-
% efficiency	-	-	-	-
Residue, metric tons/hr[c]	5.10	4.98	5.49	5.18
Ratio: fly ash/residue	0.104	0.059	0.124	0.133
Excess air, %	25.5	40.9	30.3	53.0
Flue gas temp., °C	190.6	190.6	183.3	182.2
Fly ash				
kg/metric ton[f]	22.08	13.99	30.51	31.88
j/10^6 joules[f]	2.90	2.06	4.46	4.61

DÜSSELDORF (W. GERMANY) WATERWALL INCINERATOR AND MUNICH (W. GERMANY) WATERWALL INCINERATOR[27]

Test No.	Düsseldorf 1	Munich North I 6	Munich North II 4
Refuse			
metric tons/hr	10.52	26.10	45.50
% ash	33.7	30.0	36.8
% moisture	32.4	44.4	28.0
HHV, 10^6 joules/kg[e]	7.227	6.413	7.501
Auxiliary fuel, kg/hr	0.0	0.0	0.0
Steam, 10^9 joules/hr	42.7	97.1	246.4
Fly ash, kg/hr			
ESP inlet	499.0	1,613.9	648.2
ESP outlet	-	-	-
% efficiency	-	-	-
Residue, metric tons/hr[c]	2.76	8.67	13.61
Ratio: fly ash/residue	0.181	0.186	0.048
Excess air, %	112.0	131.3	44.5
Flue gas temp., °C	235.0	157.2	164.4
Fly ash			
kg/metric ton[f]	47.43	61.84	14.25
g/10^6 joules[f]	6.56	9.64	1.90

a/ Based on daily average (composite) measurements.
b/ Average values for low, medium, and high Btu runs.
c/ Excluding metals in residue.
d/ Measured at ESP inlet.
e/ Recalculated from lower heating value of refuse fuel.
f/ Based on refuse portion of fuel.

APPENDIX C

ELECTROSTATIC PRECIPITATOR PERFORMANCE MODEL

Concurrent firing of oil and MSW will cause departures from ESP operating parameters which apply to firing oil alone. The ESP model is used to calculate the magnitude of resulting changes in performance.

As discussed previously, the most significant departures anticipated when refuse is fired concurrently with oil are in flue gas volume, moisture and composition, particulate density, size distribution, resistivity, fusion temperature, and dust loading. The calculation of resulting ESP performance, as described below, is based on the simplifying assumptions that:

1. The electric field is unaffected by the changes in particulate properties.

It is well known that the introduction of a significant number of fine dust particles into an electrostatic precipitator significantly influences the voltage-current characteristics of the interelectrode space. Qualitatively, the effect is seen by a decrease current for a given voltage compared to a dust-free situation.[67] If the dust loading increases as expected for combined oil-MSW firing, this approximation will yield a higher limit value for the corona current, and therefore an upper limit value for collection efficiency.

2. Charging time is negligible.

This is the assumption (implicitly made) when the saturation charge is used to describe the instantaneous charge on each particle. Order-of-magnitude calculations indicate that a particle residence time of less than 1 sec is required to achieve 90% of saturation for a 0.18 μm particle. For larger particles, the required residence time to achieve charge saturation will decrease.[67] Therefore, this approximation will yield an upper limit to the calculated collection efficiency.

3. Precipitator performance is not current-limited.

It is felt that this will be a reasonable assumption for gas volume and dust loadings expected.

4. The Deutsch-Anderson equation is applicable in integral form for a discrete particle size range.

This is the usual approximation which is made when this equation is used to describe the average performance of an electrostatic precipitator in design applications.

In addition to the approximation described, several nonideal effects which are known to exist in full-scale electrostatic precipitators are not dealt with explicitly in the present model.

The factors of major importance are:

1. Gas velocity distribution,

2. Gas sneakage, and

3. Rapping reentrainment.

These departures from ideality will reduce the collection efficiency that may be achieved for a precipitator operating with a given specific collecting area.[67]

In the application of the model to actual conditions for combined firing, the particle size distribution, resistivity, dielectric constant, flue gas volume, precipitator design specifications, and at least one set of performance data must be known or estimated as summarized in Table C-1. The test data need not correspond to conditions for combined firing. A computerized model, recently developed by Southern Research Institute under EPA sponsorship, was used as the basis of the analytical model.[67] Electric field calculations are omitted, and a system-dependent parameter is calculated instead from known performance data. This is a one-parameter "fit" in which effective migration velocities are determined for each particle size range and particle resistivity under a fixed set of design or test conditions. This step was done using trial-and-error, or iterative procedures. A block diagram illustrating the computational procedure is shown in Figure C-1. The computation procedure is divided into two parts. Initially, precipitator design or sizing data and at least one set of performance data are used to determine the distribution of migration velocities for the known performance data over the range of particle sizes. In the second calculation stage, migration velocities are adjusted for changes in flue gas temperature and viscosity, particulate resistivity and relative dielectric constant, operating current and voltage. ESP performance is then determined for anticipated combined-firing test conditions. The computation procedure is described in detail in the remainder of this section.

1. Determine migration velocities for each particle size based on known performance data.

Step 1 - Calculate the saturation charge on the median diameter particle within the j^{th} discrete particle size range, based on performance data. A "modified" saturation charge expression, developed by Southern Research Institute[67] is used:

$$q_s'(j) = 4\pi\mathcal{E}_o(R(j) + \lambda m)^2(1.2E_o)\left(1 + 2\,\frac{K - 1}{K + 2}\,\frac{R(j)^3}{(R(j) + \lambda m)^3)}\right) \qquad \text{(C-1)}$$

Table C-1. DATA INVENTORY FOR ELECTROSTATIC PRECIPITATOR PERFORMANCE MODEL

- Precipitator design data

  Plate area
  Plate-to-plate spacing, inlet
  Plate-to-plate spacing, outlet
  Length of electrical sections
  Corona wire diameter
  Number of Series electrical sections
  Number of Parallel electrical sections

- Performance data

  Average efficiency
  Flue gas volume
  Flue gas temperature and composition
  Precipitation rate parameter
  Operating voltage
  Current versus resistivity curve (if known)[a/]
  Voltage versus current curve (if known)[b/]
  Particle size distribution (if known)
  Particle resistivity

- Test Conditions

  Percent MSW on a Btu basis
  MSW composition, ash, and moisture
  MSW heating value
  Oil composition, ash, and moisture
  Oil heating value
  Percent excess air
  Boiler efficiency curve (if known)

---

a/ A conservative estimate of the allowable current density as a function of resistivity is given in Figure C-2.

b/ A reasonable approximation of the average electrical conditions in the precipitator is given in Figure C-3 by the curves labeled "typical."

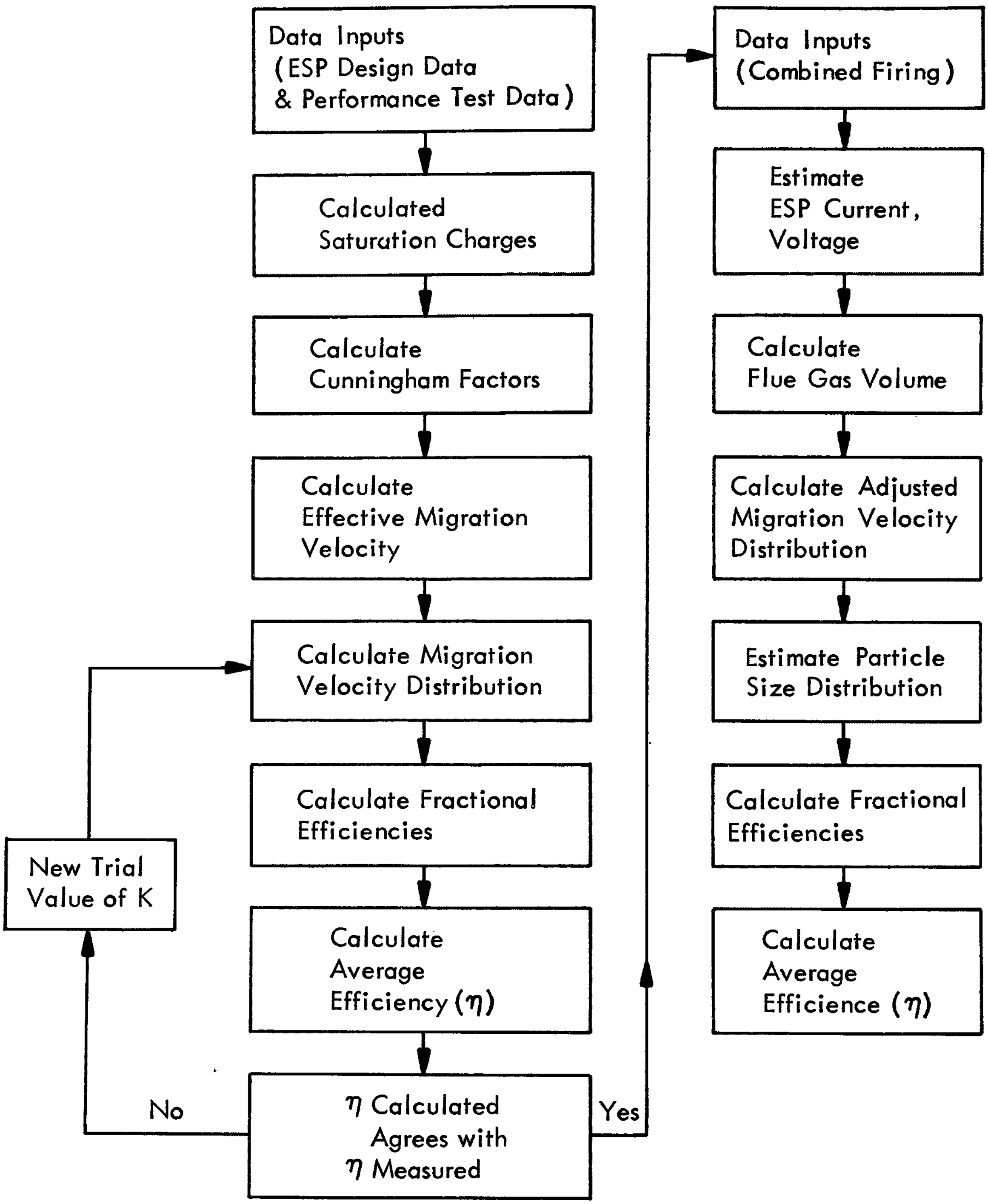


Figure C-1. Block diagram of ESP performance model.

where ε_o = permittivity of free space

= 8.85×10^{-12} $coul^2/newton\text{-}m^2$

$R(j)$ = mass median particle radius, corresponding to the j^{th} discrete particle size range, m

λm = an adjustable parameter = $m\lambda$ (C-2)

where λ = ion mean free path, m

m = number of mean free paths

E_o = average charging field, volts/m

K = relative dielectric constant of the particle

The mean free path λ is calculated using the following expression which is valid for the range of temperatures of interest for fly ash precipitators and at one atmosphere:

$$\lambda = 1.9176 \times 10^{-10} \; (T°K)$$

Step 2 - Calculate the Cunningham correction factor, or slip correction factor for each discrete particle size range, j , using performance data:

$$C(j) = 1 + A\lambda/R(j) \qquad \text{(C-3)}$$

where $A = 1.257 + 0.400 \exp(-1.10\, R(j)/\lambda)$

Step 3 - Calculate the effective or length averaged migration velocity for the different particle size ranges from the Deutsch equation using performance data.

$$w_e = \frac{Q}{A_T} \ln\left(\frac{1}{1 - \eta}\right) \qquad \text{(C-4)}$$

where w_e = effective migration velocity, m/sec

Q = flue gas volumetric flow rate, m^3/sec

A_T = total collecting area, m^2

η = collection fraction over total length

Step 4 - From the test or design data used for Steps 1 to 3, estimate the effective migration velocity, $w_e(j)$, for each discrete particle size range in the distribution. The distribution of migration velocities for each discrete size range $w_e(j)$ can be expressed in terms of the overall effective (length averaged) migration velocity w_e as follows:

$$w_e(j) = w_e \frac{q_s'(j)\ C(j)/R(j)}{q_s'\ C/K} \qquad \text{(C-5)}$$

where K = complex function of particle size distribution, precipitator geometry, and operating condition, having dimension of length (m)

$q_s' = q_s'(K)$ is the value of modified saturation charge corresponding to a radius of size "K"

$C = C(K)$ is the value of the Cunningham correction factor corresponding to a radius of size "K"

The system-dependent parameter K is determined using an iterative procedure described in the next two computational steps. A convenient starting trial value is the mass median radius of the particle size distribution.

From classical theory, the migration velocity is given by:

$$w_e(j) = \frac{q(j)\ Ep\ C(j)}{6\pi\ R(j)\ \mu} \qquad \text{(C-6)}$$

where Ep = electric field near the collection electrode, volts/m

μ = gas viscosity, kg/m-sec

C(j), R(j) = as previously defined

The direct solution of Eq. (C-6) would require the solution of two simultaneous second-order partial differential equations in order to calculate the field adjacent to the collection electrode Ep. The alternative approach used here is to assume that the ratio of instantaneous charges on particles in the j^{th} size range is approximately the same as the saturation charge ratio. Use of the modified saturation charge to describe the instantaneous charge will yield an upper limit value of the migration velocity for each particle size range, which in turn will yield an upper limit value for the collection efficiency.

Step 5 - Calculate the fractional efficiency for each discrete particle size range and each stage or series electrical section. The Deutsch equation is used in the following form:

$$\eta(j) = 1 - \exp(-w_e(j)A/Q) \qquad (C-7)$$

where $\eta(j)$ = the fractional collection efficiency

$w_e(j)$, A, Q = as previously defined

For multiple stage precipitators, the overall fractional efficiency corresponding to a given size range j is obtained as follows:

$$\eta(j) = \sum_i \eta(i,j) \qquad (C-8)$$

Step 6 - Calculate the overall fractional efficiency.

$$\eta = 1 - \sum_j Xj \exp(-w_e(j)A/Q) \qquad (C-9)$$

where Xj = the mass fraction of the j^{th} discrete particle size range

If the fractional efficiency calculated in Eq. (C-9) differs significantly from the test efficiency, a new trial value of K is used, and Steps 4 through 6 repeated until convergence is obtained.

2. Determine fractional efficiency for combined firing test conditions.

The major inputs from Part 1, computation Steps 1 through 6, are migration velocities $w_e(j)$ for each discrete particle size range j based on known performance data. These data, which implicitly contain system dependencies, and test data summarized in Table C-1 are used to calculate the electrostatic precipitator performance for combined firing according to the following procedure.

Step 7 - Calculate adjusted value of average corona current density.

Current and voltage relationships in a precipitator are governed by electrode geometry and by the mobility of the charge carriers. Electrical conditions are limited by either breakdown of the gas in the interelectrode space or by breakdown in the collected dust layer.

At present there is no theoretical basis for predicting either the current-resistivity behavior or the maximum allowable corona current. Ideally, therefore, an experimentally determined current versus resistivity curve should be used.

If current-resistivity data are not available the curve in Figure C-2 may be used to estimate the current density for a given value of dust resistivity. Figure C-2 was obtained from the literature, and is based on the observation that critical current densities in full-scale precipitators can be reduced from the theoretical dust breakdown values by a factor of about 10. The use of this curve should give a conservative estimate of the allowable current density as a function of resistivity.[67]

Field experience has shown that current density for cold-side precipitators is limited to around 50 to 70 nA/cm^2 (1×10^{-9} A = 1 nA) due to electrical breakdown of the gases in the interelectrode region.

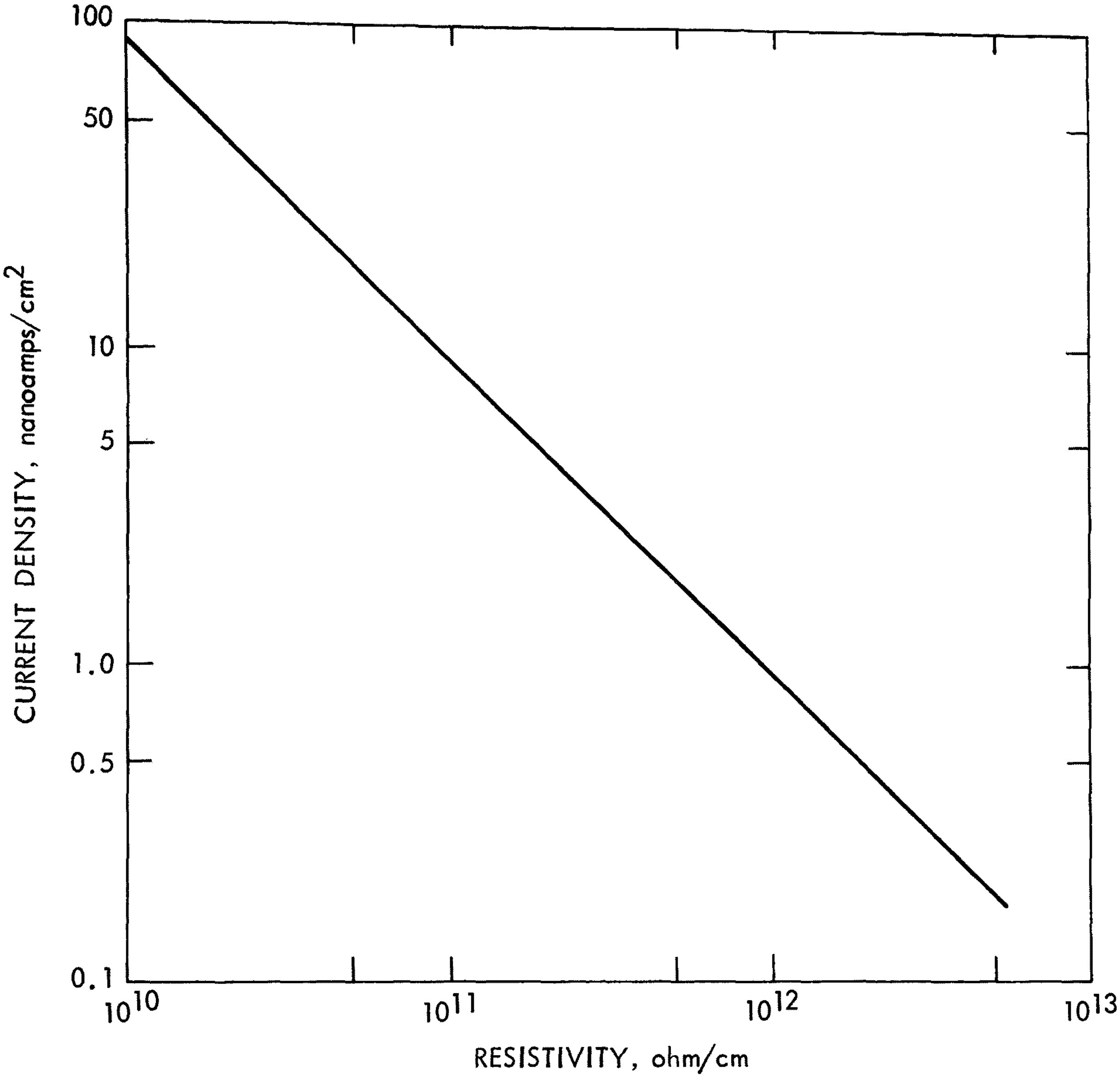
Step 8 - Calculate adjusted value of voltage corresponding to the maximum allowable corona current.

As in Step 7, the voltage-current relationships for an electrostatic precipitator are governed by the mechanical design of the collector system, the size and concentration of dust particles in the gas stream, the presence of a dust layer on the collection electrode, and the temperature and composition of the gas stream. Therefore, it is preferable to determine the operating voltage from an experimentally determined current-voltage curve (see Table C-1).

Lacking this experimental data, a reasonable approximation to the average electrical conditions in the precipitator is given in Figure C-3 by the curves labeled "typical."[67]

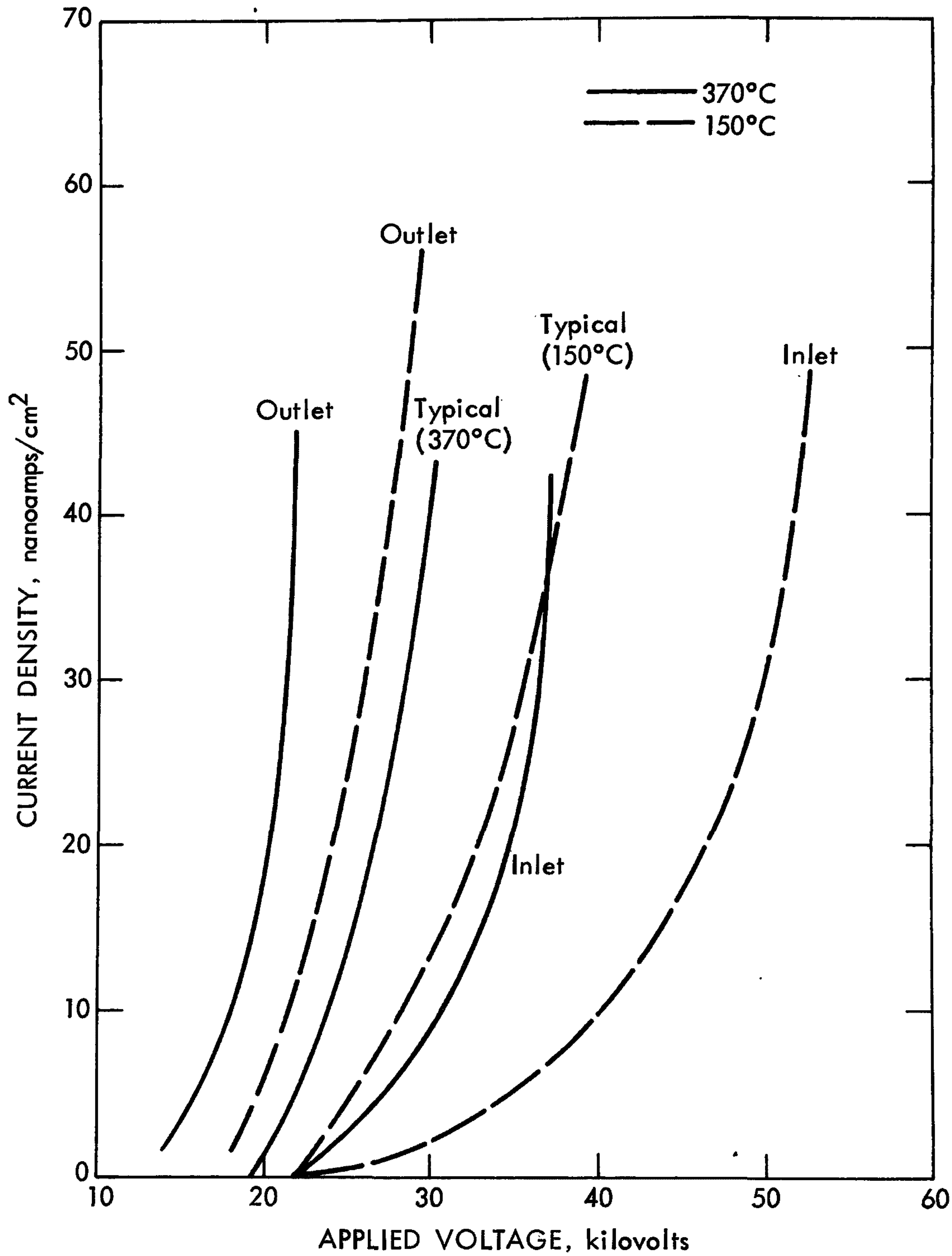
Step 9 - Calculate adjusted flue gas volume. The flue gas volume for a given combined firing application is calculated by standard procedures based on data inputs summarized in Table C-1 "test conditions." In general, flue gas volume will increase significantly with increasing MSW fraction for combined firing of oil and MSW: (a) at 10% MSW on a Btu basis, assuming 25% excess air and 5,650 Btu/lb (HHV) for the MSW portion, the theoretical gas volume will increase by 5.7%; and (b) on the same basis, the theoretical increase in flue gas volume at 20% MSW is 18.0%.

Step 10 - Estimate the particle size distribution for combined firing.



Source: Ref. 67

Figure C-2. Current density as a function of resistivity.



Source: Ref. 67

Figure C-3. Comparison between the voltage versus current characteristics for cold-side and hot-side precipitators. Corona wire radius = 0.277 cm (0.109 in.), plate spacing = 22.86 cm (9 in.).

The particle size distribution for combined firing is presently based on a linear combination of Weibull (or Rosin-Ramler) parameters.[33] The particle size distribution for firing refuse alone must be estimated. Weibull parameters are calculated separately for submicron particulate and particulate larger than 1 μm. The two-parameter Weibull distribution function is fit by a least squares technique in the following form:

$$F(R(j)) = 1 - e^{-\left(\frac{R(j)}{\theta}\right)^b} \tag{C-10}$$

where $F(R(j))$ = the weight fraction of particulate having diameters less than $R(j)$

θ, b = independent parameters

Weibull parameters for the refuse portion of the fuel are as follows:

	θ (μm)	b
(< 1 μm)	1.48	2.91
(> 1 μm)	92.1	0.23

The particle size distribution and ash content of the fossil-fuel portion must be known independently to determine the particle size distribution for the composite fly ash.

Step 11 - Calculate fractional efficiencies. When ESP current and voltage, flue gas volume, migration velocities, and particle size distribution have been adjusted for combined firing conditions, fractional efficiencies for each discrete particle size range are calculated using Eq. (C-7).

Step 12 - Calculate effective, length averaged (total) efficiency. Total efficiency η for the ESP under combined-firing conditions is calculated using Eq. (C-9).

The ESP performance calculation, as described in Appendix C, can be performed using a moderately sophisticated calculator, such as Hewlett-Packard 9810-A, or equivalent.

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16. ABSTRACT The report gives results of estimating particulate flue gas loadings for combined firing of shredded municipal waste (MSW) and oil, using existing data on particulate emissions from oil-fired electric utility boilers and from waterwall (steam generating) incinerators firing either waste or waste-plus-coal/oil auxiliary fuel. Control device performance was estimated for several planned oil/MSW resource recovery systems. On the basis of these estimates, installed particulate emission controls, designed for coal, are predicted to be significantly less efficient for control of particulate emissions from combined firing of oil/MSW. Anticipated control difficulties result mostly from relatively high particulate loadings, high flue gas volumes, fine particulates, relatively low particle density, and relatively high fractions of carbonaceous low-resistivity particulate.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air Pollution	Air Pollution Control	13B
Boilers	Stationary Sources	13A
Fuels	Combined Fuel	21D
Wastes	Municipal Solid Waste	
Fuel Oil	Oil/Municipal Solid Waste	
Dust	Particulate	11G

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