SECRETARY OF STATE

KEN HECHLER

ADMINISTRATIVE LAW DIVISION

Form #3

FEB 7 4 20 PM '95

NOTICE OF AGENCY APPROVAL OF A PROPOSED RULE AND FILING WITH THE LEGISLATIVE RULE-MAKING REVIEW COMMITTEE

AGENCY: Division of Environmental Protection Office of Air Quality TITLE NUMBER: 45CSR2

CITE AUTHORITY: WV Code §§22-5-1 et seq.

AMENDMENT TO AN EXISTING RULE: YES X NO ___

IF YES, SERIES NUMBER OF RULE BEING AMENDED: 45CSR2

TITLE OF RULE BEING AMENDED: "To Prevent and Control Particulate Air Pollution from Combustion of Fuel in Indirect Heat Exchangers"

IF NO, SERIES NUMBER OF NEW RULE BEING PROPOSED: ___

TITLE OF RULE BEING PROPOSED: ___

THE ABOVE PROPOSED LEGISLATIVE RULE HAVING GONE TO A PUBLIC HEARING OR A PUBLIC COMMENT PERIOD IS HEREBY APPROVED BY THE PROMULGATING AGENCY FOR FILING WITH THE SECRETARY OF STATE AND THE LEGISLATIVE RULE MAKING REVIEW COMMITTEE FOR THEIR REVIEW.

Authorized Signature

12-40

45CSR2

TO PREVENT AND CONTROL PARTICULATE AIR POLLUTION FROM COMBUSTION OF FUEL IN INDIRECT HEAT EXCHANGERS

STATEMENT OF CIRCUMSTANCES

The revisions proposed to 45CSR2 were initiated by a petition filed with the West Virginia Division of Environmental Protection on June 3, 1994 on behalf of the West Virginia Manufacturers Association and specific members of that organization. The revisions proposed to 45CSR2 were developed by the staff of the West Virginia Division of Environmental Protection's Office of Air Quality as compromise provisions for public hearing or otherwise incidentally made to reflect enacted changes to the West Virginia Code. The proposed rule consolidates previous rule 45CSR2 and a separate rule, 45CSR2A - "Compliance Test Procdures for Regulation 2 - 'To Prevent and Control Particulate Air Pollution From Combustion of Fuel in Indirect Heat Exchangers'". Upon authorization of this proposed rule, 45CSR2A will be repealed with the substance of 45CSR2A becoming an appendix of 45CSR2.

APPENDIX B

FISCAL NOTE FOR PROPOSED RULES

Rule Title: 45CSR2 - To Prevent and Control Particulate Air Pollution From Combustion of Fuel in Indirect Heat Exchangers

Type of Rule: X Legislative ______ Interpretive ______ Procedural

Agency: Office of Air Quality

Address: 1558 Washington Street, East

Charleston, WV 25311-2599

1. Effect of Proposed Rule	Annual		Fiscal Year		
	Increase	Decrease	Current	Next	There-after
Estimated Total Cost	$ -0-	$ -0-	$ -0-	$ -0-	$ -0-
Personal Services	-0-	-0-	-0-	-0-	-0-
Current Expense	-0-	-0-	-0-	-0-	-0-
Repairs and Alterations	-0-	-0-	-0-	-0-	-0-
Equipment	-0-	-0-	-0-	-0-	-0-
Other	-0-	-0-	-0-	-0-	-0-

2. Explanation of above estimates: The proposed revisions to 45CSR2 will have minimal effect upon the costs to the Office of Air Quality of the Division of Environmental Protection implementing this rule.

3. Objectives of these rules: The objective of 45CSR2 is to establish particulate matter emission limitations and enforcement provisions for fuel burning units as a major component of West Virginia's Implementation Plan for attainment and maintenance of the National Ambient Air Quality Standards for particulate matter.

4. Explanation of overall economic impact of proposed rule.

   A. Economic impact on state government.

      There should be minimal impact upon implementation costs to the Division of Environmental Protection associated with the proposed rule amendments.

B. Economic impact on political subdivisions; specific industries; specific groups of citizens.

Industrial facilities, particularly electric utilities in West Virginia allege that compliance with the existing visible emission standards of 45CSR2 has substantial economic impacts resulting from derating or curtailment of power boiler operating rates and retrofit of additional particulate control equipment. The proposed rule changes could reduce these economic impacts.

C. Economic impact on citizens/public at large.

Minimal impacts from rule changes are anticipated.

Date: February 7, 1995

Signature of agency head or authorized representative:

G. Dale Farley
Chief, Office of Air Quality

45CSR2

TO PREVENT AND CONTROL PARTICULATE AIR POLLUTION FROM COMBUSTION OF FUEL IN INDIRECT HEAT EXCHANGERS

SUMMARY

The purpose of 45CSR2, which became effective on September 1, 1974, is to establish particulate matter weight emission standards and visible emission standards for fuel burning units operated in West Virginia.

45CSR2 is a part of the West Virginia State Implementation Plan (SIP) approved by the USEPA to assure attainment and maintenance of attainment with the National Ambient Air Quality Standards for particulate matter. The proposed revisions to 45CSR2 are for the following purposes:

1. To modify the visible emission standards applicable to fuel burning units (including steam generating units and other indirect heat exchangers) to permit the Director to establish alternative visible emissions standards upon a demonstration that, inter alia, it is technologically or economically infeasible to comply with the applicable standard;

2. To modify the authority, terminology, and West Virginia Code citations in the rule to conform to revisions enacted by the Legislature in 1994;

3. To update or modernize certain definitions and delete rule provisions no longer applicable;

4. To combine 45CSR2 with the separate rule 45CSR2A which establishes test procedures which must be employed to determine compliance with the weight emission limitations of 45CSR2 and to incorporate by reference USEPA's test method for determining visible emissions from a burning unit; and

5. To delete the variance provisions of the rule and to establish criteria for reporting, establishing, and remediating equipment malfunctions.

45CSR2

TO PREVENT AND CONTROL PARTICULATE AIR POLLUTION FROM COMBUSTION OF FUEL IN INDIRECT HEAT EXCHANGERS

PRIVATE REAL PROPERTY PROTECTION ACT ASSESSMENT

The Division of Environmental Protection is required to perform a "constitutional takings determination" or assessment in only limited circumstances (See "Private Real Property Protection Act", W. Va. Code §§22-1A-1 et seq.). Under W. Va. Code §22-1A-3(a), such an assessment is not required, unless the action being contemplated by the Division is reasonably likely to deprive a private real property owner of his or her property in fee simple or to deprive an owner of all productive use of his or her property.

W. Va. Code §22-1A-3(c) expressly exempts rulemaking which simply limits uses pursuant to statute from the assessment requirement. In pertinent part, Section 3(c) provides that the following actions do not require an assessment:

(1) Licensing or permitting conditions, requirements or limitations to the use of private real property pursuant to any applicable state or federal statutes, rules or regulations; or

(2) Rules and emergency rules of the division that are reasonably likely to limit the use of private real property pursuant to any applicable state or federal statutes, rules or regulation;

See W. Va. Code §22-1A-3(c)(1) and (2).

Therefore, since this is a rulemaking pursuant to statute, an assessment is not required.

45CSR2

TO PREVENT AND CONTROL PARTICULATE AIR POLLUTION FROM COMBUSTION OF FUEL IN INDIRECT HEAT EXCHANGERS

Consultation with the EPAC

This rule was filed prior to the appointment of the Environmental Protection Advisory Council (EPAC). Therefore, no consultation with the EPAC has been possible.

DIVISION OF ENVIRONMENTAL PROTECTION
1558 Washington Street East
Charleston, WV 25311-2599

GASTON CAPERTON
GOVERNOR

DAVID C. CALLAGHAN
DIRECTOR

February 3, 1995

Ms. Judy Cooper
Director
Administrative Law Division
Secretary of State's Office
Building 1, Suite 157K
Charleston, WV 25305-0770

RE: 45CSR2 - To Prevent and Control Particulate Air Pollution from Combustion of Fuel in Indirect Heat Exchangers

Dear Ms. Cooper:

This is to advise you that I am giving approval for the filing of the above-captioned rule with your Office and the Legislative Rule-Making Review Committee as an agency-approved rule.

Your cooperation in this regard is very much appreciated. If you have any questions or require additional information, please feel free to contact Roger T. Hall at 759-0515.

Sincerely yours,

David C. Callaghan
Commissioner
Bureau of Environment

DCC/GDF:sep

Attachments

Office of Air Quality
Phone: (304) 558-4022 Fax: (304) 558-3287

ation was in compliance for each 1-month period; and

(2) For months of noncompliance, quarterly reports to the Administrator documenting the 1-month amount of VOC contained in the coatings, the 1-month amount of VOC recovered, and the percent emission reduction for each month.

(f) Each owner or operator of an affected coating operation, either by itself or with associated coating mix preparation equipment, shall submit the following with the reports required under paragraphs (d) and (e) of this section:

(1) All periods during actual mixing or coating operations when a required monitoring device (if any) was malfunctioning or not operating; and

(2) All periods during actual mixing or coating operations when the control device was malfunctioning or not operating.

(g) The reports required under paragraphs (b), (c), (d), and (e) of this section shall be postmarked within 30 days of the end of the reporting period.

(h) Records required in §60.747 must be retained for at least 2 years.

(i) The requirements of this section remain in force until and unless EPA, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such States. In this event, affected sources within the State will be relieved of the obligation to comply with this subsection, provided that they comply with the requirements established by the State.

§60.748 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 111(c) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Authorities that will not be delegated to States: §§60.743(a)(3)(v) (A) and (B); 60.743(e); 60.745(a); 60.746.

APPENDIXES TO PART 60

APPENDIX A—TEST METHODS

Method 1—Sample and velocity traverses for stationary sources

Method 1A—Sample and velocity traverses for stationary sources with small stacks or ducts

Method 2—Determination of stack gas velocity and volumetric flow rate (Type S pitot tube)

Method 2A—Direct measurement of gas volume through pipes and small ducts

Method 2B—Determination of exhaust gas volume flow rate from gasoline vapor incinerators

Method 2C—Determination of stack gas velocity and volumetric flow rate in small stacks or ducts (standard pitot tube)

Method 2D—Measurement of gas volumetric flow rates in small pipes and ducts

Method 3—Gas analysis for carbon dioxide, oxygen, excess air, and dry molecular weight

Method 3A—Determination of Oxygen and Carbon Dioxide Concentrations in Emissions From Stationary Sources (Instrumental Analyzer Procedure)

Method 4—Determination of moisture content in stack gases

Method 5—Determination of particulate emissions from stationary sources

Method 5A—Determination of particulate emissions from the asphalt processing and asphalt roofing industry

Method 5B—Determination of nonsulfuric acid particulate matter from stationary sources

Method 5C [Reserved]

Method 5D—Determination of particulate emissions from positive pressure fabric filters

Method 5E—Determination of particulate emissions from the wool fiberglass insulation manufacturing industry

Method 5F—Determination of nonsulfate particulate matter from stationary sources

Method 5G—Determination of particulate emissions from wood heaters from a dilution tunnel sampling location

Method 5H—Determination of particulate emissions from wood heaters from a stack location

Method 6—Determination of sulfur dioxide emissions from stationary sources

Method 6A—Determination of sulfur dioxide, moisture, and carbon dioxide emissions from fossil fuel combustion sources

Method 6B—Determination of sulfur dioxide and carbon dioxide daily average emissions from fossil fuel combustion sources

Method 6C—Determination of Sulfur Dioxide Emissions From Stationary Sources (Instrumental Analyzer Procedure)
Method 7—Determination of nitrogen oxide emissions from stationary sources
Method 7A—Determination of nitrogen oxide emissions from stationary sources—Ion chromatographic method
Method 7B—Determination of nitrogen oxide emissions from stationary sources (Ultraviolet spectrophotometry)
Method 7C—Determination of nitrogen oxide emissions from stationary sources—Alkaline-permanganate/colorimetric method
Method 7D—Determination of nitrogen oxide emissions from stationary sources—Alkaline-permanganate/ion chromatographic method
Method 7E—Determination of Nitrogen Oxides Emissions From Stationary Sources (Instrumental Analyzer Procedure)
Method 8—Determination of sulfuric acid mist and sulfur dioxide emissions from stationary sources
Method 9—Visual determination of the opacity of emissions from stationary sources
Alternate method 1—Determination of the opacity of emissions from stationary sources remotely by lidar
Method 10—Determination of carbon monoxide emissions from stationary sources
Method 10A—Determination of carbon monoxide emissions in certifying continuous emission monitoring systems at petroleum refineries
Method 10B—Determination of carbon monoxide emissions from stationary sources
Method 11—Determination of hydrogen sulfide content of fuel gas streams in petroleum refineries
Method 12—Determination of inorganic lead emissions from stationary sources
Method 13A—Determination of total fluoride emissions from stationary sources—SPADNS zirconium lake method
Method 13B—Determination of total fluoride emissions from stationary sources—Specific ion electrode method
Method 14—Determination of fluoride emissions from potroom roof monitors for primary aluminum plants
Method 15—Determination of hydrogen sulfide, carbonyl sulfide, and carbon disulfide emissions from stationary sources
Method 15A—Determination of total reduced sulfur emissions from sulfur recovery plants in petroleum refineries
Method 16—Semicontinuous determination of sulfur emissions from stationary sources
Method 16A—Determination of total reduced sulfur emissions from stationary sources (impinger technique)
Method 16B—Determination of total reduced sulfur emissions from stationary sources
Method 17—Determination of particulate emissions from stationary sources (in-stack filtration method)
Method 18—Measurement of gaseous organic compound emissions by gas chromatography
Method 19—Determination of sulfur dioxide removal efficiency and particulate, sulfur dioxide and nitrogen oxides emission rates
Method 20—Determination of nitrogen oxides, sulfur dioxide, and diluent emissions from stationary gas turbines
Method 21—Determination of volatile organic compound leaks
Method 22—Visual determination of fugitive emissions from material sources and smoke emissions from flares
Method 23—Determination of Polychlorinated Dibenzo-p-Dioxins and Polychlorinated Dibenzofurans From Stationary Sources
Method 24—Determination of volatile matter content, water content, density, volume solids, and weight solids of surface coatings
Method 24A—Determination of volatile matter content and density of printing inks and related coatings
Method 25—Determination of total gaseous nonmethane organic emissions as carbon
Method 25A—Determination of total gaseous organic concentration using a flame ionization analyzer
Method 25B—Determination of total gaseous organic concentration using a nondispersive infrared analyzer
Method 26—Determination of Hydrogen Chloride Emissions From Stationary Sources
Method 27—Determination of vapor tightness of gasoline delivery tank using pressure-vacuum test
Method 28—Certification and auditing of wood heaters
Method 28A—Measurement of air to fuel ratio and minimum achievable burn rates for wood-fired appliances

The test methods in this appendix are referred to in §60.8 (Performance Tests) and §60.11 (Compliance With Standards and Maintenance Requirements) of 40 CFR part 60, subpart A (General Provisions). Specific uses of these test methods are described in the standards of performance contained in the subparts, beginning with Subpart D.

Within each standard of performance, a section title "Test Methods and Procedures" is provided to: (1) Identify the test methods to be used as reference methods to the facility subject to the respective standard and (2) identify any special instructions or conditions to be followed when applying a method to the respective facility. Such instructions (for example, establish sampling rates, volumes, or temperatures) are to be used either in addition to, or as a substitute for procedures in a test method. Similarly, for sources subject to emission monitoring requirements, specific instructions pertaining to any use of a test method as a reference method are provided in the subpart or in Appendix B.

Inclusion of methods in this appendix is not intended as an endorsement or denial of their applicability to sources that are not subject to standards of performance. The methods are potentially applicable to other sources; however, applicability should be confirmed by careful and appropriate evaluation of the conditions prevalent at such sources.

The approach followed in the formulation of the test methods involves specifications for equipment, procedures, and performance. In concept, a performance specification approach would be preferable in all methods because this allows the greatest flexibility to the user. In practice, however, this approach is impractical in most cases because performance specifications cannot be established. Most of the methods described herein, therefore, involve specific equipment specifications and procedures, and only a few methods in this appendix rely on performance criteria.

Minor changes in the test methods should not necessarily affect the validity of the results and it is recognized that alternative and equivalent methods exist. Section 60.8 provides authority for the Administrator to specify or approve (1) equivalent methods, (2) alternative methods, and (3) minor changes in the methodology of the test methods. It should be clearly understood that unless otherwise identified all such methods and changes must have prior approval of the Administrator. An owner employing such methods or deviations from the test methods without obtaining prior approval does so at the risk of subsequent disapproval and retesting with approved methods.

Within the test methods, certain specific equipment or procedures are recognized as being acceptable or potentially acceptable and are specifically identified in the methods. The items identified as acceptable options may be used without approval but must be identified in the test report. The potentially approvable options are cited as "subject to the approval of the Administrator" or as "or equivalent." Such potentially approvable techniques or alternatives may be used at the discretion of the owner without prior approval. However, detailed descriptions for applying these potentially approvable techniques or alternatives are not provided in the test methods. Also, the potentially approvable options are not necessarily acceptable in all applications. Therefore, an owner electing to use such potentially approvable techniques or alternatives is responsible for: (1) assuring that the techniques or alternatives are in fact applicable and are properly executed; (2) including a written description of the alternative method in the test report (the written method must be clear and must be capable of being performed without additional instruction, and the the degree of detail should be similar to the detail contained in the test methods); and (3) providing any rationale or supporting data necessary to show the validity of the alternative in the particular application. Failure to meet these requirements can result in the Administrator's disapproval of the alternative.

METHOD 1—SAMPLE AND VELOCITY TRAVERSES FOR STATIONARY SOURCES

1. *Principle and Applicability*

1.1 Principle. To aid in the representative measurement of pollutant emissions and/or total volumetric flow rate from a stationary source, a measurement site where the effluent stream is flowing in a known direction is selected, and the cross-section of the stack is divided into a number of equal areas. A traverse point is then located within each of these equal areas.

1.2 Applicability. This method is applicable to flowing gas streams in ducts, stacks, and flues. The method cannot be used when: (1) flow is cyclonic or swirling (see Section 2.4), (2) a stack is smaller than about 0.30 meter (12 in.) in diameter, or 0.071 m^2 (113 $in.^2$) cross-sectional area, or (3) the measurement site is less than two stack or duct diameters downstream or less than a half diameter upstream from a flow disturbance.

The requirements of this method must be considered before construction of a new facility from which emissions will be measured; failure to do so may require subsequent alterations to the stack or deviation from the standard procedure. Cases involving variants are subject to approval by the Administrator, U.S. Environmental Protection Agency.

2. *Procedure*

2.1 Selection of Measurement Site. Sampling or velocity measurement is performed at a site located at least eight stack or duct diameters downstream and two diameters upstream from any flow disturbance such as a bend, expansion, or contraction in the stack, or from a visible flame. If necessary, an alternative location may be selected, at a position at least two stack or duct diameters downstream and a half diameter upstream from any flow disturbance. For a rectangular cross section, an equivalent diameter (D_e) shall be calculated from the following equation, to determine the upstream and downstream distances:

$$D_e = \frac{2LW}{(L+W)}$$

where L=length and W=width.

An alternative procedure is available for determining the acceptability of a measurement location not meeting the criteria above. This procedure, determination of gas flow angles at the sampling points and comparing the results with acceptability criteria, is described in Section 2.5.

2.2 Determining the Number of Traverse Points.

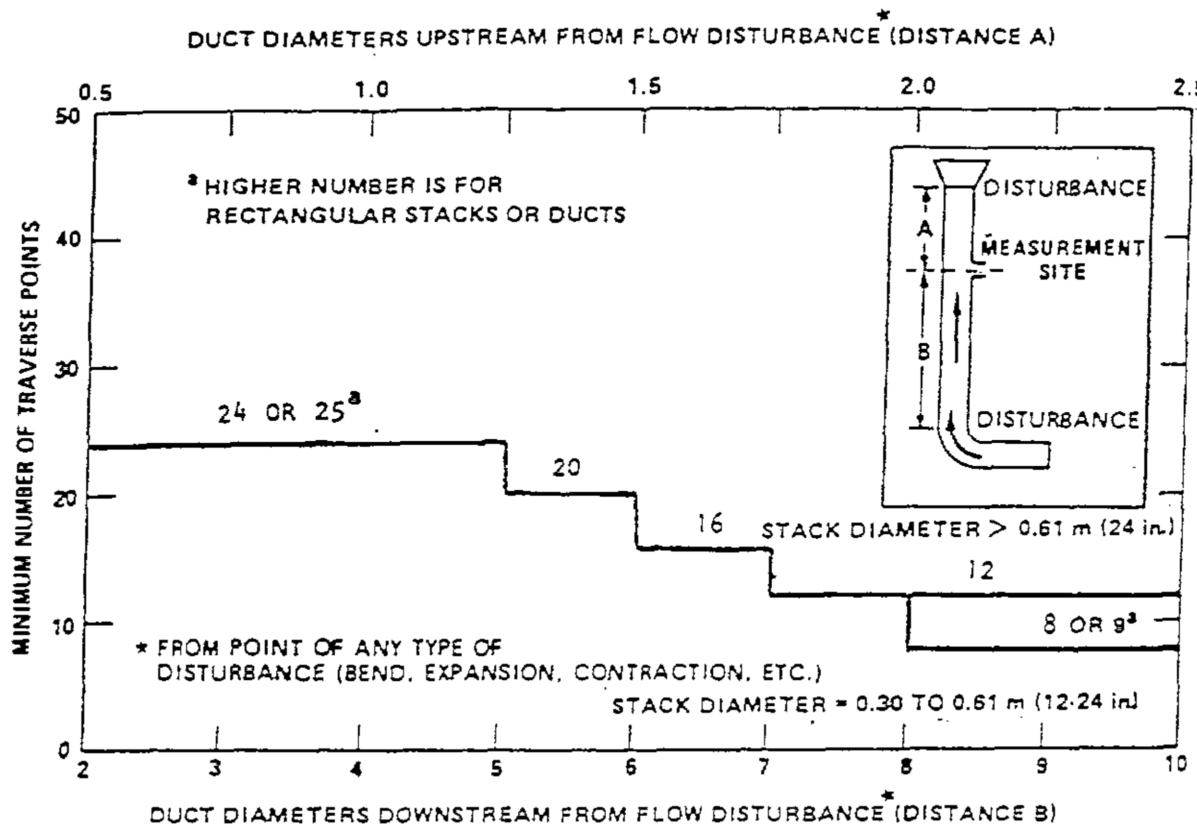

Figure 1-1. Minimum number of traverse points for particulate traverses.

2.2.1 Particulate Traverses. When the eight- and two-diameter criterion can be met, the minimum number of traverse points shall be: (1) twelve, for circular or rectangular stacks with diameters (or equivalent diameters) greater than 0.61 meter (24 in.); (2) eight, for circular stacks with diameters between 0.30 and 0.61 meter (12–24 in.); (3) nine, for rectangular stacks with equivalent diameters between 0.30 and 0.61 meter (12–24 in.).

When the eight- and two-diameter criterion cannot be met, the minimum number of traverse points is determined from Figure 1-1. Before referring to the figure, however, determine the distances from the chosen measurement site to the nearest upstream and downstream disturbances, and divide each distance by the stack diameter or equivalent diameter, to determine the distance in terms of the number of duct diameters. Then, determine from Figure 1-1 the minimum number of traverse points that corresponds: (1) to the number of duct diameters upstream; and (2) to the number of diameters downstream. Select the higher of the two minimum numbers of traverse points, or a greater value, so that for circular stacks the number is a multiple of 4, and for rectangular stacks, the number is one of those shown in Table 1-1.

TABLE 1–1. CROSS-SECTION LAYOUT FOR RECTANGULAR STACKS

Number of traverse points	Matrix layout
9	3x3
12	4x3
16	4x4
20	5x4
25	5x5
30	6x5
36	6x6
42	7x6
49	7x7

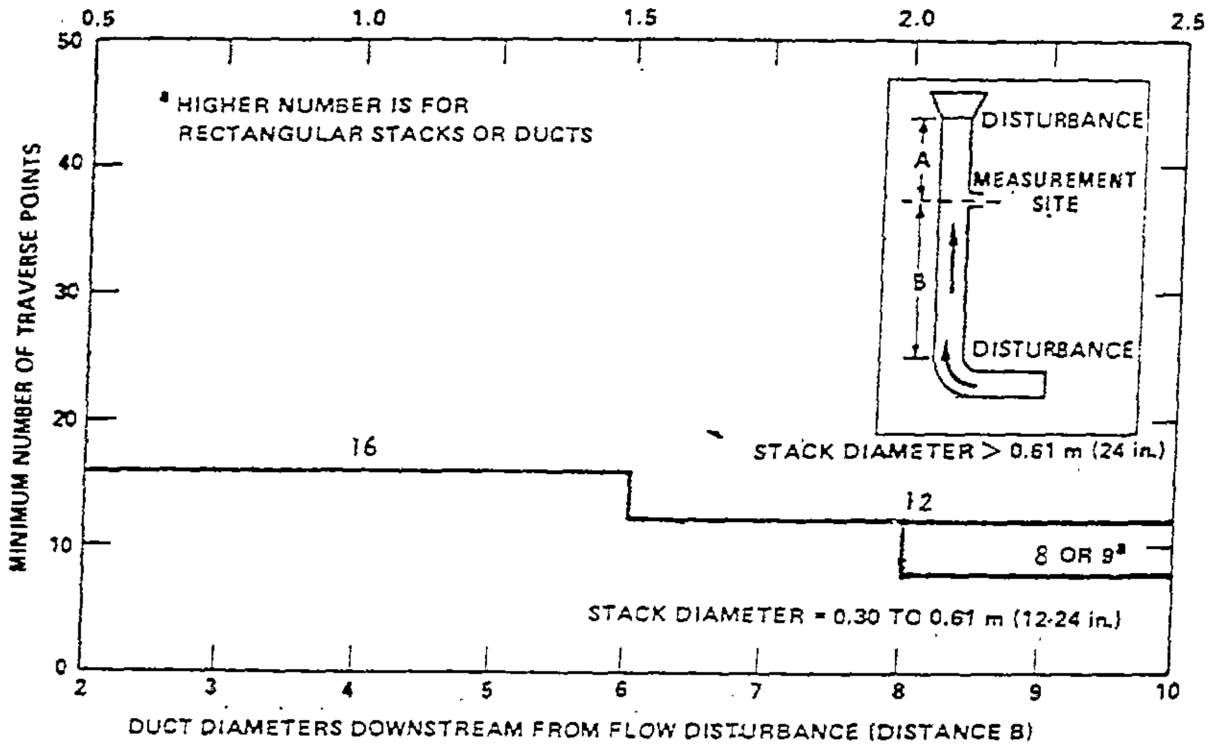

Figure 1-2. Minimum number of traverse points for velocity (nonparticulate) traverses.

2.2.2 Velocity (Non-Particulate) Traverses. When velocity or volumetric flow rate is to be determined (but not particulate matter), the same procedure as that for particulate traverses (Section 2.2.1) is followed, except that Figure 1-2 may be used instead of Figure 1-1.

2.3 Cross-sectional Layout and Location of Traverse Points.

2.3.1 Circular Stacks. Locate the traverse points on two perpendicular diameters according to Table 1-2 and the example shown in Figure 1-3. Any equation (for examples, see Citations 2 and 3 in the Bibliography) that gives the same values as those in Table 1-2 may be used in lieu of Table 1-2.

For particulate traverses, one of the diameters must be in a plane containing the greatest expected concentration variation, e.g., after bends, one diameter shall be in the plane of the bend. This requirement becomes less critical as the distance from the disturbance increases; therefore, other diameter locations may be used, subject to approval of the Administrator.

In addition for stacks having diameters greater than 0.61 m (24 in.) no traverse points shall be located within 2.5 centimeters (1.00 in.) of the stack walls; and for stack diameters equal to or less than 0.61 m (24 in.), no traverse points shall be located within 1.3 cm (0.50 in.) of the stack walls. To meet these criteria, observe the procedures given below.

2.3.1.1 Stacks With Diameters Greater Than 0.61 m (24 in.). When any of the traverse points as located in Section 2.3.1 fall within 2.5 cm (1.00 in.) of the stack walls, relocate them away from the stack walls to: (1) a distance of 2.5 cm (1.00 in.); or (2) a distance equal to the nozzle inside diameter, whichever is larger. These relocated traverse points (on each end of a diameter) shall be the "adjusted" traverse points.

Whenever two successive traverse points are combined to form a single adjusted traverse point, treat the adjusted point as two separate traverse points, both in the sampling (or velocity measurement) procedure, and in recording the data.

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TRAVERSE POINT	DISTANCE. % of diameter
1	4.4
2	14.7
3	29.5
4	70.5
5	85.3
6	95.6

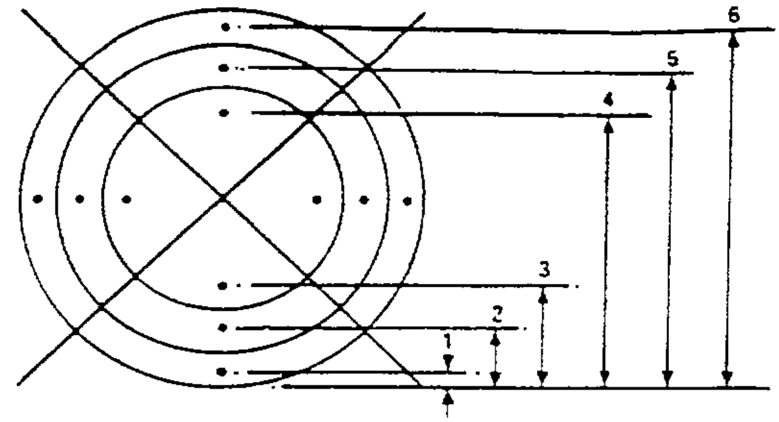

Figure 1-3. Example showing circular stack cross section divided into 12 equal areas, with location of traverse points indicated.

TABLE 1–2. LOCATION OF TRAVERSE POINTS IN CIRCULAR STACKS

[Percent of stack diameter from inside wall to traverse point]

Traverse point number on a diameter	Number of traverse points on a diameter—											
	2	4	6	8	10	12	14	16	18	20	22	24
1	14.6	6.7	4.4	3.2	2.6	2.1	1.8	1.6	1.4	1.3	1.1	1.1
2	85.4	25.0	14.6	10.5	8.2	6.7	5.7	4.9	4.4	3.9	3.5	3.2
3	......	75.0	29.6	19.4	14.6	11.8	9.9	8.5	7.5	6.7	6.0	5.5
4	......	93.3	70.4	32.3	22.6	17.7	14.6	12.5	10.9	9.7	8.7	7.9
5	......	......	85.4	67.7	34.2	25.0	20.1	16.9	14.6	12.9	11.6	10.5
6	......	......	95.6	80.6	65.8	35.6	26.9	22.0	18.8	16.5	14.6	13.2
7	......	......	......	89.5	77.4	64.4	36.6	28.3	23.6	20.4	18.0	16.1
8	......	......	......	96.8	85.4	75.0	63.4	37.5	29.6	25.0	21.8	19.4
9	......	......	......	......	91.8	82.3	73.1	62.5	38.2	30.6	26.2	23.0
10	......	......	......	......	97.4	88.2	79.9	71.7	61.8	38.8	31.5	27.2
11	......	......	......	......	......	93.3	85.4	78.0	70.4	61.2	39.3	32.3
12	......	......	......	......	......	97.9	90.1	83.1	76.4	69.4	60.7	39.8
13	......	......	......	......	......	......	94.3	87.5	81.2	75.0	68.5	60.2
14	......	......	......	......	......	......	98.2	91.5	85.4	79.6	73.8	67.7
15	......	......	......	......	......	......	......	95.1	89.1	83.5	78.2	72.8
16	......	......	......	......	......	......	......	98.4	92.5	87.1	82.0	77.0
17	......	......	......	......	......	......	......	......	95.6	90.3	85.4	80.6
18	......	......	......	......	......	......	......	......	98.6	93.3	88.4	83.9
19	......	......	......	......	......	......	......	......	......	96.1	91.3	86.8
20	......	......	......	......	......	......	......	......	......	98.7	94.0	89.5
21	......	......	......	......	......	......	......	......	......	......	96.5	92.1
22	......	......	......	......	......	......	......	......	......	......	98.9	94.5
23	......	......	......	......	......	......	......	......	......	......	......	96.8
24	......	......	......	......	......	......	......	......	......	......	......	98.9

2.3.1.2 Stacks With Diameters Equal to or Less Than 0.61 m (24 in.). Follow the procedure in Section 2.3.1.1, noting only that any "adjusted" points should be relocated away from the stack walls to: (1) a distance of 1.3 cm (0.50 in.); or (2) a distance equal to the nozzle inside diameter, whichever is larger.

2.3.2 Rectangular Stacks. Determine the number of traverse points as explained in Sections 2.1 and 2.2 of this method. From Table 1–1, determine the grid configuration. Divide the stack cross-section into as many equal rectangular elemental areas as traverse points, and then locate a traverse point at the centroid of each equal area according to the example in Figure 1–4.

If the tester desires to use more than the minimum number of traverse points, expand the "minimum number of traverse points" matrix (see Table 1–1) by adding the extra traverse points along one or the other or both legs of the matrix; the final matrix need not be balanced. For example, if a 4x3 "minimum number of points" matrix were expanded to 36 points, the final matrix could be 9x4 or 12x3, and would not necessarily have to be 6x6. After constructing the final matrix, divide the stack cross-section into as many equal rectangular, elemental areas as traverse points, and locate a traverse point at the centroid of each equal area.

The situation of traverse points being too close to the stack walls is not expected to arise with rectangular stacks. If this problem should ever arise, the Administrator must be contacted for resolution of the matter.

2.4 Verification of Absence of Cyclonic Flow. In most stationary sources, the direction of stack gas flow is essentially parallel to the stack walls. However, cyclonic flow may exist (1) after such devices as cyclones and inertial demisters following venturi scrubbers, or (2) in stacks having tangential inlets or other duct configurations which tend to induce swirling; in these instances, the presence or absence of cyclonic flow at the sampling location must be determined. The following techniques are acceptable for this determination.

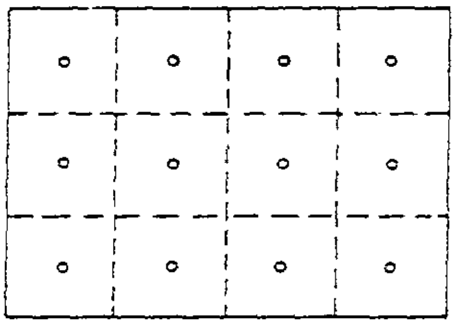

Figure 1.4. Example showing rectangular stack cross section divided into 12 equal areas, with a traverse point at centroid of each area.

Level and zero the manometer. Connect a Type S pitot tube to the manometer. Position the Type S pitot tube at each traverse point, in succession, so that the planes of the face openings of the pitot tube are perpendicular to the stack cross-sectional plane; when the Type S pitot tube is in this position, it is at "0° reference." Note the differential pressure (Δp) reading at each traverse point. If a null (zero) pitot reading is obtained at 0° reference at a given traverse point, an acceptable flow condition exists at that point. If the pitot reading is not zero at 0° reference, rotate the pitot tube (up to ±90° yaw angle), until a null reading is obtained. Carefully determine and record the value of the rotation angle (α) to the nearest degree. After the null technique has been applied at each traverse point, calculate the average of the absolute values of α; assign α values of 0° to those points for which no rotation was required, and include these in the overall average. If the average value of α is greater than 20°, the overall flow condition in the stack is unacceptable and alternative methodology, subject to the approval of the Administrator, must be used to perform accurate sample and velocity traverses.

The alternative procedure described in Section 2.5 may be used to determine the rotation angles in lieu of the procedure described above.

2.5 Alternative Measurement Site Selection Procedure. This alternative applies to sources where measurement locations are less than 2 equivalent stack or duct diameters downstream or less than ½ duct diameter upstream from a flow disturbance. The alternative should be limited to ducts larger than 24 in. in diameter where blockage and wall effects are minimal. A directional flow-sensing probe is used to measure pitch and yaw angles of the gas flow at 40 or more traverse points; the resultant angle is calculated and compared with acceptable criteria for mean and standard deviation.

NOTE: Both the pitch and yaw angles are measured from a line passing through the traverse point and parallel to the stack axis. The pitch angle is the angle of the gas flow component in the plane that INCLUDES the traverse line and is parallel to the stack axis. The yaw angle is the angle of the gas flow component in the plane PERPENDICULAR to the traverse line at the traverse point and is measured from the line passing through the traverse point and parallel to the stack axis.

2.5.1 Apparatus.

2.5.1.1 Directional Probe. Any directional probe, such as United Sensor Type DA Three-Dimensional Directional Probe, capable of measuring both the pitch and yaw angles of gas flows is acceptable. (NOTE: Mention of trade name or specific products does not constitute endorsement by the U.S. Environmental Protection Agency.) Assign an identification number to the directional probe, and permanently mark or engrave the number on the body of the probe. The pressure holes of directional probes are susceptible to plugging when used in particulate-laden gas streams. Therefore, a system for cleaning the pressure holes by "back-purging" with pressurized air is required.

2.5.1.2 Differential Pressure Gauges. Inclined manometers, U-tube manometers, or other differential pressure gauges (e.g., magnehelic gauges) that meet the specifications described in Method 2, section 2.2.

NOTE: If the differential pressure gauge produces both negative and positive readings, then both negative and positive pressure readings shall be calibrated at a minimum of three points as specified in Method 2, section 2.2.

2.5.2 Traverse Points. Use a minimum of 40 traverse points for circular ducts and 42 points for rectangular ducts for the gas flow angle determinations. Follow section 2.3 and Table 1-1 or 1-2 for the location and layout of the traverse points. If the measurement location is determined to be acceptable according to the criteria in this alternative procedure, use the same traverse point number and locations for sampling and velocity measurements.

2.5.3 Measurement Procedure.

2.5.3.1 Prepare the directional probe and differential pressure gauges as recommended by the manufacturer. Capillary tubing or surge tanks may be used to dampen pressure fluctuations. It is recommended, but not required, that a pretest leak check be conducted. To perform a leak check, pressurize or use suction on the impact opening until a reading of at least 7.6 cm (3 in.) H_2O registers on the differential pressure gauge, then plug the impact opening. The pressure of a leak-free system will remain stable for at least 15 seconds.

2.5.3.2 Level and zero the manometers. Since the manometer level and zero may drift because of vibrations and temperature changes, periodically check the level and zero during the traverse.

2.5.3.3 Position the probe at the appropriate locations in the gas stream, and rotate until zero deflection is indicated for the yaw angle pressure gauge. Determine and record the yaw angle. Record the pressure gauge readings for the pitch angle, and determine the pitch angle from the calibration curve. Repeat this procedure for each traverse point. Complete a "back-purge" of the pressure lines and the impact openings prior to measurements of each traverse point.

A post-test check as described in section 2.5.3.1 is required. If the criteria for a leak-free system are not met, repair the equipment, and repeat the flow angle measurements.

2.5.4 Calculate the resultant angle at each traverse point, the average resultant angle, and the standard deviation using the following equations. Complete the calculations retaining at least one extra significant figure beyond that of the acquired data. Round the values after the final calculations.

2.5.4.1 Calculate the resultant angle at each traverse point:

$$R_i = \text{arc cosine}\left[(\text{cosine } Y_i)(\text{cosine } P_i)\right] \qquad \text{Eq. 1-2}$$

Where:

R_i=Resultant angle at traverse point i, degree.

Y_i=Yaw angle at traverse point i, degree.

P_i=Pitch angle at traverse point i, degree.

2.5.4.2 Calculate the average resultant for the measurements:

$$\bar{R} = \frac{\Sigma R_i}{n} \qquad \text{Eq. 1-3}$$

Where:

$\bar{R}$=Average resultant angle, degree.

n=Total number of traverse points.

2.5.4.3 Calculate the standard deviations:

$$S_d = \sqrt{\frac{\sum_{i=1}^{n}(R_i - \bar{R})^2}{(n-1)}} \qquad \text{Eq. 1-4}$$

Where:

S_d=Standard deviation, degree.

2.5.5 The measurement location is acceptable if $\bar{R} \le 20°$ and $S_d \le 10°$.

2.5.6 Calibration. Use a flow system as described in Sections 4.1.2.1 and 4.1.2.2 of Method 2. In addition, the flow system shall have the capacity to generate two test-section velocities: one between 365 and 730 m/min (1200 and 2400 ft/min) and one between 730 and 1100 m/min (2400 and 3600 ft/min).

2.5.6.1 Cut two entry ports in the test section. The axis through the entry ports shall be perpendicular to each other and intersect in the centroid of the test section. The ports should be elongated slots parallel to the axis of the test section and of sufficient length to allow measurement of pitch angles while maintaining the pitot head position at the test-section centroid. To facilitate alignment of the directional probe during calibration, the test section should be constructed of plexiglass or some other transparent material. All calibration measurements should be made at the same point in the test section, preferably at the centroid of the test section.

2.5.6.2 To ensure that the gas flow is parallel to the central axis of the test section, follow the procedure in Section 2.4 for cyclonic flow determination to measure the gas flow angles at the centroid of the test section from two test ports located 90° apart. The gas flow angle measured in each port must be ±2° of 0°. Straightening vanes should be installed, if necessary, to meet this criterion.

2.5.6.3 Pitch Angle Calibration. Perform a calibration traverse according to the manufacturer's recommended protocol in 5° increments for angles from −60° to +60° at one velocity in each of the two ranges specified above. Average the pressure ratio values obtained for each angle in the two flow ranges, and plot a calibration curve with the average values of the pressure ratio (or other suitable measurement factor as recommended by the manufacturer) versus the pitch angle. Draw a smooth line through the data points. Plot also the data values for each traverse point. Determine the differences between the measured data values and the angle from the calibration curve at the same pressure ratio. The difference at each comparison must be within 2° for angles between 0° and 40° and within 3° for angles between 40° and 60°.

2.5.6.4 Yaw Angle Calibration. Mark the three-dimensional probe to allow the determination of the yaw position of the probe. This is usually a line extending the length of the probe and aligned with the impact opening. To determine the accuracy of measurements of the yaw angle, only the zero or null position need be calibrated as follows. Place the directional probe in the test section, and rotate the probe until the zero position is found. With a protractor or other angle measuring device, measure the angle indicated by the yaw angle indicator on the three-dimensional probe. This should be within 2° of 0°. Repeat this measurement for any other points along the length of the pitot where yaw angle measurements could be read in order to account for variations in the pitot markings used to indicate pitot head positions.

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METHOD 1A—SAMPLE AND VELOCITY TRAVERSES FOR STATIONARY SOURCES WITH SMALL STACKS OR DUCTS

1. Applicability and Principle

1.1 The applicability and principle of this method are identical to Method 1, except this method's applicability is limited to stacks or ducts less than about 0.30 meter (12 in.) in diameter or 0.071 m² (113 in.²) in cross-sectional area, but equal to or greater than about 0.10 meter (4 in.) in diameter or 0.0081 m² (12.57 in.²) in cross-sectional area.

1.2 In these small diameter stacks or ducts, the conventional Method 5 stack assembly (consisting of a Type S pitot tube attached to a sampling probe, equipped with a nozzle and thermocouple) blocks a significant portion of the cross section of the duct and causes inaccurate measurements. Therefore, for particulate matter (PM) sampling in small stacks or ducts, the gas velocity is measured using a standard pitot tube downstream of the actual emission sampling site. The straight run of duct between the PM sampling and velocity measurement sites allows the flow profile, temporarily disturbed by the presence of the sampling probe, to redevelop and stabilize.

1.3 The cross-sectional layout and location of traverse points and the verification of the absence of cyclonic flow are the same as in Method 1, Sections 2.3 and 2.4, respectively. Differences from Method 1, except as noted, are given below.

2. Procedure

2.1 Selection of Sampling and Measurement Sites.

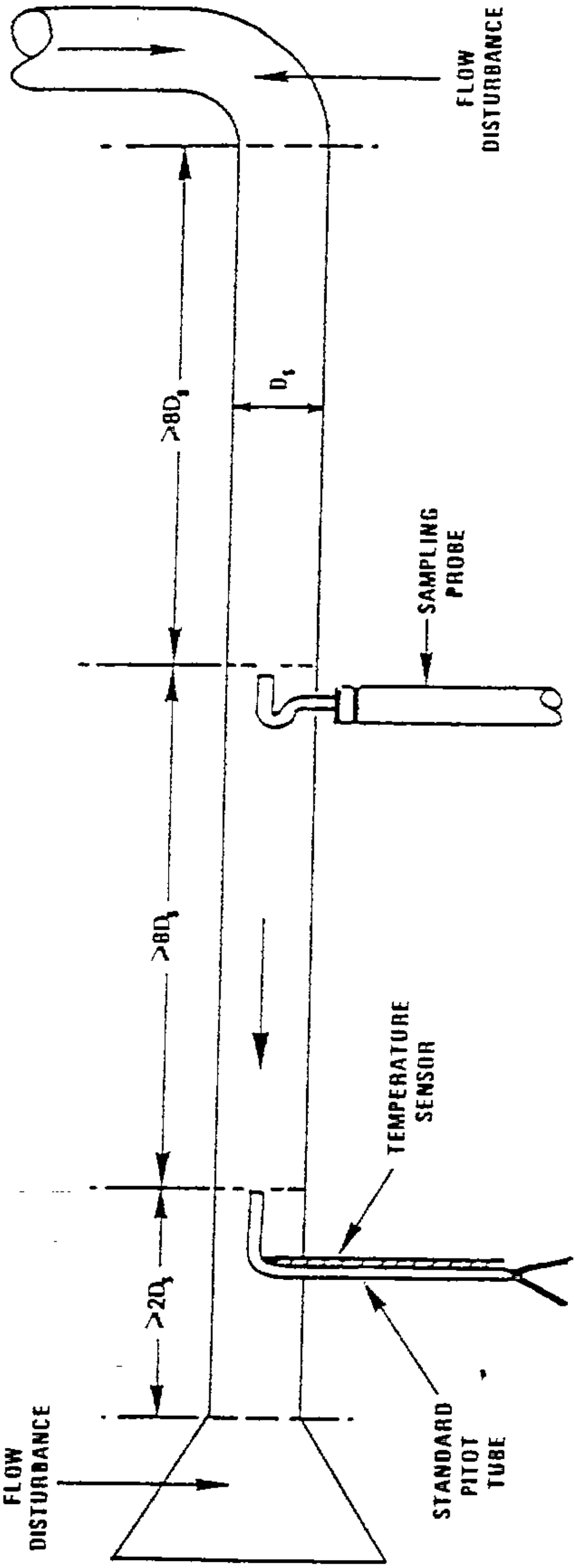

Figure 1A-1. Recommended sampling arrangement for small ducts.

2.1.2 PM Sampling (Steady Flow) or only Velocity Measurements. For PM sampling when the volumetric flow rate in a duct is constant with respect to time, Section 2.1 of Method 1 may be followed, with the PM sampling and velocity measurement performed at one location. To demonstrate that the flow rate is constant (within 10 percent) when PM measurements are made, perform complete velocity traverses before and after the PM sampling run, and calculate the deviation of the flow rate derived after the PM sampling run from the one derived before the PM sampling run. The PM sampling run is acceptable if the deviation does not exceed 10 percent.

2.2 Determining the Number of Traverse Points.

2.2.1 PM Sampling. Use Figure 1–1 of Method 1 to determine the number of traverse points to use at both the velocity measurement and PM sampling locations. Before referring to the figure, however, determine the distances between both the velocity measurement and PM sampling sites to the nearest upstream and downstream disturbances. Then divide each distance by the stack diameter or equivalent diameter to express the distances in terms of the number of duct diameters. Next, determine the number of traverse points from Figure 1–1 of Method 1 corresponding to each of these four distances. Choose the highest of the four numbers of traverse points (or a greater number) so that, for circular ducts, the number is a multiple of four, and for rectangular ducts, the number is one of those shown in Table 1–1 of Method 1. When the optimum duct diameter location criteria can be satisfied, the minimum number of traverse points required is eight for circular ducts and nine for rectangular ducts.

2.2.2 PM Sampling (Steady Flow) or Velocity Measurements. Use Figure 1–2 of Method 1 to determine the number of traverse points, following the same procedure used for PM sampling traverses as described in Section 2.2.1 of Method 1. When the optimum duct diameter location criteria can be satisfied, the minimum number of traverse points required is eight for circular ducts and nine for rectangular ducts.

3. Bibliography

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2. Vollaro, Robert F. Recommended Procedure for Sample Traverses in Ducts Smaller Than 12 Inches in Diameter. U.S. Environmental Protection Agency, Emission Measurement Branch, Research Triangle Park, NC. January 1977.

Method 2—Determination of Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot Tube)

1. Principle and Applicability

1.1 Principle. The average gas velocity in a stack is determined from the gas density and from measurement of the average velocity head with a Type S (Stausscheibe or reverse type) pitot tube.

1.2 Applicability. This method is applicable for measurement of the average velocity of a gas stream and for quantifying gas flow.

This procedure is not applicable at measurement sites which fail to meet the criteria of Method 1, Section 2.1. Also, the method cannot be used for direct measurement in cyclonic or swirling gas streams; Section 2.4 of Method 1 shows how to determine cyclonic or swirling flow conditions. When unacceptable conditions exist, alternative procedures, subject to the approval of the Administrator, U.S. Environmental Protection Agency, must be employed to make accurate flow rate determinations; examples of such alternative procedures are: (1) to install straightening vanes; (2) to calculate the total volumetric flow rate stoichiometrically, or (3) to move to another measurement site at which the flow is acceptable.

2. Apparatus

Specifications for the apparatus are given below. Any other apparatus that has been demonstrated (subject to approval of the Administrator) to be capable of meeting the specifications will be considered acceptable.

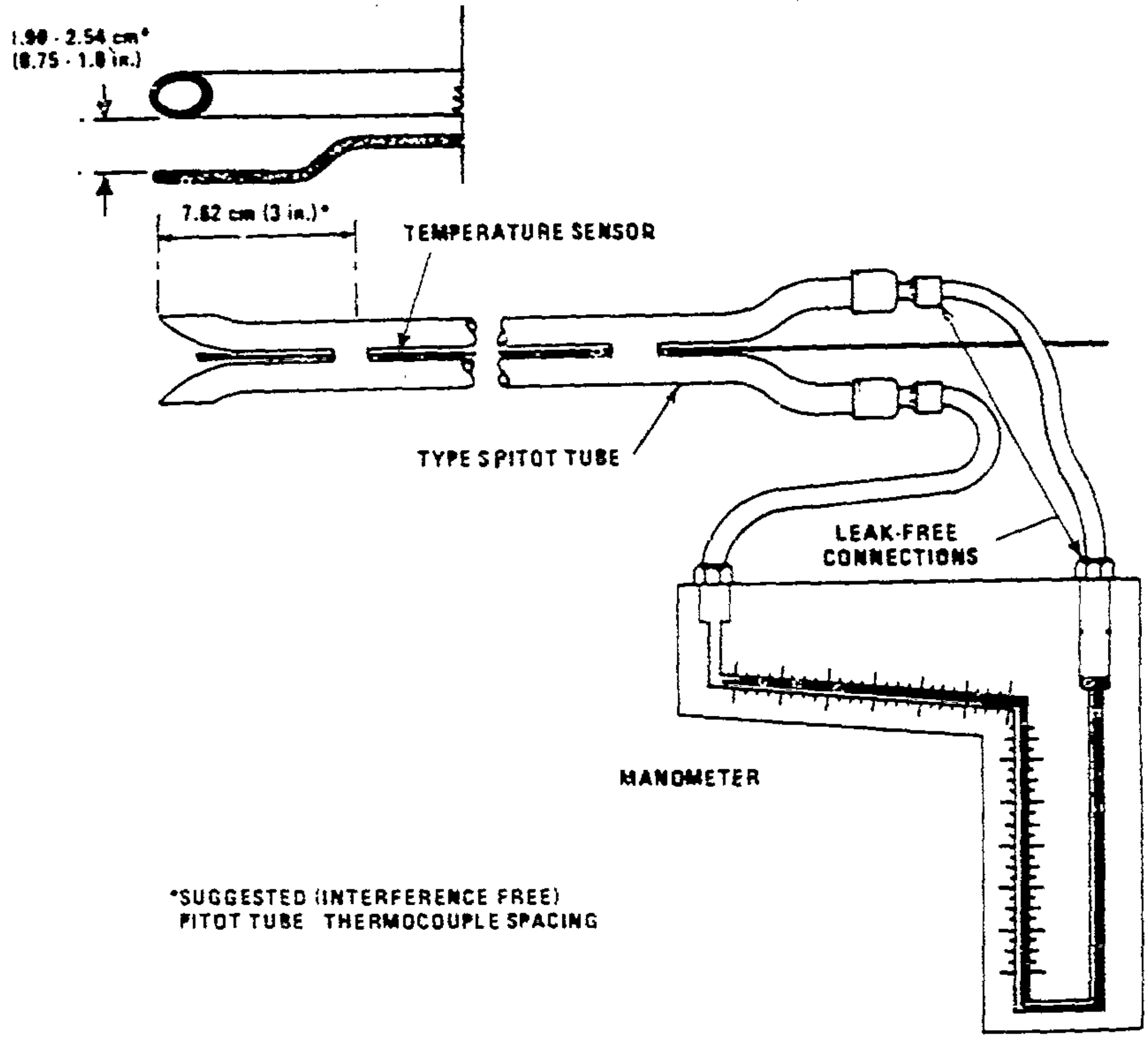


Figure 2-1. Type S pitot tube manometer assembly.

2.1 Type S Pitot Tube. The Type S pitot tube (Figure 2-1) shall be made of metal tubing (e.g., stainless steel). It is recommended that the external tubing diameter (dimension D_t Figure 2-2b) be between 0.48 and 0.95 centimeter (3/16 and 3/8 inch). There shall be an equal distance from the base of each leg of the pitot tube to its face-opening plane (dimensions P_A and P_B Figure 2-2b); it is recommended that this distance be between 1.05 and 1.50 times the external tubing diameter. The face openings of the pitot tube shall, preferably, be aligned as shown in Figure 2-2; however, slight misalignments of the openings are permissible (see Figure 2-3).

The Type S pitot tube shall have a known coefficient, determined as outlined in Section 4. An identification number shall be assigned to the pitot tube; this number shall be permanently marked or engraved on the body of the tube.

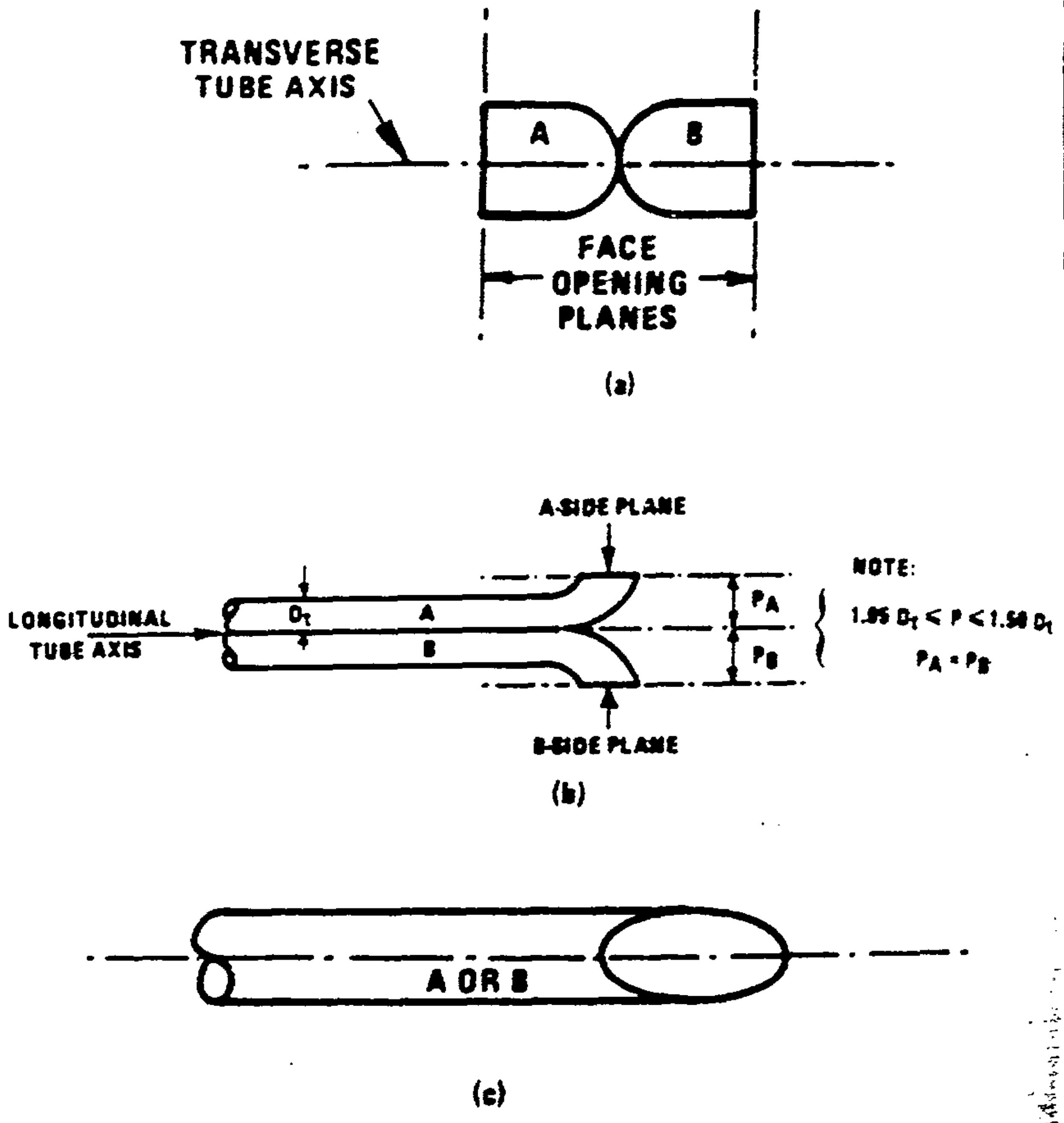


Figure 2-2. Properly constructed Type S pitot tube, shown in: (a) end view; face opening planes perpendicular to transverse axis; (b) top view; face opening planes parallel to longitudinal axis; (c) side view; both legs of equal length and centerlines coincident, when viewed from both sides. Baseline coefficient values of 0.84 may be assigned to pitot tubes constructed this way.

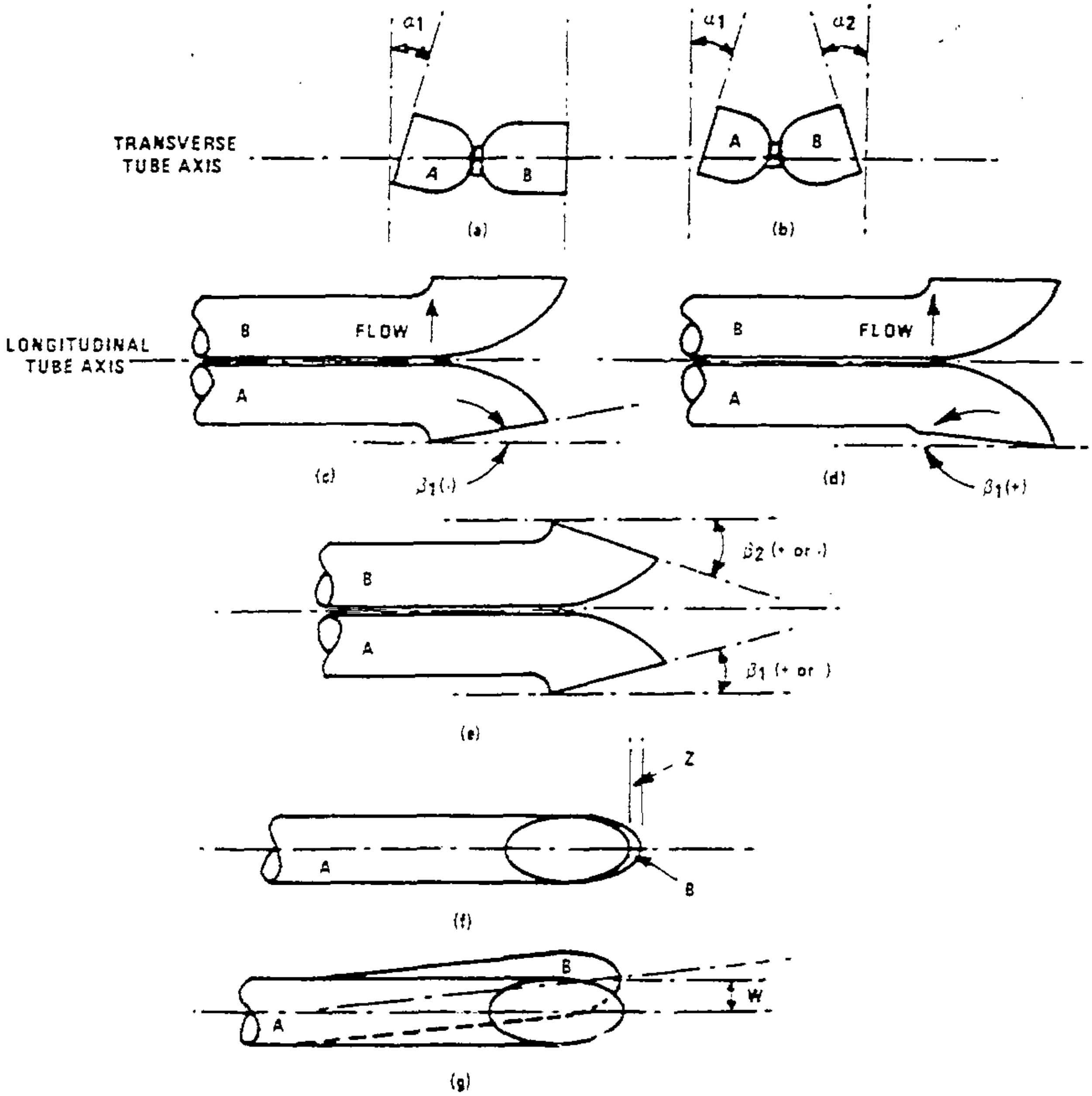


Figure 2–3. Types of face-opening misalignment that can result from field use or improper construction of Type S pitot tubes. These will not affect the baseline value of Cp(s) so long as α^1 and $\alpha^2 \leq 10°$, β^1 and $\beta^2 \leq 5°$, $z \leq 0.32$ cm (1/8 in.) and $w \leq 0.08$ cm (1/32 in.) (citation 11 in Bibliography).

A standard pitot tube may be used instead of a Type S, provided that it meets the specifications of Sections 2.7 and 4.2; note, however, that the static and impact pressure holes of standard pitot tubes are susceptible to plugging in particulate-laden gas streams. Therefore, whenever a standard pitot tube is used to perform a traverse, adequate proof must be furnished that the openings of the pitot tube have not plugged up during the traverse period; this can be done by taking a velocity head (Δp) reading at the final traverse point, cleaning out the impact and static holes of the standard pitot tube by "back-purging" with pressurized air, and then taking another Δp reading. If the Δp readings made before and after the air purge are the same (±5 percent), the traverse is acceptable. Otherwise, reject the run. Note that if Δp at the final traverse point is unsuitably low, another point may be selected. If "back-purging" at regular intervals is part of the procedure, then comparative Δp readings shall be taken, as above, for the last two back purges at which suitably high Δp readings are observed.

2.2 Differential Pressure Gauge. An inclined manometer or equivalent device is used. Most sampling trains are equipped with a 10-in. (water column) inclined-vertical manometer, having 0.01-in. H_2O divisions on the 0-to 1-in. inclined scale, and 0.1-in. H_2O divisions on the 1- to 10-in. vertical scale. This type of manometer (or other gauge of equivalent sensitivity) is satisfactory for the measurement of Δp values as low as 1.3 mm (0.05 in.) H_2O. However, a differential pressure gauge of greater sensitivity shall be used (subject to the approval of the Administrator), if any of the following is found to be true: (1) the arithmetic average of all Δp readings at the traverse points in the stack is less than 1.3 mm (0.05 in.) H_2O; (2) for traverses of 12 or more points, more than 10 percent of the individual Δp readings are below 1.3 mm (0.05 in.) H_2O; (3) for traverses of fewer than 12 points, more than one Δp reading is below 1.3 mm (0.05 in.) H_2O. Citation 18 in Bibliography describes commercially available instrumentation for the measurement of low-range gas velocities.

As an alternative to criteria (1) through (3) above, the following calculation may be performed to determine the necessity of using a more sensitive differential pressure gauge:

$$T=\frac{\sum_{i=1}^{n}\sqrt{\Delta p_i+K}}{\sum_{i=1}^{n}\sqrt{\Delta p_i}}$$

Where:

Δp_i=Individual velocity head reading at a traverse point, mm H_2O (in. H_2O).

n=Total number of traverse points.

K=0.13 mm H_2O when metric units are used and 0.005 in. H_2O when English units are used.

If T is greater than 1.05, the velocity head data are unacceptable and a more sensitive differential pressure gauge must be used.

NOTE: If differential pressure gauges other than inclined manometers are used (e.g., magnehelic gauges), their calibration must be checked after each test series. To check the calibration of a differential pressure gauge, compare Δp readings of the gauge with those of a gauge-oil manometer at a minimum of three points, approximately representing the range of Δp values in the stack. If, at each point, the values of Δp as read by the differential pressure gauge and gauge-oil manometer agree to within 5 percent, the differential pressure gauge shall be considered to be in proper calibration. Otherwise, the test series shall either be voided, or procedures to adjust the measured Δp values and final results shall be used subject to the approval of the Administrator.

2.3 Temperature Gauge. A thermocouple, liquid-filled bulb thermometer, bimetallic thermometer, mercury-in-glass thermometer, or other gauge, capable of measuring temperature to within 1.5 percent of the minimum absolute stack temperature shall be used. The temperature gauge shall be attached to the pitot tube such that the sensor tip does not touch any metal; the gauge shall be in an interference-free arrangement with respect to the pitot tube face openings (see Figure 2-1 and also Figure 2-7 in Section 4). Alternative positions may be used if the pitot tube-temperature gauge system is calibrated according to the procedure of Section 4. Provided that a difference of not more than 1 percent in the average velocity measurement is introduced, the temperature gauge need not be attached to the pitot tube; this alternative is subject to the approval of the Administrator.

2.4 Pressure Probe and Gauge. A piezometer tube and mercury- or water-filled U-tube manometer capable of measuring stack pressure to within 2.5 mm (0.1 in.) Hg is used. The static tap of a standard type pitot tube or one leg of a Type S pitot tube with the face opening planes positioned parallel to the gas flow may also be used as the pressure probe.

2.5 Barometer. A mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg) may be used. In many cases, the barometric reading may be obtained from a nearby National Weather Service station, in which case the station value (which is the absolute barometric pressure) shall be requested and an adjustment for elevation differences between the weather station and the sampling point shall be applied at a rate of minus 2.5 mm (0.1 in.) Hg per 30-meter (100 foot) elevation increase or vice-versa for elevation decrease.

2.6 Gas Density Determination Equipment. Method 3 equipment, if needed (see Section 3.6), to determine the stack gas dry molecular weight, and Reference Method 4 or Method 5 equipment for moisture content determination; other methods may be used subject to approval of the Administrator.

2.7 Calibration Pitot Tube. When calibration of the Type S pitot tube is necessary (see Section 4), a standard pitot tube is used as a reference. The standard pitot tube shall, preferably, have a known coefficient, obtained either (1) directly from the National Bureau of Standards, Route 270, Quince Orchard Road, Gaithersburg, Maryland, or (2) by calibration against another standard pitot tube with an NBS-traceable coefficient. Alternatively, a standard pitot tube designed according to the criteria given in 2.7.1 through 2.7.5 below and illustrated in Figure 2-4 (see also Citations 7, 8, and 17 in Bibliography) may be used. Pitot tubes designed according to these specifications will have baseline coefficients of about 0.99±0.01.

2.7.1 Hemispherical (shown in Figure 2-4), ellipsoidal, or conical tip.

2.7.2 A minimum of six diameters straight run (based upon *D*, the external diameter of the tube) between the tip and the static pressure holes.

2.7.3 A minimum of eight diameters straight run between the static pressure holes and the centerline of the external tube, following the 90 degree bend.

2.7.4 Static pressure holes of equal size (approximately 0.1 *D*), equally spaced in a piezometer ring configuration.

2.7.5 Ninety degree bend, with curved or mitered junction.

2.8 Differential Pressure Gauge for Type S Pitot Tube Calibration. An inclined manometer or equivalent is used. If the single-velocity calibration technique is employed (see Section 4.1.2.3), the calibration differential pressure gauge shall be readable to the nearest 0.13 mm H_2O (0.005 in. H_2O). For multivelocity calibrations, the gauge shall be readable to the nearest 0.13 mm H_2O (0.005 in. H_2O) for Δp values between 1.3 and 25 mm H_2O (0.05 and 1.0 in. H_2O), and to the nearest 1.3 mm H_2O (0.05 in. H_2O) for Δp values above 25 mm H_2O (1.0 in. H_2O). A special, more sensitive gauge will be required to read Δp values below 1.3 mm H_2O [0.05 in. H_2O] (see Citation 18 in Bibliography).

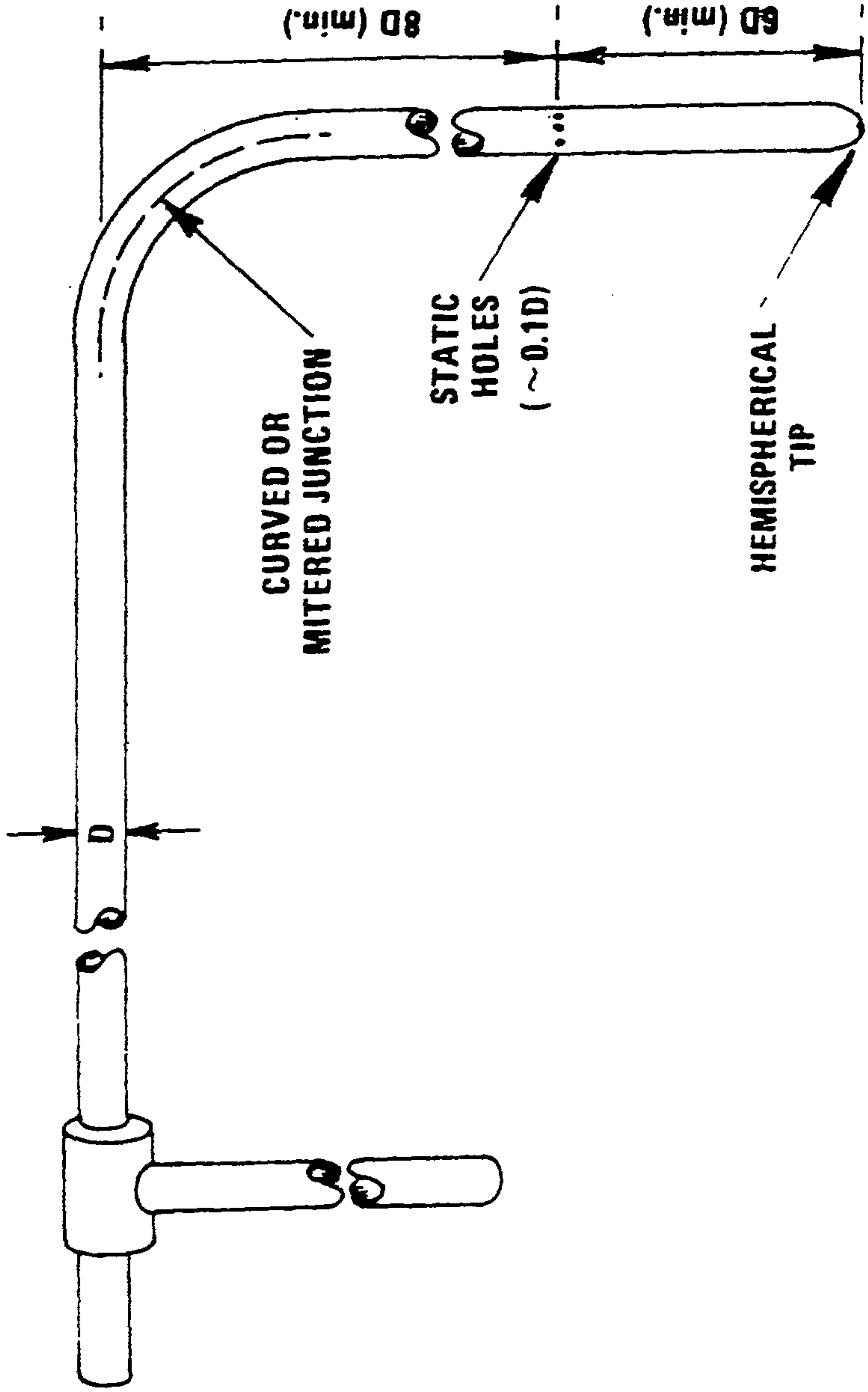


Figure 2-4. Standard pitot tube design specifications

3. *Procedure*

3.1 Set up the apparatus as shown in Figure 2–1. Capillary tubing or surge tanks installed between the manometer and pitot tube may be used to dampen Δp fluctuations. It is recommended, but not required, that a pretest leak-check be conducted, as follows: (1) blow through the pitot impact opening until at least 7.6 cm (3 in.) H_2O velocity pressure registers on the manometer; then, close off the impact opening. The pressure shall remain stable for at least 15 seconds; (2) do the same for the static pressure side, except using suction to obtain the minimum of 7.6 cm (3 in.) H_2O. Other leak-check procedures, subject to the approval of the Administrator, may be used.

3.2 Level and zero the manometer. Because the manometer level and zero may drift due to vibrations and temperature changes, make periodic checks during the traverse. Record all necessary data as shown in the example data sheet (Figure 2–5).

3.3 Measure the velocity head and temperature at the traverse points specified by Method 1. Ensure that the proper differential pressure gauge is being used for the range of Δp values encountered (see Section 2.2). If it is necessary to change to a more sensitive gauge, do so, and remeasure the Δp and temperature readings at each traverse point. Conduct a post-test leak-check (mandatory), as described in Section 3.1 above, to validate the traverse run.

3.4 Measure the static pressure in the stack. One reading is usually adequate.

3.5 Determine the atmospheric pressure.

PLANT ____________________

DATE ____________________ RUN NO. ____________________

STACK DIAMETER OR DIMENSIONS, m(in.) ____________________

BAROMETRIC PRESSURE, mm Hg (in. Hg) ____________________

CROSS SECTIONAL AREA, $m^2 (ft^2)$ ____________________

OPERATORS ____________________

PITOT TUBE I.D. NO. ____________________

AVG. COEFFICIENT, C_p = ____________________

LAST DATE CALIBRATED ____________________

SCHEMATIC OF STACK CROSS SECTION

Traverse Pt. No.	Vel. Hd., Δp mm (in.) H_2O	Stack Temperature		P_g mm Hg (in.Hg)	$\sqrt{\Delta p}$
		t_s, °C (°F)	T_s, °K (°R)		
		Average			

Figure 2-5. Velocity traverse data.

3.6 Determine the stack gas dry molecular weight. For combustion processes or processes that emit essentially CO_2, O_2, CO, and N_2, use Method 3. For processes emitting essentially air, an analysis need not be conducted; use a dry molecular weight of 29.0. For other processes, other methods, subject to the approval of the Administrator, must be used.

3.7 Obtain the moisture content from Reference Method 4 (or equivalent) or from Method 5.

3.8 Determine the cross-sectional area of the stack or duct at the sampling location. Whenever possible, physically measure the stack dimensions rather than using blueprints.

4. *Calibration*

4.1 Type S Pitot Tube. Before its initial use, carefully examine the Type S pitot tube in top, side, and end views to verify that the face openings of the tube are aligned within the specifications illustrated in Figure 2–2 or 2–3. The pitot tube shall not be used if it fails to meet these alignment specifications.

After verifying the face opening alignment, measure and record the following dimensions of the pitot tube: (a) the external tubing diameter (dimension D_t, Figure 2–2b); and (b) the base-to-opening plane distances (dimensions P_A and P_B, Figure 2–2b). If D_t is between 0.48 and 0.95 cm (3⁄16 and 3⁄8 in.) and if P_A and P_B are equal and between 1.05 and 1.50 D_t, there are two possible options: (1) the pitot tube may be calibrated according to the procedure outlined in Sections 4.1.2 through 4.1.5 below, or (2) a baseline (isolated tube) coefficient value of 0.84 may be assigned to the pitot tube. Note, however, that if the pitot tube is part of an assembly, calibration may still be required, despite knowledge of the baseline coefficient value (see Section 4.1.1).

If D_t, P_A, and P_B are outside the specified limits, the pitot tube must be calibrated as outlined in 4.1.2 through 4.1.5 below.

4.1.1 Type S Pitot Tube Assemblies. During sample and velocity traverses, the isolated Type S pitot tube is not always used; in many instances, the pitot tube is used in combination with other source-sampling components (thermocouple, sampling probe, nozzle) as part of an "assembly." The presence of other sampling components can sometimes affect the baseline value of the Type S pitot tube coefficient (Citation 9 in Bibliography); therefore an assigned (or otherwise known) baseline coefficient value may or may not be valid for a given assembly. The baseline and assembly coefficient values will be identical only when the relative placement of the components in the assembly is such that aerodynamic interference effects are eliminated. Figures 2–6 through 2–8 illustrate interference-free component arrangements for Type S pitot tubes having external tubing diameters between 0.48 and 0.95 cm (3⁄16 and 3⁄8 in.). Type S pitot tube assemblies that fail to meet any or all of the specifications of Figures 2–6 through 2–8 shall be calibrated according to the procedure outlined in Sections 4.1.2 through 4.1.5 below, and prior to calibration, the values of the intercomponent spacings (pitot-nozzle, pitot-thermocouple, pitot-probe sheath) shall be measured and recorded.

NOTE: Do not use any Type S pitot tube assembly which is constructed such that the impact pressure opening plane of the pitot tube is below the entry plane of the nozzle (see Figure 2–6b).

4.1.2 Calibration Setup. If the Type S pitot tube is to be calibrated, one leg of the tube shall be permanently marked A, and the other, B. Calibration shall be done in a flow system having the following essential design features:

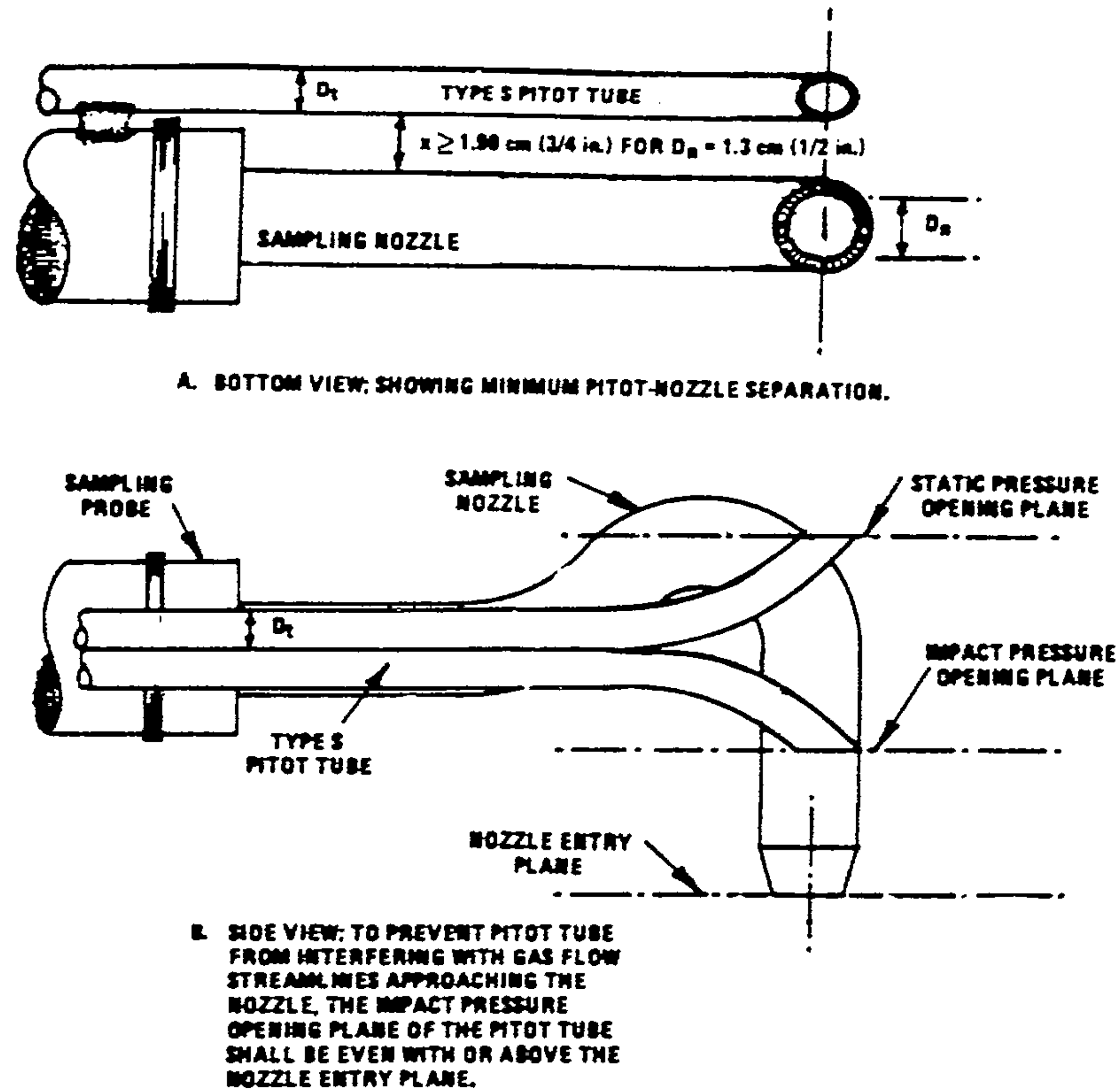


Figure 2-6. Proper pitot tube-sampling nozzle configuration to prevent aerodynamic interference; buttonhook-type nozzle; centers of nozzle and pitot opening aligned; D_t between 0.48 and 0.95 cm (3/16 and 3/8 in.).

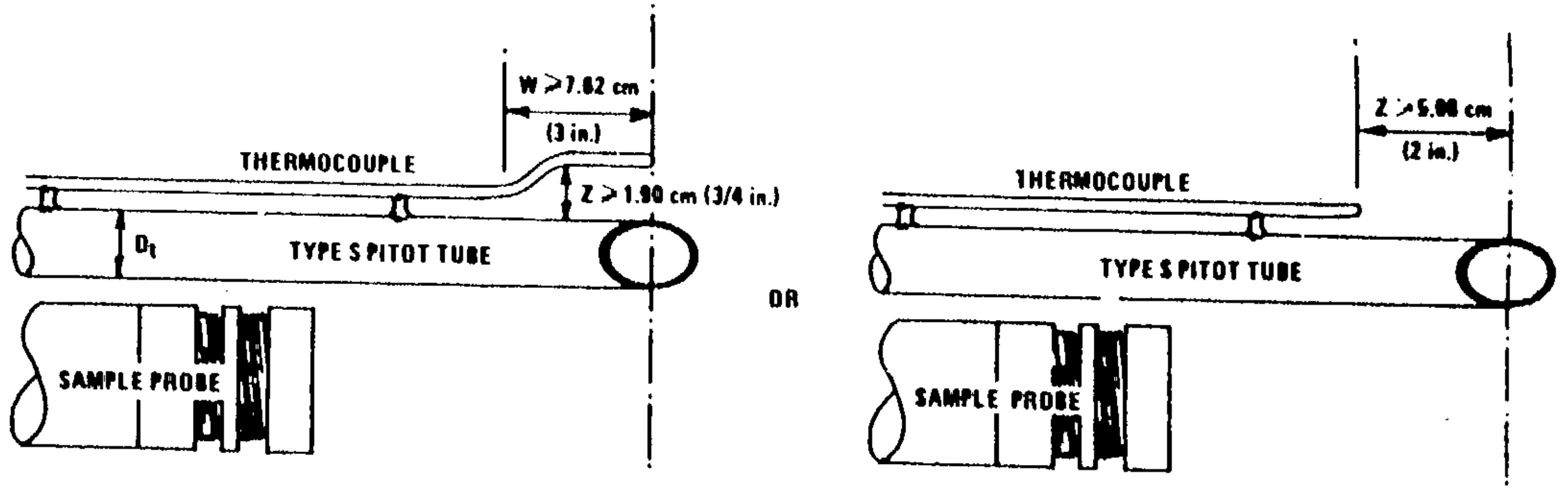


Figure 2-7. Proper thermocouple placement to prevent interference; D_t between 0.48 and 0.95 cm (3/16 and 3/8 in.).

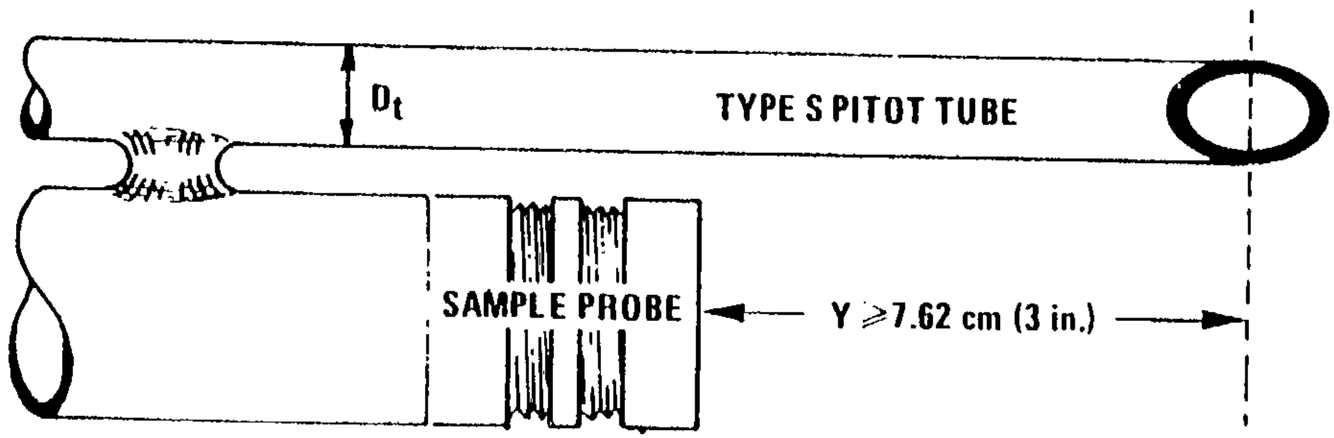


Figure 2-8. Minimum pitot-sample probe separation needed to prevent interference; D_t between 0.48 and 0.95 cm (3/16 and 3/8 in.).

4.1.2.1 The flowing gas stream must be confined to a duct of definite cross-sectional area, either circular or rectangular. For circular cross-sections, the minimum duct diameter shall be 30.5 cm (12 in.); for rectangular cross-sections, the width (shorter side) shall be at least 25.4 cm (10 in.).

4.1.2.2 The cross-sectional area of the calibration duct must be constant over a distance of 10 or more duct diameters. For a rectangular cross-section, use an equivalent diameter, calculated from the following equation, to determine the number of duct diameters:

$$D_e = \frac{2LW}{(L+W)} \qquad \text{Eq. 2-1}$$

Where:
D_e=Equivalent diameter
L=Length
W=Width

To ensure the presence of stable, fully developed flow patterns at the calibration site, or "test section," the site must be located at least eight diameters downstream and two diameters upstream from the nearest disturbances.

NOTE: The eight- and two-diameter criteria are not absolute; other test section locations may be used (subject to approval of the Administrator), provided that the flow at the test site is stable and demonstrably parallel to the duct axis.

4.1.2.3 The flow system shall have the capacity to generate a test-section velocity around 915 m/min (3,000 ft/min). This velocity must be constant with time to guarantee steady flow during calibration. Note that Type S pitot tube coefficients obtained by single-velocity calibration at 915 m/min (3,000 ft/min) will generally be valid to within ±3 percent for the measurement of velocities above 305 m/min (1,000 ft/min) and to within ±5 to 6 percent for the measurement of velocities between 180 and 305 m/min (600 and 1,000 ft/min). If a more precise correlation between C_p and velocity is desired, the flow system shall have the capacity to generate at least four distinct, time-invariant test-section velocities covering the velocity range from 180 to 1,525 m/min (600 to 5,000 ft/min), and calibration data shall be taken at regular velocity intervals over this range (see Citations 9 and 14 in Bibliography for details).

4.1.2.4 Two entry ports, one each for the standard and Type S pitot tubes, shall be cut in the test section; the standard pitot entry port shall be located slightly downstream of the Type S port, so that the standard and Type S impact openings will lie in the same cross-sectional plane during calibration. To facilitate alignment of the pitot tubes during calibration, it is advisable that the test section be constructed of plexiglas or some other transparent material.

4.1.3 Calibration Procedure. Note that this procedure is a general one and must not be used without first referring to the special considerations presented in Section 4.1.5. Note also that this procedure applies only to single-velocity calibration. To obtain calibration data for the A and B sides of the Type S pitot tube, proceed as follows:

4.1.3.1 Make sure that the manometer is properly filled and that the oil is free from contamination and is of the proper density. Inspect and leak-check all pitot lines; repair or replace if necessary.

4.1.3.2 Level and zero the manometer. Turn on the fan and allow the flow to stabilize. Seal the Type S entry port.

4.1.3.3 Ensure that the manometer is level and zeroed. Position the standard pitot tube at the calibration point (determined as outlined in Section 4.1.5.1), and align the tube so that its tip is pointed directly into the flow. Particular care should be taken in aligning the tube to avoid yaw and pitch angles. Make sure that the entry port surrounding the tube is properly sealed.

4.1.3.4 Read Δp_{std} and record its value in a data table similar to the one shown in Figure 2–9. Remove the standard pitot tube from the duct and disconnect it from the manometer. Seal the standard entry port.

4.1.3.5 Connect the Type S pitot tube to the manometer. Open the Type S entry port. Check the manometer level and zero. Insert and align the Type S pitot tube so that its A side impact opening is at the same point as was the standard pitot tube and is pointed directly into the flow. Make sure that the entry port surrounding the tube is properly sealed.

4.1.3.6 Read Δp_s and enter its value in the data table. Remove the Type S pitot tube from the duct and disconnect it from the manometer.

4.1.3.7 Repeat steps 4.1.3.3 through 4.1.3.6 above until three pairs of Δp readings have been obtained.

4.1.3.8 Repeat steps 4.1.3.3 through 4.1.3.7 above for the B side of the Type S pitot tube.

4.1.3.9 Perform calculations, as described in Section 4.1.4 below.

4.1.4 Calculations.

4.1.4.1 For each of the six pairs of Δp readings (i.e., three from side A and three from side B) obtained in Section 4.1.3 above, calculate the value of the Type S pitot tube coefficient as follows:

PITOT TUBE IDENTIFICATION NUMBER: __________ DATE: __________

CALIBRATED BY: __________

	"A" SIDE CALIBRATION			
RUN NO.	Δp_{std} cm H_2O (in. H_2O)	$\Delta p_{(s)}$ cm H_2O (in. H_2O)	$C_{p(s)}$	DEVIATION $C_{p(s)} - \bar{C}_p(A)$
1				
2				
3				
		$\bar{C}_p$ (SIDE A)		

	"B" SIDE CALIBRATION			
RUN NO.	Δp_{std} cm H_2O (in. H_2O)	$\Delta p_{(s)}$ cm H_2O (in. H_2O)	$C_{p(s)}$	DEVIATION $C_{p(s)} - \bar{C}_p(B)$
1				
2				
3				
		$\bar{C}_p$ (SIDE B)		

$$\text{AVERAGE DEVIATION} = \sigma\,(\text{A OR B}) = \frac{\sum_{1}^{3} \left| C_p(s) - \bar{C}_p(\text{A OR B}) \right|}{3} \longleftarrow \text{MUST BE} \leq 0.01$$

$$\left| \bar{C}_p\,(\text{SIDE A}) - \bar{C}_p\,(\text{SIDE B}) \right| \longleftarrow \text{MUST BE} < 0.01$$

Figure 2-9. Pitot tube calibration data.

$$C_{p(s)} = C_{p(std)} \sqrt{\frac{\Delta p_{std}}{\Delta p_s}}$$

Equation 2-2

Where:

$C_{p(s)}$=Type S pitot tube coefficient

$C_{p(std)}$=Standard pitot tube coefficient; use 0.99 if the coefficient is unknown and the tube is designed according to the criteria of Sections 2.7.1 to 2.7.5 of this method.

Δp_{std}=Velocity head measured by the standard pitot tube, cm H_2O (in. H_2O)

Δp_s=Velocity head measured by the Type S pitot tube, cm H_2O (in. H_2O)

4.1.4.2 Calculate $\bar{C}_p$ (side A), the mean A-side coefficient, and $\bar{C}_p$ (side B), the mean B-side coefficient: calculate the difference between these two average values.

4.1.4.3 Calculate the deviation of each of the three A-side values of $C_{p(s)}$ from $\bar{C}_p$ (side A), and the deviation of each B-side value of $C_{p(s)}$ from $\bar{C}_p$ (side B). Use the following equation:

$$\text{Deviation} = C_{p(s)} - \bar{C}_p(\text{A or B})$$

Equation 2-3

4.1.4.4 Calculate σ, the average deviation from the mean, for both the A and B sides of the pitot tube. Use the following equation:

$$\sigma\,(\text{side A or B}) = \frac{\sum_{1}^{3} |C_{p(s)} - \bar{C}_p(A \text{ or } B)|}{3}$$

Equation 2-4

4.1.4.5 Use the Type S pitot tube only if the values of σ (side A) and σ (side B) are less than or equal to 0.01 and if the absolute value of the difference between $\bar{C}_p$ (A) and $\bar{C}_p$ (B) is 0.01 or less.

4.1.5 Special considerations.

4.1.5.1 Selection of calibration point.

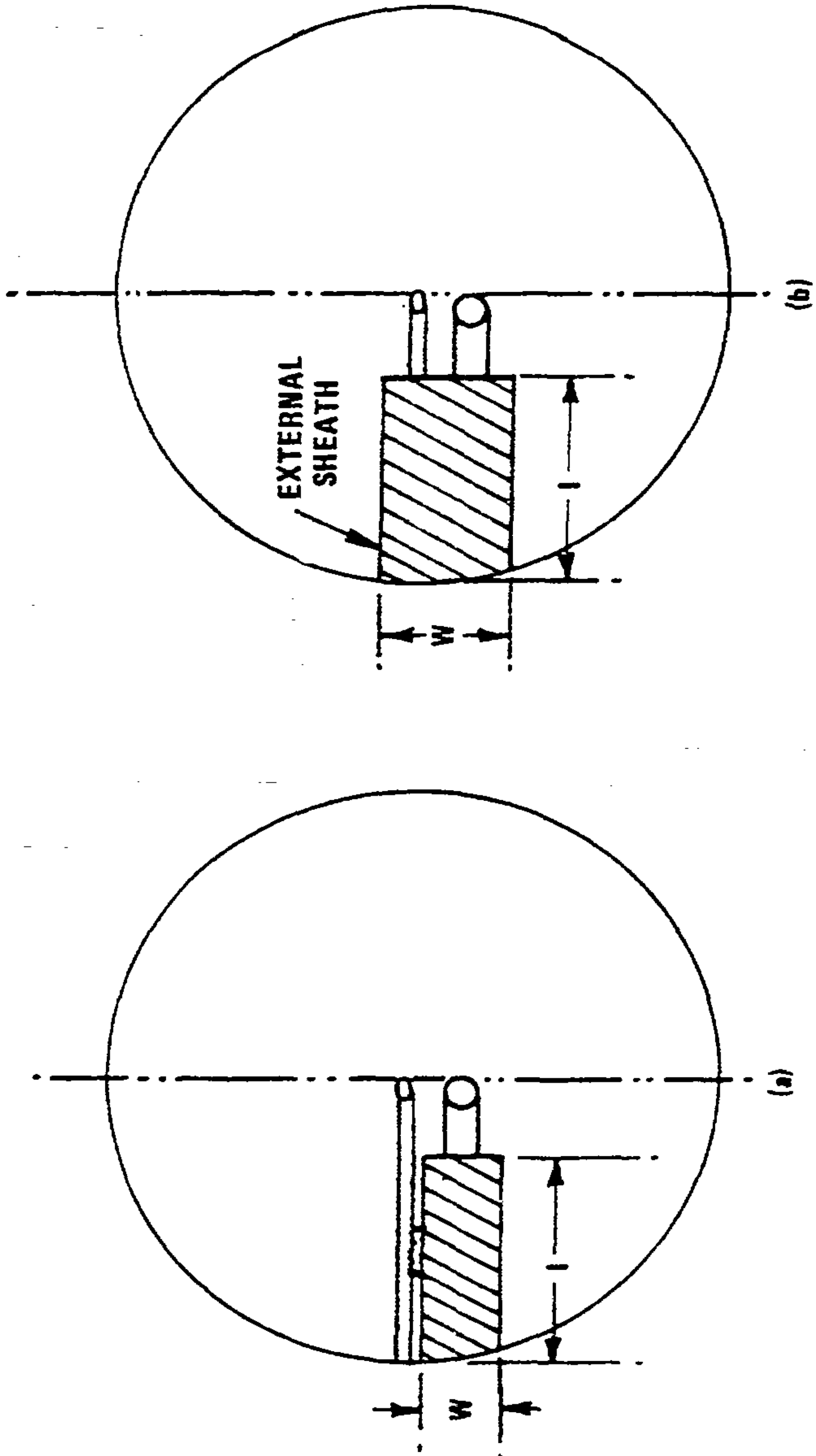
4.1.5.1.1 When an isolated Type S pitot tube is calibrated, select a calibration point at or near the center of the duct, and follow the procedures outlined in Sections 4.1.3 and 4.1.4 above. The Type S pitot coefficients so obtained, i.e., $\bar{C}_p$ (side A) and $\bar{C}_p$ (side B), will be valid, so long as either: (1) the isolated pitot tube is used; or (2) the pitot tube is used with other components (nozzle, thermocouple, sample probe) in an arrangement that is free from aerodynamic interference effects (see Figures 2-6 through 2-8).

4.1.5.1.2 For Type S pitot tube-thermocouple combinations (without sample probe), select a calibration point at or near the center of the duct, and follow the procedures outlined in Sections 4.1.3 and 4.1.4 above. The coefficients so obtained will be valid so long as the pitot tube-thermocouple combination is used by itself or with other components in an interference-free arrangement (Figures 2-6 and 2-8).

4.1.5.1.3 For assemblies with sample probes, the calibration point should be located at or near the center of the duct; however, insertion of a probe sheath into a small duct may cause significant cross-sectional area blockage and yield incorrect coefficient values (Citation 9 in Bibliography). Therefore, to minimize the blockage effect, the calibration point may be a few inches off-center if necessary. The actual blockage effect will be negligible when the theoretical blockage, as determined by a projected-area model of the probe sheath, is 2 percent or less of the duct cross-sectional area for assemblies without external sheaths (Figure 2-10a), and 3 percent or less for assemblies with external sheaths (Figure 2-10b).

4.1.5.2 For those probe assemblies in which pitot tube-nozzle interference is a factor (i.e., those in which the pitot-nozzle separation distance fails to meet the specification illustrated in Figure 2-6a), the value of $C_{p(s)}$ depends upon the amount of free-space between the tube and nozzle, and therefore is a function of nozzle size. In these instances, separate calibrations shall be performed with each of the commonly used nozzle sizes in place. Note that the single-velocity calibration technique is acceptable for this purpose, even though the larger nozzle sizes (>0.635 cm or ¼ in.) are not ordinarily used for isokinetic sampling at velocities around 915 m/min (3,000 ft/min), which is the calibration velocity; note also that it is not necessary to draw an isokinetic sample during calibration (see Citation 19 in Section 6).

4.1.5.3 For a probe assembly constructed such that its pitot tube is always used in the same orientation, only one side of the pitot tube need be calibrated (the side which will face the flow). The pitot tube must still meet the alignment specifications of Figure 2-2 or 2-3, however, and must have an average deviation (σ) value of 0.01 or less (see Section 4.1.4.4).



$$\text{ESTIMATED SHEATH BLOCKAGE (\%)} = \left[\frac{l \times W}{\text{DUCT AREA}}\right] \times 100$$

Figure 2-10. Projected-area models for typical pitot tube assemblies.

4.1.6 Field Use and Recalibration.

4.1.6.1 Field Use.

4.1.6.1.1 When a Type S pitot tube (isolated tube or assembly) is used in the field, the appropriate coefficient value (whether assigned or obtained by calibration) shall be used to perform velocity calculations. For calibrated Type S pitot tubes, the A side coefficient shall be used when the A side of the tube faces the flow, and the B side coefficient shall be used when the B side faces the flow; alternatively, the arithmetic average of the A and B side coefficient values may be used, irrespective of which side faces the flow.

4.1.6.1.2 When a probe assembly is used to sample a small duct (12 to 36 in. in diameter), the probe sheath sometimes blocks a significant part of the duct cross-section, causing a reduction in the effective value of $C_{p(s)}$. Consult Citation 9 in Bibliography for details. Conventional pitot-sampling probe assemblies are not recommended for use in ducts having inside diameters smaller than 12 inches (Citation 16 in Bibliography).

4.1.6.2 Recalibration.

4.1.6.2.1 Isolated Pitot Tubes. After each field use, the pitot tube shall be carefully reexamined in top, side, and end views. If the pitot face openings are still aligned within the specifications illustrated in Figure 2–2 or 2–3, it can be assumed that the baseline coefficient of the pitot tube has not changed. If, however, the tube has been damaged to the extent that it no longer meets the specifications of Figure 2–2 or 2–3, the damage shall either be repaired to restore proper alignment of the face openings or the tube shall be discarded.

4.1.6.2.2 Pitot Tube Assemblies. After each field use, check the face opening alignment of the pitot tube, as in Section 4.1.6.2.1; also, remeasure the intercomponent spacings of the assembly. If the intercomponent spacings have not changed and the face opening alignment is acceptable, it can be assumed that the coefficient of the assembly has not changed. If the face opening alignment is no longer within the specifications of Figures 2–2 or 2–3, either repair the damage or replace the pitot tube (calibrating the new assembly, if necessary). If the intercomponent spacings have changed, restore the original spacings or recalibrate the assembly.

4.2 Standard pitot tube (if applicable). If a standard pitot tube is used for the velocity traverse, the tube shall be constructed according to the criteria of Section 2.7 and shall be assigned a baseline coefficient value of 0.99. If the standard pitot tube is used as part of an assembly, the tube shall be in an interference-free arrangement (subject to the approval of the Administrator).

4.3 Temperature Gauges. After each field use, calibrate dial thermometers, liquid-filled bulb thermometers, thermocouple-potentiometer systems, and other gauges at a temperature within 10 percent of the average absolute stack temperature. For temperatures up to 405° C (761° F), use an ASTM mercury-in-glass reference thermometer, or equivalent, as a reference; alternatively, either a reference thermocouple and potentiometer (calibrated by NBS) or thermometric fixed points, e.g., ice bath and boiling water (corrected for barometric pressure) may be used. For temperatures above 405° C (761° F), use an NBS-calibrated reference thermocouple-potentiometer system or an alternate reference, subject to the approval of the Administrator.

If, during calibration, the absolute temperatures measured with the gauge being calibrated and the reference gauge agree within 1.5 percent, the temperature data taken in the field shall be considered valid. Otherwise, the pollutant emission test shall either be considered invalid or adjustments (if appropriate) of the test results shall be made, subject to the approval of the Administrator.

4.4 Barometer. Calibrate the barometer used against a mercury barometer.

5. *Calculations*

Carry out calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after final calculation.

5.1 Nomenclature.

A=Cross-sectional area of stack, m^2 (ft^2).

B_{ws}=Water vapor in the gas stream (from Method 5 or Reference Method 4), proportion by volume.

C_p=Pitot tube coefficient, dimensionless.

K_p=Pitot tube constant,

$$34.97\ \frac{m}{sec}\left[\frac{(g/g\text{-mole})(mm\ Hg)}{(°K)(mm\ H_2O)}\right]^{1/2}$$

for the metric system and

$$85.49\ \frac{ft}{sec}\left[\frac{(lb/lb\text{-mole})(in.\ Hg)}{(°R)(in.\ H_2O)}\right]^{1/2}$$

for the English system.

M_d=Molecular weight of stack gas, dry basis (see Section 3.6) g/g-mole (lb/lb-mole).

M_s=Molecular weight of stack gas, wet basis, g/g-mole (lb/lb-mole).

$=M_d\ (1-B_{ws})+18.0\ B_{ws}$

Eq. 2–

P_{bar}=Barometric pressure at measurement site, mm Hg (in. Hg).

P_g=Stack static pressure, mm Hg (in. Hg).

P_s=Absolute stack gas pressure, mm Hg (in. Hg).

$=P_{bar}+P_g$

Eq. 2-6

P_{std}=Standard absolute pressure, 760 mm Hg (29.92 in. Hg).

Q_{sd}=Dry volumetric stack gas flow rate corrected to standard conditions, dscm/hr (dscf/hr).

t_s=Stack temperature, °C (°F).

T_s=Absolute stack temperature, °K, (°R).

=273+t_s for metric.

Eq. 2-7

=460+t_s for English.

Eq. 2-8

T_{std}=Standard absolute temperature, 293 °K (528° R).

v_s=Average stack gas velocity, m/sec (ft/sec).

Δp=Velocity head of stack gas, mm H_2O (in. H_2O).

3,600=Conversion factor, sec/hr.

18.0=Molecular weight of water, g/g-mole (lb/lb-mole).

5.2 Average Stack Gas Velocity.

$$v_s = K_p C_p (\sqrt{\Delta p})_{avg} \sqrt{\frac{T_{s(avg)}}{P_s M_s}}$$

Equation 2-9

5.3 Average Stack Gas Dry Volumetric Flow Rate.

$$Q_{sd} = 3{,}600(1 - B_{ws}) v_s A \frac{T_{std}}{T_{s(avg)}} \frac{P_s}{P_{std}}$$

Eq. 2-10

To convert Q_{sd} from dscm/hr (dscf/hr) to dscm/min (dscf/min), divide Q_{sd} by 60.

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pressure, compressibility, and molecular weight. Use the procedure in Section 3.3.1. Record all the measuring device parameters on a time interval frequency sufficient to adequately profile each process cyclical or noncontinuous event. A multichannel continuous recorder may be used.

4. Calibration

4.1 Flow Rate Measuring Device. Use the procedure in Method 2A, Section 4, and apply the same performance standards. Calibrate the measuring device with the principal stack gas to be measured (e.g., air, nitrogen) against a standard reference meter. A calibrated dry gas meter is an acceptable reference meter. Ideally, calibrate the measuring device in the field with the actual gas to be measured. For measuring devices that have a volume rate readout, calculate the measuring device calibration coefficient, Y_m, for each run as follows:

$$Y_m = \frac{(Q_r)\,(T_r)\,P_{bar}}{(Q_m)\,(T_m)\,(P_{bar} + P_g)} \qquad \text{Eq. 2D-1}$$

where:

Q_r=reference meter flow rate reading, m³/min (ft³/min).

Q_m=measuring device flow rate reading, m³/min (ft³/min).

T_r=reference meter average absolute temperature, °K (°R).

T_m=measuring device average absolute temperature, °K (°R).

P_{bar}=barometric pressure, mm Hg (in. Hg).

P_g=measuring device average static pressure, mm Hg (in. Hg).

For measuring devices that do not have a readout as flow rate, refer to the manufacturer's instructions to calculate the Q_m corresponding to each Q_r.

4.2 Temperature Gauge. Use the procedure and specifications in Method 2A, Section 4.2. Perform the calibration at a temperature that approximates field test conditions.

4.3 Barometer. Calibrate the barometer to be used in the field test with a mercury barometer prior to the field test.

5. Gas Flow Rate Calculation

Calculate the stack gas flow rate, Q_s, as follows:

$$Q_s = K_1 Y_m Q_m \frac{(P_{bar} + P_g)}{T_m} \qquad \text{Eq. 2D-2}$$

where:

K_1 = 0.3858 for international system of units (SI); 17.64 for English units.

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METHOD 3—GAS ANALYSIS FOR THE DETERMINATION OF DRY MOLECULAR WEIGHT

1. APPLICABILITY AND PRINCIPLE

1.1 Applicability.

1.1.1 This method is applicable for determining carbon dioxide (CO_2) and oxygen (O_2) concentrations and dry molecular weight of a sample from a gas stream of a fossil-fuel combustion process. The method may also be applicable to other processes where it has been determined that compounds other than CO_2, O_2, carbon monoxide (CO), and nitrogen (N_2) are not present in concentrations sufficient to affect the results.

1.1.2 Other methods, as well as modifications to the procedure described herein, are also applicable for some or all of the above determinations. Examples of specific methods and modifications include: (1) A multipoint sampling method using an Orsat analyzer to analyze individual grab samples obtained at each point; (2) a method using CO_2 or O_2 and stoichiometric calculations to determine dry molecular weight; and (3) assigning a value of 30.0 for dry molecular weight, in lieu of actual measurements, for processes burning natural gas, coal, or oil. These methods and modifications may be used, but are subject to the approval of the Administrator, U.S. Environmental Protection Agency (EPA).

1.1.3 Note. Mention of trade names or specific products does not constitute endorsements by EPA.

1.2 Principle. A gas sample is extracted from a stack by one of the following methods: (1) Single-point, grab sampling; (2) single-point, integrated sampling; or (3) multipoint, integrated sampling. The gas sample is analyzed for pecent CO_2, percent O_2, and if necessary, for percent CO. For dry molecular weight determination, either an Orsat or a Fyrite analyzer may be used for the analysis.

2. APPARATUS

As an alternative to the sampling apparatus and systems described herein, other sampling systems (e.g., liquid displacement) may be used, provided such systems are capable of obtaining a representative sample and maintaining a constant sampling rate, and are, otherwise, capable of yielding acceptable results. Use of such systems is subject to the approval of the Administrator.

2.1 Grab Sampling (Figure 3–1).

2.1.1 Probe. Stainless steel or borosilicate glass tubing equipped with an in-stack or out-stack filter to remove particulate matter (a plug of glass wool is satisfactory for this purpose). Any other materials, inert to O_2, CO_2, CO, and N_2 and resistant to temperature at sampling conditions, may be used for the probe. Examples of such materials are aluminum, copper, quartz glass, and Teflon.

2.1.2 Pump. A one-way squeeze bulb, or equivalent, to transport the gas sample to the analyzer.

2.2 Integrated Sampling (Figure 3–2).

2.2.1 Probe. Same as in Section 2.1.1.

2.2.2 Condenser. An air-cooled or water-cooled condenser, or other condenser no greater than 250 ml that will not remove O_2, CO_2, CO, and N_2, to remove excess moisture which would interfere with the operation of the pump and flowmeter.

2.2.3 Valve. A needle valve, to adjust sample gas flow rate.

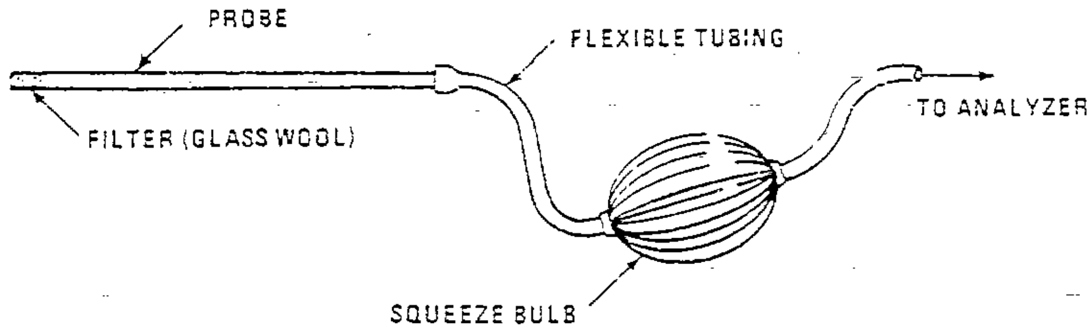

Figure 3-1. Grab-sampling train.

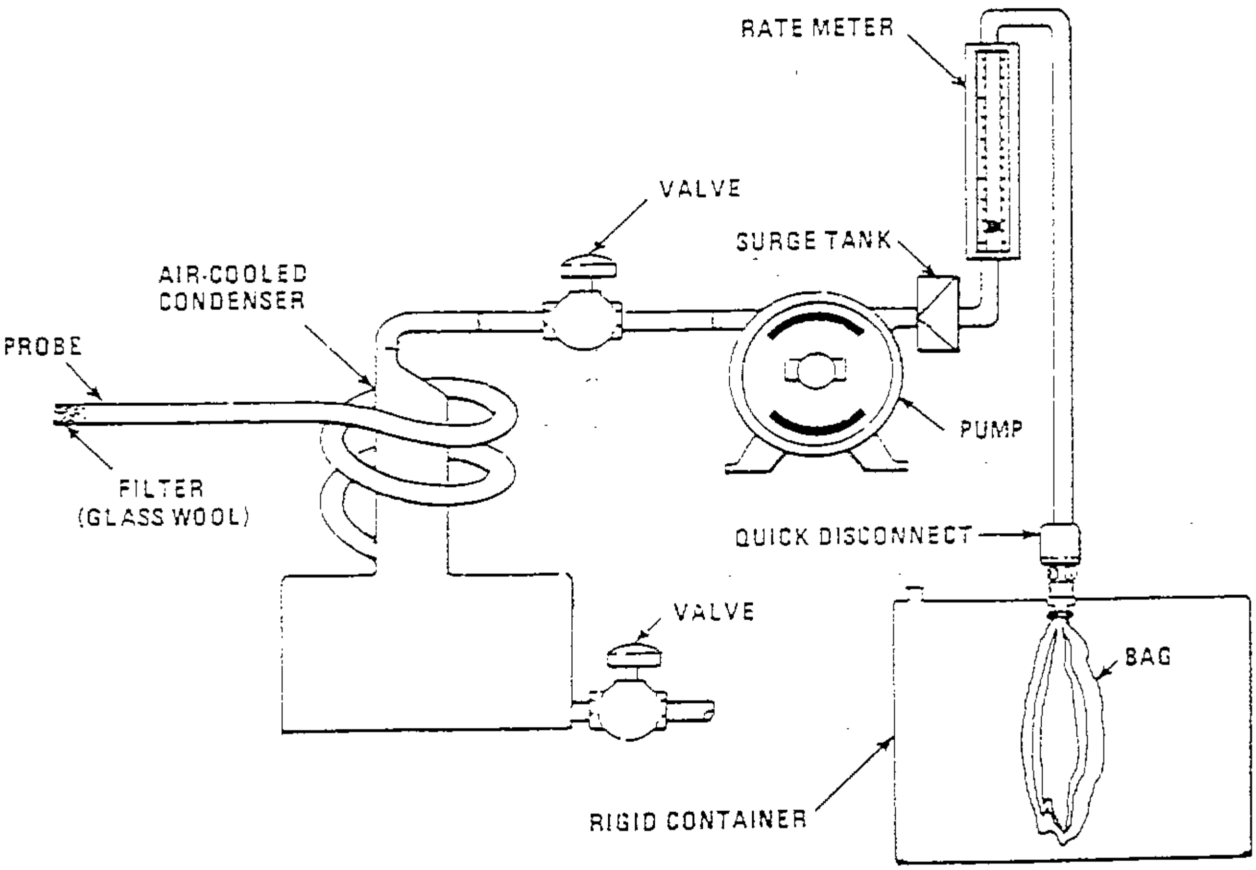

Figure 3-2. Integrated gas-sampling train.

2.2.4 Pump. A leak-free, diaphragm-type pump, or equivalent, to transport sample gas to the flexible bag. Install a small surge tank between the pump and rate meter to eliminate the pulsation effect of the diaphragm pump on the rotameter.

2.2.5 Rate Meter. A rotameter, or equivalent rate meter, capable of measuring flow rate to within 2 percent of the selected flow rate. A flow rate range of 500 to 1000 cc/min is suggested.

2.2.6 Flexible Bag. Any leak-free plastic (e.g., Tedlar, Mylar, Teflon) or plastic-coated aluminum (e.g., aluminized Mylar) bag, or equivalent, having a capacity consistent with the selected flow rate and time length of the test run. A capacity in the range of 55 to 90 liters is suggested. To leak check the bag, connect it to a water manometer, and pressurize the bag to 5 to 10 cm H_2O (2 to 4 in. H_2O). Allow to stand for 10 minutes. Any displacement in the water manometer indicates a leak. An alternative leak-check method is to pressurize the bag to 5 to 10 cm (2 to 4 in.) H_2O and allow to stand overnight. A deflated bag indicates a leak.

2.2.7 Pressure Gauge. A water-filled U-tube manometer, or equivalent, of about 30 cm (12 in.), for the flexible bag leak check.

2.2.8 Vacuum Gauge. A mercury manometer, or equivalent, of at least 760 mm (30 in.) Hg, for the sampling train leak check.

2.3 Analysis. An Orsat or Fyrite type combustion gas analyzer. For Orsat and Fyrite analyzer maintenance and operation procedures, follow the instructions recommended by the manufacturer, unless otherwise specified herein.

3. SINGLE-POINT, GRAB SAMPLING AND ANALYTICAL PROCEDURE

3.1 The sampling point in the duct shall either be at the centroid of the cross section or at a point no closer to the walls than 1.00 m (3.3 ft), unless otherwise specified by the Administrator.

3.2 Set up the equipment as shown in Figure 3–1, making sure all connections ahead of the analyzer are tight. If an Orsat analyzer is used, it is recommended that the analyzer be leak checked by following the procedure in Section 6; however, the leak check is optional.

3.3 Place the probe in the stack, with the tip of the probe positioned at the sampling point; purge the sampling line long enough to allow at least five exchanges. Draw a sample into the analyzer, and immediately analyze it for percent CO_2 and percent O_2. Determine the percentage of the gas that is N_2 and CO by subtracting the sum of the percent CO_2 and percent O_2O from 100 percent. Calculate the dry molecular weight as indicated in Section 7.2.

3.4 Repeat the sampling, analysis, and calculation procedures until the dry molecular weights of any three grab samples differ from their mean by no more than 0.3 g/g-mole (0.3 lb/lb-mole). Average these three molecular weights, and report the results to the nearest 0.1 g/g-mole (0.1 lb/lb-mole).

4. SINGLE-POINT, INTEGRATED SAMPLING AND ANALYTICAL PROCEDURE

4.1 The sampling point in the duct shall be located as specified in Section 3.1.

4.2 Leak check (optional) the flexible bag as in Section 2.2.6. Set up the equipment as shown in Figure 3–2. Just before sampling, leak check (optional) the train by placing a vacuum gauge at the condenser inlet, pulling a vacuum of at least 250 mm Hg (10 in. Hg), plugging the outlet at the quick disconnect, and then turning off the pump. The vacuum should remain stable for at least 0.5 minute. Evacuate the flexible bag. Connect the probe, and place it in the stack, with the tip of the probe positioned at the sampling point; purge the sampling line. Next, connect the bag, and make sure that all connections are tight.

4.3 Sample at a constant rate. The sampling run should be simultaneous with, and for the same total length of time as, the pollutant emission rate determination. Collection of at least 30 liters (1.00 ft^3) of sample gas is recommended; however, smaller volumes may be collected, if desired.

4.4 Obtain one integrated flue gas sample during each pollutant emission rate determination. Within 8 hours after the sample is taken, analyze it for percent CO_2 and percent O_2 using either an Orsat analyzer or a Fyrite type combustion gas analyzer. If an Orsat analyzer is used, it is recommended that Orsat leak check described in Section 6, be performed before this determination; however, the check is optional. Determine the percentage of the gas that is N_2 and CO by subtracting the sum of the percent CO_2 and percent 0 from 100 percent. Calculate the dry molecular weight as indicated in Section 7.2.

4.5 Repeat the analysis and calculation procedures until the individual dry molecular weights for any three analyses differ from their mean by no more than 0.3 g/g-mole (0.3 lb/lb-mole). Average these three molecular weights, and report the results to the nearest 0.1 g/g-mole (0.1 lb/lb-mole).

5. MULTI-POINT, INTEGRATED SAMPLING AND ANALYTICAL PROCEDURE

5.1 Unless otherwise specified by the Administrator, a minimum of eight traverse points shall be used for circular stacks having diameters less than 0.61 m (24 in.), a minimum of nine shall be used for rectangular stacks having equivalent diameters less than 0.61 m (24 in.), and a minimum of 12 traverse points shall be used for all other cases. The traverse points shall be located according to Method 1. The use of fewer points is subject to approval of the Administrator.

5.2 Follow the procedures outlined in Sections 4.2 through 4.5, except for the following: Traverse all sampling points, and sample at each point for an equal length of time. Record sampling data as shown in Figure 3-3.

Time	Traverse pt.	Q, liter/min	% dev.[a]
Average			

[a] % dev. = $(Q - Q_{avg})/Q_{avg} \times 100$ (Must be ≤10%)

Figure 3-3. Sampling rate data.

6. Leak-Check Procedure for Orsat Analyzer

Moving an Orsat analyzer frequently causes it to leak. Therefore, an Orsat analyzer should be thoroughly leak checked on site before the flue gas sample is introduced into it. The procedure for leak checking an Orsat analyzer is as follows:

6.1 Bring the liquid level in each pipette up to the reference mark on the capillary tubing, and then close the pipette stopcock.

6.2 Raise the leveling bulb sufficiently to bring the confining liquid meniscus onto the graduated portion of the burette, and then close the manifold stopcock.

6.3 Record the meniscus position.

6.4 Observe the menisus in the burette and the liquid level in the pipette for movement over the next 4 minutes.

6.5 For the Orsat analyzer to pass the leak check, two conditions must be met:

6.5.1 The liquid level in each pipette must not fall below the botton of the capillary tubing during this 4-minute interval.

6.5.2 The menisus in the burette must not change by more than 0.2 ml during this 4-minute interval.

6.6 If the anlyzer fails the leak-check procedure, check all rubber connections and stopcocks to determine whether they might be the cause of the leak. Disassemble, clean, and regrease leaking stopcocks. Replace leaking rubber connections. After the analyzer is reassembled, repeat the lead-check procedure.

7. Calculations

7.1 Nomenclature

M_d = Dry molecular weight, g/g-mole (lb/lb-mole).
%CO_2 = Percent CO_2 by volume, dry basis.
%O_2 = Percent O_2 by volume, dry basis.
%CO = Percent CO by volume, dry basis.
%N_2 = Percent N_2 by volume, dry basis.
0.280 = Molecular weight of N_2 or CO, divided by 100.
0.320 = Molecular wight of O_2 divided by 100.
0.440 = Molecular weight of CO_2 divided by 100.

7.2 Dry Molecular Weight. Use Equation 3-1 to calculate the dry molecular weight of the stack gas.

$$M_d = 0.440(\%CO_2) + 0.320\ (\%O_2) + 0.280(\%N_2 + \%CO) \qquad \text{Eq. 3-1}$$

NOTE. The above equation does not consider argon in air (about 0.9 percent, molecular weight of 39.9). A negative error of about 0.4 percent is introduced. The tester may choose to include argon in the analysis using procedures subject to approval of the Administrator.

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Method 3A—Determination of Oxygen and Carbon Dioxide Concentrations in Emissions From Stationary Sources (Instrumental Analyzer Procedure)

1. Applicability and Principle

1.1 Applicability. This method is applicable to the determination of oxygen (O_2) and carbon dioxide (CO_2) concentrations in emissions from stationary sources only when specified within the regulations.

1.2 Principle. A sample is continuously extracted from the effluent stream: a portion of the sample stream is conveyed to an instrumental analyzer(s) for determination of O_2 and CO_2 concentration(s). Performance specifications and test procedures are provided to ensure reliable data.

2. Range and Sensitivity

Same as Method 6C, Sections 2.1 and 2.2, except that the span of the monitoring system shall be selected such that the average O_2 or CO_2 concentration is not less than 20 percent of the span.

3. Definitions

3.1 Measurement System. The total equipment required for the determination of the

O_2 or CO_2 concentration. The measurement system consists of the same major subsystems as defined in Method 6C, Sections 3.1.1, 3.1.2, and 3.1.3.

3.2 Span, Calibration Gas, Analyzer Calibration Error, Sampling System Bias, Zero Drift, Calibration Drift, Response Time, and Calibration Curve. Same as Method 6C, Sections 3.2 through 3.8, and 3.10.

3.3 Interference Response. The output response of the measurement system to a component in the sample gas, other than the gas component being measured.

4. *Measurement System Performance Specifications*

Same as Method 6C, Sections 4.1 through 4.4.

5. *Apparatus and Reagents*

5.1 Measurement System. Any measurement system for O_2 or CO_2 that meets the specifications of this method. A schematic of an acceptable measurement system is shown in Figure 6C–1 of Method 6C. The essential components of the measurement system are described below:

5.1.1 Sample Probe. A leak-free probe, of sufficient length to traverse the sample points.

5.1.2 Sample Line. Tubing, to transport the sample gas from the probe to the moisture removal system. A heated sample line is not required for systems that measure the O_2 or CO_2 concentration on a dry basis, or transport dry gases.

5.1.3 Sample Transport Line, Calibration Value Assembly, Moisture Removal System, Particulate Filter, Sample Pump, Sample Flow Rate Control, Sample Gas Manifold, and Data Recorder. Same as Method 6C, Sections 5.1.3 through 5.1.9, and 5.1.11, except that the requirements to use stainless steel, Teflon, and nonreactive glass filters do not apply.

5.1.4 Gas Analyzer. An analyzer to determine continuously the O_2 or CO_2 concentration in the sample gas stream. The analyzer shall meet the applicable performance specifications of Section 4. A means of controlling the analyzer flow rate and a device for determining proper sample flow rate (e.g., precision rotameter, pressure gauge downstream of all flow controls, etc.) shall be provided at the analyzer. The requirements for measuring and controlling the analyzer flow rate are not applicable if data are presented that demonstrate the analyzer is insensitive to flow variations over the range encountered during the test.

5.2 Calibration Gases. The calibration gases for CO_2 analyzers shall be CO_2 in N_2 or CO_2 in air. Alternatively, CO_2/SO_2, O_2/SO_2, or $O_2/CO_2/SO_2$ gas mixtures in N_2 may be used. Three calibration gases, as specified Section 5.3.1 through 5.3.3 of Method 6C, shall be used. For O_2 monitors that cannot analyze zero gas, a calibration gas concentration equivalent to less than 10 percent of the span may be used in place of zero gas.

6. *Measurement System Performance Test Procedures*

Perform the following procedures before measurement of emissions (Section 7).

6.1 Calibration Concentration Verification. Follow Section 6.1 of Method 6C, except if calibration gas analysis is required, use Method 3 and change the acceptance criteria for agreement among Method 3 results to 5 percent (or 0.2 percent by volume, whichever is greater).

6.2 Interference Response. Conduct an interference response test of the analyzer prior to its initial use in the field. Thereafter, recheck the measurement system if changes are made in the instrumentation that could alter the interference response (e.g., changes in the type of gas detector). Conduct the interference response in accordance with Section 5.4 of Method 20.

6.3 Measurement System Preparation, Analyzer Calibration Error, and Sampling System Bias Check. Follow Sections 6.2 through 6.4 of Method 6C.

7. *Emission Test Procedure*

7.1 Selection of Sampling Site and Sampling Points. Select a measurement site and sampling points using the same criteria that are applicable to tests performed using Method 3.

7.2 Sample Collection. Position the sampling probe at the first measurement point, and begin sampling at the same rate as used during the sampling system bias check. Maintain constant rate sampling (i.e., ±10 percent) during the entire run. The sampling time per run shall be the same as for tests conducted using Method 3 plus twice the system response time. For each run, use only those measurements obtained after twice the response time of the measurement system has elapsed to determine the average effluent concentration.

7.3 Zero and Calibration Drift Test. Follow Section 7.4 of Method 6C.

8. *Quality Control Procedures*

The following quality control procedures are recommended when the results of this method are used for an emission rate correction factor, or excess air determination. The tester should select one of the following options for validating measurement results:

8.1 If both O_2 and CO_2 are measured using Method 3A, the procedures described in Section 4.4 of Method 3 should be followed to validate the O_2 and CO_2 measurement results.

8.2 If only O_2 is measured using Method 3A, measurements of the sample stream CO_2 concentration should be obtained at the sample by-pass vent discharge using an Orsat or Fyrite analyzer, or equivalent. Duplicate samples should be obtained concurrent with at least one run. Average the duplicate Orsat or Fyrite analysis results for each run. Use the average CO_2 values for comparison with the O_2 measurements in accordance with the procedures described in Section 4.4 of Method 3.

8.3 If only CO_2 is measured using Method 3A, concurrent measurements of the sample stream CO_2 concentration should be obtained using an Orsat or Fyrite analyzer as described in Section 8.2. For each run, differences greater than 0.5 percent between the Method 3A results and the average of the duplicate Fyrite analysis should be investigated.

9. *Emission Calculation*

For all CO_2 analyzers, and for O_2 analyzers that can be calibrated with zero gas, follow Section 8 of Method 6C, except express all concentrations as percent, rather than ppm.

For O_2 analyzers that use a low-level calibration gas in place of a zero gas, calculate the effluent gas concentration using Equation 3A–1.

$$C_{gas} = \frac{C_{ma} - C_{oa}}{C_m - C_o} (\bar{C} - C_m) + C_{ma} \qquad \text{Eq. 3A–1}$$

Where:

C_{gas}=Effluent gas concentration, dry basis, percent.

C_{ma}=Actual concentration of the upscale calibration gas, percent.

C_{oa}=Actual concentration of the low-level calibration gas, percent.

C_m=Average of initial and final system calibration bias check responses for the upscale calibration gas, percent.

C_o=Average of initial and final system calibration bias check responses for the low-level gas, percent.

$\bar{C}$=Average gas concentration indicated by the gas analyzer, dry basis, percent.

10. *Bibliography*

Same as bibliography of Method 6C.

METHOD 3B—GAS ANALYSIS FOR THE DETERMINATION OF EMISSION RATE CORRECTION FACTOR OR EXCESS AIR

1. APPLICABILITY AND PRINCIPLE

1.1 Applicability

1.1.1 This method is applicable for determining carbon dioxide (CO_2), oxygen (O_2), and carbon monoxide (CO) concentrations of a sample from a gas stream of a fossil-fuel combustion provess for excess air or emission rate correction factor calculations.

1.1.2 Other methods, as well as modifications to the procedure described herein, are also applicable for all of the above determinations. Examples of specific methods and modifications include: (1) A multi-point sampling method using an Orsat analyzer to analyze individual grab samples obtained at each point, and (2) a method using CO_2 or O_2 and stoichiometric calculations to determine excess air. These methods and modifications may be used, but are subject to the approval of the Administrator, U.S. Environmental Protection Agency (FPA).

1.1.3 Note. Mention of trade names or specific products does not constitute endorsement by EPA.

1.2 Principle. A gas sample is extracted from a stack by one of the following methods: (1) Single-point, grab sampling; (2) single-point, integrated sampling; or (3) multipoint, integrated sampling. The gas sample is analyzed for percent CO_2 percent O_2, and, if necessary, percent CO. An Orsat analyzer must be used for excess air or emission rate correction factor determinations.

2. APPARATUS

The alternative sampling systems are the same as those mentioned in Section 2 of Method 3.

2.1 Grab Sampling and Integrated Sampling. Same as in Sections 2.1 and 2.2, respectively, of Method 3.

2.2 Analysis. An Orsat analyzer only. For low CO_2 (less than 4.0 percent) or high O_2 (greater than 15.0 percent) concentrations, the measuring burette of the Orsat must have at least 0.1 percent subdivisions. For Orsat maintenance and operation procedures, follow the instructions recommended by the manufacturer, unless otherwise specified herein.

3. PROCEDURES

Each of the three procedures below shall be used only when specified in an applicable subpart of the standards. The use of these procedures for other purposes must have specific prior approval of the Adminsitrator.

NOTE.—A Fyrite-type combustion gas analyzer is not acceptable for excess air or emission rate correction factor determinations, unless approved by the Administrator. If both percent CO_2 and percent O_2 are measured, the analytical results of any of the three procedures given below may be used for calculating the dry molecular weight (see Method 3).

3.1 Single-Point, Grab Sampling and Analytical Procedure.

3.1.1 The sampling point in the duct shall be as described in Section 3.1 of Method 3.

3.1.2 Set up the equipment as shown in Figure 3–1 of Method 3, making sure all connections ahead of the analyzer are tight. Leak check the Orsat analyzer according to the procedure described in Section 6 of Method 3. This leak check is mandatory.

3.1.3 Place the probe in the stack, with the tip of the probe positioned at the sampling point; purge the sampling line long enough to allow at least five exchanges. Draw a sample into the analyzer. For emission rate correction factor determinations, immediately analyze the sample, as outlined in Sections 3.1.4 and 3.1.5, for percent CO_2 or percent O_2. If excess air is desired, proceed as follows: (1) immediately analyze the sample, as in Sections 3.1.4 and 3.1.5, for percent CO_2, O_2, and CO; (2) determine the percentage of the gas that is N_2 by subtracting the sum of the percent CO_2, percent O_2, and percent CO from 100 percent, and (3) calculate percent excess air as outlined in Section 4.2.

3.1.4 To ensure complete absorption of the CO_2, O_2, or if applicable, CO, make repeated passes through each absorbing solution until two consecutive readings are the same. Several passes (three or four) should be made between readings. (If constant readings cannot be obtained after three consecutive readings, replace the absorbing solution.)

NOTE.—Since this single-point, grab sampling and analytical procedure is normally conducted in conjunction with a single-point, grab sampling and analytical procedure for a pollutant, only one analysis is ordinarily conducted. Therefore, great care must be taken to obtain a valid sample and analysis. Although in most cases, only CO_2 or O_2 is required, it is recommended that both CO_2 and O_2 be measured, and that Section 3.4 be used to validate the analytical data.

3.1.5 After the analysis is completed, leak check (mandatory) the Orsat analyzer once again, as described in Section 6 of Method 3. For the results of the analysis to be valid, the Orsat analyzer must pass this leak test before and after the analysis.

3.2 Single-Point, Integrated Sampling and Analytical Procedure.

3.2.1 The sampling point in the duct shall be located as specified in Section 3.1.1.

3.2.2 Leak check (mandatory) the flexible bag as in Section 2.2.6 of Method 3. Set up the equipment as shown in Figure 3–2 of Method 3. Just before sampling, leak check (mandatory) the train as described in Section 4.2 of Method 3.

3.2.3 Sample at a constant rate, or as specified by the Administrator. The sampling run must be simultaneous with, and for the same total length of time as, the pollutant emission rate determination. Collect at least 30 liters (1.00 ft^3) of sample gas. Smaller volumes may be collected, subject to approval of the Administrator.

3.2.4 Obtain one integrated flue gas sample during each pollutant emission rate determination. For emission rate correction factor determination, analyze the sample within 4 hours after it is taken for percent CO_2 or percent O_2 (as outlined in Sections 3.2.5 through 3.2.7). The Orsat analyzer must be leak checked (see Section 6 of Method 3) before the analysis. If excess air is desired, procede as follows: (1) within 4 hours after the sample is taken, analyze it (as in Sections 3.2.5 through 3.2.7) for percent CO_2, O_2, and CO; (2) determine the percentage of the gas that is N_2 by subtracting the sum of the percent CO_2, percent O_2, and percent CO from 100 percent; and (3) calculate percent excess air, as outlined in Section 4.2.

3.2.5 To ensure complete absorption of the CO_2, O_2, or if applicable, CO, follow the procedure described in Section 3.1.4.

NOTE.—Although in most instances only CO_2 or O_2 is required, it is recommended that both CO_2 and O_2 be measured, and that Section 3.4.1 be used to validate the analytical data.

3.2.6 Repeat the analysis until the following criteria are met:

3.2.6.1 For percent CO_2, repeat the analytical procedure until the results of any three analyses differ by no more than (a) 0.3 percent by volume when CO_2 is greater than 4.0 percent or (b) 0.2 percent by volume when CO_2 is less than or equal to 4.0 percent. Average three acceptable values of percent CO_2, and report the results to the nearest 0.2 percent.

3.2.6.2 For percent O_2, repeat the analytical procedure until the results of any three analyses differ by no more than (a) 0.3 percent by volume when O_2 is less than 15.0 percent or (b) 0.2 percent by volume when O_2 is greater than or equal to 15.0 percent. Average the three acceptable values of percent O_2, and report the results to the nearest 0.1 percent.

3.2.6.3 For percent CO, repeat the analytical procedure until the results of any three analyses differ by no more than 0.3 percent. Average the three acceptable values of percent CO, and report the results to the nearest 0.1 percent.

3.2.7 After the analysis is completed, leak check (mandatory) the Orsat analyzer once again, as described in Section 6 of Method 3. For the results of the analysis to be valid, the Orsat analyzer must pass this leak test before and after the analysis.

3.3 Multi-Point, Integrated Sampling and Analytical Procedure.

3.3.1 The sampling points shall be determined as specified in Section 5.3 of Method 3.

3.3.2 Follow the procedures outlined in Sections 3.2.2 through 3.2.7, except for the following: Traverse all sampling points, and sample at each point for an equal length of time. Record sampling data as shown in Figure 3–3 of Method 3.

3.4 Quality Control Procedure.

3.4.1 Data Validation When Both CO_2 and O_2 Are Measured. Although in most instances, only CO_2 or O_2 measurement is required, it is recommended that both CO_2 and O_2 be measured to provide a check on the quality of the data. The following quality control procedure is suggested.

NOTE.—Since the method for validating the CO_2 and O_2 analyses is based on combustion of organic and fossil fuels and dilution of the gas stream with air, this method does not apply to sources that (1) remove CO_2 or O_2 through processes other than combustion, (2) add O_2 (e.g., oxygen enrichment) and N_2 in proportions different from that of air, (3) add CO_2 (e.g., cement or lime kilns) or (4) have no fuel factor, F_o, values obtainable (e.g., extremely variable waste mixtures). This method validates the measured proportions of CO_2 and O_2 for fuel type, but the method does not detect sample dilution resulting from leaks during or after sample collection. The method is applicable for samples collected downstream of most lime or limestone flue-gas desulfurization units as the CO_2 added or removed from the gas stream is not significant in relation to the total CO_2 concentration. The CO_2 concentrations from other types of scrubbers using only water or basic slurry can be significantly affected and would render the F_o check minimally useful.

3.4.1.1 Calculate a fuel factor, F_o, using the following equation:

$$F_o = \frac{20.9 - \%O_2}{\%CO_2} \qquad \text{Eq. 3B-1}$$

where:

$\%O_2$=Percent O_2 by volume, dry basis.
$\%CO_2$=Percent CO_2 by volume, dry basis.
20.9=Percent O_2 by volume in ambient air.

If CO present in quantities measurable by this method, adjust the O_2 and CO_2 values before performing the calculation for F_o as follows:

$\%CO_2\,(adj) = \%CO_2 + \%CO$
$\%O_2\,(adj) = \%O_2 - 0.5\,\%CO$
where:
%5CO = Percent CO by volume, dry basis.

3.4.1.2 Compare the calculated F_o factor with the expected F_o values. The following table may be used in establishing acceptable ranges for the expected F_o if the fuel being burned is known. When fuels are burned in combinations, calculate the combined fuel F_d and F_c factors (as defined in Method 19) according to the procedure in Method 19, Section 5.2.3. Then calculate the F_o factor as follows:

$$F_o = \frac{0.209\, F_d}{F_c} \qquad \text{Eq. 3B-2}$$

Fuel type	F_o range
Coal:	
Anthracite and lignite	1.016–1.130
Bituminous	1.083–1.230
Oil:	
Distillate	1.260–1.413
Residual	1.210–1.370
Gas:	
Natural	1.600–1.836
Propane	1.434–1.586
Butane	1.405–1.553
Wood	1.000–1.120
Wood bark	1.003–1.130

3.4.1.3 Calculated F_o values, beyond the acceptable ranges shown in this table, should be investigated before accepting the test results. For example, the strength of the solutions in the gas analyzer and the analyzing technique should be checked by sampling and analyzing a known concentration, such as air; the fuel factor should be reviewed and verified. An acceptability range of ±12 percent is appropriate for the F_o factor of mixed fuels with variable fuel ratios. The level of the emission rate relative to the compliance level should be considered in determining if a retest is appropriate, i.e., if the measured emissions are much lower or much greater than the compliance limit, repetition of the test would not significantly change the compliance status of the source and would be unnecessarily time consuming and costly.

4. Calculations

4.1 Nomenclature. Same as Section 5 of Method 3 with the addition of the following:

%EA = Percent excess air.
0.264 = Ratio of O_2 to N_2 in air, v/v.

4.2 Percent Excess Air. Calculate the percent excess air (if applicable) by substituting the appropriate values of percent O_2, CO, and N_2 (obtained from Section 3.1.3 or 3.2.4) into Equation 3B–3.

$$\%EA = \frac{\%O_2 - 0.5\,\%CO}{0.264\,\%N_2 - (\%O_2 - 0.5\,\%CO)} \times 100 \qquad \text{Eq. 3B-3}$$

NOTE.—The equation above assumes that ambient air is used as the source of O_2 and that the fuel does not contain appreciable amounts of N_2 (as do coke oven or blast furnace gases). For those cases when appreciable amounts of N_2 are present (coal, oil and natural gas do not contain appreciable amounts of N_2) or when oxygen enrichment is used, alternative methods, subject to approval of the Administrator, are required.

5. BIBLIOGRAPHY

Same as Method 3.

METHOD 4—DETERMINATION OF MOISTURE CONTENT IN STACK GASES

1. *Principle and Applicability*

1.1 Principle. A gas sample is extracted at a constant rate from the source; moisture is removed from the sample stream and determined either volumetrically or gravimetrically.

1.2 Applicability. This method is applicable for determining the moisture content of stack gas.

Two procedures are given. The first is a reference method, for accurate determinations of moisture content (such as are needed to calculate emission data). The second is an approximation method, which provides estimates of percent moisture to aid in setting isokinetic sampling rates prior to a pollutant emission measurement run. The approximation method described herein is only a suggested approach; alternative means for approximating the moisture content, e.g., drying tubes, wet bulb-dry bulb techniques, condensation techniques, stoichiometric calculations, previous experience, etc., are also acceptable.

The reference method is often conducted simultaneously with a pollutant emission measurement run; when it is, calculation of percent isokinetic, pollutant emission rate, etc., for the run shall be based upon the results of the reference method or its equivalent; these calculations shall not be based upon the results of the approximation method, unless the approximation method is shown, to the satisfaction of the Administrator, U.S. Environmental Protection Agency, to be capable of yielding results within 1 percent H_2O of the reference method.

NOTE: The reference method may yield questionable results when applied to saturated gas streams or to streams that contain water droplets. Therefore, when these conditions exist or are suspected, a second determination of the moisture content shall be made simultaneously with the reference method, as follows: Assume that the gas stream is saturated. Attach a temperature sensor [capable of measuring to ±1° C (2° F)] to the reference method probe. Measure the stack gas temperature at each traverse point (see Section 2.2.1) during the reference method traverse; calculate the average stack gas temperature. Next, determine the moisture percentage, either by: (1) using a psychrometric chart and making appropriate corrections if stack pressure is different from that of the chart, or (2) using saturation vapor pressure tables. In cases where the pyschrometric chart or the saturation vapor pressure tables are not applicable (based on evaluation of the process), alternative methods, subject to the approval of the Administrator, shall be used.

2. *Reference Method*

The procedure described in Method 5 for determining moisture content is acceptable as a reference method.

2.1 Apparatus. A schematic of the sampling train used in this reference method is shown in Figure 4-1. All components shall be maintained and calibrated according to the procedure outlined in Method 5.

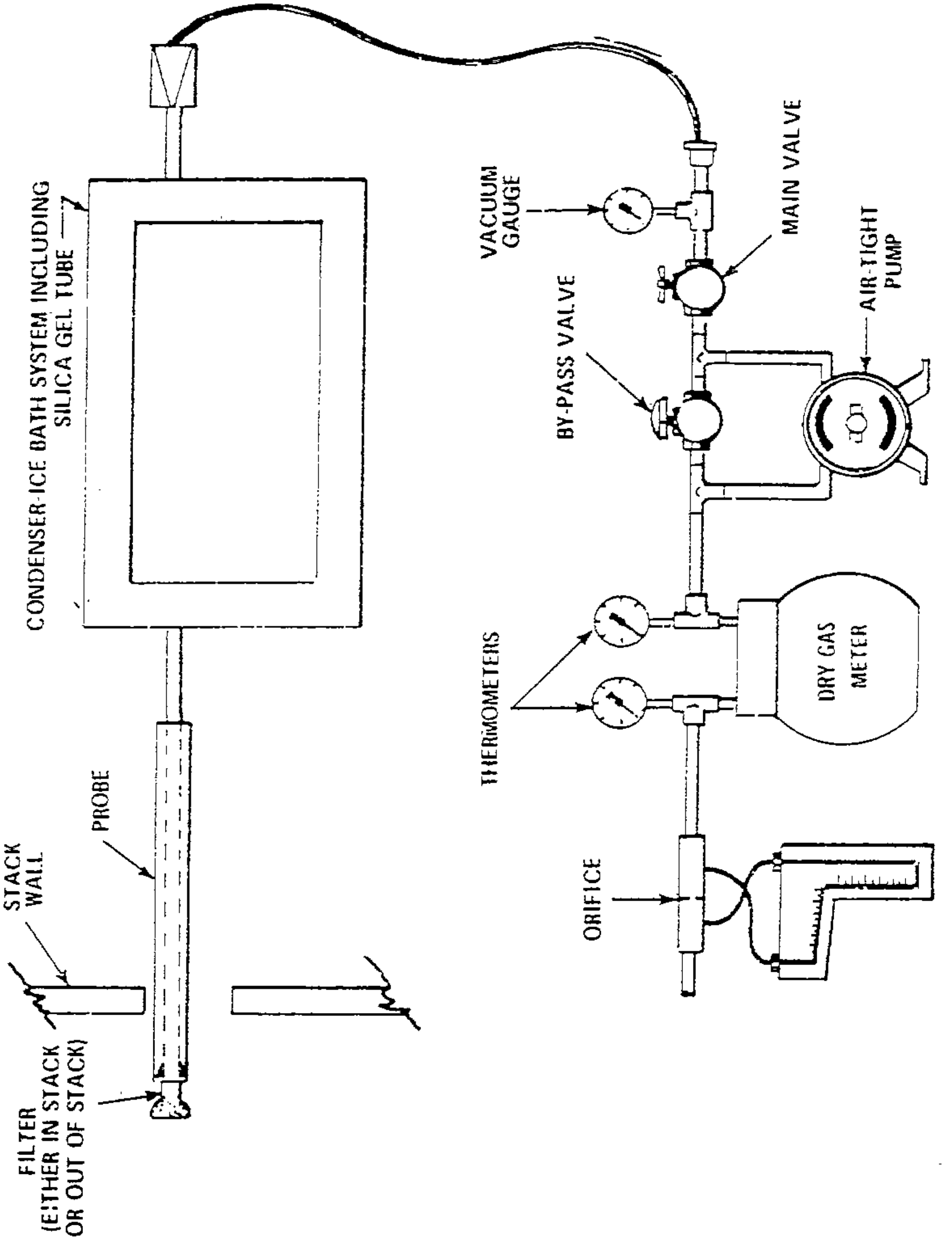

Figure 4-1. Moisture sampling train-reference method.

2.1.1 Probe. The probe is constructed of stainless steel or glass tubing, sufficiently heated to prevent water condensation, and is equipped with a filter, either in-stack (e.g., a plug of glass wool inserted into the end of the probe) or heated out-stack (e.g., as described in Method 5), to remove particular matter.

When stack conditions permit, other metals or plastic tubing may be used for the probe, subject to the approval of the Administrator.

2.1.2 Condenser. The condenser consists of four impingers connected in series with ground glass, leak-free fittings or any similarly leak-free non-contaminating fittings. The first, third, and fourth impingers shall be of the Greenburg-Smith design, modified by replacing the tip with a 1.3 centimeter (½ inch) ID glass tube extending to about 1.3 cm (½ in.) from the bottom of the flask. The second impinger shall be of the Greenburg-Smith design with the standard tip. Modifications (e.g., using flexible connections between the impingers, using materials other than glass, or using flexible vacuum lines to connect the filter holder to the condenser) may be used, subject to the approval of the Administrator.

The first two impingers shall contain known volumes of water, the third shall be empty, and the fourth shall contain a known weight of 6- to 16-mesh indicating type silica gel, or equivalent desiccant. If the silica gel has been previously used, dry at 175° C (350° F) for 2 hours. New silica gel may be used as received. A thermometer, capable of measuring temperature to within 1° C (2° F), shall be placed at the outlet of the fourth impinger, for monitoring purposes.

Alternatively, any system may be used (subject to the approval of the Administrator) that cools the sample gas stream and allows measurement of both the water that has been condensed and the moisture leaving the condenser, each to within 1 ml or 1 g. Acceptable means are to measure the condensed water, either gravimetrically or volumetrically, and to measure the moisture leaving the condenser by: (1) monitoring the temperature and pressure at the exit of the condenser and using Dalton's law of partial pressures, or (2) passing the sample gas stream through a tared silica gel (or equivalent desiccant) trap, with exit gases kept below 20° C (68° F), and determining the weight gain.

If means other than silica gel are used to determine the amount of moisture leaving the condenser, it is recommended that silica gel (or equivalent) still be used between the condenser system and pump, to prevent moisture condensation in the pump and metering devices and to avoid the need to make corrections for moisture in the metered volume.

2.1.3 Cooling System. An ice bath container and crushed ice (or equivalent) are used to aid in condensing moisture.

2.1.4 Metering System. This system includes a vacuum gauge, leak-free pump, thermometers capable of measuring temperature to within 3° C (5.4° F), dry gas meter capable of measuring volume to within 2 percent, and related equipment as shown in Figure 4–1. Other metering systems, capable of maintaining a constant sampling rate and determining sample gas volume, may be used, subject to the approval of the Administrator.

2.1.5 Barometer. Mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg) may be used. In many cases, the barometric reading may be obtained from a nearby National Weather Service station, in which case the station value (which is the absolute barometric pressure) shall be requested and an adjustment for elevation differences between the weather station and the sampling point shall be applied at a rate of minus 2.5 mm Hg (0.1 in. Hg) per 30 m (100 ft) elevation increase or vice versa for elevation decrease.

2.1.6 Graduated Cylinder and/or Balance. These items are used to measure condensed water and moisture caught in the silica gel to within 1 ml or 0.5 g. Graduated cylinders shall have subdivisions no greater than 2 ml. Most laboratory balances are capable of weighing to the nearest 0.5 g or less. These balances are suitable for use here.

2.2 Procedure. The following procedure is written for a condenser system (such as the impinger system described in Section 2.1.2) incorporating volumetric analysis to measure the condensed moisture, and silica gel and gravimetric analysis to measure the moisture leaving the condenser.

2.2.1 Unless otherwise specified by the Administrator, a minimum of eight traverse points shall be used for circular stacks having diameters less than 0.61 m (24 in.), a minimum of nine points shall be used for rectangular stacks having equivalent diameters less than 0.61 m (24 in.), and a minimum of twelve traverse points shall be used in all other cases. The traverse points shall be located according to Method 1. The use of fewer points is subject to the approval of the Administrator. Select a suitable probe and probe length such that all traverse points can be sampled. Consider sampling from opposite sides of the stack (four total sampling ports) for large stacks, to permit use of shorter probe lengths. Mark the probe with heat resistant tape or by some other method to denote the proper distance into the stack or duct for each sampling point. Place known volumes of water in the first two impingers. Weigh and record the weight of the silica gel to the nearest 0.5 g, and transfer the silica gel to the fourth impinger; alternatively, the silica gel may first be transferred to the impinger, and the weight of the silica gel plus impinger recorded.

2.2.2 Select a total sampling time such that a minimum total gas volume of 0.60 scm (21 scf) will be collected, at a rate no greater than 0.021 m^3/min (0.75 cfm). When both moisture content and pollutant emission rate are to be determined, the moisture determination shall be simultaneous with, and for the same total length of time as, the pollutant emission rate run, unless otherwise specified in an applicable subpart of the standards.

2.2.3 Set up the sampling train as shown in Figure 4–1. Turn on the probe heater and (if applicable) the filter heating system to temperatures of about 120° C (248° F), to prevent water condensation ahead of the condenser; allow time for the temperatures to stabilize. Place crushed ice in the ice bath container. It is recommended, but not required, that a leak check be done, as follows: Disconnect the probe from the first impinger or (if applicable) from the filter holder. Plug the inlet to the first impinger (or filter holder) and pull a 380 mm (15 in.) Hg vacuum; a lower vacuum may be used, provided that it is not exceeded during the test. A leakage rate in excess of 4 percent of the average sampling rate or 0.00057 m^3/min (0.02 cfm), whichever is less, is unacceptable. Following the leak check, reconnect the probe to the sampling train.

2.2.4 During the sampling run, maintain a sampling rate within 10 percent of constant rate, or as specified by the Administrator. For each run, record the data required on the example data sheet shown in Figure 4–2. Be sure to record the dry gas meter reading at the beginning and end of each sampling time increment and whenever sampling is halted. Take other appropriate readings at each sample point, at least once during each time increment.

2.2.5 To begin sampling, position the probe tip at the first traverse point. Immediately start the pump and adjust the flow to the desired rate. Traverse the cross section, sampling at each traverse point for an equal length of time. Add more ice and, if necessary, salt to maintain a temperature of less 20° C (68° F) at the silica gel outlet.

2.2.6 After collecting the sample, disconnect the probe from the filter holder (or from the first impinger) and conduct a leak check (mandatory) as described in Section 2.2.3. Record the leak rate. If the leakage rate exceeds the allowable rate, the tester shall either reject the test results or shall correct the sample volume as in Section 6.3 of Method 5. Next, measure the volume of the moisture condensed to the nearest ml. Determine the increase in weight of the silica gel (or silica gel plus impinger) to the nearest 0.5 g. Record this information (see example data sheet, Figure 4–3) and calculate the moisture percentage, as described in 2.3 below.

2.2.7 A quality control check of the volume metering system at the field site is suggested before collecting the sample following the procedure in Method 5, Section 4.4

2.3 Calculations. Carry out the following calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after final calculation.

FIGURE 4–2—FIELD MOISTURE DETERMINATION REFERENCE METHOD

Plant ....
Location ....
Operator ....
Date ....
Run No. ....
Ambient temperature ....
Barometric pressure ....
Probe length m (ft) ....

SCHEMATIC OF STACK CROSS SECTION

Traverse point number	Sampling time (θ), min.	Stack temperature °C (°F)	Pressure differential across orifice meter ΔH mm (in.) H_2O	Meter reading gas sample volume m^3 (ft^3)	ΔV_m m^3 (ft^3)	Gas Sample temperature at dry gas meter: Inlet (Tm_{in}), °C (°F)	Gas Sample temperature at dry gas meter: Outlet (Tm_{out}), °C (°F)	Temperaturem of gas leaving condenser or last impinger °C (°F)
Total								
Average					Avg.	Avg.	Avg.	

FIGURE 4-3—ANALYTICAL DATA—REFERENCE METHOD

	Impinger volume, ml	Silica gel weight, g
Final		
Initial		
Difference		

2.3.1 Nomenclature.

B_{ws}=Proportion of water vapor, by volume, in the gas stream.

M_w=Molecular weight of water, 18.0 g/g-mole (18.0 lb/lb-mole).

P_m=Absolute pressure (for this method, same as barometric pressure) at the dry gas meter, mm Hg (in. Hg).

P_{std}=Standard absolute pressure, 760 mm Hg (29.92 in. Hg).

R=Ideal gas constant, 0.06236 (mm Hg) (m³)/(g-mole) (°K) for metric units and 21.85 (in. Hg) (ft³)/(lb-mole) (°R) for English units.

T_m=Absolute temperature at meter, °K (°R).

T_{std}=Standard absolute temperature, 293° K (528°R).

V_m=Dry gas volume measured by dry gas meter, dcm (dcf).

ΔV_m=Incremental dry gas volume measured by dry gas meter at each traverse point, dcm (dcf).

$V_{m(std)}$=Dry gas volume measured by the dry gas meter, corrected to standard conditions, dscm (dscf).

$V_{wc(std)}$=Volume of water vapor condensed corrected to standard conditions, scm (scf).

$V_{wsg(std)}$=Volume of water vapor collected in silica gel corrected to standard conditions, scm (scf).

V_f=Final volume of condenser water, ml.

V_i=Initial volume, if any, of condenser water, ml.

W_f=Final weight of silica gel or silica gel plus impinger, g.

W_i=Initial weight of silica gel or silica gel plus impinger, g.

Y=Dry gas meter calibration factor.

ρ_w=Density of water, 0.9982 g/ml (0.002201 lb/ml).

2.3.2 Volume of Water Vapor Condensed.

$$V_{wc(std)} = \frac{(V_f - V_i)\rho_w R T_{std}}{P_{std} M_w}$$

$$= K_1(V_f - V_i)$$

Eq. 4-1

Where:

K_1=0.001333 m³/ml for metric units
=0.04707 ft³/ml for English units

2.3.3 Volume of Water Vapor Collected in Silica Gel.

$$V_{wsg(std)} = \frac{(W_f - W_i) R T_{std}}{P_{std} M_w}$$

$$= K_2(W_f - W_i)$$

Eq. 4-2

Where:

K_2=0.001335 m³/g for metric units
=0.04715 ft³/g for English units

2.3.4 Sample Gas Volume.

$$V_{m(std)} = V_m Y \frac{(P_m)(T_{std})}{(P_{std})(T_m)}$$

$$= K_3 Y \frac{V_m P_m}{T_m}$$

Eq. 4-3

Where:

K_3=0.3858 °K/mm Hg for metric units
=17.64 °R/in. Hg for English units

NOTE: If the post-test leak rate (Section 2.2.6) exceeds the allowable rate, correct the value of V_m in Equation 4-3, as described in Section 6.3 of Method 5.

2.3.5 Moisture Content.

$$B_{ws} = \frac{V_{wc(std)} + V_{wsg(std)}}{V_{wc(std)} + V_{wsg(std)} + V_{m(std)}}$$

Eq. 4-4

NOTE: In saturated or moisture droplet-laden gas streams, two calculations of the moisture content of the stack gas shall be made, one using a value based upon the saturated conditions (see Section 1.2), and another based upon the results of the impinger analysis. The lower of these two values of B_{ws} shall be considered correct.

2.3.6 Verification of Constant Sampling Rate. For each time increment, determine the ΔV_m. Calculate the average. If the value for any time increment differs from the average by more than 10 percent, reject the results and repeat the run.

3. *Approximation Method*

The approximation method described below is presented only as a suggested method (see Section 1.2).

3.1 Apparatus.

3.1.1 Probe. Stainless steel glass tubing, sufficiently heated to prevent water condensation and equipped with a filter (either in-stack or heated out-stack) to remove particulate matter. A plug of glass wool, inserted into the end of the probe, is a satisfactory filter.

3.1.2 Impingers. Two midget impingers, each with 30 ml capacity, or equivalent.

3.1.3 Ice Bath. Container and ice, to aid in condensing moisture in impingers.

3.1.4 Drying Tube. Tube packed with new or regenerated 6- to 16-mesh indicating-type silica gel (or equivalent desiccant), to dry the sample gas and to protect the meter and pump.

3.1.5 Valve. Needle valve, to regulate the sample gas flow rate.

3.1.6 Pump. Leak-free, diaphragm type, or equivalent, to pull the gas sample through the train.

3.1.7 Volume Meter. Dry gas meter, sufficiently accurate to measure the sample volume within 2%, and calibrated over the range of flow rates and conditions actually encountered during sampling.

3.1.8 Rate Meter. Rotameter, to measure the flow range from 0 to 3 lpm (0 to 0.11 cfm).

3.1.9 Graduated Cylinder. 25 ml.

3.1.10 Barometer. Mercury, aneroid, or other barometer, as described in Section 2.1.5 above.

3.1.11 Vacuum Gauge. At least 760 mm Hg (30 in. Hg) gauge, to be used for the sampling leak check.

3.2 Procedure.

3.2.1 Place exactly 5 ml distilled water in each impinger.

Leak check the sampling train as follows: Temporarily insert a vacuum gauge at or near the probe inlet; then, plug the probe inlet and pull a vacuum of at least 250 mm Hg (10 in. Hg). Note the time rate of change of the dry gas meter dial; alternatively, a rotameter (0–40 cc/min) may be temporarily attached to the dry gas meter outlet to determine the leakage rate. A leak rate not in excess of 2 percent of the average sampling rate is acceptable.

NOTE: Carefully release the probe inlet plug before turning off the pump.

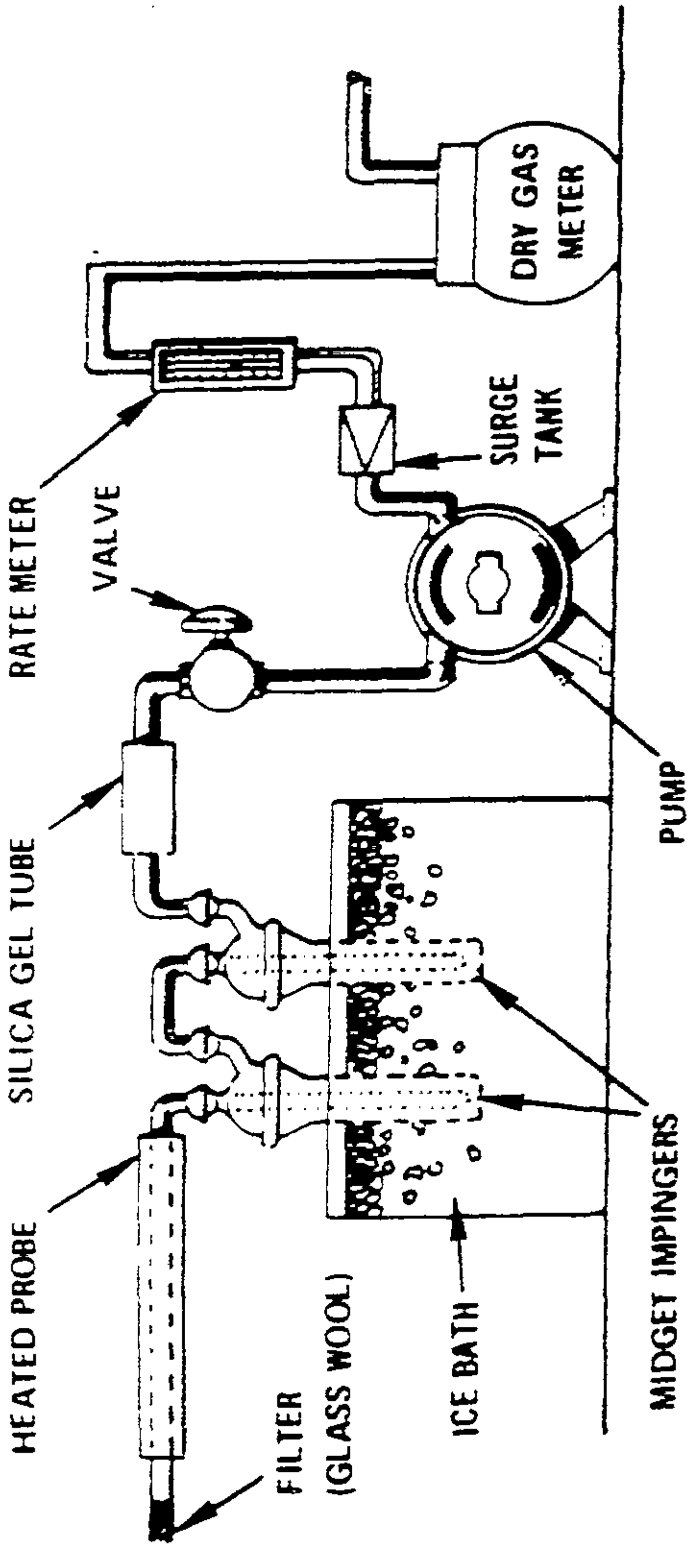

Figure 4-4. Moisture-sampling train - approximation method.

FIGURE 4–5—FIELD MOISTURE DETERMINATION—APPROXIMATION METHOD

FIGURE 4–5—FIELD MOISTURE DETERMINATION—APPROXIMATION METHOD

Location .... Comments:
Test ....
Date ....
Operator ....
Barometric pressure ....

Clock time	Gas volume through meter, (V_m), m^3 (ft^3)	Rate meter setting m^3/min (ft^3/min)	Meter temperature, °C (°F)

3.2.2 Connect the probe, insert it into the stack, and sample at a constant rate of 2 lpm (0.071 cfm). Continue sampling until the dry gas meter registers about 30 liters (1.1 ft^3) or until visible liquid droplets are carried over from the first impinger to the second. Record temperature, pressure, and dry gas meter readings as required by Figure 4–5.

3.2.3 After collecting the sample, combine the contents of the two impingers and measure the volume to the nearest 0.5 ml.

3.3 Calculations. The calculation method presented is designed to estimate the moisture in the stack gas; therefore, other data, which are only necessary for accurate moisture determinations, are not collected. The following equations adequately estimate the moisture content, for the purpose of determining isokinetic sampling rate settings.

3.3.1 Nomenclature.

B_{wm}=Approximate proportion, by volume, of water vapor in the gas stream leaving the second impinger, 0.025.

B_{ws}=Water vapor in the gas stream, proportion by volume.

M_w=Molecular weight of water, 18.0 g/g-mole (18.0 lb/lb-mole).

P_m=Absolute pressure (for this method, same as barometric pressure) at the dry gas meter.

P_{std}=Standard absolute pressure, 760 mm Hg (29.92 in. Hg).

R=Ideal gas constant, 0.06236 (mm Hg) (m^3)/(g-mole) (°K) for metric units and 21.85 (in. Hg) (ft^3)/lb-mole) (°R) for English units.

T_m=Absolute temperature at meter, °K (°R).

T_{std}=Standard absolute temperature, 293° K (528° R).

V_f=Final volume of impinger contents, ml.

V_i=Initial volume of impinger contents, ml.

V_m=Dry gas volume measured by dry gas meter, dcm (dcf).

$V_{m(std)}$=Dry gas volume measured by dry gas meter, corrected to standard conditions, dscm (dscf).

$V_{wc(std)}$=Volume of water vapor condensed, corrected to standard conditions, scm (scf).

ρ_w=Density of water, 0.9982 g/ml (0.002201 lb/ml).

Y=Dry gas meter calibration factor.

3.3.2 Volume of Water Vapor Collected.

$$V_{wc} = \frac{(V_f - V_i)\rho_w R T_{std}}{P_{std} M_w}$$

$$= K_1 (V_f - V_i)$$

Eq. 4–5

Where:

K_1=0.001333 m^3/ml for metric units
=0.04707 ft^3/ml for English units.

3.3.3 Gas Volume.

$$V_{m(std)} = V_m \left(\frac{P_m}{P_{std}}\right) \left(\frac{T_{std}}{T_m}\right)$$

$$= K_2 \frac{V_m P_m}{T_m}$$

Equation 4–6

where:

K_2=0.3858 °K/mm Hg for metric units
=17.64 °R/in. Hg for English units

3.3.4 Approximate Moisture Content.

$$B_{ws} = \frac{V_{wc}}{V_{wc} + V_{m(std)}} + B_{wm}$$

$$= \frac{V_{wc}}{V_{wc} + V_{m(std)}} + (0.025)$$

Equation 4–7

4. *Calibration*

4.1 For the reference method, calibrate equipment as specified in the following sections of Method 5: Section 5.3 (metering system); Section 5.5 (temperature gauges); and Section 5.7 (barometer). The recommended leak check of the metering system (Section 5.6 of Method 5) also applies to the reference method. For the approximation method, use the procedures outlined in Section 5.1.1 of Method 6 to calibrate the metering system, and the procedure of Method 5, Section 5.7 to calibrate the barometer.

5. *Bibliography*

1. Air Pollution Engineering Manual (Second Edition). Danielson, J. A. (ed.). U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Research Triangle Park, NC. Publication No. AP-40. 1973.

2. Devorkin, Howard. et al. Air Pollution Source Testing Manual. Air Pollution Con-

trol District, Los Angeles, CA. November, 1963.

3. Methods for Determination of Velocity, Volume, Dust and Mist Content of Gases. Western Precipitation Division of Joy Manufacturing Co., Los Angeles, CA. Bulletin WP-50. 1968.

METHOD 5—DETERMINATION OF PARTICULATE EMISSIONS FROM STATIONARY SOURCES

1. *Principle and Applicability*

1.1 Principle. Particulate matter is withdrawn isokinetically from the source and collected on a glass fiber filter maintained at a temperature in the range of 120±14° C (248±25° F) or such other temperature as specified by an applicable subpart of the standards or approved by Administrator, U.S. Environmental Protection Agency, for a particular application. The particulate mass, which includes any material that condenses at or above the filtration temperature, is determined gravimetrically after removal of uncombined water.

1.2 Applicability. This method is applicable for the determination of particulate emissions from stationary sources.

2. *Apparatus*

2.1 Sampling Train. A schematic of the sampling train used in this method is shown in Figure 5-1. Complete construction details are given in APTD-0581 (Citation 2 in Bibliography); commercial models of this train are also available. For changes from APTD-0581 and for allowable modifications of the train shown in Figure 5-1, see the following subsections.

The operating and maintenance procedures for the sampling train are described in APTD-0576 (Citation 3 in Bibliography). Since correct usage is important in obtaining valid results, all users should read APTD-0576 and adopt the operating and maintenance procedures outlined in it, unless otherwise specified herein. The sampling train consists of the following components:

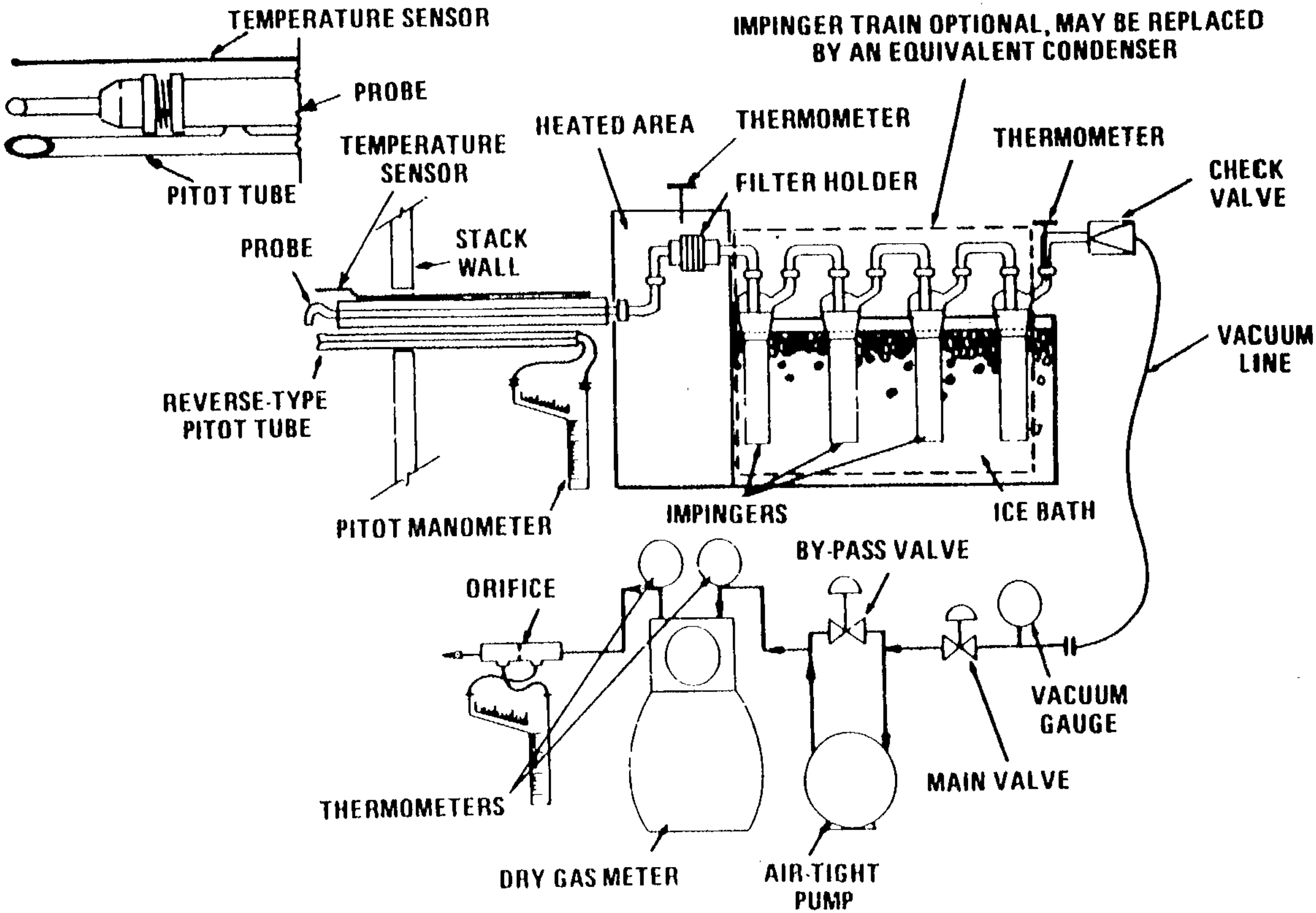

Figure 5-1. Particulate-sampling train.

2.1.1 Probe Nozzle. Stainless steel (316) or glass with sharp, tapered leading edge. The angle of taper shall be ≤30° and the taper shall be on the outside to preserve a constant internal diameter. The probe nozzle shall be of the button-hook or elbow design, unless otherwise specified by the Administrator. If made of stainless steel, the nozzle shall be constructed from seamless tubing; other materials of construction may be used, subject to the approval of the Administrator.

A range of nozzle sizes suitable for isokinetic sampling should be available, e.g., 0.32 to 1.27 cm (⅛ to ½ in.)—or larger if higher volume sampling trains are used—inside diameter (ID) nozzles in increments of 0.16 cm (1/16 in.). Each nozzle shall be calibrated according to the procedures outlined in Section 5.

2.1.2 Probe Liner. Borosilicate or quartz glass tubing with a heating system capable of maintaining a gas temperature at the exit end during sampling of 120±14° C (248±25° F), or such other temperature as specified by an applicable subpart of the standards or approved by the Administrator for a particular application. (The tester may opt to operate the equipment at a temperature lower than that specified.) Since the actual temperature at the outlet of the probe is not usually monitored during sampling, probes constructed according to APTD–0581 and utilizing the calibration curves of APTD–0576 (or calibrated according to the procedure outlined in APTD–0576) will be considered acceptable.

Either borosilicate or quartz glass probe liners may be used for stack temperatures up to about 480° C (900° F); quartz liners shall be used for temperatures between 480 and 900° C (900 and 1,650° F). Both types of liners may be used at higher temperatures than specified for short periods of time, subject to the approval of the Administrator. The softening temperature for borosilicate is 820° C (1,508° F), and for quartz it is 1,500° C (2,732° F).

Whenever practical, every effort should be made to use borosilicate or quartz glass probe liners. Alternatively, metal liners (e.g., 316 stainless steel, Incoloy 825,[2] or other corrosion resistant metals) made of seamless tubing may be used, subject to the approval of the Administrator.

2.1.3 Pitot Tube. Type S, as described in Section 2.1 of Method 2, or other device approved by the Administrator. The pitot tube shall be attached to the probe (as shown in Figure 5–1) to allow constant monitoring of the stack gas velocity. The impact (high pressure) opening plane of the pitot tube shall be even with or above the nozzle entry plane (see Method 2, Figure 2–6b) during sampling. The Type S pitot tube assembly shall have a known coefficient, determined as outlined in Section 4 of Method 2.

2.1.4 Differential Pressure Gauge. Inclined manometer or equivalent device (two), as described in Section 2.2 of Method 2. One manometer shall be used or velocity head (Δp) readings, and the other, for orifice differential pressure readings.

2.1.5 Filter Holder. Borosilicate glass, with a glass frit filter support and a silicone rubber gasket. Other materials of construction (e.g., stainless steel, Teflon, Viton) may be used, subject to approval of the Administrator. The holder design shall provide a positive seal against leakage from the outside or around the filter. The holder shall be attached immediately at the outlet of the probe (or cyclone, it used).

2.1.6 Filter Heating System. Any heating system capable of maintaining a temperature around the filter holder during sampling of 120±14° C (248±25° F), or such other temperature as specified by an applicable subpart of the standards or approved by the Administrator for a particular application. Alternatively, the tester may opt to operate the equipment at a temperature lower than that specified. A temperature gauge capable of measuring temperature to within 3° C (5.4° F) shall be installed so that the temperature around the filter holder can be regulated and monitored during sampling. Heating systems other than the one shown in APTD–0581 may be used.

2.1.7 Condenser. The following system shall be used to determine the stack gas moisture content: Four impingers connected in series with leak-free ground glass fittings or any similar leak-free non-contaminating fittings. The first, third, and fourth impingers shall be of the Greenburg-Smith design, modified by replacing the tip with 1.3 cm (½ in.) ID glass tube extending to about 1.3 cm (½ in.) from the bottom of the flask. The second impinger shall be of the Greenburg-Smith design with the standard tip. Modifications (e.g., using flexible connections between the impingers, using materials other than glass, or using flexible vacuum lines to connect the filter holder to the condenser) may be used, subject to the approval of the Administrator. The first and second impingers shall contain known quantities of water (Section 4.1.3), the third shall be empty, and the fourth shall contain a known weight of silica gel, or equivalent desiccant. A thermometer, capable of measuring temperature to within 1° C (2° F) shall be placed at the outlet of the fourth impinger for monitoring purposes.

Alternatively, any system that cools the sample gas stream and allows measurement of the water condensed and moisture leaving the condenser, each to within 1 ml or 1 g may be used, subject to the approval of the Administrator. Acceptable means are to measure the condensed water either gravi-

[2] Mention of trade names or specific product does not constitute endorsement by the Environmental Protection Agency.

metrically or volumetrically and to measure the moisture leaving the condenser by: (1) monitoring the temperature and pressure at the exit of the condenser and using Dalton's law of partial pressures; or (2) passing the sample has stream through a tared silica gel (or equivalent desiccant) trap with exit gases kept below 20° C (68° F) and determining the weight gain.

If means other than silica gel are used to determine the amount of moisture leaving the condenser, it is recommended that silica gel (or equivalent) still be used between the condenser system and pump to prevent moisture condensation in the pump and metering devices and to avoid the need to make corrections for moisture in the metered volume.

NOTE: If a determination of the particulate matter collected in the impingers is desired in addition to moisture content, the impinger system described above shall be used, without modification. Individual States or control agencies requiring this information shall be contacted as to the sample recovery and analysis of the impinger contents.

2.1.8 Metering System. Vacuum gauge, leak-free pump, thermometers capable of measuring temperature to within 3° C (5.4° F), dry gas meter capable of measuring volume to within 2 percent, and related equipment, as shown in Figure 5–1. Other metering systems capable of maintaining sampling rates within 10 percent of isokinetic and of determining sample volumes to within 2 percent may be used, subject to the approval of the Administrator. When the metering system is used in conjunction with a pitot tube, the system shall enable checks of isokinetic rates.

Sampling trains utilizing metering systems designed for higher flow rates than that decribed in APTD–0581 or APDT–0576 may be used provided that the specifications of this method are met.

2.1.9 Barometer. Mercury aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg). In many cases the barometric reading may be obtained from a nearby National Weather Service station, in which case the station value (which is the absolute barometric pressure) shall be requested and an adjustment for elevation differences between the weather station and sampling point shall be applied at a rate of minus 2.5 mm Hg (0.1 in. Hg) per 30 m (100 ft) elevation increase or vice versa for elevation decrease.

2.1.10 Gas Density Determination Equipment. Temperature sensor and pressure gauge, as described in Sections 2.3 and 2.4 of Method 2, and gas analyzer, if necessary, as described in Method 3. The temperature sensor shall, preferably, be permanently attached to the pitot tube or sampling probe in a fixed configuration, such that the tip of the sensor extends beyond the leading edge of the probe sheath and does not touch any metal. Alternatively, the sensor may be attached just prior to use in the field. Note, however, that if the temperature sensor is attached in the field, the sensor must be placed in an interference-free arrangement with respect to the Type S pitot tube openings (see Method 2, Figure 2–7). As a second alternative, if a difference of not more than 1 percent in the average velocity measurement is to be introduced, the temperature gauge need not be attached to the probe or pitot tube. (This alternative is subject to the approval of the Administrator.)

2.2 Sample Recovery. The following items are needed.

2.2.1 Probe-Liner and Probe-Nozzle Brushes. Nylon bristle brushes with stainless steel wire handles. The probe brush shall have extensions (at least as long as the probe) of stainless steel, Nylon, Teflon, or similarly inert material. The brushes shall be properly sized and shaped to brush out the probe liner and nozzle.

2.2.2 Wash Bottles—Two. Glass wash bottles are recommended; polyethylene wash bottles may be used at the option of the tester. It is recommended that acetone not be stored in polyethylene bottles for longer than a month.

2.2.3 Glass Sample Storage Containers. Chemically resistant, borosilicate glass bottles, for acetone washes, 500 ml or 1000 ml. Screw cap liners shall either be rubber-backed Teflon or shall be constructed so as to be leak-free and resistant to chemical attack by acetone. (Narrow mouth glass bottles have been found to be less prone to leakage.) Alternatively, polyethylene bottles may be used.

2.2.4 Petri Dishes. For filter samples, glass or polyethylene, unless otherwise specified by the Administrator.

2.2.5 Graduated Cylinder and/or Balance. To measure condensed water to within 1 ml or 1 g. Graduated cylinders shall have subdivisions no greater than 2 ml. Most laboratory balances are capable of weighing to the nearest 0.5 g or less. Any of these balances is suitable or use here and in Section 2.3.4.

2.2.6 Plastic Storage Containers. Air-tight containers to store silica gel.

2.2.7 Funnel and Rubber Policeman. To aid in transfer of silica gel to container; not necessary if silica gel is weighed in the field.

2.2.8 Funnel. Glass or polyethylene, to aid in sample recovery.

2.3 Analysis. For analysis, the following equipment is needed.

2.3.1 Glass Weighing Dishes.

2.3.2 Desiccator.

2.3.3 Analytical Balance. To measure to within 0.1 mg.

2.3.4 Balance. To measure to within 0.5 g.

2.3.5 Beakers. 250 ml.

2.3.6 Hygrometer. To measure the relative humidity of the laboratory environment.

2.3.7 Temperature Gauge. To measure the temperature of the laboratory environment.

3. *Reagents*

3.1 Sampling. The reagents used in sampling are as follows:

3.1.1 Filters. Glass fiber filters, without organic binder, exhibiting at least 99.95 percent efficiency (<0.05 percent penetration) on 0.3-micron dioctyl phthalate smoke particles. The filter efficiency test shall be conducted in accordance with ASTM Standard Method D2986-71 (Reapproved 1978) (incorporated by reference—see § 60.17). Test data from the supplier's quality control program are sufficient for this purpose. In sources containing SO_2 or SO_3, the filter material must be of a type that is unreactive to SO_2 or SO_3. Citation 10 in Bibliography, may be used to select the appropriate filter.

3.1.2 Silica Gel. Indicating type, 6 to 16 mesh. If previously used, dry at 175° C (350° F) for 2 hours. New silica gel may be used as received. Alternatively, other types of desiccants (equivalent or better) may be used, subject to the approval of the Administrator.

3.1.3 Water. When analysis of the material caught in the impingers is required, deionized distilled water shall be used. Run blanks prior to field use to eliminate a high blank on test samples.

3.1.4 Crushed Ice.

3.1.5 Stopcock Grease. Acetone-insoluble, heat-stable silicone grease. This is not necessary if screw-on connectors with Teflon sleeves, or similar, are used. Alternatively, other types of stopcock grease may be used, subject to the approval of the Administrator.

3.2 Sample Recovery. Acetone-reagent grade, ≤0.001 percent residue, in glass bottles—is required. Acetone from metal containers generally has a high residue blank and should not be used. Sometimes, suppliers transfer acetone to glass bottles from metal containers; thus, acetone blanks shall be run prior to field use and only acetone with low blank values (≤0.001 percent) shall be used. In no case shall a blank value of greater than 0.001 percent of the weight of acetone used be subtracted from the sample weight.

3.3 Analysis. Two reagents are required for the analysis:

3.3.1 Acetone. Same as 3.2.

3.3.2 Desiccant. Anhydrous calcium sulfate, indicating type. Alternatively, other types of desiccants may be used, subject to the approval of the Administrator.

4. *Procedure*

4.1 Sampling. The complexity of this method is such that, in order to obtain reliable results, testers should be trained and experienced with the test procedures.

4.1.1 Pretest Preparation. It is suggested that sampling equipment be maintained according to the procedure described in APTD-0576.

Weigh several 200 to 300 g portions of silica gel in air-tight containers to the nearest 0.5 g. Record the total weight of the silica gel plus container, on each container. As an alternative, the silica gel need not be preweighed, but may be weighed directly in the impinger or sampling holder just prior to train assembly.

Check filters visually against light for irregularities and flaws or pinhole leaks. Label filters of the proper diameter on the back side near the edge using numbering machine ink. As an alternative, label the shipping containers (glass or plastic petri dishes) and keep the filters in these containers at all times except during sampling and weighing.

Desiccate the filters at 20±5.6° C (68±10° F) and ambient pressure for at least 24 hours and weigh at intervals of at least 6 hours to a constant weight, i.e., 0.5 mg change from previous weighing; record results to the nearest 0.1 mg. During each weighing the filter must not be exposed to the laboratory atmosphere for a period greater than 2 minutes and a relative humidity above 50 percent. Alternatively (unless otherwise specified by the Administrator), the filters may be oven dried at 105° C (220° F) for 2 to 3 hours, desiccated for 2 hours, and weighed. Procedures other than those described, which account for relative humidity effects, may be used, subject to the approval of the Administrator.

4.1.2 Preliminary Determinations. Select the sampling site and the minimum number of sampling points according to Method 1 or as specified by the Administrator. Determine the stack pressure, temperature, and the range of velocity heads using Method 2; it is recommended that a leak-check of the pitot lines (see Method 2, Section 3.1) be performed. Determine the moisture content using Approximation Method 4 or its alternatives for the purpose of making isokinetic sampling rate settings. Determine the stack gas dry molecular weight, as described in Method 2, Section 3.6; if integrated Method 3 sampling is used for molecular weight determination, the integrated bag sample shall be taken simultaneously with, and for the same total length of time as, the particulate sample run.

Select a nozzle size based on the range of velocity heads, such that it is not necessary to change the nozzle size in order to maintain isokinetic sampling rates. During the run, do not change the nozzle size. Ensure that the proper differential pressure gauge is chosen for the range of velocity heads encountered (see Section 2.2 of Method 2).

Select a suitable probe liner and probe length such that all traverse points can be sampled. For large stacks, consider sampling from opposite sides of the stack to reduce the length of probes.

Select a total sampling time greater than or equal to the minimum total sampling time specified in the test procedures for the specific industry such that (1) the sampling time per point is not less than 2 min (or some greater time interval as specified by the Administrator), and (2) the sample volume taken (corrected to standard conditions) will exceed the required minimum total gas sample volume. The latter is based on an approximate average sampling rate.

It is recommended that the number of minutes sampled at each point be an integer or an integer plus one-half minute, in order to avoid timekeeping errors. The sampling time at each point shall be the same.

In some circumstances, e.g., batch cycles, it may be necessary to sample for shorter times at the traverse points and to obtain smaller gas sample volumes. In these cases, the Administrator's approval must first be obtained.

4.1.3 Preparation of Collection Train. During preparation and assembly of the sampling train, keep all openings where contamination can occur covered until just prior to assembly or until sampling is about to begin.

Place 100 ml of water in each of the first two impingers, leave the third impinger empty, and transfer approximately 200 to 300 g of preweighed silica gel from its container to the fourth impinger. More silica gel may be used, but care should be taken to ensure that it is not entrained and carried out from the impinger during sampling. Place the container in a clean place for later use in the sample recovery. Alternatively, the weight of the silica gel plus impinger may be determined to the nearest 0.5 g and recorded.

Using a tweezer or clean disposable surgical gloves, place a labeled (identified) and weighed filter in the filter holder. Be sure that the filter is properly centered and the gasket properly placed so as to prevent the sample gas stream from circumventing the filter. Check the filter for tears after assembly is completed.

When glass liners are used, install the selected nozzle using a Viton A O-ring when stack temperatures are less than 260° C (500° F) and an asbestos string gasket when temperatures are higher. See APTD–0576 for details. Other connecting systems using either 316 stainless steel or Teflon ferrules may be used. When metal liners are used, install the nozzle as above or by a leak-free direct mechanical connection. Mark the probe with heat resistant tape or by some other method to denote the proper distance into the stack or duct for each sampling point.

Set up the train as in Figure 5–1, using (if necessary) a very light coat of silicone grease on all ground glass joints, greasing only the outer portion (see APTD–0576) to avoid possibility of contamination by the silicone grease. Subject to the approval of the Administrator, a glass cyclone may be used between the probe and filter holder when the total particulate catch is expected to exceed 100 mg or when water droplets are present in the stack gas.

Place crushed ice around the impingers.

4.1.4 Leak-Check Procedures.

4.1.4.1 Pretest Leak-Check. A pretest leak-check is recommended, but not required. If the tester opts to conduct the pretest leak-check, the following procedure shall be used.

After the sampling train has been assembled, turn on and set the filter and probe heating systems at the desired operating temperatures. Allow time for the temperatures to stabilize. If a Viton A O-ring or other leak-free connection is used in assembling the probe nozzle to the probe liner, leak-check the train at the sampling site by plugging the nozzle and pulling a 380 mm Hg (15 in. Hg) vacuum.

NOTE: A lower vacuum may be used, provided that it is not exceeded during the test.

If an asbestos string is used, do not connect the probe to the train during the leak-check. Instead, leak-check the train by first plugging the inlet to the filter holder (cyclone, if applicable) and pulling a 380 mm Hg (15 in. Hg) vacuum (see Note immediately above). Then connect the probe to the train and leak-check at about 25 mm Hg (1 in. Hg) vacuum; alternatively, the probe may be leak-checked with the rest of the sampling train, in one step, at 380 mm Hg (15 in. Hg) vacuum. Leakage rates in excess of 4 percent of the average sampling rate or 0.00057 m^3/min (0.02 cfm), whichever is less, are unacceptable.

The following leak-check instructions for the sampling train described in APTD–0576 and APTD–0581 may be helpful. Start the pump with bypass valve fully open and coarse adjust valve, completely closed. Partially open the coarse adjust valve and slowly close the bypass valve until the desired vacuum is reached. Do not reverse direction of bypass valve; this will cause water to back up into the filter holder. If the desired vacuum is exceeded, either leak-check at this higher vacuum or end the leak-check as shown below and start over.

When the leak-check is completed, first slowly remove the plug from the inlet to the probe, filter holder, or cyclone (if applicable) and immediately turn off the vacuum pump. This prevents the water in the impingers from being forced backward into the filter holder and silica gel from being entrained backward into the third impinger.

4.1.4.2 Leak-Checks During Sample Run. If, during the sampling run, a component (e.g., filter assembly or impinger) change becomes necessary, a leak-check shall be conducted immediately before the change is made. The leak-check shall be done according to the procedure outlined in Section 4.1.4.1 above, except that it shall be done at a vacuum equal to or greater than the maximum value recorded up to that point in the test. If the leakage rate is found to be no greater than 0.00057 m³/min (0.02 cfm) or 4 percent of the average sampling rate (whichever is less), the results are acceptable, and no correction will need to be applied to the total volume of dry gas metered; if, however, a higher leakage rate is obtained, the tester shall either record the leakage rate and plan to correct the sample volume as shown in Section 6.3 of this method, or shall void the sampling run.

Immediately after component changes, leak-checks are optional; if such leak-checks are done, the procedure outlined in Section 4.1.4.1 above shall be used.

4.1.4.3 Post-test Leak-Check. A leak-check is mandatory at the conclusion of each sampling run. The leak-check shall be done in accordance with the procedures outlined in Section 4.1.4.1, except that it shall be conducted at a vacuum equal to or greater than the maximum value reached during the sampling run. If the leakage rate is found to be no greater than 0.00057 m³/min (0.02 cfm) or 4 percent of the average sampling rate (whichever is less), the results are acceptable, and no correction need be applied to the total volume of dry gas metered. If, however, a higher leakage rate is obtained, the tester shall either record the leakage rate and correct the sample volume as shown in Section 6.3 of this method, or shall void the sampling run.

4.1.5 Particulate Train Operation. During the sampling run, maintain an isokinetic sampling rate (within 10 percent of true isokinetic unless otherwise specified by the Administrator) and a temperature around the filter of 120±14° C (248±25° F), or such other temperature as specified by an applicable subpart of the standards or approved by the Administrator.

For each run, record the data required on a data sheet such as the one shown in Figure 5-2. Be sure to record the initial dry gas meter reading. Record the dry gas meter readings at the beginning and end of each sampling time increment, when changes in flow rates are made, before and after each leak-check, and when sampling is halted. Take other readings required by Figure 5-2 at least once at each sample point during each time increment and additional readings when significant changes (20 percent variation in velocity head readings) necessitate additional adjustments in flow rate. Level and zero the manometer. Because the manometer level and zero may drift due to vibrations and temperature changes, make periodic checks during the traverse.

Clean the portholes prior to the test run to minimize the chance of sampling deposited material. To begin sampling, remove the nozzle cap, verify that the filter and probe heating systems are up to temperature, and that the pitot tube and probe are properly positioned. Position the nozzle at the first traverse point with the tip pointing directly into the gas stream. Immediately start the pump and adjust the flow to isokinetic conditions. Nomographs are available, which aid in the rapid adjustment of the isokinetic sampling rate without excessive computations. These nomographs are designed for use when the Type S pitot tube coefficient is 0.85±0.02, and the stack gas equivalent density (dry molecular weight) is equal to 29±4. APTD-0576 details the procedure for using the nomographs. If C_p and M_d are outside the above stated ranges do not use the nomographs unless appropriate steps (see Citation 7 in Bibliography) are taken to compensate for the deviations.

FIGURE 5-2—PARTICULATE FIELD DATA

Plant ....
Location ....
Operator ....
Date ....
Run No ....
Sample box No ....
Meter box No ....
Meter ΔH@ ....
C factor ....
Pitot tube coefficient, Cp ....

SCHEMATIC OF STACK CROSS SECTION

Ambient temperature ....
Barometric pressure ....
Assumed moisture, % ....
Probe length, m. (ft.) ....
Nozzle identification No. ....
Average calibrated nozzle diameter, cm (in.) ....
Probe heater setting ....
Leak rate, m^3/min, (cfm) ....
Probe liner material ....
Static pressure, mm. Hg (in. Hg) ....
Filter No. ....

Traverse point number	Sampling time	Vacuum	Stack temperature	Velocity head	Pressure differential across orifice meter	Gas sample volume	Gas sample temperature at dry gas meter		Filter holder temperature	Temperature of gas leaving condenser or last impinger
							Inlet	Outlet		
	(θ). min.	mm Hg (in. Hg)	(T_S). °C (° F)	(ΔP_S). mm (in.) H_2O	mm H_2O (in. H_2O)	m^3 (ft^3)	°C (° F)	° C (° F)	° C (° F)	° C (° F)
Total							Avg.	Avg.		
Average							Avg.			

When the stack is under significant negative pressure (height of impinger stem), take care to close the coarse adjust valve before inserting the probe into the stack to prevent water from backing into the filter holder. If necessary, the pump may be turned on with the coarse adjust valve closed.

When the probe is in position, block off the openings around the probe and porthole to prevent unrepresentative dilution of the gas stream.

Traverse the stack cross-section, as required by Method 1 or as specified by the Administrator, being careful not to bump the probe nozzle into the stack walls when sampling near the walls or when removing or inserting the probe through the portholes; this minimizes the chance of extracting deposited material.

During the test run, make periodic adjustments to keep the temperature around the filter holder at the proper level; add more ice and, if necessary, salt to maintain a temperature of less than 20° C (68° F) at the condenser/silica gel outlet. Also, periodically check the level and zero of the manometer.

If the pressure drop across the filter becomes too high, making isokinetic sampling difficult to maintain, the filter may be replaced in the midst of a sample run. It is recommended that another complete filter assembly be used rather than attempting to change the filter itself. Before a new filter assembly is installed, conduct a leak-check (see Section 4.1.4.2). The total particulate weight shall include the summation of all filter assembly catches.

A single train shall be used for the entire sample run, except in cases where simultaneous sampling is required in two or more separate ducts or at two or more different locations within the same duct, or, in cases where equipment failure necessitates a change of trains. In all other situations, the use of two or more trains will be subject to the approval of the Administrator.

Note that when two or more trains are used, separate analyses of the front-half and (if applicable) impinger catches from each train shall be performed, unless identical nozzle sizes were used on all trains, in which case, the front-half catches from the individual trains may be combined (as may the impinger catches) and one analysis of front-half catch and one analysis of impinger catch may be performed. Consult with the Administrator for details concerning the calculation of results when two or more trains are used.

At the end of the sample run, turn off the coarse adjust valve, remove the probe and nozzle from the stack, turn off the pump, record the final dry gas meter reading, and conduct a post-test leak-check, as outlined in Section 4.1.4.3. Also, leak-check the pitot lines as described in Method 2, Section 3.1; the lines must pass this leak-check, in order to validate the velocity head data.

4.1.6 Calculation of Percent Isokinetic. Calculate percent isokinetic (see Calculations, Section 6) to determine whether the run was valid or another test run should be made. If there was difficulty in maintaining isokinetic rates due to source conditions, consult with the Administrator for possible variance on the isokinetic rates.

4.2 Sample Recovery. Proper cleanup procedure begins as soon as the probe is removed from the stack at the end of the sampling period. Allow the probe to cool.

When the probe can be safely handled, wipe off all external particulate matter near the tip of the probe nozzle and place a cap over it to prevent losing or gaining particulate matter. Do not cap off the probe tip tightly while the sampling train is cooling down as this would create a vacuum in the filter holder, thus drawing water from the impingers into the filter holder.

Before moving the sample train to the cleanup site, remove the probe from the sample train, wipe off the silicone grease, and cap the open outlet of the probe. Be careful not to lose any condensate that might be present. Wipe off the silicone grease from the filter inlet where the probe was fastened and cap it. Remove the umbilical cord from the last impinger and cap the impinger. If a flexible line is used between the first impinger or condenser and the filter holder, disconnect the line at the filter holder and let any condensed water or liquid drain into the impingers or condenser. After wiping off the silicone grease, cap off the filter holder outlet and impinger inlet. Either ground-glass stoppers, plastic caps, or serum caps may be used to close these openings.

Transfer the probe and filter-impinger assembly to the cleanup area. This area should be clean and protected from the wind so that the chances of contaminating or losing the sample will be minimized.

Save a portion of the acetone used for cleanup as a blank. Take 200 ml of this acetone directly from the wash bottle being used and place it in a glass sample container labeled "acetone blank."

Inspect the train prior to and during disassembly and note any abnormal conditions. Treat the samples as follows:

Container No. 1. Carefully remove the filter from the filter holder and place it in its identified petri dish container. Use a pair of tweezers and/or clean disposable surgical gloves to handle the filter. If it is necessary to fold the filter, do so such that the particulate cake is inside the fold. Carefully transfer to the petri dish any particulate matter and/or filter fibers which adhere to the filter holder gasket, by using a dry Nylon bristle brush and/or a sharp-edged blade. Seal the container.

Container No. 2. Taking care to see that dust on the outside of the probe or other exterior surfaces does not get into the sample, quantitatively recover particulate matter or any condensate from the probe nozzle, probe fitting, probe liner, and front half of the filter holder by washing these components with acetone and placing the wash in a glass container. Distilled water may be used instead of acetone when approved by the Administrator and shall be used when specified by the Administrator; in these cases, save a water blank and follow the Administrator's directions on analysis. Perform the acetone rinses as follows:

Carefully remove the probe nozzle and clean the inside surface by rinsing with acetone from a wash bottle and brushing with a Nylon bristle brush. Brush until the acetone rinse shows no visible particles, after which make a final rinse of the inside surface with acetone.

Brush and rinse the inside parts of the Swagelok fitting with acetone in a similar way until no visible particles remain.

Rinse the probe liner with acetone by tilting and rotating the probe while squirting acetone into its upper end so that all inside surfaces will be wetted with acetone. Let the acetone drain from the lower end into the sample container. A funnel (glass or polyethylene) may be used to aid on transferring liquid washes to the container. Follow the acetone rinse with a probe brush. Hold the probe in an inclined position, squirt acetone into the upper end as the probe brush is being pushed with a twisting action through the probe; hold a sample container underneath the lower end of the probe, and catch any acetone and particulate matter which is brushed from the probe. Run the brush through the probe three times or more until no visible particulate matter is carried out with the acetone or until none remains in the probe liner on visual inspection. With stainless steel or other metal probes, run the brush through in the above prescribed manner at least six times since metal probes have small crevices in which particulate matter can be entrapped. Rinse the brush with acetone, and quantitatively collect these washings in the sample container. After the brushing, make a final acetone rinse of the probe as described above.

It is recommended that two people clean the probe to minimize sample losses. Between sampling runs, keep brushes clean and protected from contaminations.

After ensuring that all joints have been wiped clean of silicone grease, clean the inside of the front half of the filter holder by rubbing the surfaces with a Nylon bristle brush and rinsing with acetone. Rinse each surface three times or more if needed to remove visible particulate. Make a final rinse of the brush and filter holder. Carefully rinse out the glass cyclone, also (if applicable). After all acetone washings and particulate matter have been collected in the sample container, tighten the lid on the sample container so that acetone will not leak out when it is shipped to the laboratory. Mark the height of the fluid level to determine whether or not leakage occured during transport. Label the container to clearly identify its contents.

Container No. 3. Note the color of the indicating silica gel to determine if it has been completely spent and make a notation of its condition. Transfer the silica gel from the fourth impinger to its original container and seal. A funnel may make it easier to pour the silica gel without spilling. A rubber policeman may be used as an aid in removing the silica gel from the impinger. It is not necessary to remove the small amount of dust particles that may adhere to the impinger wall and are difficult to remove. Since the gain in weight is to be used for moisture calculations, do not use any water or other liquids to transfer the silica gel. If a balance is available in the field, follow the procedure for container No. 3 in Section 4.3.

Impinger Water. Treat the impingers as follows; Make a notation of any color or film in the liquid catch. Measure the liquid which is in the first three impingers to within ±1 ml by using a graduated cylinder or by weighing it to within ±0.5 g by using a balance (if one is available). Record the volume or weight of liquid present. This information is required to calculate the moisture content of the effluent gas.

Discard the liquid after measuring and recording the volume or weight, unless analysis of the impinger catch is required (see Note, Section 2.1.7).

If a different type of condenser is used, measure the amount of moisture condensed either volumetrically or gravimetrically.

Whenever possible, containers should be shipped in such a way that they remain upright at all times.

4.3 Analysis. Record the data required on a sheet such as the one shown in Figure 5–3. Handle each sample container as follows:

FIGURE 5–3—ANALYTICAL DATA

Plant ________
Date ________
Run No. ________
Filter No. ________
Amount liquid lost during transport ________
Acetone blank volume, ml ________
Acetone wash volume, ml ________
Acetone blank concentration, mg/mg (Equation 5–4) ________
Acetone wash blank, mg (Equation 5–5) ________

Container number	Weight of particulate collected, mg		
	Final weight	Tare weight	Weight gain
1.			

Container number	Weight of particulate collected, mg		
	Final weight	Tare weight	Weight gain
2			
Total.			
Less acetone blank.			
Weight of particulate matter.			

	Volume of liquid water collected	
	Impinger volume, ml	Silica gel weight, g
Final.		
Initial.		
Liquid collected.		
Total volume collected		g* ml

*Convert weight of water to volume by dividing total weight increase by density of water (1 g/ml).

$$\frac{\text{Increase, g}}{(1\ \text{g/ml})} = \text{Volume water, ml}$$

Container No. 1. Leave the contents in the shipping container or transfer the filter and any loose particulate from the sample container to a tared glass weighing dish. Desiccate for 24 hours in a desiccator containing anhydrous calcium sulfate. Weigh to a constant weight and report the results to the nearest 0.1 mg. For purposes of this Section, 4.3, the term "constant weight" means a difference of no more than 0.5 mg or 1 percent of total weight less tare weight, whichever is greater, between two consecutive weighings, with no less than 6 hours of desiccation time between weighings.

Alternatively, the sample may be oven dried at 105° C (220° F) for 2 to 3 hours, cooled in the desiccator, and weighed to a constant weight, unless otherwise specified by the Administrator. The tester may also opt to oven dry the sample at 105° C (220° F) for 2 to 3 hours, weigh the sample, and use this weight as a final weight.

Container No. 2. Note the level of liquid in the container and confirm on the analysis sheet whether or not leakage occurred during transport. If a noticeable amount of leakage has occurred, either void the sample or use methods, subject to the approval of the Administrator, to correct the final results. Measure the liquid in this container either volumetrically to ±1 ml or gravimetrically to ±0.5 g. Transfer the contents to a tared 250-ml beaker and evaporate to dryness at ambient temperature and pressure. Desiccate for 24 hours and weigh to a constant weight. Report the results to the nearest 0.1 mg.

Container No. 3. Weigh the spent silica gel (or silica gel plus impinger) to the nearest 0.5 g using a balance. This step may be conducted in the field.

"Acetone Blank" Container. Measure acetone in this container either volumetrically or gravimetrically. Transfer the acetone to a tared 250-ml beaker and evaporate to dryness at ambient temperature and pressure. Desiccate for 24 hours and weigh to a constant weight. Report the results to the nearest 0.1 mg.

NOTE: At the option of the tester, the contents of Container No. 2 as well as the acetone blank container may be evaporated at temperatures higher than ambient. If evaporation is done at an elevated temperature, the temperature must be below the boiling point of the solvent; also, to prevent "bumping," the evaporation process must be closely supervised, and the contents of the beaker must be swirled occasionally to maintain an even temperature. Use extreme care, as acetone is highly flammable and has a low flash point.

4.4 Quality Control Procedures. The following quality control procedures are suggested to check the volume metering system calibration values at the field test site prior to sample collection. These procedures are optional for the tester.

4.4.1 Meter Orifice Check. Using the calibration data obtained during the calibration procedure described in Section 5.3, determine the $\Delta H_@$ for the metering system orifice. The $\Delta H_@$ is the orifice pressure differential in units of in. H_2O that correlates to 0.75 cfm of air at 528°R and 29.92 in. Hg. The $\Delta H_@$ is calculated as follows:

$$\Delta H_@ = 0.0319\ \Delta H\ \frac{T_m}{P_{bar}}\ \frac{\Theta^2}{Y^2 V_m^2}$$

Eq. 5-9

Where:

ΔH=Average pressure differential across the orifice meter, in. H_2O.

T_m=Absolute average dry gas meter temperature, °R.

P_{bar}=Barometric pressure, in. Hg.

Θ=Total sampling time, min.

Y=Dry gas meter calibration factor, dimensionless.

V_m=Volume of gas sample as measured by dry gas meter, dcf.

0.0319=(0.0567 in. Hg/°R) x (0.75 cfm)^2.

Before beginning the field test (a set of three runs usually constitutes a field test), operate the metering system (i.e., pump, volume meter, and orifice) at the $\Delta H_@$ pressure differential for 10 minutes. Record the volume collected, the dry gas meter temperature, and the barometric pressure. Calculate a dry gas meter calibration check value, Y_c, as follows:

$$Y_c = \frac{10}{V_m}\left[\frac{0.0319\ T_m}{P_{bar}}\right]^{1/2}$$

Eq. 5-10

Where:

Y_c=Dry gas meter calibration check value, dimensionless.

10=10 minutes of run time.

Compare the Y_c value with the dry gas meter calibration factor Y to determine that:

$$0.97Y<Y_c<1.03Y$$

If the Y_c value is not within this range, the volume metering system should be investigated before beginning the test.

4.4.2 Calibrated Critical Orifice. A calibrated critical orifice, calibrated against a wet test meter or spirometer and designed to be inserted at the inlet of the sampling meter box may be used as a quality control check by following the procedure of Section 7.2.

5. *Calibration*

Maintain a laboratory log of all calibrations.

5.1 Probe Nozzle. Probe nozzles shall be calibrated before their initial use in the field. Using a micrometer, measure the inside diameter of the nozzle to the nearest 0.025 mm (0.001 in.). Make three separate measurements using different diameters each time, and obtain the average of the measurements. The difference between the high and low numbers shall not exceed 0.1 mm (0.004 in.). When nozzles become nicked, dented, or corroded, they shall be reshaped, sharpened, and recalibrated before use. Each nozzle shall be permanently and uniquely identified.

5.2 Pitot Tube. The Type S pitot tube assembly shall be calibrated according to the procedure outlined in Section 4 of Method 2.

5.3 Metering System.

5.3.1 Calibration Prior to Use. Before its initial use in the field, the metering system shall be calibrated as follows: Connect the metering system inlet to the outlet of a wet test meter that is accurate to within 1 percent. Refer to Figure 5.5. The wet test meter should have a capacity of 30 liters/rev (1 ft^3/rev). A spirometer of 400 liters (14 ft^3) or more capacity, or equivalent, may be used for this calibration, although a wet test meter is usually more practical. The wet test meter should be periodically calibrated with a spirometer or a liquid displacement meter to ensure the accuracy of the wet test meter. Spirometers or wet test meters of other sizes may be used, provided that the specified accuracies of the procedure are maintained. Run the metering system pump for about 15 minutes with the orifice manometer indicating a median reading as expected in field use to allow the pump to warm up and to permit the interior surface of the wet test meter to be thoroughly wetted. Then, at each of a minimum of three orifice manometer settings, pass an exact quantity of gas through the wet test meter and note the gas volume indicated by the dry gas meter. Also note the barometric pressure, and the temperatures of the wet test meter, the inlet of the dry gas meter, and the outlet of the dry gas meter. Select the highest and lowest orifice settings to bracket the expected field operating range of the orifice. Use a minimum volume of 0.15 m^3 (5 cf) at all orifice settings. Record all the data on a form similar to Figure 5.6, and calculate Y, the dry gas meter calibration factor, and $\Delta H_@$, the orifice calibration factor, at each orifice setting as shown on Figure 5.6. Allowable tolerances for individual Y and $\Delta H_@$ values are given in Figure 5.6. Use the average of the Y values in the calculations in Section 6.

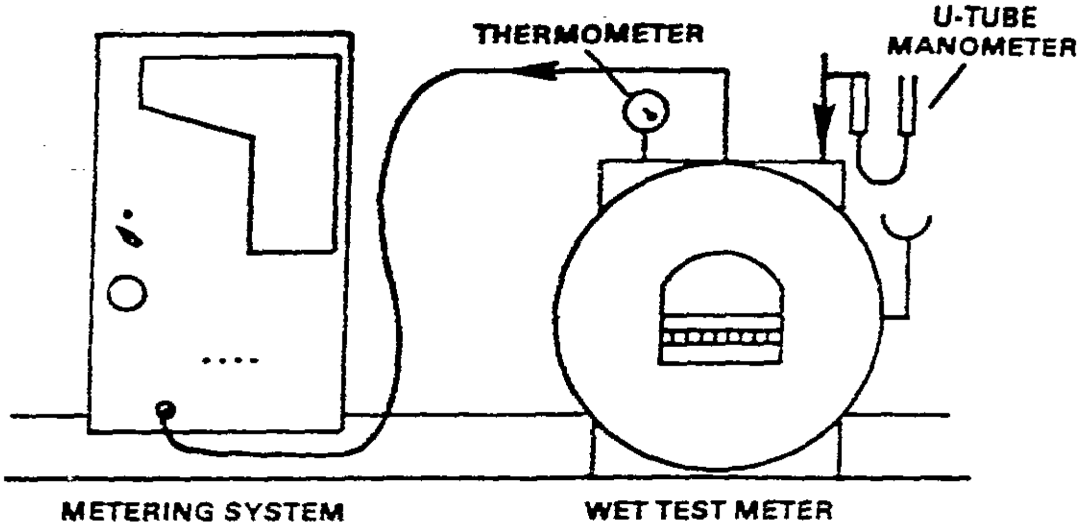

Figure 5.5 Equipment arrangement for metering system calibration.

Date ______________________ Metering System Identification: ______________

Barometric pressure, P_b = ______ in. Hg

Orifice manometer setting ΔH in. H_2O	Spirometer (wet meter) gas volume V_w ft^3	Dry gas meter volume V_m ft^3	Temperatures: Spirometer (wet meter) t_w °F	Temperatures: Dry Gas Meter: Inlet t_i °F	Temperatures: Dry Gas Meter: Outlet t_o °F	Temperatures: Dry Gas Meter: Average t_m °F	Time θ min

Calculations

ΔH in. H_2O	Y: $\dfrac{V_w\ P_b\ (t_m + 460)}{V_m \left[P_b + \dfrac{\Delta H}{13.6}\right] (t_w + 460)}$	$\Delta H@$: $\dfrac{0.0317\ \Delta H}{P_b\ (t_o + 460)} \left[\dfrac{(t_w + 460)\ \theta}{V_w}\right]^2$
Average		

Y = Ratio of reading of wet test meter to dry test meter; tolerance for individual values ±0.02 from average.

$\Delta H_@$ = Orifice pressure differential that equates to 0.75 cfm of air @ 68°F and 29.92 inches of mercury, in. H_2O; tolerance for individual values ±0.20 from average.

Figure 5.6. Example data sheet for calibration of metering system (English units).

Before calibrating the metering system, it is suggested that a leak-check be conducted. For metering systems having diaphragm pumps, the normal leak-check procedure will not detect leakages within the pump. For *these cases* the following leak-check procedure is suggested: make a 10-minute calibration run at 0.00057 m^3/min (0.02 cfm); at the end of the run, take the difference of the measured wet test meter and dry gas meter volumes; divide the difference by 10, to get the leak rate. The leak rate should not exceed 0.00057 m^3/min (0.02 cfm).

5.3.2 Calibration After Use. After each field use, the calibration of the metering system shall be checked by performing three calibration runs at a single, intermediate orifice setting (based on the previous field test), with the vacuum set at the maximum value reached during the test series. To adjust the vacuum, insert a valve between the wet test meter and the inlet of the metering system. Calculate the average value of the dry gas meter calibration factor. If the value has changed by more than 5 percent, recalibrate the meter over the full range of orifice settings, as previously detailed.

Alternative procedures, e.g., rechecking the orifice meter coefficient may be used, subject to the approval of the Administrator.

5.3.3 Acceptable Variation in Calibration. If the dry gas meter coefficient values obtained before and after a test series differ by more than 5 percent, the test series shall either be voided, or calculations for the test series shall be performed using whichever meter coefficient value (i.e., before or after) gives the lower value of total sample volume.

5.4 Probe Heater Calibration. The probe heating system shall be calibrated before its initial use in the field.

Use a heat source to generate air heated to selected temperatures that approximate those expected to occur in the sources to be sampled. Pass this air through the probe at a typical simple flow rate while measuring the probe inlet and outlet temperatures at various probe heater settings. For each air temperature generated, construct a graph of probe heating system setting versus probe outlet temperature. The procedure outlined in APTD–0576 can also be used. Probes constructed according to APTD–0581 need not be calibrated if the calibration curves in APTD–0576 are used. Also, probes with outlet temperature monitoring capabilities do not require calibration.

5.5 Temperature Gauges. Use the procedure in Section 4.3 of Method 2 to calibrate in-stack temperature gauges. Dial thermometers, such as are used for the dry gas meter and condenser outlet, shall be calibrated against mercury-in-glass thermometers.

5.6 Leak Check of Metering System Shown in Figure 5–1. That portion of the sampling train from the pump to the orifice meter should be leak checked prior to initial use and after each shipment. Leakage after the pump will result in less volume being recorded than is actually sampled. The following procedure is suggested (see Figure 5–4): Close the main valve on the meter box. Insert a one-hole rubber stopper with rubber tubing attached into the orifice exhaust pipe. Disconnect and vent the low side of the orifice manometer. Close off the low side orifice tap. Pressurize the system to 13 to 18 cm (5 to 7 in.) water column by blowing into the rubber tubing. Pinch off the tubing and observe the manometer for one minute. A loss of pressure on the manometer indicates a leak in the meter box; leaks, if present, must be corrected.

5.7 Barometer. Calibrate against a mercury barometer.

6. *Calculations*

Carry out calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after the final calculation. Other forms of the equations may be used as long as they give equivalent results.

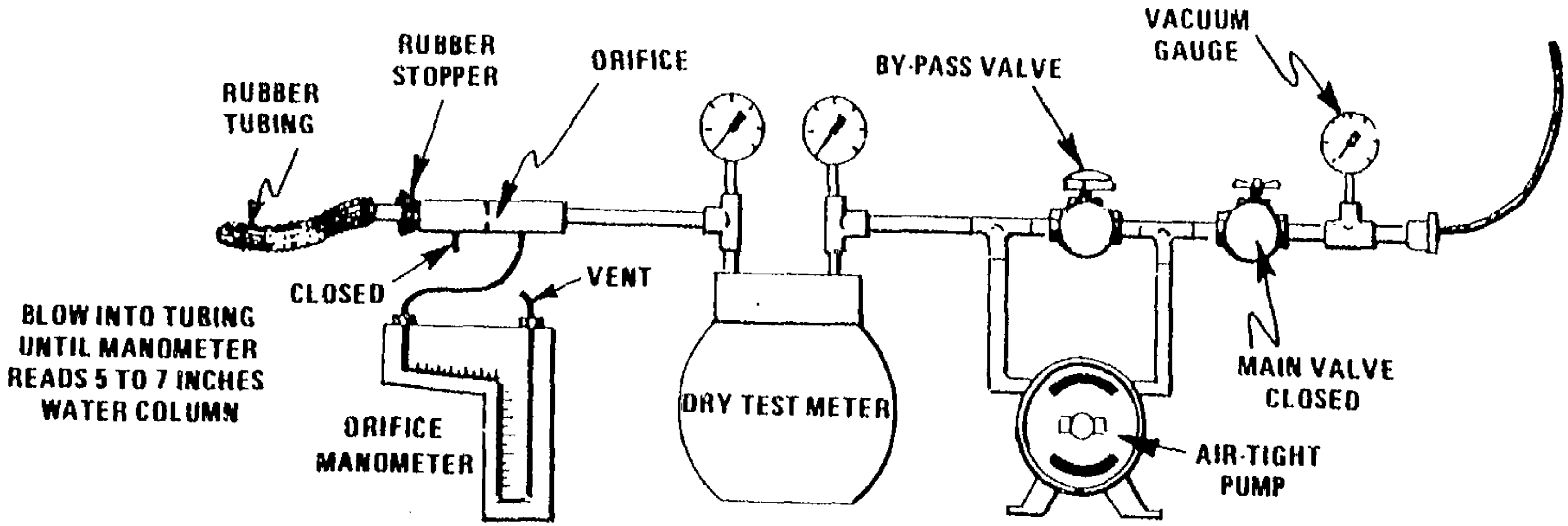

Figure 5-4. Leak check of meter box.

6.1 Nomenclature.

A_n=Cross-sectional area of nozzle, m^2 (ft^2).

B_{ws}=Water vapor in the gas stream, proportion by volume.

C_a=Acetone blank residue concentration, mg/mg.

c_s=Concentration of particulate matter in stack gas, dry basis, corrected to standard conditions, g/dscm (g/dscf).

I=Percent of isokinetic sampling.

L_a=Maximum acceptable leakage rate for either a pretest leak check or for a leak check following a component change; equal to 0.00057 m^3/min (0.02 cfm) or 4 percent of the average sampling rate, whichever is less.

L_i=Individual leakage rate observed during the leak check conducted prior to the "i^{th}" component change (i=1, 2, 3....n), m^3/min (cfm).

L_p=Leakage rate observed during the post-test leak check, m^3/min (cfm).

m_a=Mass of residue of acetone after evaporation, mg.

m_n=Total amount of particulate matter collected, mg.

M_w=Molecular weight of water, 18.0 g/g-mole (18.0lb/lb-mole).

P_{bar}=Barometric pressure at the sampling site, mm Hg (in. Hg).

P_s=Absolute stack gas pressure, mm Hg (in. Hg).

P_{std}=Standard absolute pressure, 760 mm Hg (29.92 in. Hg).

R=Ideal gas constant, 0.06236 mm Hg-m^3/°K-g-mole (21.85 in. Hg-ft^3/°R-lb-mole).

T_m=Absolute average dry gas meter temperature (see Figure 5–2), °K (°R).

T_s=Absolute average stack gas temperature (see Figure 5–2), °K (°R).

T_{std}=Standard absolute temperature, 293° K (528° R).

V_a=Volume of acetone blank, ml.

V_{aw}=Volume of acetone used in wash, ml.

V_{lc}=Total volume of liquid collected in impingers and silica gel (see Figure 5–3), ml.

V_m=Volume of gas sample as measured by dry gas meter, dcm (dscf).

$V_{m(std)}$=Volume of gas sample measured by the dry gas meter, corrected to standard conditions, dscm (dscf).

$V_{w(std)}$=Volume of water vapor in the gas sample, corrected to standard conditions, scm (scf).

v_s=Stack gas velocity, calculated by Method 2, Equation 2–9, using data obtained from Method 5, m/sec (ft/sec).

W_a=Weight of residue in acetone wash, mg.

Y=Dry gas meter calibration factor.

ΔH=Average pressure differential across the orifice meter (see Figure 5–2), mm H_2O (in. H_2O).

ρ_a=Density of acetone, mg/ml (see label on bottle).

ρ_w=Density of water, 0.9982 g/ml (0.002201 lb/ml).

θ=Total sampling time, min.

θ_1=Sampling time interval, from the beginning of a run until the first component change, min.

θ_i=Sampling time interval, between two successive component changes, beginning with the interval between the first and second changes, min.

θ_p=Sampling time interval, from the final (n^{th}) component change until the end of the sampling run, min.

13.6=Specific gravity of mercury.

60=Sec/min.

100=Conversion to percent.

6.2 Average Dry Gas Meter Temperature and Average Orifice Pressure Drop. See data sheet (Figure 5–2).

6.3 Dry Gas Volume. Correct the sample volume measured by the dry gas meter to standard conditions (20° C, 760 mm Hg or 68° F, 29.92 in. Hg) by using Equation 5–1.

$$V_{m(std)} = V_m Y\left(\frac{T_{std}}{T_m}\right)\left[\frac{P_{bar}+\frac{\Delta H}{13.6}}{P_{std}}\right] = K_1 V_m Y \frac{P_{bar}+(\Delta H/13.6)}{T_m}$$

Equation 5–1

Where;

K_1=0.3858 °K/mm Hg for metric units

=17.64 °R/in. Hg for English units

NOTE: Equation 5–1 can be used as written unless the leakage rate observed during any of the mandatory leak checks (i.e., the post-test leak check or leak checks conducted prior to component changes) exceeds L_a. If L_p or L_i exceeds L_a, Equation 5–1 must be modified as follows:

(a) Case I. No component changes made during sampling run. In this case, replace V_m in Equation 5–1 with the expression:

$$[V_m-(L_p-L_a)\theta]$$

(b) Case II. One or more component changes made during the sampling run. In this case, replace V_m in Equation 5–1 by the expression:

$$\left[V_m-(L_1-L_a)\theta_1 - \sum_{i=2}^{n}(L_i-L_a)\theta_i-(L_p-L_a)\theta_p\right]$$

and substitute only for those leakage rates (L_i or L_p) which exceed L_a.

6.4 Volume of Water Vapor.

$$V_{w(std)} = \frac{V_{1c}\,\rho_w\,R\,T_{std}}{M_w\,P_{std}} = K_2\,V_{1c}$$

Eq. 5-2

Where:
K_2=0.001333 m^3/ml for metric units
=0.04707 ft^3/ml for English units.

6.5 Moisture Content.

$$B_{ws} = \frac{V_{w(std)}}{V_{m(std)}+V_{w(std)}}$$

Eq. 5–3

NOTE: In saturated or water droplet-laden gas streams, two calculations of the moisture content of the stack gas shall be made, one from the impinger analysis (Equation 5-3), and a second from the assumption of saturated conditions. The lower of the two values of B_{ws} shall be considered correct. The procedure for determining the moisture content based upon assumption of saturated conditions is given in the Note of Section 1.2 of Method 4. For the purposes of this method, the average stack gas temperature from Figure 5–2 may be used to make this determination, provided that the accuracy of the in-stack temperature sensor is ±1° C (2° F).

6.6 Acetone Blank Concentration.

$$C_a = \frac{m_a}{V_a \rho_a} \qquad \text{Eq. 5–4}$$

6.7 Acetone Wash Blank.

$$W_a = C_a V_{aw} \rho_a \qquad \text{Eq. 5–5}$$

6.8 Total Particulate Weight. Determine the total particulate catch from the sum of the weights obtained from Containers 1 and 2 less the acetone blank (see Figure 5–3).

NOTE: Refer to Section 4.1.5 to assist in calculation of results involving two or more filter assemblies or two or more sampling trains.

6.9 Particulate Concentration.

$$c_s = (0.001\ g/mg)\ (m_n/V_{m\,(std)})$$

Eq. 5–6

6.10 Conversion Factors:

From	To	Multiply by
scf	m^3	0.02832.
g	mg	0.001
g/ft³	gr/ft³	15.43.
g/ft³	lb/ft³	2.205×10^{-3}.
g/ft³	g/m³	35.31.

6.11 Isokinetic Variation.

6.11.1 Calculation From Raw Data.

$$I = \frac{100\ T_s[K_3 V_{lc} + (V_m Y/T_m)(P_{bar} + \Delta H/13.6)]}{60\theta v_s P_s A_n}$$

Eq. 5–7

Where:
K_3=0.003454 mm Hg − m^3/ml − °K for metric units.
=0.002669-in. Hg − ft^3/ml − °R for English units.

6.11.2 Calculation From Intermediate Values.

$$I = \frac{100\ T_s\ V_{m(std)}\ P_{std}}{60\ T_{std}\ v_s\ \theta\ A_n\ P_s\ (1 - B_{ws})} = \frac{K_4\ T_s\ V_{m(std)}}{P_s\ v_s\ A_n\ \theta\ (1 - B_{ws})} \qquad \text{Eq. 5-8}$$

Where:
K_4=4.320 for metric units
=0.09450 for English units.

6.12 Acceptable Results. If 90 percent ≤ I ≤ 110 percent, the results are acceptable. If the particulate results are low in comparison to the standard, and I is over 110 percent or less than 90 percent, the Administrator may accept the results. Citation 4 in the bibliography section can be used to make acceptability judgments. If I is judged to be unacceptable, reject the particulate results and repeat the test.

6.13 Stack Gas Velocity and Volumetric Flow Rate. Calculate the average stack gas velocity and volumetric flow rate, if needed, using data obtained in this method and the equations in Sections 5.2 and 5.3 of Method 2.

7. *Alternative Procedures*

7.1 Dry Gas Meter as a Calibration Standard. A dry gas meter may be used as a calibration standard for volume measurements in place of the wet test meter specified in Section 5.3, provided that it is calibrated initially and recalibrated periodically as follows:

7.1.1 Standard Dry Gas Meter Calibration.

7.1.1.1 The dry gas meter to be calibrated and used as a secondary reference meter should be of high quality and have an appropriately sized capacity, e.g., 3 liters/rev (0.1 ft³/rev). A spirometer (400 liters or more capacity), or equivalent, may be used for this calibration, although a wet test meter is usually more practical. The wet test meter should have a capacity of 30 liters/rev (1 ft³/rev) and capable of measuring volume to within ±1.0 percent; wet test meters should be checked against a spirometer or a liquid displacement meter to ensure the accuracy of the wet test meter. Spirometers or wet test meters of other sizes may be used, provided that the specified accuracies of the procedure are maintained.

7.1.1.2 Set up the components as shown in Figure 5.7. A spirometer, or equivalent, may be used in place of the wet test meter in the system. Run the pump for at least 5 minutes at a flow rate of about 10 liters/min (0.35 cfm) to condition the interior surface of the wet test meter. The pressure drop indicated by the manometer at the inlet side of the dry gas meter should be minimized [no greater than 100 mm H_2O (4 in. H_2O) at a flow rate of 30 liters/min (1 cfm)]. This can be accomplished by using large diameter tubing connections and straight pipe fittings.

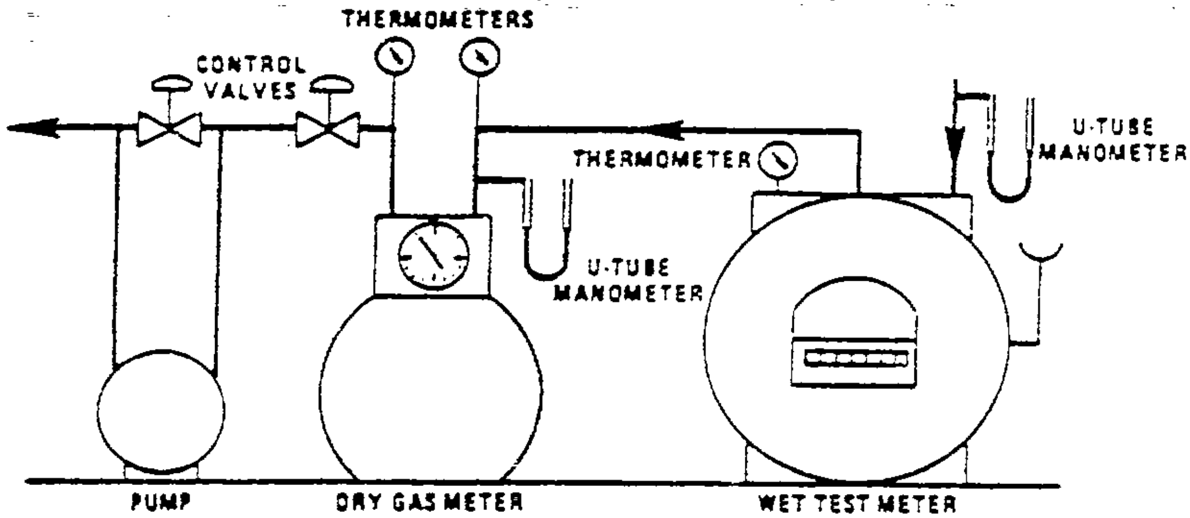

Figure 5.7 . Equipment arrangement for dry-gas meter calibration.

7.1.1.3 Collect the data as shown in the example data sheet (see Figure 5-8). Make triplicate runs at each of the flow rates and at no less than five different flow rates. The range of flow rates should be between 10 and 34 liters/min (0.35 and 1.2 cfm) or over the expected operating range.

DATE: ______________________

DRY GAS METER IDENTIFICATION: ______________________

BAROMETRIC PRESSURE (P_b): ______________ in. Hg

APPROXIMATE FLOW RATE ($\tilde{Q}$) cfm	SPIROMETER (WET METER) GAS VOLUME (V_s) ft³	DRY GAS METER VOLUME (V_{dg}) ft³	TEMPERATURES: SPIROMETER (WET METER) (t_s) °F	TEMPERATURES: DRY GAS METER: INLET (t_i) °F	TEMPERATURES: DRY GAS METER: OUTLET (t_o) °F	TEMPERATURES: DRY GAS METER: AVERAGE ($\bar{t}_d$) °F	DRY GAS METER PRESSURE (Δp) in. H_2O	TIME (Θ) min.	FLOW RATE (Q) cfm	METER COEFFICIENT (Y_{ds})	AVERAGE METER COEFFICIENT ($\bar{Y}_{ds}$)
0.40											
0.60											
0.80											
1.00											
1.20											

$$Q = 17.65 \cdot \frac{V_s}{\Theta} \cdot \frac{P_b}{(t_s + 460)}$$

$$Y_{ds} = \frac{V_s}{V_{dg}} \cdot \frac{(\bar{t}_d + 460)}{(t_s + 460)} \cdot \frac{P_b}{\left(P_b + \frac{\Delta p}{13.6}\right)}$$

Figure 5.8. Example data sheet for calibration of a standard dry gas meter for method 5 sampling equipment (English units)

7.1.1.4 Calculate flow rate, Q, for each run using the wet test meter gas volume, V_w, and the run time, θ. Calculate the dry gas meter coefficient, Y_{ds}, for each run. These calculations are as follows:

$$Q = K_1 \frac{P_{bar}}{t_w + t_{std}} \frac{V_w}{\theta}$$

$$Y_{ds} = \frac{V_w \, (t_{ds} + t_{std}) \quad P_{bar}}{V_{ds} \, (t_w + t_{std}) \quad \left(P_{bar} + \frac{\Delta p}{13.6}\right)}$$

Where:

K_1=0.3858 for international system of units (SI); 17.64 for English units.

V_w=Wet test meter volume, liters (ft³).

V_{ds}=Dry gas meter volume, liters (ft³).

t_{ds}=Average dry gas meter temperature, °C (°F).

t_{std}=273° C for SI units; 460° F for English units.

t_w=Average wet test meter temperature, °C (°F).

P_{bar}=Barometric pressure, mm Hg (in. Hg).

Δp=Dry gas meter inlet differential pressure, mm H_2O (in. H_2O).

θ=Run time, min.

7.1.1.5 Compare the three Y_{ds} values at each of the flow rates and determine the maximum and minimum values. The difference between the maximum and minimum values at each flow rate should be no greater than 0.030. Extra sets of triplicate runs may be made in order to complete this requirement. In addition, the meter coefficients should be between 0.95 and 1.05. If these specifications cannot be met in three sets of successive triplicate runs, the meter is not suitable as a calibration standard and should not be used as such. If these specifications are met, average the three Y_{ds} values at each flow rate resulting in five average meter coefficients, Y_{ds}.

7.1.1.6 Prepare a curve of meter coefficient, Y_{ds}, versus flow rate, Q, for the dry gas meter. This curve shall be used as a reference when the meter is used to calibrate other dry gas meters and to determine whether recalibration is required.

7.1.2 Standard Dry Gas Meter Recalibration.

7.1.2.1 Recalibrate the standard dry gas meter against a wet test meter or spirometer annually or after every 200 hours of operation, whichever comes first. This requirement is valid provided the standard dry gas meter is kept in a laboratory and, if transported, cared for as any other laboratory instrument. Abuse to the standard meter may cause a change in the calibration and will require more frequent recalibrations.

7.1.2.2 As an alternative to full recalibration, a two-point calibration check may be made. Follow the same procedure and equipment arrangement as for a full recalibration, but run the meter at only two flow rates [suggested rates are 14 and 28 liters/min (0.5 and 1.0 cfm)]. Calculate the meter coefficients for these two points, and compare the values with the meter calibration curve. If the two coefficients are within ±1.5 percent of the calibration curve values at the same flow rates, the meter need not be recalibrated until the next date for a recalibration check.

7.2 Critical Orifices As Calibration Standards. Critical orifices may be used as calibration standards in place of the wet test meter specified in Section 5.3, provided that they are selected, calibrated, and used as follows:

7.2.1 Section of Critical Orifices.

7.2.1.1 The procedure that follows describes the use of hypodermic needles or stainless steel needle tubings which have been found suitable for use as critical orifices. Other materials and critical orifice designs may be used provided the orifices act as true critical orifices; i.e., a critical vacuum can be obtained, as described in Section 7.2.2.2.3. Select five critical orifices that are appropriately sized to cover the range of flow rates between 10 and 34 liters/min or the expected operating range. Two of the critical orifices should bracket the expected operating range.

A minimum of three critical orifices will be needed to calibrate a Method 5 dry gas meter (DGM); the other two critical orifices can serve as spares and provide better selection for bracketing the range of operating flow rates. The needle sizes and tubing lengths shown below give the following approximate flow rates:

Gauge/cm	Flow rate (liters/min)	Gauge/cm	Flow rate (liters/min)
12/7.6	32.56	14/2.5	19.54
12/10.2	30.02	14/5.1	17.27
13/2.5	25.77	14/7.6	16.14
13/5.1	23.50	15/3.2	14.16
13/7.6	22.37	15/7.6	11.61
13/10.2	20.67	15/10.2	10.48

7.2.1.2 These needles can be adapted to a Method 5 type sampling train as follows: Insert a serum bottle stopper, 13- by 20-mm sleeve type, into a ½-inch Swagelok quick connect. Insert the needle into the stopper as shown in Figure 5–9.

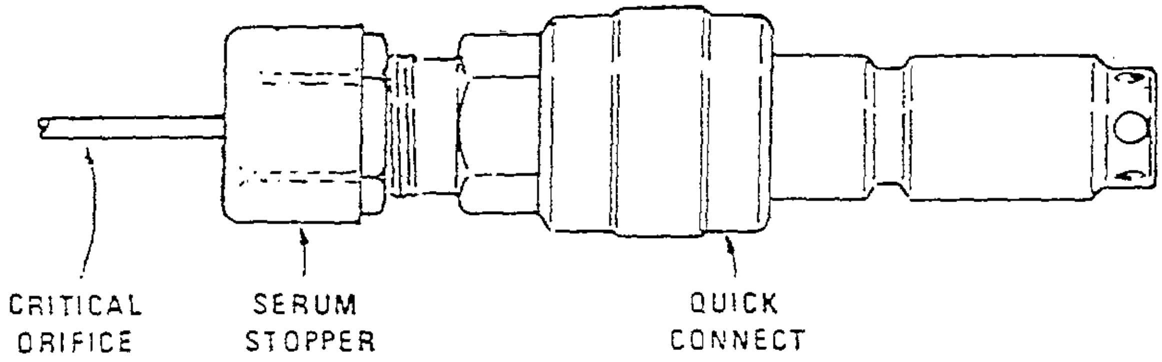

Figure 5-9. Critical orifice adaptation to Method 5 metering system.

7.2.2 Critical Orifice Calibration. The procedure described in this section uses the Method 5 meter box configuration with a DGM as described in Section 2.1.8 to calibrate the critical orifices. Other schemes may be used, subject to the approval of the Administrator.

7.2.2.1 Calibration of Meter Box. The critical orifices must be calibrated in the same configuration as they will be used; i.e., there should be no connections to the inlet of the orifice.

7.2.2.1.1 Before calibrating the meter box, leak check the system as follows: Fully open the coarse adjust valve, and completely close the by-pass valve. Plug the inlet. Then trun on the pump, and determine whether there is any leakage. The leakage rate shall be zero; i.e., no detectable movement of the DGM dial shall be seen for 1 minute.

7.2.2.1.2 Check also for leakages in that portion of the sampling train between the pump and the orifice meter. See Section 5.6 for the procedure; make any corrections, if necessary. If leakage is detected, check for cracked gaskets, loose fittings, worn O-rings, etc., and make the necessary repairs.

7.2.2.1.3 After determining that the meter box is leakless, calibrate the meter box according to the procedure given in Section 5.3. Make sure that the wet test meter meets the requirements stated in Section 7.1.1.1. Check the water level in the wet test meter. Record the DGM calibration factor, Y.

7.2.2.2 Calibration of Critical Orifices. Set up the apparatus as shown in Figure 5-10.

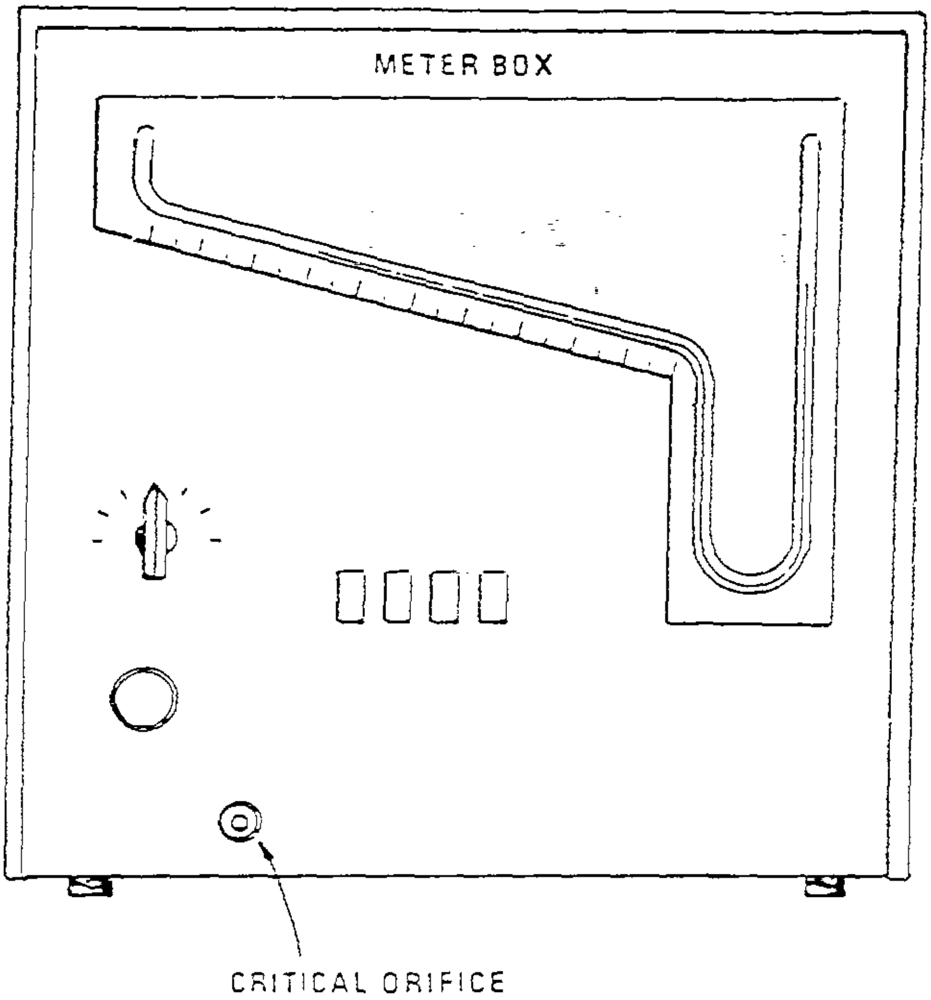

Figure 5-10. Apparatus setup.

7.2.2.2.1 Allow a warm-up time of 15 minutes. This step is important to equilibrate the temperature conditions through the DGM.

7.2.2.2.2 Leak check the system as in Section 7.2.2.1.1. The leakage rate shall be zero.

7.2.2.2.3 Before calibrating the critical orifice, determine its suitability and the appropriate operating vacuum as follows: Turn on the pump, fully open the coarse adjust valve, and adjust the by-pass valve to give a vacuum reading corresponding to about half of atmospheric pressure. Observe the meter box orifice manometer reading, H. Slowly increase the vacuum reading until a stable reading is obtained on the meter box orifice manometer. Record the critical vacuum for each orifice. Orifices that do not reach a critical value shall not be used.

7.2.2.2.4 Obtain the barometric pressure using a barometer as described in Section 2.1.9. Record the barometric pressure, P_{bar}, in mm Hg (in. Hg).

7.2.2.2.5 Conduct duplicate runs at a vacuum of 25 to 50 mm Hg (1 to 2 in. Hg) above the critical vacuum. The runs shall be at least 5 minutes each. The DGM volume readings shall be in increments of 0.00283 m^3 (0.1 ft^3) or in increments of complete revolutions of the DGM. As a guideline, the times should not differ by more than 3.0 seconds (this includes allowance for changes in the DGM temperatures) to achieve ± 0.5 percent in K′. Record the information listed in Figure 5-11.

7.2.2.2.6 Calculate K′ using Equation 5-9.

$$K' = \frac{\dfrac{K_1 V_m Y (P_{bar}+\Delta H/13.6)\sqrt{T_{amb}}}{}}{P_{bar} T_m \Theta} \quad \text{Eq. 5–9}$$

Where:

K' = Critical orifice coefficient, $\frac{(m^3)(°K)^{1/2}}{(mm.\ Hg)(min)} \left[\frac{(ft^3)(°R)^{1/2}}{(in.\ Hg)(min)}\right]$

T_{amb}=Absolute ambient temperature, °K (°R).

Average the K′ values. The individual K′ values should not differ by more than ±0.5 percent from the average.

7.2.3 Using the Critical Orifices as Calibration Standards.

7.2.3.1 Record the barometric pressure.

Date ______ Train ID ______ DGM cal. factor ______ Critical orifice ID ______

Dry gas meter		Run number 1	Run number 2
Final reading	m^3 (ft^3)		
Initial reading	m^3 (ft^3)		
Difference, V_m	m^3 (ft^3)		
Inlet/Outlet temperatures:			
Initial	°C (°F)	/	/
Final	°C (°F)	/	/
Avg. Temperature, t_m	°C (°F)		
Time, Θ	min/sec	/	/
	min		
Orifice man. rdg., ΔH	mm (in.) H_2O		
Bar. pressure, P_{bar}	mm (in.) Hg		
Ambient temperature, t_{amb}	°C (°F)		
Pump vacuum	mm (in.) Hg		
K′ factor			
Average			

Figure 5–11. Data sheet for determining K′ factor.

7.2.3.2 Calibrate the metering system according to the procedure outlined in Sections 7.2.2.2.1 to 7.2.2.2.5. Record the information listed in Figure 5.12.

7.2.3.3 Calculate the standard volumes of air passed through the DGM and the critical orifices, and calculate the DGM calibration factor, Y, using the equations below:

$$V_m(std) = K_1\ V_m\ \frac{P_{bar}+(\Delta H/13.6)}{T_m} \quad \text{Eq. 5–10}$$

$$V_{cr}(std)=K'\ \frac{P_{bar}\Theta}{T_{amb}} \quad \text{Eq. 5–11}$$

$$Y= \frac{V_{cr(std)}}{V_{m(std)}} \quad \text{Eq. 5–12}$$

where:

$V_{cr(std)}$=Volume of gas sample passed through the critical orifice, corrected to standard conditions, dsm³ (dscf).

K_1=0.3858 °K/mm Hg for metric units =17.64 °R/in. Hg for English units.

7.2.3.4 Average the DGM calibration values for each of the flow rates. The calibration factor, Y, at each of the flow rates should not differ by more than ±2 percent from the average.

7.2.3.5 To determine the need for recalibrating the critical orifices, compare the DGM Y factors obtained from two adjacent orifices each time a DGM is calibrated; for example, when checking 13/2.5, use orifices 12/10.2 and 13/5.1. If any critical orifice yields a DGM Y factor differing by more than 2 percent from the others, recalibrate the critical orifice according to Section 7.2.2.2.

Date ______ Train ID ______ Critical orifice ID ______ Critical orifice K′ factor ______

Dry gas meter		Run number 1	Run number 2
Final reading	m^3 (ft^3)		
Initial reading	m^3 (ft^3)		
Difference, V_m	m^3 (ft^3)		
Inlet/outlet temperatures:			
Initial	°C (°F)	/	
Final	°C (°F)	/	
Avg. Temperature, t_m	°C (°F)		
Time, Θ	min/sec	/	
	min		
Orifice man. rdg., ΔH	mm (in.) H_2O		
Bar. pressure, P_{bar}	mm (in.) Hg		
Ambient temperature, t_{amb}	°C (°F)		
Pump vacuum	mm (in.) Hg		
$V_{m(std)}$	m^3 (ft^3)		
$V_{cr(std)}$	m^3 (ft^3)		
DGM cal. factor, Y			

Figure 5–12. Data sheet for determining DGM Y factor.

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Method 5A—Determination of Particulate Emissions From the Asphalt Processing and Asphalt Roofing Industry

1. *Applicability and Principle*

1.1 Applicability. This method applies to the determination of particulate emissions from asphalt roofing industry process saturators, blowing stills, and other sources as specified in the regulations.

1.2 Principle. Particulate matter is withdrawn isokinetically from the source and collected on a glass filter fiber maintained at a temperature of 42°±10°C (108°±18°F). The particulate mass, which includes any material that condenses at or above the filtration temperature, is determined gravimetrically after removal of uncombined water.

2. *Apparatus*

2.1 Sampling Train. The sampling train configuration is the same as shown in Figure 5-1 of Method 5. The sampling train consists of the following components:

2.1.1 Probe Nozzle, Pitot Tube, Differential Pressure Gauge, Filter Holder, Condenser, Metering System, Barometer, and Gas Density Determination Equipment. Same as Method 5, Sections 2.1.1, 2.1.3 to 2.1.5, and 2.1.7 to 2.1.10, respectively.

2.1.2 Probe Liner. Same as in Method 5, Section 2.1.2, with the note that at high stack gas temperatures (greater than 250°C (480°F)), water-cooled probes may be required to control the probe exit temperature to 42°±10°C (108±18°F).

2.1.3 Precollector Cyclone. Borosilicate glass following the construction details shown in Air Pollution Technical Document-0581, "Construction Details of Isokinetic Source-Sampling Equipment".

NOTE: The tester shall use the cyclone when the stack gas moisture is greater than 10 percent. The tester shall not use the precollector cyclone under other, less severe conditions.

2.1.4 Filter Heating System. Any heating (or cooling) system capable of maintaining a sample gas temperature at the exit end of the filter holder during sampling at 42°±10°C (108°±18°F). Install a temperature gauge capable of measuring temperature within 3°C (5.4°F) at the exit side of the filter holder so that the sensing tip of the temperature gauge is in direct contact with the sample gas, and the sample gas temperature can be regulated and monitored during sampling. The temperature gauge shall comply with the calibration specifications defined in Section 5. The tester may use systems other than the one shown in APTD-0581.

2.2 Sample Recovery. The equipment required for sample recovery is as follows:

2.2.1 Probe-Liner and Probe-Nozzle Brushes, Graduated Cylinder and/or Balance, Plastic Storage Containers, and Funnel and Rubber Policeman. Same as Method 5, Sections 2.2.1, 2.2.5, 2.2.6, and 2.2.7, respectively.

2.2.2 Wash Bottles. Glass.

2.2.3 Sample Storage Containers. Chemically resistant, borosilicate glass bottles, with rubber-backed Teflon screw cap liners or caps that are constructed so as to be leak-free and resistant to chemical attack by 1,1,1-trichloroethane (TCE), 500-ml or 1000-ml. (Narrow mouth glass bottles have been found to be less prone to leakage.)

2.2.4 Petri Dishes. Glass, unless otherwise specified by the Administrator.

2.2.5 Funnel. Glass.

2.3 Analysis. For analysis, the following equipment is needed:

one from the impinger and precollector analysis (Equations 5A-1 and 5A-2) and a second from the assumption of saturated conditions. The lower of the two values of moisture content shall be considered correct. The procedure for determining the moisture content based upon assumption of saturated conditions is given in the note of Section 1.2 of Method 4. For the purpose of this method, the average stack gas temperature from Figure 5-2 of Method 5 may be used to make this determination, provided that the accuracy of the in-stack temperature sensor is within ±1°C (2°F).

6.6 TCE Blank Concentration.

$$C_t = m_t / V_t \rho_t \qquad \text{Eq. 5A-3}$$

6.7 TCE Wash Blank.

$$W_t = C_t V_{tw} \rho_t \qquad \text{Eq. 5A-4}$$

6.8 Total Particulate Weight. Determine the total particulate catch from the sum of the weights obtained from Containers 1, 2, and 3, less the TCE blank.

6.9 Particulate Concentration.

$$c_s = K_2 m_n / V_{m(std)} \qquad \text{Eq. 5A-5}$$

Where:

K_2=0.001 g/mg.

6.10 Isokinetic Variation and Acceptable Results. Same as in Method 5, Sections 6.11 and 6.12, respectively.

7. *Bibliography*

The bibliography for Method 5A is the same as that for Method 5.

METHOD 5B—DETERMINATION OF NONSULFURIC ACID PARTICULATE MATTER FROM STATIONARY SOURCES

1. *Applicability and Principle.*

1.1 Applicability. This method is to be used for determining nonsulfuric acid particulate matter from stationary sources. Use of this method must be specified by an applicable subpart, or approved by the Administrator, U.S. Environmental Protection Agency, for a particular application.

1.2 Principle. Particulate matter is withdrawn isokinetically from the source using the Method 5 train at 160°C (320°F). The collected sample is then heated in the oven at 160°C (320°F) for 6 hours to volatilize any condensed sulfuric acid that may have been collected, and the nonsulfuric acid particulate mass is determined gravimetrically.

2. *Procedure.*

The procedure is identical to EPA Method 5 except for the following:

2.1 Initial Filter Tare. Oven dry the filter at 160±5°C (320 ±10°F) for 2 to 3 hours, cool in a desiccator for 2 hours, and weigh. Desiccate to constant weight to obtain the initial tare. Use the applicable specifications and techniques of Section 4.1.1 of Method 5 for this determination.

2.2 Probe and Filter Temperatures. Maintain the probe outlet and filter temperatures at 160±14°C (320±25°F).

2.3 Analysis. Dry the probe sample at ambient temperature. Then oven-dry the probe and filter samples at a temperature of 160±5°C (320±10°F) for 6 hours. Cool in a desiccator for 2 hours, and weigh to constant weight. Use the applicable specifications and techniques of Section 4.3 of Method 5 for this determination.

METHOD 5C—[RESERVED]

METHOD 5D—DETERMINATION OF PARTICULATE MATTER EMISSIONS FROM POSITIVE PRESSURE FABRIC FILTERS

1. *Applicability and Principle*

1.1 Applicability. This method applies to the determination of particulate matter emissions from positive pressure fabric filters. Emissions are determined in terms of concentration (mg/m³) and emission rate (kg/h).

The General Provisions of 40 CFR Part 60, §60.8(e), require that the owner or operator of an affected facility shall provide performance testing facilities. Such performance testing facilities include sampling ports, safe sampling platforms, safe access to sampling sites, and utilities for testing. It is intended that affected facilities also provide sampling locations that meet the specification for adequate stack length and minimal flow disturbances as described in Method 1. Provisions for testing are often overlooked factors in designing fabric filters or are extremely costly. The purpose of this procedure is to identify appropriate alternative locations and procedures for sampling the emissions from positive pressure fabric filters. The requirements that the affected facility owner or operator provide adequate access to performance testing facilities remain in effect.

1.2 Principle. Particulate matter is withdrawn isokinetically from the source and collected on a glass fiber filter maintained at a temperature at or above the exhaust gas temperature up to a nominal 120°C (120±14°C or 248±25°F). The particulate mass, which includes any material that condenses at or above the filtration temperature, is determined gravimetrically after removal of uncombined water.

2. *Apparatus*

The equipment requirements for the sampling train, sample recovery, and analysis are the same as specified in Sections 2.1, 2.2, and 2.3, respectively, of Method 5 or Method 17.

3. *Reagents*

The reagents used in sampling, sample recovery, and analysis are the same as speciwhere:

K_3=0.003464 mm Hg-m^3/ml-°K for metric units.

=0.002676 in. Hg-ft^3/ml-°R for English units.

6.7.2 Calculation from Intermediate Values.

$$I=\frac{T_s V_{m(std)} P_{std} 100}{T_{std} v_s \theta A_n P_s 60 (1-B_{ws})}$$

$$=K_5 \frac{T_s V_{m(std)}}{P_s v_s A_n \theta (1-B_{ws})}$$

Equation 8–5

where:

K_5=4.320 for metric units.

=0.09450 for English units

6.8 Acceptable Results. If 90 percent <I <110 percent, the results are acceptable. If the results are low in comparison to the standards and I is beyond the acceptable range, the Administrator may opt to accept the results. Use Citation 4 in the Bibliography of Method 5 to make judgments. Otherwise, reject the results and repeat the test.

6.9 Stack Gas Velocity and Volumetric Flow Rate. Calculate the average stack gas velocity and volumetric flow rate, if needed, using data obtained in this method and equations in Sections 5.2 and 5.3 of Method 2.

6.10 Relative Error (RE) for QA Audit Samples. Same as in Method 6, Section 6.4.

7. *Bibliography*

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Method 9—Visual Determination of the Opacity of Emissions From Stationary Sources

Many stationary sources discharge visible emissions into the atmosphere; these emissions are usually in the shape of a plume. This method involves the determination of plume opacity by qualified observers. The method includes procedures for the training and certification of observers, and procedures to be used in the field for determination of plume opacity. The appearance of a plume as viewed by an observer depends upon a number of variables, some of which may be controllable and some of which may not be controllable in the field. Variables which can be controlled to an extent to which they no longer exert a significant influence upon plume appearance include: Angle of the observer with respect to the plume; angle of the observer with respect to the sun; point of observation of attached and detached steam plume; and angle of the observer with respect to a plume emitted from a rectangular stack with a large length to width ratio. The method includes specific criteria applicable to these variables.

Other variables which may not be controllable in the field are luminescence and color contrast between the plume and the background against which the plume is viewed. These variables exert an influence upon the appearance of a plume as viewed by an observer, and can affect the ability of the observer to accurately assign opacity values to the observed plume. Studies of the theory of plume opacity and field studies have demonstrated that a plume is most visible and presents the greatest apparent opacity when viewed against a contrasting background. It follows from this, and is confirmed by field trials, that the opacity of a plume, viewed under conditions where a contrasting background is present can be assigned with the greatest degree of accuracy. However, the potential for a positive error is also the greatest when a plume is viewed under such contrasting conditions. Under conditions presenting a less contrasting background, the apparent opacity of a plume is less and approaches zero as the color and luminescence contrast decrease toward zero. As a result, significant negative bias and negative errors can be made when a plume is viewed under less contrasting conditions. A negative bias decreases rather than increases the possibility that a plant operator will be cited for a violation of opacity standards due to observer error.

Studies have been undertaken to determine the magnitude of positive errors which can be made by qualified observers while reading plumes under contrasting conditions and using the procedures set forth in this method. The results of these studies (field trials) which involve a total of 769 sets of 25 readings each are as follows:

(1) For black plumes (133 sets at a smoke generator), 100 percent of the sets were read with a positive error[1] of less than 7.5 percent opacity; 99 percent were read with a positive error of less than 5 percent opacity.

(2) For white plumes (170 sets at a smoke generator, 168 sets at a coal-fired power plant, 298 sets at a sulfuric acid plant), 99 percent of the sets were read with a positive error of less than 7.5 percent opacity; 95 percent were read with a positive error of less than 5 percent opacity.

The positive observational error associated with an average of twenty-five readings is therefore established. The accuracy of the method must be taken into account when determining possible violations of applicable opacity standards.

1. *Principle and Applicability*

1.1 Principle. The opacity of emissions from stationary sources is determined visually by a qualified observer.

1.2 Applicability. This method is applicable for the determination of the opacity of emissions from stationary sources pursuant to § 60.11(b) and for qualifying observers for visually determining opacity of emissions.

2. *Procedures*

The observer qualified in accordance with section 3 of this method shall use the following procedures for visually determining the opacity of emissions:

2.1 Position. The qualified observer shall stand at a distance sufficient to provide a clear view of the emissions with the sun oriented in the 140° sector to his back. Consistent with maintaining the above requirement, the observer shall, as much as possible, make his observations from a position such that his line of vision is approximately perpendicular to the plume direction, and when observing opacity of emissions from rectangular outlets (e.g., roof monitors, open baghouses, noncircular stacks), approximately perpendicular to the longer axis of the outlet. The observer's line of sight should not include more than one plume at a time when multiple stacks are involved, and in any case the observer should make his observations with his line of sight perpendicular to the longer axis of such a set of multiple stacks (e.g., stub stacks on baghouses).

2.2 Field Records. The observer shall record the name of the plant, emission location, type facility, observer's name and affiliation, a sketch of the observer's position relative to the source, and the date on a field data sheet (Figure 9–1). The time, estimated distance to the emission location, approximate wind direction, estimated wind speed, description of the sky condition (presence and color of clouds), and plume background are recorded on a field data sheet at the time opacity readings are initiated and completed.

2.3 Observations. Opacity observations shall be made at the point of greatest opacity in that portion of the plume where condensed water vapor is not present. The observer shall not look continuously at the plume, but instead shall observe the plume momentarily at 15-second intervals.

2.3.1 Attached Steam Plumes. When condensed water vapor is present within the plume as it emerges from the emission outlet, opacity observations shall be made beyond the point in the plume at which condensed water vapor is no longer visible. The observer shall record the approximate distance from the emission outlet to the point in the plume at which the observations are made.

2.3.2 Detached Steam Plume. When water vapor in the plume condenses and becomes visible at a distinct distance from the emission outlet, the opacity of emissions should be evaluated at the emission outlet prior to the condensation of water vapor and the formation of the steam plume.

2.4 Recording Observations. Opacity observations shall be recorded to the nearest 5 percent at 15-second intervals on an observational record sheet. (See Figure 9–2 for an example.) A minimum of 24 observations shall be recorded. Each momentary observation recorded shall be deemed to represent the average opacity of emissions for a 15-second period.

2.5 Data Reduction. Opacity shall be determined as an average of 24 consecutive observations recorded at 15-second intervals. Divide the observations recorded on the record sheet into sets of 24 consecutive observations. A set is composed of any 24 consecutive observations. Sets need not be consecutive in time and in no case shall two sets overlap. For each set of 24 observations, calculate the average by summing the opacity of the 24 observations and dividing this sum by 24. If an applicable standard specifies an averaging time requiring more than 24 observations, calculate the average for all observations made during the specified time period. Record the average opacity on a record sheet. (See Figure 9–1 for an example.)

3. *Qualifications and Testing*

3.1 Certification Requirements. To receive certification as a qualified observer, a candidate must be tested and demonstrate the ability to assign opacity readings in 5 percent increments to 25 different black plumes and 25 different white plumes, with an error

[1] For a set, positive error = average opacity determined by observers' 25 observations—average opacity determined from transmissometer's 25 recordings.

not to exceed 15 percent opacity on any one reading and an average error not to exceed 7.5 percent opacity in each category. Candidates shall be tested according to the procedures described in section 3.2. Smoke generators used pursuant to section 3.2 shall be equipped with a smoke meter which meets the requirements of section 3.3.

The certification shall be valid for a period of 6 months, at which time the qualification procedure must be repeated by any observer in order to retain certification.

3.2 Certification Procedure. The certification test consists of showing the candidate a complete run of 50 plumes—25 black plumes and 25 white plumes—generated by a smoke generator. Plumes within each set of 25 black and 25 white runs shall be presented in random order. The candidate assigns an opacity value to each plume and records his observation on a suitable form. At the completion of each run of 50 readings, the score of the candidate is determined. If a candidate fails to qualify, the complete run of 50 readings must be repeated in any retest. The smoke test may be administered as part of a smoke school or training program, and may be preceded by training or familiarization runs of the smoke generator during which candidates are shown black and white plumes of known opacity.

3.3 Smoke Generator Specifications. Any smoke generator used for the purposes of section 3.2 shall be equipped with a smoke meter installed to measure opacity across the diameter of the smoke generator stack. The smoke meter output shall display instack opacity based upon a pathlength equal to the stack exit diameter, on a full 0 to 100 percent chart recorder scale. The smoke meter optical design and performance shall meet the specifications shown in Table 9-1. The smoke meter shall be calibrated as prescribed in section 3.3.1 prior to the conduct of each smoke reading test. At the completion of each test, the zero and span drift shall be checked and if the drift exceeds ±1 percent opacity, the condition shall be corrected prior to conducting any subsequent test runs. The smoke meter shall be demonstrated, at the time of installation, to meet the specifications listed in Table 9-1. This demonstration shall be repeated following any subsequent repair or replacement of the photocell or associated electronic circuitry including the chart recorder or output meter, or every 6 months, whichever occurs first.

TABLE 9-1—SMOKE METER DESIGN AND PERFORMANCE SPECIFICATIONS

Parameter	Specification
a. Light source	Incandescent lamp operated at nominal rated voltage.
b. Spectral response of photocell.	Photopic (daylight spectral response of the human eye—Citation 3).
c. Angle of view	15° maximum total angle.
d. Angle of projection	15° maximum total angle.
e. Calibration error	±3% opacity, maximum.
f. Zero and span drift	±1% opacity, 30 minutes
g. Response time	5 seconds.

3.3.1 Calibration. The smoke meter is calibrated after allowing a minimum of 30 minutes warmup by alternately producing simulated opacity of 0 percent and 100 percent. When stable response at 0 percent or 100 percent is noted, the smoke meter is adjusted to produce an output of 0 percent or 100 percent, as appropriate. This calibration shall be repeated until stable 0 percent and 100 percent readings are produced without adjustment. Simulated 0 percent and 100 percent opacity values may be produced by alternately switching the power to the light source on and off while the smoke generator is not producing smoke.

3.3.2 Smoke Meter Evaluation. The smoke meter design and performance are to be evaluated as follows:

3.3.2.1 Light Source. Verify from manufacturer's data and from voltage measurements made at the lamp, as installed, that the lamp is operated within ±5 percent of the nominal rated voltage.

3.3.2.2 Spectral Response of Photocell. Verify from manufacturer's data that the photocell has a photopic response; i.e., the spectral sensitivity of the cell shall closely approximate the standard spectral-luminosity curve for photopic vision which is referenced in (b) of Table 9-1.

FIGURE 9-1
RECORD OF VISUAL DETERMINATION OF OPACITY

PAGE___of___

COMPANY__________
LOCATION__________
TEST NUMBER__________
DATE__________
TYPE FACILITY__________
CONTROL DEVICE__________

HOURS OF OBSERVATION__________
OBSERVER__________
OBSERVER CERTIFICATION DATE__________
OBSERVER AFFILIATION__________
POINT OF EMISSIONS__________
HEIGHT OF DISCHARGE POINT__________

	Initial			Final
CLOCK TIME				
OBSERVER LOCATION Distance to Discharge				
Direction from Discharge				
Height of Observation Point				
BACKGROUND DESCRIPTION				
WEATHER CONDITIONS Wind Direction				
Wind Speed				
Ambient Temperature				
SKY CONDITIONS (clear, overcast, % clouds, etc.)				
PLUME DESCRIPTION Color				
Distance Visible				
OTHER INFORMATION				

SUMMARY OF AVERAGE OPACITY

Set Number	Time	Opacity	
	Start--End	Sum	Average

Readings ranged from ____ to ____ % opacity

The source was/was not in compliance with ____ at the time evaluation was made.

FIGURE 9-2—OBSERVATION RECORD

Page ____ of ____

Company ....
Location ....
Test Number ....
Date.

Observer ....
Type facility ....
Point of emissions ....

Hr.	Min.	Seconds				Steam plume (check if applicable)		Comments
		0	15	30	45	Attached	Detached	
	0							
	1							
	2							
	3							
	4							
	5							
	6							
	7							
	8							
	9							
	10							
	11							
	12							
	13							
	14							
	15							
	16							
	17							
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	22							
	23							
	24							
	25							
	26							
	27							
	28							
	29							

FIGURE 9–2—OBSERVATION RECORD—(CONTINUED)

Page ___ of ___

Company ....
Location ....
Test Number ....
Date.

Observer ....
Type facility ....
Point of emissions ....

Hr.	Min.	Seconds				Steam plume (check if applicable)		Comments
		0	15	30	45	Attached	Detached	
	30							
	31							
	32							
	33							
	34							
	35							
	36							
	37							
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	59							

3.3.2.3 Angle of View. Check construction geometry to ensure that the total angle of view of the smoke plume, as seen by the photocell, does not exceed 15°. The total angle of view may be calculated from: $\theta = 2 \tan^{-1} d/2L$, where θ=total angle of view; d=the sum of the photocell diameter+the diameter of the limiting aperture; and L=the distance from the photocell to the limiting aperture. The limiting aperture is the point in the path between the photocell and the smoke plume where the angle of view is most restricted. In smoke generator smoke meters this is normally an orifice plate.

3.3.2.4 Angle of Projection. Check construction geometry to ensure that the total angle of projection of the lamp on the smoke plume does not exceed 15°. The total angle of projection may be calculated from: $\theta=2\tan^{-1}d/2L$, where θ= total angle of projection; d= the sum of the length of the lamp filament + the diameter of the limiting aperture; and L= the distance from the lamp to the limiting aperture.

3.3.2.5 Calibration Error. Using neutral-density filters of known opacity, check the error between the actual response and the theoretical linear response of the smoke meter. This check is accomplished by first calibrating the smoke meter according to 3.3.1 and then inserting a series of three neutral-density filters of nominal opacity of 20, 50, and 75 percent in the smoke meter pathlength. Filters calibrated within ±2 percent shall be used. Care should be taken when inserting the filters to prevent stray light from affecting the meter. Make a total of five nonconsecutive readings for each filter. The maximum error on any one reading shall be 3 percent opacity.

3.3.2.6 Zero and Span Drift. Determine the zero and span drift by calibrating and operating the smoke generator in a normal manner over a 1-hour period. The drift is measured by checking the zero and span at the end of this period.

3.3.2.7 Response Time. Determine the response time by producing the series of five simulated 0 percent and 100 percent opacity values and observing the time required to reach stable response. Opacity values of 0 percent and 100 percent may be simulated by alternately switching the power to the light source off and on while the smoke generator is not operating.

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3. Condon, E.U., and Odishaw, H., Handbook of Physics, McGraw-Hill Co., New York, NY, 1958, Table 3.1, p. 6–52.

Alternate Method 1—Determination of the Opacity of Emissions From Stationary Sources Remotely by Lidar

This alternate method provides the quantitative determination of the opacity of an emissions plume remotely by a mobile lidar system (laser radar; Light Detection and Ranging). The method includes procedures for the calibration of the lidar and procedures to be used in the field for the lidar determination of plume opacity. The lidar is used to measure plume opacity during either day or nighttime hours because it contains its own pulsed light source or transmitter. The operation of the lidar is not dependent upon ambient lighting conditions (light, dark, sunny or cloudy).

The lidar mechanism or technique is applicable to measuring plume opacity at numerous wavelengths of laser radiation. However, the performance evaluation and calibration test results given in support of this method apply only to a lidar that employs a ruby (red light) laser [Reference 5.1].

1. *Principle and Applicability*

1.1 Principle. The opacity of visible emissions from stationary sources (stacks, roof vents, etc.) is measured remotely by a mobile lidar (laser radar).

1.2 Applicability. This method is applicable for the remote measurement of the opacity of visible emissions from stationary sources during both nighttime and daylight conditions, pursuant to 40 CFR §60.11(b). It is also applicable for the calibration and performance verification of the mobile lidar for the measurement of the opacity of emissions. A performance/design specification for a basic lidar system is also incorporated into this method.

1.3 Definitions.

Azimuth angle: The angle in the horizontal plane that designates where the laser beam is pointed. It is measured from an arbitrary fixed reference line in that plane.

Backscatter: The scattering of laser light in a direction opposite to that of the incident laser beam due to reflection from particulates along the beam's atmospheric path which may include a smoke plume.

Backscatter signal: The general term for the lidar return signal which results from laser light being backscattered by atmospheric and smoke plume particulates.

Convergence distance: The distance from the lidar to the point of overlap of the lidar receiver's field-of-view and the laser beam.

Elevation angle: The angle of inclination of the laser beam referenced to the horizontal plane.

Far region: The region of the atmosphere's path along the lidar line-of-sight beyond or behind the plume being measured.

Lidar: Acronym for Light Detection and Ranging.

Lidar range: The range or distance from the lidar to a point of interest along the lidar line-of-sight.

Near region: The region of the atmospheric path along the lidar line-of-sight between the lidar's convergence distance and the plume being measured.

calibrated and certified at some convenient operation temperature may be used. The permeation rate of the device must be such that at a dilution gas flow rate of 3 liters/min, an SO₂ concentration in the range of the stack gas or within 20 percent of the standard can be generated.

3.3 *Combustion Gas.* Gas containing less than 50 ppb reduced sulfur compounds and less than 10 ppm total hydrocarbons. The gas may be generated from a clean-air system that purifies ambient air and consists of the following components: diaphragm pump, silica gel drying tube, activated charcoal tube, and flow rate measuring device. Gas from a compressed air cylinder is also acceptable.

4. *Pretest Procedures*

Same as in Method 16, Section 7.

5. *Calibration*

Same as in Method 16, Section 8, except SO_2 is used instead of H_2S.

6. *Sampling and Analysis Procedure*

6.1 *Sampling.* Before any source sampling is done, conduct a system performance check as detailed in Section 7.1 to validate the sampling train components and procedures. Although this test is optional, it would significantly reduce the possibility of rejecting tests as a result of failing the post-test performance check. At the completion of the pretest system performance check, insert the sampling probe into the test port making certain that no dilution air enters the stack through the port. Condition the entire system with sample for a minimum of 15 minutes before beginning analysis. If the sample is diluted, determine the precise dilution factor as in Section 8.5 of Method 16.

6.2 *Analysis.* Pass aliquots of diluted sample through the SO_2 scrubber and oxidation furnace, and then inject into the GC/FPD analyzer for analysis. The rest of the analysis is the same as in Method 16, Sections 9.2.1 and 9.2.2.

7. Post-Test Procedures

7.1 *System Performance Check.* Same as in Method 16A, Section 4.3. Sufficient numbers of sample injections should be made so that the precision requirements of Section 4.1 of Method 16 are satisfied.

7.2 *Recalibration.* Same as in Method 16, Section 10.2.

7.3 *Determination of Calibration Drift.* Same as in Method 16, Section 10.3.

8. Calculations

8.1 *Nomenclature.*

C_{SO_2} = Sulfur dioxide concentration, ppm.
C_{TRS} = Total reduced sulfur concentration as determined by Equation 16B–1, ppm.
d = Dilution factor, dimensionless.
N = Number of samples.

8.2 SO_2 *Concentration.* Determine the concentration of SO_2 (C_{SO_2}) directly from the calibration curves. Alternatively, the concentration may be calculated using the equation for the least-squares line.

8.3 *TRS Concentration.*

$$C_{TRS} = (C_{SO_2})\,(d) \qquad \text{Eq. 16B–1}$$

8.4 *Average TRS Concentration.*

$$\text{Avg. } C_{TRS} = \frac{\sum_{i=1}^{n} C_{TRS}}{N} \qquad \text{Eq. 16B-2}$$

9. *Example System*

Same as in Method 16, Section 12. Single column systems using the column in Section 12.1.4.1.1 of Method 16 or a 7-ft Carbosorb B HT 100 column have been found satisfactory in resolving SO_2 from CO_2.

10. *Bibliography*

1. Same as in Method 16, Sections 13.1 to 13.6.

2. National Council of the Paper Industry for Air and Stream Improvement, Inc. A Study of TRS Measurement Methods. Technical Bulletin No. 434. New York, NY. May 1984. 12 p.

3. Margeson, J.H., J.E. Knoll, and M.R. Midgett. A Manual Method for TRS Determination. Draft available from the authors. Source Branch, Quality Assurance Division, U.S. Environmental Protection Agency, Research Triangle Park, NC 27711.

METHOD 17—DETERMINATION OF PARTICULATE EMISSIONS FROM STATIONARY SOURCES (IN-STACK FILTRATION METHOD)

Introduction

Particulate matter is not an absolute quantity; rather, it is a function of temperature and pressure. Therefore, to prevent variability in particulate matter emission regulations and/or associated test methods, the temperature and pressure at which particulate matter is to be measured must be carefully defined. Of the two variables (i.e., temperature and pressure), temperature has the greater effect upon the amount of particulate matter in an effluent gas stream; in most stationary source categories, the effect of pressure appears to be negligible.

In Method 5, 250° F is established as a nominal reference temperature. Thus, where Method 5 is specified in an applicable subpart of the standards, particulate matter is defined with respect to temperature. In order to maintain a collection temperature of 250° F, Method 5 employs a heated glass sample probe and a heated filter holder. This equipment is somewhat cumbersome and requires care in its operation. Therefore, where particulate matter concentrations (over the normal range of temperature associated with a specified source category) are known to be independent of temperature, it is desirable to eliminate the glass probe and heating systems, and sample at stack temperature.

This method describes an in-stack sampling system and sampling procedures for use in such cases. It is intended to be used only when specified by an applicable subpart of the standards, and only within the applicable temperature limits (if specified), or when otherwise approved by the Administrator.

1. *Principle and Applicability*

1.1 Principle. Particulate matter is withdrawn isokinetically from the source and collected on a glass fiber filter maintained at stack temperature. The particulate mass is determined gravimetrically after removal of uncombined water.

1.2 Applicability. This method applies to the determination of particulate emissions from stationary sources for determining compliance with new source performan standards, only when specifically provid for in an applicable subpart of the standard. This method is not applicable to stacks th contain liquid droplets or are saturated wi water vapor. In addition, this method sha not be used as written if the projected cros sectional area of the probe extension-filt holder assembly covers more than 5 percen of the stack cross-sectional area (see Sectio 4.1.2).

2. *Apparatus*

2.1 Sampling Train. A schematic of t sampling train used in this method is show in Figure 17-1. Construction details f many, but not all, of the train componen are given in APTD-0581 (Citation 2 in Bibl ography); for changes from the APTD-05 document and for allowable modifications Figure 17-1, consult with the Administrat

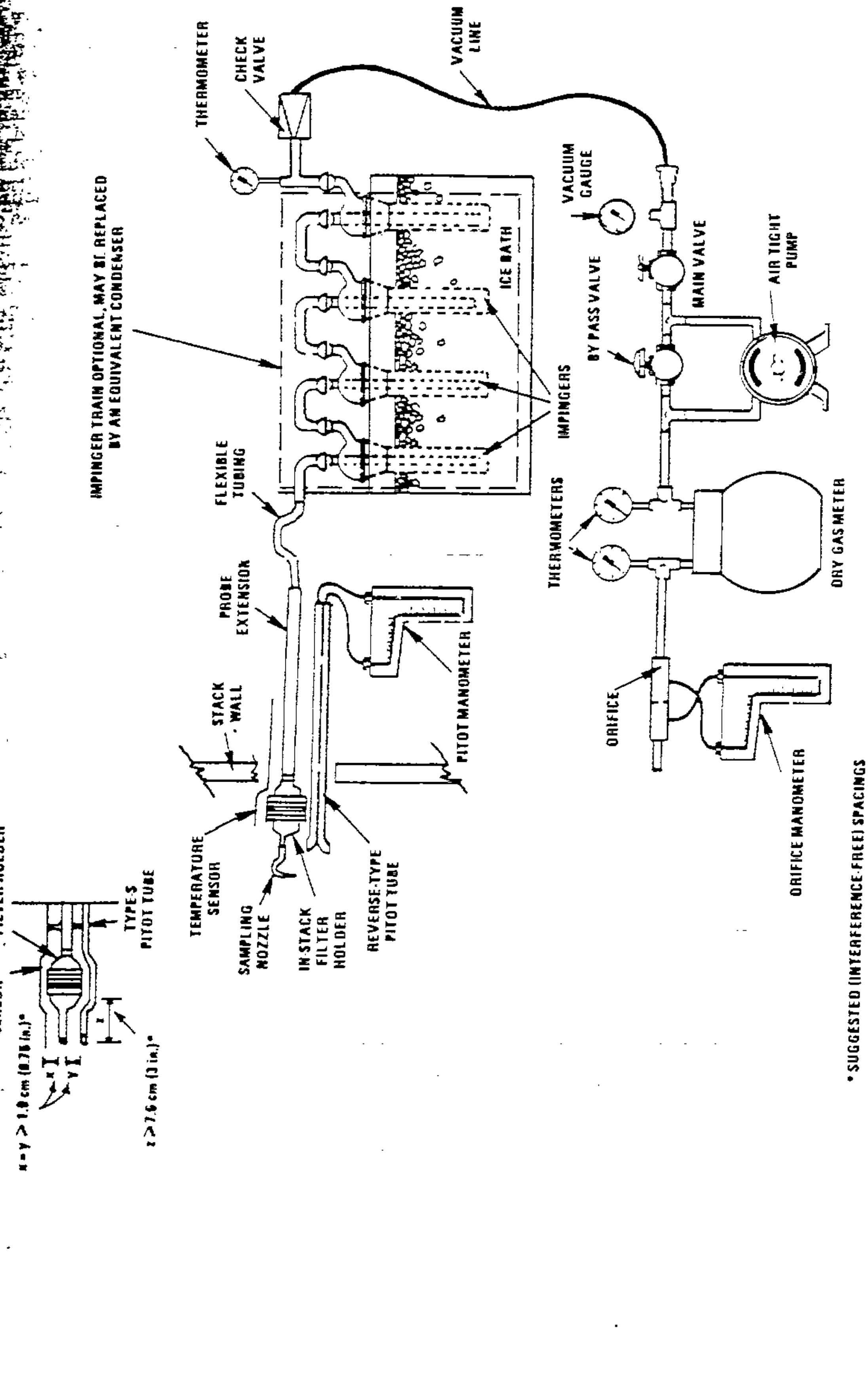


Figure 17-1. Particulate Sampling Train, Equipped with In-Stack Filter.

The operating and maintenance procedures for many of the sampling train components are described in APTD-0576 (Citation 3 in Bibliography). Since correct usage is important in obtaining valid results, all users should read the APTD-0576 document and adopt the operating and maintenance procedures outlined in it, unless otherwise specified herein. The sampling train consists of the following components:

2.1.1 Probe Nozzle. Stainless steel (316) or glass, with sharp, tapered leading edge. The angle of taper shall be 30° and the taper shall be on the outside to preserve a constant internal diameter. The probe nozzle shall be of the button-hook or elbow design, unless otherwise specified by the Administrator. If made of stainless steel, the nozzle shall be constructed from seamless tubing. Other materials of construction may be used subject to the approval of the Administrator.

A range of sizes suitable for isokinetic sampling should be available, e.g., 0.32 to 1.27 cm (1/8 to 1/2 in.)—or larger if higher volume sampling trains are used—inside diameter (ID) nozzles in increments of 0.16 cm (1/16 in.). Each nozzle shall be calibrated according to the procedures outlined in Section 5.1.

2.1.2 Filter Holder. The in-stack filter holder shall be constructed of borosilicate or quartz glass, or stainless steel; if a gasket is used, it shall be made of silicone rubber, Teflon, or stainless steel. Other holder and gasket materials may be used subject to the approval of the Administrator. The filter holder shall be designed to provide a positive seal against leakage from the outside or around the filter.

2.1.3 Probe Extension. Any suitable rigid probe extension may be used after the filter holder.

2.1.4 Pitot Tube. Type S, as described in Section 2.1 of Method 2, or other device approved by the Administrator; the pitot tube shall be attached to the probe extension to allow constant monitoring of the stack gas velocity (see Figure 17-1). The impact (high pressure) opening plane of the pitot tube shall be even with or above the nozzle entry plane during sampling (see Method 2, Figure 2-6b). It is recommended: (1) that the pitot tube have a known baseline coefficient, determined as outlined in Section 4 of Method 2; and (2) that this known coefficient be preserved by placing the pitot tube in an interference-free arrangement with respect to the sampling nozzle, filter holder, and temperature sensor (see Figure 17-1). Note that the 1.9 cm (0.75 in.) free-space between the nozzle and pitot tube shown in Figure 17-1, is based on a 1.3 cm (0.5 in.) ID nozzle. If the sampling train is designed for sampling at higher flow rates than that described in APTD-0581, thus necessitating the use of larger sized nozzles, the free-space shall be 1.9 cm (0.75 in.) with the largest sized nozzle in place.

Source-sampling assemblies that do not meet the minimum spacing requirements of Figure 17-1 (or the equivalent of these requirements, e.g., Figure 2-7 of Method 2) may be used; however, the pitot tube coefficients of such assemblies shall be determined by calibration, using methods subject to the approval of the Administrator.

2.1.5 Differential Pressure Gauge. Inclined manometer or equivalent device (two), as described in Section 2.2 of Method 2. One manometer shall be used for velocity head (Δp) readings, and the other, for orifice differential pressure readings.

2.1.6 Condenser. It is recommended that the impinger system described in Method 5 be used to determine the moisture content of the stack gas. Alternatively, any system that allows measurement of both the water condensed and the moisture leaving the condenser, each to within 1 ml or 1 g, may be used. The moisture leaving the condenser can be measured either by: (1) monitoring the temperature and pressure at the exit of the condenser and using Dalton's law of partial pressures; or (2) passing the sample gas stream through a silica gel trap with exit gases kept below 20° C (68° F) and determining the weight gain.

Flexible tubing may be used between the probe extension and condenser. If means other than silica gel are used to determine the amount of moisture leaving the condenser, it is recommended that silica gel still be used between the condenser system and pump to prevent moisture condensation in the pump and metering devices and to avoid the need to make corrections for moisture in the metered volume.

2.1.7 Metering System. Vacuum gauge, leak-free pump, thermometers capable of measuring temperature to within 3° C (5.4° F), dry gas meter capable of measuring volume to within 2 percent, and related equipment, as shown in Figure 17-1. Other metering systems capable of maintaining sampling rates within 10 percent of isokinetic and of determining sample volumes to within 2 percent may be used, subject to the approval of the Administrator. When the metering system is used in conjunction with a pitot tube, the system shall enable checks of isokinetic rates.

Sampling trains utilizing metering systems designed for higher flow rates than that described in APTD-0581 or APTD-0576 may be used provided that the specifications of this method are met.

2.1.8 Barometer. Mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg). In many cases, the barometric reading may be obtained from a nearby National Weather Service station, in which case the station value (which is the absolute barometric pressure) shall be requested and an adjustment for elevation differences between the weather station and sampling point shall be applied at a rate of minus 2.5 mm Hg (0.1 in. Hg) per 30 m (100 ft) elevation increase or vice versa for elevation decrease.

2.1.9 Gas Density Determination Equipment. Temperature sensor and pressure gauge, as described in Sections 2.3 and 2.4 of Method 2, and gas analyzer, if necessary, as described in Method 3.

The temperature sensor shall be attached to either the pitot tube or to the probe extension, in a fixed configuration. If the temperature sensor is attached in the field, the sensor shall be placed in an interference-free arrangement with respect to the Type S pitot tube openings (as shown in Figure 17-1 or in Figure 2-7 of Method 2). Alternatively, the temperature sensor need not be attached to either the probe extension or pitot tube during sampling, provided that a difference of not more than 1 percent in the average velocity measurement is introduced. This alternative is subject to the approval of the Administrator.

2.2 Sample Recovery.

2.2.1 Probe Nozzle Brush. Nylon bristle brush with stainless steel wire handle. The brush shall be properly sized and shaped to brush out the probe nozzle.

2.2.2 Wash Bottles—Two. Glass wash bottles are recommended; polyethylene wash bottles may be used at the option of the tester. It is recommended that acetone not be stored in polyethylene bottles for longer than a month.

2.2.3 Glass Sample Storage Containers. Chemically resistant, borosilicate glass bottles, for acetone washes, 500 ml or 1000 ml. Screw cap liners shall either be rubber-backed Teflon or shall be constructed so as to be leak-free and resistant to chemical attack by acetone. (Narrow mouth glass bottles have been found to be less prone to leakage.) Alternatively, polyethylene bottles may be used.

2.2.4 Petri Dishes. For filter samples; glass or polyethylene, unless otherwise specified by the Administrator.

2.2.5 Graduated Cylinder and/or Balance. To measure condensed water to within 1 ml or 1 g. Graduated cylinders shall have subdivisions no greater than 2 ml. Most laboratory balances are capable of weighing to the nearest 0.5 g or less. Any of these balances is suitable for use here and in Section 2.3.4.

2.2.6 Plastic Storage Containers. Air tight containers to store silica gel.

2.2.7 Funnel and Rubber Policeman. To aid in transfer of silica gel to container; not necessary if silica gel is weighed in the field.

2.2.8 Funnel. Glass or polyethylene, to aid in sample recovery.

2.3 Analysis.

2.3.1 Glass Weighing Dishes.

2.3.2 Desiccator.

2.3.3 Analytical Balance. To measure to within 0.1 mg.

2.3.4 Balance. To measure to within 0.5 mg.

2.3.5 Beakers. 250 ml.

2.3.6 Hygrometer. To measure the relative humidity of the laboratory environment.

2.3.7 Temperature Gauge. To measure the temperature of the laboratory environment.

3. *Reagents*

3.1 Sampling.

3.1.1 Filters. The in-stack filters shall be glass mats or thimble fiber filters, without organic binders, and shall exhibit at least 99.95 percent efficiency (0.05 percent penetration) on 0.3 micron dioctyl phthalate smoke particles. The filter efficiency tests shall be conducted in accordance with ASTM Standard Method D2986-71 (Reapproved 1978) (incorporated by reference—see § 60.17). Test data from the supplier's quality control program are sufficient for this purpose.

3.1.2 Silica Gel. Indicating type, 6- to 16-mesh. If previously used, dry at 175° C (350° F) for 2 hours. New silica gel may be used as received. Alternatively, other types of desiccants (equivalent or better) may be used, subject to the approval of the Administrator.

3.1.3 Crushed Ice.

3.1.4 Stopcock Grease. Acetone-insoluble, heat-stable silicone grease. This is not necessary if screw-on connectors with Teflon sleeves, or similar, are used. Alternatively, other types of stopcock grease may be used, subject to the approval of the Administrator.

3.1.5 Water. Same as in Method 5, section 3.1.3.

3.2 Sample Recovery. Acetone, reagent grade, 0.001 percent residue, in glass bottles. Acetone from metal containers generally has a high residue blank and should not be used. Sometimes, suppliers transfer acetone to glass bottles from metal containers. Thus, acetone blanks shall be run prior to field use and only acetone with low blank values (0.001 percent) shall be used. In no case shall a blank value of greater than 0.001 percent of the weight of acetone used be subtracted from the sample weight.

3.3 Analysis.

3.3.1 Acetone. Same as 3.2.

3.3.2 Desiccant. Anhydrous calcium sulfate, indicating type. Alternatively, other types of desiccants may be used, subject to the approval of the Administrator.

4. *Procedure*

4.1 Sampling. The complexity of this method is such that, in order to obtain reliable results, testers should be trained and experienced with the test procedures.

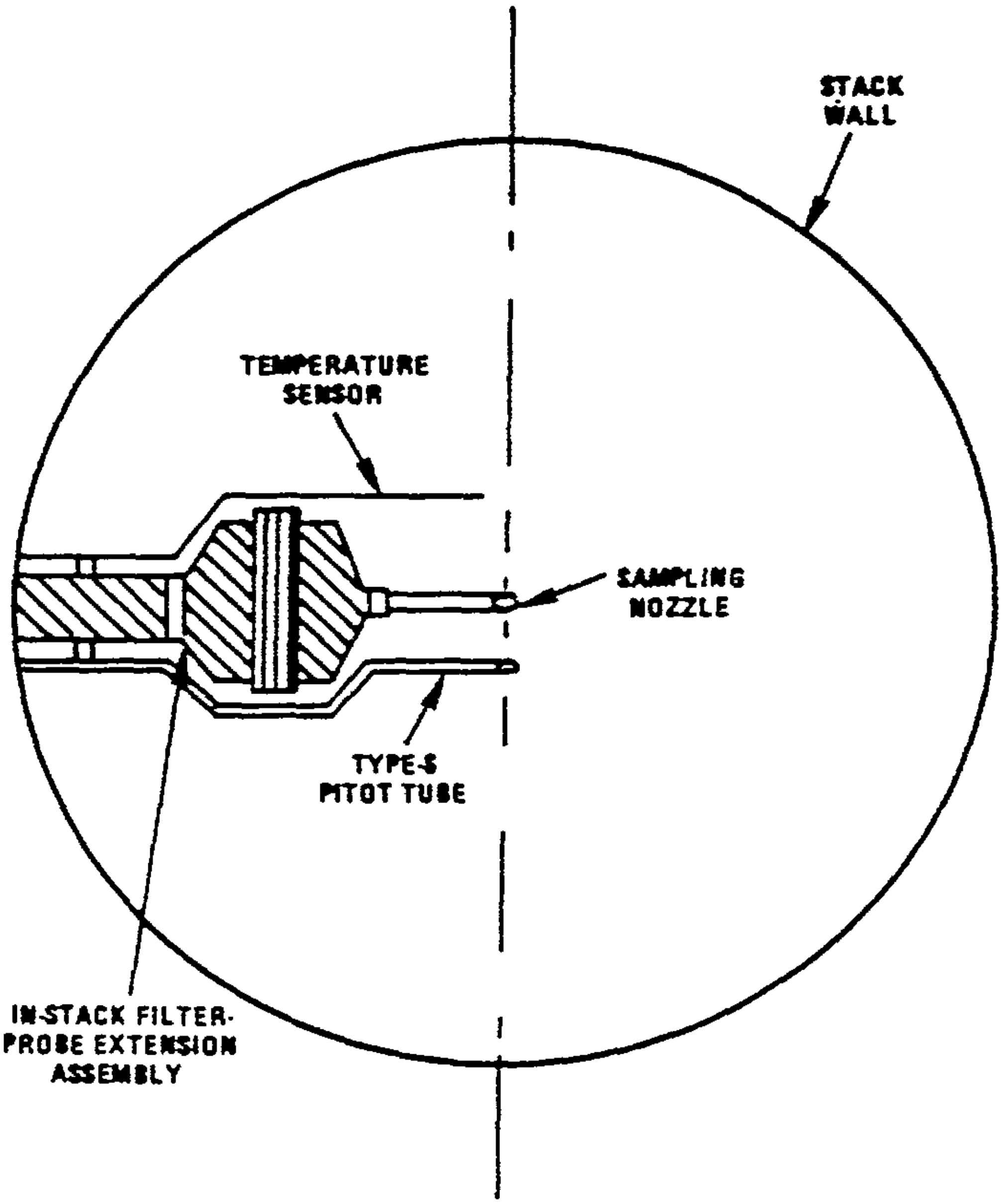
4.1.1 Pretest Preparation. All components shall be maintained and calibrated according to the procedure described in APTD-0576, unless otherwise specified herein.

Weigh several 200 to 300 g portions of silica gel in air-tight containers to the nearest 0.5 g. Record the total weight of the silica gel plus container, on each container. As an alternative, the silica gel need not be preweighed, but may be weighed directly in its impinger or sampling holder just prior to train assembly.

Check filters visually against light for irregularities and flaws or pinhole leaks. Label filters of the proper size on the back side near the edge using numbering machine ink. As an alternative, label the shipping containers (glass or plastic petri dishes) and keep the filters in these containers at all times except during sampling and weighing.

Desiccate the filters at 20±5.6° C (68±10° F) and ambient pressure for at least 24 hours and weigh at intervals of at least 6 hours to a constant weight, i.e., 0.5 mg change from previous weighing; record results to the nearest 0.1 mg. During each weighing the filter must not be exposed to the laboratory atmosphere for a period greater than 2 minutes and a relative humidity above 50 percent. Alternatively (unless otherwise specified by the Administrator), the filters may be oven dried at 105° C (220° F) for 2 to 3 hours, desiccated for 2 hours, and weighed. Procedures other than those described, which account for relative humidity effects, may be used, subject to the approval of the Administrator.

4.1.2 Preliminary Determinations. Select the sampling site and the minimum number of sampling points according to Method 1 or as specified by the Administrator. Make a projected-area model of the probe extension-filter holder assembly, with the pitot tube face openings positioned along the centerline of the stack, as shown in Figure 17–2. Calculate the estimated cross-section blockage, as shown in Figure 17–2. If the blockage exceeds 5 percent of the duct cross sectional area, the tester has the following options: (1) a suitable out-of-stack filtration method may be used instead of in-stack filtration; or (2) a special in-stack arrangement, in which the sampling and velocity measurement sites are separate, may be used; for details concerning this approach, consult with the Administrator (see also Citation 10 in Bibliography). Determine the stack pressure, temperature, and the range of velocity heads using Method 2; it is recommended that a leak-check of the pitot lines (see Method 2, Section 3.1) be performed. Determine the moisture content using Approximation Method 4 or its alternatives for the purpose of making isokinetic sampling rate settings. Determine the stack gas dry molecular weight, as described in Method 2, Section 3.6; if integrated Method 3 sampling is used for molecular weight determination, the integrated bag sample shall be taken simultaneously with, and for the same total length of time as, the particulate sample run.



$$\text{ESTIMATED BLOCKAGE (\%)} = \left[\frac{\text{SHADED AREA}}{\text{DUCT AREA}}\right] \times 100$$

Figure 17-2. Projected-area model of cross-section blockage (approximate average for a sample traverse) caused by an in-stack filter holder-probe extension assembly.

Select a nozzle size based on the range of velocity heads, such that it is not necessary to change the nozzle size in order to maintain isokinetic sampling rates. During the run, do not change the nozzle size. Ensure that the proper differential pressure gauge is chosen for the range of velocity heads encountered (see Section 2.2 of Method 2).

Select a probe extension length such that all traverse points can be sampled. For large stacks, consider sampling from opposite sides of the stack to reduce the length of probes.

Select a total sampling time greater than or equal to the minimum total sampling time specified in the test procedures for the specific industry such that (1) the sampling time per point is not less than 2 minutes (or some greater time interval if specified by the Administrator), and (2) the sample volume taken (corrected to standard conditions) will exceed the required minimum total gas sample volume. The latter is based on an approximate average sampling rate.

It is recommended that the number of minutes sampled at each point be an integer or an integer plus one-half minute, in order to avoid timekeeping errors.

In some circumstances, e.g., batch cycles, it may be necessary to sample for shorter times at the traverse points and to obtain smaller gas sample volumes. In these cases, the Administrator's approval must first be obtained.

4.1.3 Preparation of Collection Train. During preparation and assembly of the sampling train, keep all openings where contamination can occur covered until just prior to assembly or until sampling is about to begin.

If impingers are used to condense stack gas moisture, prepare them as follows: place 100 ml of water in each of the first two impingers, leave the third impinger empty, and transfer approximately 200 to 300 g of preweighed silica gel from its container to the fourth impinger. More silica gel may be used, but care should be taken to ensure that it is not entrained and carried out from the impinger during sampling. Place the container in a clean place for later use in the sample recovery. Alternatively, the weight of the silica gel plus impinger may be determined to the nearest 0.5 g and recorded.

If some means other than impingers is used to condense moisture, prepare the condenser (and, if appropriate, silica gel for condenser outlet) for use.

Using a tweezer or clean disposable surgical gloves, place a labeled (identified) and weighed filter in the filter holder. Be sure that the filter is properly centered and the gasket properly placed so as not to allow the sample gas stream to circumvent the filter. Check filter for tears after assembly is completed. Mark the probe extension with heat resistant tape or by some other method to denote the proper distance into the stack or duct for each sampling point.

Assemble the train as in Figure 17-1, using a very light coat of silicone grease on all ground glass joints and greasing only the outer portion (see APTD-0576) to avoid possibility of contamination by the silicone grease. Place crushed ice around the impingers.

4.1.4 Leak Check Procedures.

4.1.4.1 Pretest Leak-Check. A pretest leak-check is recommended, but not required. If the tester opts to conduct the pretest leak-check, the following procedure shall be used.

After the sampling train has been assembled, plug the inlet to the probe nozzle with a material that will be able to withstand the stack temperature. Insert the filter holder into the stack and wait approximately 5 minutes (or longer, if necessary) to allow the system to come to equilibrium with the temperature of the stack gas stream. Turn on the pump and draw a vacuum of at least 380 mm Hg (15 in. Hg); note that a lower vacuum may be used, provided that it is not exceeded during the test. Determine the leakage rate. A leakage rate in excess of 4 percent of the average sampling rate or 0.00057 m^3/min. (0.02 cfm), whichever is less, is unacceptable.

The following leak-check instructions for the sampling train described in APTD-0576 and APTD-0581 may be helpful. Start the pump with by-pass valve fully open and coarse adjust valve completely closed. Partially open the coarse adjust valve and slowly close the by-pass valve until the desired vacuum is reached. Do not reverse direction of by-pass valve. If the desired vacuum is exceeded, either leak-check at this higher vacuum or end the leak-check as shown below and start over.

When the leak-check is completed, first slowly remove the plug from the inlet to the probe nozzle and immediately turn off the vacuum pump. This prevents water from being forced backward and keeps silica gel from being entrained backward.

4.1.4.2 Leak-Checks During Sample Run. If, during the sampling run, a component (e.g., filter assembly or impinger) change becomes necessary, a leak-check shall be conducted immediately before the change is made. The leak-check shall be done according to the procedure outlined in Section 4.1.4.1 above, except that it shall be done at a vacuum equal to or greater than the maximum value recorded up to that point in the test. If the leakage rate is found to be no greater than 0.00057 m^3/min (0.02 cfm) or 4 percent of the average sampling rate (whichever is less), the results are acceptable, and no correction will need to be applied to the total volume of dry gas metered; if, however, a higher leakage rate is obtained, the tester shall either record the leakage rate and plan to correct the sample volume as shown in

Section 6.3 of this method, or shall void the sampling run.

Immediately after component changes, leak-checks are optional; if such leak-checks are done, the procedure outlined in Section 4.1.4.1 above shall be used.

4.1.4.3 Post-Test Leak-Check. A leak-check is mandatory at the conclusion of each sampling run. The leak-check shall be done in accordance with the procedures outlined in Section 4.1.4.1, except that it shall be conducted at a vacuum equal to or greater than the maximum value reached during the sampling run. If the leakage rate is found to be no greater than 0.00057 m^3/min (0.02 cfm) or 4 percent of the average sampling rate (whichever is less), the results are acceptable, and no correction need be applied to the total volume of dry gas metered. If, however, a higher leakage rate is obtained, the tester shall either record the leakage rate and correct the sample volume as shown in Section 6.3 of this method, or shall void the sampling run.

4.1.5 Particulate Train Operation. During the sampling run, maintain a sampling rate such that sampling is within 10 percent of true isokinetic, unless otherwise specified by the Administrator.

For each run, record the data required on the example data sheet shown in Figure 17-3. Be sure to record the initial dry gas meter reading. Record the dry gas meter readings at the beginning and end of each sampling time increment, when changes in flow rates are made, before and after each leak check, and when sampling is halted. Take other readings required by Figure 17-3 at least once at each sample point during each time increment and additional readings when significant changes (20 percent variation in velocity head readings) necessitate additional adjustments in flow rate. Level and zero the manometer. Because the manometer level and zero may drift due to vibrations and temperature changes, make periodic checks during the traverse.

FIGURE 17–3—PARTICULATE FIELD DATA

Plant ....
Location ....
Operator ....
Date ....
Run No ....
Sample box No ....
Meter box No ....
Meter ΔH@ ....
C factor.
Pitot tube coefficient, Cp.

SCHEMATIC OF STACK CROSS SECTION

Barometric pressure ....
Assumed moisture, % ....
Probe extension length, m (ft.) ....
Nozzle identification No. ....
Average calibrated nozzle diameter cm (in.) ....
Filter No. ....
Leak rate, m^3/min, (cfm) ....
Static pressure, mm Hg (in. Hg) ....

Traverse point number	Sampling time	Vacuum	Stack temperature (T_S)	Velocity head (ΔP)	Pressure differential across orifice meter	Gas sample volume	Gas sample temperature at dry gas meter		Temperature of gas leaving condenser or last impinger
							Inlet	Outlet	
	(θ), min.	mm Hg (in. Hg)	°C (°F)	mm H_2O (in H_2O)	mm H_2O (in H_2O)	m^3 (ft^3)	°C (°F)	°C (°F)	°C (°F)
Total							Avg.	Avg.	
Average							Avg.		

Clean the portholes prior to the test run to minimize the chance of sampling the deposited material. To begin sampling, remove the nozzle cap and verify that the pitot tube and probe extension are properly positioned. Position the nozzle at the first traverse point with the tip pointing directly into the gas stream. Immediately start the pump and adjust the flow to isokinetic conditions. Nomographs are available, which aid in the rapid adjustment to the isokinetic sampling rate without excessive computations. These nomographs are designed for use when the Type S pitot tube coefficient is 0.85±0.02, and the stack gas equivalent density (dry molecular weight) is equal to 29±4. APTD-0576 details the procedure for using the nomographs. If C_p and M_d are outside the above stated ranges, do not use the nomographs unless appropriate steps (see Citation 7 in Bibliography) are taken to compensate for the deviations.

When the stack is under significant negative pressure (height of impinger stem), take care to close the coarse adjust valve before inserting the probe extension assembly into the stack to prevent water from being forced backward. If necessary, the pump may be turned on with the coarse adjust valve closed.

When the probe is in position, block off the openings around the probe and porthole to prevent unrepresentative dilution of the gas stream.

Traverse the stack cross section, as required by Method 1 or as specified by the Administrator, being careful not to bump the probe nozzle into the stack walls when sampling near the walls or when removing or inserting the probe extension through the portholes, to minimize chance of extracting deposited material.

During the test run, take appropriate steps (e.g., adding crushed ice to the impinger ice bath) to maintain a temperature of less than 20° C (68° F) at the condenser outlet; this will prevent excessive moisture losses. Also, periodically check the level and zero of the manometer.

If the pressure drop across the filter becomes too high, making isokinetic sampling difficult to maintain, the filter may be replaced in the midst of a sample run. It is recommended that another complete filter holder assembly be used rather than attempting to change the filter itself. Before a new filter holder is installed, conduct a leak check, as outlined in Section 4.1.4.2. The total particulate weight shall include the summation of all filter assembly catches.

A single train shall be used for the entire sample run, except in cases where simultaneous sampling is required in two or more separate ducts or at two or more different locations within the same duct, or, in cases where equipment failure necessitates a change of trains. In all other situations, the use of two or more trains will be subject to the approval of the Administrator. Note that when two or more trains are used, a separate analysis of the collected particulate from each train shall be performed, unless identical nozzle sizes were used on all trains, in which case the particulate catches from the individual trains may be combined and a single analysis performed.

At the end of the sample run, turn off the pump, remove the probe extension assembly from the stack, and record the final dry gas meter reading. Perform a leak-check, as outlined in Section 4.1.4.3. Also, leak-check the pitot lines as described in Section 3.1 of Method 2; the lines must pass this leak-check, in order to validate the velocity head data.

4.1.6 Calculation of Percent Isokinetic. Calculate percent isokinetic (see Section 6.11) to determine whether another test run should be made. If there is difficulty in maintaining isokinetic rates due to source conditions, consult with the Administrator for possible variance on the isokinetic rates.

4.2 Sample Recovery. Proper cleanup procedure begins as soon as the probe extension assembly is removed from the stack at the end of the sampling period. Allow the assembly to cool.

When the assembly can be safely handled, wipe off all external particulate matter near the tip of the probe nozzle and place a cap over it to prevent losing or gaining particulate matter. Do not cap off the probe tip tightly while the sampling train is cooling down as this would create a vacuum in the filter holder, forcing condenser water backward.

Before moving the sample train to the cleanup site, disconnect the filter holder-probe nozzle assembly from the probe extension; cap the open inlet of the probe extension. Be careful not to lose any condensate, if present. Remove the umbilical cord from the condenser outlet and cap the outlet. If a flexible line is used between the first impinger (or condenser) and the probe extension, disconnect the line at the probe extension and let any condensed water or liquid drain into the impingers or condenser. Disconnect the probe extension from the condenser; cap the probe extension outlet. After wiping off the silicone grease, cap off the condenser inlet. Ground glass stoppers, plastic caps, or serum caps (whichever are appropriate) may be used to close these openings.

Transfer both the filter holder-probe nozzle assembly and the condenser to the cleanup area. This area should be clean and protected from the wind so that the chances of contaminating or losing the sample will be minimized.

Save a portion of the acetone used for cleanup as a blank. Take 200 ml of this acetone directly from the wash bottle being used and place it in a glass sample container labeled "acetone blank."

Inspect the train prior to and during disassembly and note any abnormal conditions. Treat the samples as follows:

Container No. 1. Carefully remove the filter from the filter holder and place it in its identified petri dish container. Use a pair of tweezers and/or clean disposable surgical gloves to handle the filter. If it is necessary to fold the filter, do so such that the particulate cake is inside the fold. Carefully transfer to the petri dish any particulate matter and/or filter fibers which adhere to the filter holder gasket, by using a dry Nylon bristle brush and/or a sharp-edged blade. Seal the container.

Container No. 2. Taking care to see that dust on the outside of the probe nozzle or other exterior surfaces does not get into the sample, quantitatively recover particulate matter or any condensate from the probe nozzle, fitting, and front half of the filter holder by washing these components with acetone and placing the wash in a glass container. Distilled water may be used instead of acetone when approved by the Administrator and shall be used when specified by the Administrator; in these cases, save a water blank and follow Administrator's directions on analysis. Perform the acetone rinses as follows:

Carefully remove the probe nozzle and clean the inside surface by rinsing with acetone from a wash bottle and brushing with a Nylon bristle brush. Brush until acetone rinse shows no visible particles, after which make a final rinse of the inside surface with acetone.

Brush and rinse with acetone the inside parts of the fitting in a similar way until no visible particles remain. A funnel (glass or polyethylene) may be used to aid in transferring liquid washes to the container. Rinse the brush with acetone and quantitatively collect these washings in the sample container. Between sampling runs, keep brushes clean and protected from contamination.

After ensuring that all joints are wiped clean of silicone grease (if applicable), clean the inside of the front half of the filter holder by rubbing the surfaces with a Nylon bristle brush and rinsing with acetone. Rinse each surface three times or more if needed to remove visible particulate. Make final rinse of the brush and filter holder. After all acetone washings and particulate matter are collected in the sample container, tighten the lid on the sample container so that acetone will not leak out when it is shipped to the laboratory. Mark the height of the fluid level to determine whether or not leakage occurred during transport. Label the container to clearly identify its contents.

Container No. 3. If silica gel is used in the condenser system for mositure content determination, note the color of the gel to determine if it has been completely spent; make a notation of its condition. Transfer the silica gel back to its original container and seal. A funnel may make it easier to pour the silica gel without spilling, and a rubber policeman may be used as an aid in removing the silica gel. It is not necessary to remove the small amount of dust particles that may adhere to the walls and are difficult to remove. Since the gain in weight is to be used for moisture calculations, do not use any water or other liquids to transfer the silica gel. If a balance is available in the field, follow the procedure for Container No. 3 under "Analysis."

Condenser Water. Treat the condenser or impinger water as follows: make a notation of any color or film in the liquid catch. Measure the liquid volume to within ±1 ml by using a graduated cylinder or, if a balance is available, determine the liquid weight to within ±0.5 g. Record the total volume or weight of liquid present. This information is required to calculate the moisture content of the effluent gas. Discard the liquid after measuring and recording the volume or weight.

4.3 Analysis. Record the data required on the example sheet shown in Figure 17–4. Handle each sample container as follows:

Container No. 1. Leave the contents in the shipping container or transfer the filter and any loose particulate from the sample container to a tared glass weighing dish. Desiccate for 24 hours in a desiccator containing anhydrous calcium sulfate. Weigh to a constant weight and report the results to the nearest 0.1 mg. For purposes of this Section, 4.3, the term "constant weight" means a difference of no more than 0.5 mg or 1 percent of total weight less tare weight, whichever is greater, between two consecutive weighings, with no less than 6 hours of desiccation time between weighings.

Alternatively, the sample may be oven dried at the average stack temperature or 105° C (220° F), whichever is less, for 2 to 3 hours, cooled in the desiccator, and weighed to a constant weight, unless otherwise specified by the Administrator. The tester may also opt to oven dry the sample at the average stack temperature or 105° C (220° F), whichever is less, for 2 to 3 hours, weigh the sample, and use this weight as a final weight.

FIGURE 17–4—ANALYTICAL DATA

Plant __________
Date __________
Run No. __________
Filter No. __________
Amount liquid lost during transport __________
Acetone blank volume, ml __________
Acetone wash volume, ml __________
Acetone blank concentration, mg/mg (Equation 17–4) __________
Acetone wash blank, mg (Equation 17–5) __________

Container number	Weight of particulate collected, mg		
	Final weight	Tare weight	Weight gain
1.			
2.			
Total.			
Less acetone blank.			
Weight of particulate matter.			

	Volume of liquid water collected	
	Impinger volume, ml	Silica gel weight, g
Final.		
Initial.		
Liquid collected.		
Total volume collected		g* ml

*Convert weight of water to volume by dividing total weight increase by density of water (1 g/ml).

$$\frac{\text{Increase, g}}{(1\ \text{g/ml})} = \text{Volume water, ml}$$

Container No. 2. Note the level of liquid in the container and confirm on the analysis sheet whether or not leakage occurred during transport. If a noticeable amount of leakage has occurred, either void the sample or use methods, subject to the approval of the Administrator, to correct the final results. Measure the liquid in this container either volumetrically to ±1 ml or gravimetrically to ±0.5 g. Transfer the contents to a tared 250-ml beaker and evaporate to dryness at ambient temperature and pressure. Desiccate for 24 hours and weigh to a constant weight. Report the results to the nearest 0.1 mg.

Container No. 3. This step may be conducted in the field. Weigh the spent silica gel (or silica gel plus impinger) to the nearest 0.5 g using a balance.

"Acetone Blank" Container. Measure acetone in this container either volumetrically or gravimetrically. Transfer the acetone to a tared 250-ml beaker and evaporate to dryness at ambient temperature and pressure. Desiccate for 24 hours and weigh to a constant weight. Report the results to the nearest 0.1 mg.

NOTE: At the option of the tester, the contents of Container No. 2 as well as the acetone blank container may be evaporated at temperatures higher than ambient. If evaporation is done at an elevated temperature, the temperature must be below the boiling point of the solvent; also, to prevent "bumping," the evaporation process must be closely supervised, and the contents of the beaker must be swirled occasionally to maintain an even temperature. Use extreme care, as acetone is highly flammable and has a low flash point.

5. *Calibration*

Maintain a laboratory log of all calibrations.

5.1 Probe Nozzle. Probe nozzles shall be calibrated before their initial use in the field. Using a micrometer, measure the inside diameter of the nozzle to the nearest 0.025 mm (0.001 in.). Make three separate measurements using different diameters each time, and obtain the average of the measurements. The difference between the high and low numbers shall not exceed 0.1 mm (0.004 in.). When nozzles become nicked, dented, or corroded, they shall be reshaped, sharpened, and recalibrated before use. Each nozzle shall be permanently and uniquely identified.

5.2 Pitot Tube. If the pitot tube is placed in an interference-free arrangement with respect to the other probe assembly components, its baseline (isolated tube) coefficient shall be determined as outlined in Section 4 of Method 2. If the probe assembly is not interference-free, the pitot tube assembly coefficient shall be determined by calibration, using methods subject to the approval of the Administrator.

5.3 Metering System. Before its initial use in the field, the metering system shall be calibrated according to the procedure outlined in APTD–0576. Instead of physically adjusting the dry gas meter dial readings to correspond to the wet test meter readings, calibration factors may be used to mathematically correct the gas meter dial readings to the proper values.

Before calibrating the metering system, it is suggested that a leak-check be conducted. For metering systems having diaphragm pumps, the normal leak-check procedure will not detect leakages within the pump. For these cases the following leak-check procedure is suggested: make a 10-minute calibration run at 0.00057 m^3/min (0.02 cfm); at the end of the run, take the difference of the measured wet test meter and dry gas meter volumes; divide the difference by 10, to get the leak rate. The leak rate should not exceed 0.00057 m^3/min (0.02 cfm).

After each field use, the calibration of the metering system shall be checked by performing three calibration runs at a single, intermediate orifice setting (based on the previous field test), with the vacuum set at the maximum value reached during the test series. To adjust the vacuum, insert a valve between the wet test meter and the inlet of the metering system. Calculate the average value of the calibration factor. If the calibration has changed by more than 5 percent, recalibrate the meter over the full range of orifice settings, as outlined in APTD–0576.

Alternative procedures, e.g., using the orifice meter coefficients, may be used, subject to the approval of the Administrator.

NOTE: If the dry gas meter coefficient values obtained before and after a test series differ by more than 5 percent, the test series shall either be voided, or calculations for the test series shall be performed using whichever meter coefficient value (i.e., before or after) gives the lower value of total sample volume.

5.4 Temperature Gauges. Use the procedure in Section 4.3 of Method 2 to calibrate in-stack temperature gauges. Dial thermometers, such as are used for the dry gas meter and condenser outlet, shall be calibrated against mercury-in-glass thermometers.

5.5 Leak Check of Metering System Shown in Figure 17–1. That portion of the sampling train from the pump to the orifice meter should be leak checked prior to initial use and after each shipment. Leakage after the pump will result in less volume being recorded than is actually sampled. The following procedure is suggested (see Figure 17–5). Close the main valve on the meter box. Insert a one-hole rubber stopper with rubber tubing attached into the orifice exhaust pipe. Disconnect and vent the low side of the orifice manometer. Close off the low side orifice tap. Pressurize the system to 13 to 18 cm (5 to 7 in.) water column by blowing into the rubber tubing. Pinch off the tubing and observe the manometer for one minute. A loss of pressure on the manometer indicates a leak in the meter box; leaks, if present, must be corrected.

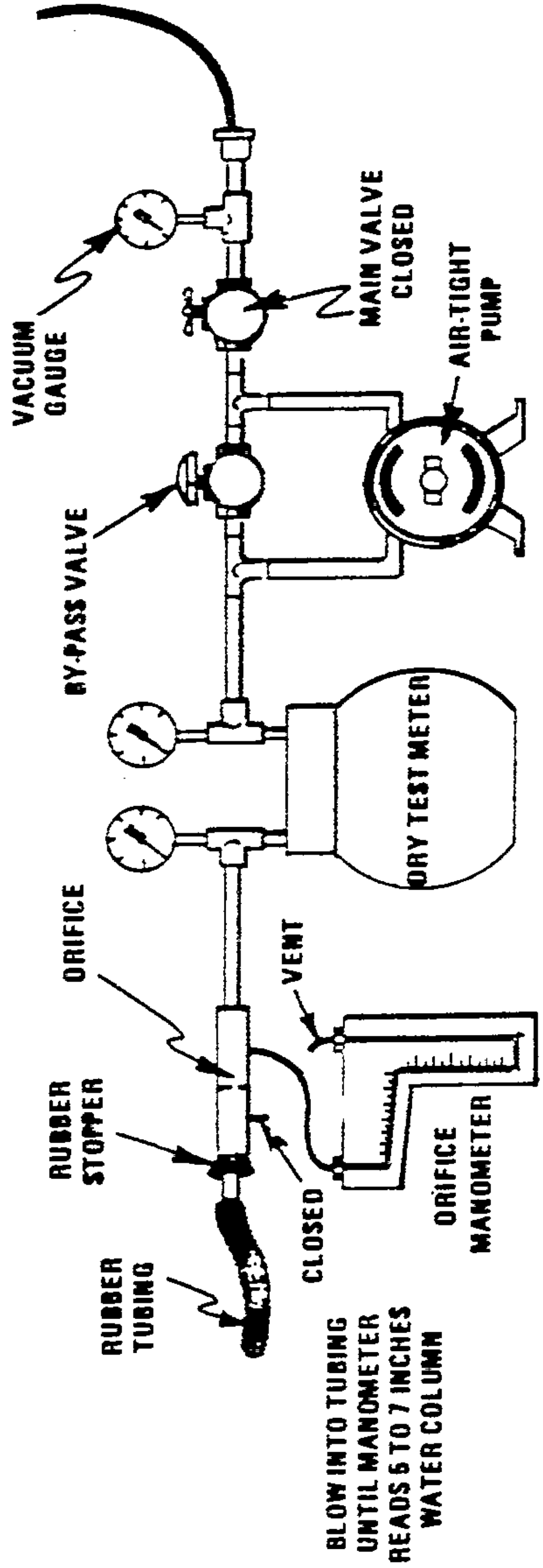


Figure 17-5. Leak check of meter box.

5.6 Barometer. Calibrate against a mercury barometer.

6. *Calculations*

Carry out calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after the final calculation. Other forms of the equations may be used as long as they give equivalent results.

6.1 Nomenclature.

A_n=Cross-sectional area of nozzle, m^2 (ft^2).

B_{ws}=Water vapor in the gas stream, proportion by volume.

C_a=Acetone blank residue concentration, mg/mg.

c_s=Concentration of particulate matter in stack gas, dry basis, corrected to standard conditions, g/dscm (g/dscf).

I=Percent of isokinetic sampling.

L_a=Maximum acceptable leakage rate for either a pretest leak check or for a leak check following a component change; equal to 0.00057 m^3/min (0.02 cfm) or 4 percent of the average sampling rate, whichever is less.

L_i=Individual leakage rate observed during the leak check conducted prior to the "i^{th}" component change (i=1, 2, 3 . . . n), m^3/min (cfm).

L_p=Leakage rate observed during the post-test leak check, m^3/min (cfm).

m_a=Mass of residue of acetone after evaporation, mg.

m_n=Total amount of particulate matter collected, mg.

M_w=Molecular weight of water, 18.0 g/g-mole (18.0 lb/lb-mole).

P_{bar}=Barometric pressure at the sampling site, mm Hg (in. Hg).

P_s=Absolute stack gas pressure, mm Hg (in. Hg).

P_{std}=Standard absolute pressure, 760 mm Hg (29.92 in. Hg).

R=Ideal gas constant, 0.06236 mm Hg-m^3/°K-g-mole (21.85 in. Hg-ft^3/°R-lb-mole).

T_m=Absolute average dry gas meter temperature (see Figure 17–3), °K (°R).

T_s=Absolute average stack gas temperature (see Figure 17–3), °K (°R).

T_{std}=Standard absolute temperature, 293°K (528°R).

V_a=Volume of acetone blank, ml.

V_{aw}=Volume of acetone used in wash, ml.

V_{lc}=Total volume of liquid collected in impingers and silica gel (see Figure 17–4), ml.

V_m=Volume of gas sample as measured by dry gas meter, dcm (dcf).

$V_{m(std)}$=Volume of gas sample measured by the dry gas meter, corrected to standard conditions, dscm (dscf).

$V_{w(std)}$=Volume of water vapor in the gas sample, corrected to standard conditions, scm (scf).

v_s=Stack gas velocity, calculated by Method 2, Equation 2–9, using data obtained from Method 17, m/sec (ft/sec).

W_a=Weight of residue in acetone wash, mg.

Y=Dry gas meter calibration coefficient.

ΔH=Average pressure differential across the orifice meter (see Figure 17–3), mm H_2O (in. H_2O).

ρ_a=Density of acetone, mg/ml (see label on bottle).

ρ_w=Density of water, 0.9982 g/ml (0.002201 lb/ml).

θ=Total sampling time, min.

θ_1=Sampling time interval, from the beginning of a run until the first component change, min.

θ_i=Sampling time interval, between two successive component changes, beginning with the interval between the first and second changes, min.

θ_p=Sampling time interval, from the final (n^{th}) component change until the end of the sampling run, min.

13.6=Specific gravity of mercury.

60=Sec/min.

100=Conversion to percent.

6.2 Average Dry Gas Meter Temperature and Average Orifice Pressure Drop. See data sheet (Figure 17–3).

6.3 Dry Gas Volume. Correct the sample volume measured by the dry gas meter to standard conditions (20° C, 760 mm Hg or 68° F, 29.92 in. Hg) by using Equation 17–1.

$$V_{m(std)} = V_m Y \left(\frac{T_{std}}{T_m}\right)\left[\frac{P_{bar} + \frac{\Delta H}{13.6}}{P_{std}}\right] = K_1 V_m Y \frac{P_{bar} + (\Delta H/13.6)}{T_m}$$

Eq. 17–1

Where:

K_1=0.3858° K/mm Hg for metric units; 17.64° R/in. Hg for English units.

NOTE: Equation 17–1 can be used as written unless the leakage rate observed during any of the mandatory leak checks (i.e., the post-test leak check or leak checks conducted prior to component changes) exceeds L_a. If L_p or L_i exceeds L_a, Equation 17–1 must be modified as follows:

(a) Case I. No component changes made during sampling run. In this case, replace V_m in Equation 17–1 with the expression:

$$[V_m - (L_p - L_a)\theta]$$

(b) Case II. One or more component changes made during the sampling run. In this case, replace V_m in Equation 17–1 by the expression:

$$[V_m - (L_1 - L_a)\,\theta_1 - \sum_{i=2}^{n} (L_i - L_a)\,\theta_i - (L_p - L_a)\,\theta_p]$$

and substitute only for those leakage rates (L_i or L_p) which exceed L_a.

6.4 Volume of Water Vapor.

$$V_{w(std)} = V_{1c}\left(\frac{\rho_w}{M_w}\right)\left(\frac{RT_{std}}{P_{std}}\right) = K_2\,V_{1c}$$

Eq. 17–2

Where:

K_2=0.001333 m³/ml for metric units; 0.04707 ft³/ml for English units.

6.5 Moisture Content.

$$B_{ws} = \frac{V_{w(std)}}{V_{m(std)} + V_{w(std)}}$$

Eq. 17–3

6.6 Acetone Blank Concentration.

$$C_a = \frac{m_a}{V_a \rho_a}$$

Eq. 17–4

6.7 Acetone Wash Blank.

$$W_a = C_a V_{aw} \rho_a$$

Eq. 17–5

6.8 Total Particulate Weight. Determine the total particulate catch from the sum of the weights obtained from Containers 1 and 2 less the acetone blank (see Figure 17–4).

NOTE: Refer to Section 4.1.5 to assist in calculation of results involving two or more filter assemblies or two or more sampling trains.

6.9 Particulate Concentration.

$$c_s = (0.001\ \mathrm{g/mg})\ (m_n / V_{m(std)})$$

Eq. 17–6

6.10 Conversion Factors:

From	To	Multiply by
scf	m³	0.02832
g/ft³	gr/ft³	15.43
g/ft³	lb/ft³	2.205×10⁻³
g/ft³	g/m³	35.31

6.11 Isokinetic Variation.

6.11.1 Calculation from Raw Data.

$$I = \frac{100\,T_s\,[K_3 V_{1c} + (V_m Y / T_m)\,(P_{bar} + \Delta H/13.6)]}{60\,\theta\,v_s\,P_s\,A_n}$$

Eq. 17–7

Where:

K_3=0.003454 mm Hg-m³/ml-°K for metric units; 0.002669 in. Hg-ft³/ml-°R for English units.

6.11.2 Calculation from Intermediate Values.

$$I = \frac{T_s\,V_{m(std)}\,P_{std}\,100}{T_{std}\,v_s\,\theta\,A_n\,P_s\,60\,(1 - B_{ws})}$$

$$= K_4\,\frac{T_s\,V_{m(std)}}{P_s\,v_s\,A_n\,\theta\,(1 - B_{ws})}$$

Eq. 17–8

Where:

K_4=4.320 for metric units; 0.09450 for English units.

6.12 Acceptable Results. If 90 percent <I <110 percent, the results are acceptable. If the results are low in comparison to the standard and I is beyond the acceptable range, or, if I is less than 90 percent, the Administrator may opt to accept the results. Use Citation 4 in Bibliography to make judgments. Otherwise, reject the results and repeat the test.

7. *Bibliography*

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METHOD 18—MEASUREMENT OF GASEOUS ORGANIC COMPOUND EMISSIONS BY GAS CHROMATOGRAPHY

Introduction

This method should not be attempted by persons unfamiliar with the performance characteristics of gas chromatography, nor by those persons who are unfamiliar with source sampling. Particular care should be exercised in the area of safety concerning choice of equipment and operation in potentially explosive atmospheres.

1. *Applicability and Principle*

1.1 Applicability. This method applies to the analysis of approximately 90 percent of the total gaseous organics emitted from an industrial source. It does not include techniques to identify and measure trace amounts of organic compounds, such as those found in building air and fugitive emission sources.

This method will not determine compounds that (1) are polymeric (high molecular weight), (2) can polymerize before analysis, or (3) have very low vapor pressures at stack or instrument conditions.

1.2 Principle.

The major organic components of a gas mixture are separated by gas chromatography (GC) and individually quantified by flame ionization, photoionization, electron capture, or other appropriate detection principles.

The retention times of each separated component are compared with those of known compounds under identical conditions. Therefore, the analyst confirms the identity and approximate concentrations of the organic emission components beforehand. With this information, the analyst then prepares or purchases commercially available standard mixtures to calibrate the GC under conditions identical to those of the samples. The analyst also determines the need for sample dilution to avoid detector saturation, gas stream filtration to eliminate particulate matter, and prevention of moisture condensation.

2. *Range and Sensitivity*

2.1 Range. The lower range of this method is determined by the sampling system; adsorbents may be used to concentrate the sample, thus lowering the limit of detection below the 1 part per million (ppm) typically achievable with direct interface or bag sampling. The upper limit is governed by GC detector saturation or column overloading; the upper range can be extended by dilution of sample with an inert gas or by using smaller volume gas sampling loops. The upper limit can also be governed by condensation of higher boiling compounds.

2.2 Sensitivity. The sensitivity limit for a compound is defined as the minimum detectable concentration of that compound, or the concentration that produces a signal-to-noise ratio of three to one. The minimum detectable concentration is determined during the presurvey calibration for each compound.

3. *Precision and Accuracy*

Gas chromatographic techniques typically provide a precision of 5 to 10 percent relative standard deviation (RSD), but an experienced GC operator with a reliable instrument can readily achieve 5 percent RSD. For this method, the following combined GC/operator values are required.

(a) Precision. Duplicate analyses are within 5 percent of their mean value.

(b) Accuracy. Analysis results of prepared audit samples are within 10 percent of preparation values.

(c) Recovery. After developing an appropriate sampling and analytical system for the pollutants of interest, conduct the procedure in Section 7.6. Conduct the appropriate recovery study in Section 7.6 at each sampling point where the method is being applied. Submit the data and results of the recovery procedure with the reporting of results under Section 7.5.

4. *Interferences*

Resolution interferences that may occur can be eliminated by appropriate GC column and detector choice or by shifting the retention times through changes in the column flow rate and the use of temperature programming.

The analytical system is demonstrated to be essentially free from contaminants by periodically analyzing blanks that consist of hydrocarbon-free air or nitrogen.

Sample cross-contamination that occurs when high-level and low-level samples or standards are analyzed alternately, is best

The operating and maintenance procedures for many of the sampling train components are described in APTD–0576 (Citation 3 in Bibliography). Since correct usage is important in obtaining valid results, all users should read the APTD–0576 document and adopt the operating and maintenance procedures outlined in it, unless otherwise specified herein. The sampling train consists of the following components:

2.1.1 Probe Nozzle. Stainless steel (316) or glass, with sharp, tapered leading edge. The angle of taper shall be 30° and the taper shall be on the outside to preserve a constant internal diameter. The probe nozzle shall be of the button-hook or elbow design, unless otherwise specified by the Administrator. If made of stainless steel, the nozzle shall be constructed from seamless tubing. Other materials of construction may be used subject to the approval of the Administrator.

A range of sizes suitable for isokinetic sampling should be available, e.g., 0.32 to 1.27 cm (¼ to ½ in.)—or larger if higher volume sampling trains are used—inside diameter (ID) nozzles in increments of 0.16 cm (1/16 in.). Each nozzle shall be calibrated according to the procedures outlined in Section 5.1.

2.1.2 Filter Holder. The in-stack filter holder shall be constructed of borosilicate or quartz glass, or stainless steel; if a gasket is used, it shall be made of silicone rubber, Teflon, or stainless steel. Other holder and gasket materials may be used subject to the approval of the Administrator. The filter holder shall be designed to provide a positive seal against leakage from the outside or around the filter.

2.1.3 Probe Extension. Any suitable rigid probe extension may be used after the filter holder.

2.1.4 Pitot Tube. Type S, as described in Section 2.1 of Method 2, or other device approved by the Administrator; the pitot tube shall be attached to the probe extension to allow constant monitoring of the stack gas velocity (see Figure 17–1). The impact (high pressure) opening plane of the pitot tube shall be even with or above the nozzle entry plane during sampling (see Method 2, Figure 2–6b). It is recommended: (1) that the pitot tube have a known baseline coefficient, determined as outlined in Section 4 of Method 2; and (2) that this known coefficient be preserved by placing the pitot tube in an interference-free arrangement with respect to the sampling nozzle, filter holder, and temperature sensor (see Figure 17–1). Note that the 1.9 cm (0.75 in.) free-space between the nozzle and pitot tube shown in Figure 17–1, is based on a 1.3 cm (0.5 in.) ID nozzle. If the sampling train is designed for sampling at higher flow rates than that described in APTD–0581, thus necessitating the use of larger sized nozzles, the free-space shall be 1.9 cm (0.75 in.) with the largest sized nozzle in place.

Source-sampling assemblies that do not meet the minimum spacing requirements of Figure 17–1 (or the equivalent of these requirements, e.g., Figure 2–7 of Method 2) may be used; however, the pitot tube coefficients of such assemblies shall be determined by calibration, using methods subject to the approval of the Administrator.

2.1.5 Differential Pressure Gauge. Inclined manometer or equivalent device (two), as described in Section 2.2 of Method 2. One manometer shall be used for velocity head (Δp) readings, and the other, for orifice differential pressure readings.

2.1.6 Condenser. It is recommended that the impinger system described in Method 5 be used to determine the moisture content of the stack gas. Alternatively, any system that allows measurement of both the water condensed and the moisture leaving the condenser, each to within 1 ml or 1 g, may be used. The moisture leaving the condenser can be measured either by: (1) monitoring the temperature and pressure at the exit of the condenser and using Dalton's law of partial pressures; or (2) passing the sample gas stream through a silica gel trap with exit gases kept below 20° C (68° F) and determining the weight gain.

Flexible tubing may be used between the probe extension and condenser. If means other than silica gel are used to determine the amount of moisture leaving the condenser, it is recommended that silica gel still be used between the condenser system and pump to prevent moisture condensation in the pump and metering devices and to avoid the need to make corrections for moisture in the metered volume.

2.1.7 Metering System. Vacuum gauge, leak-free pump, thermometers capable of measuring temperature to within 3° C (5.4° F), dry gas meter capable of measuring volume to within 2 percent, and related equipment, as shown in Figure 17–1. Other metering systems capable of maintaining sampling rates within 10 percent of isokinetic and of determining sample volumes to within 2 percent may be used, subject to the approval of the Administrator. When the metering system is used in conjunction with a pitot tube, the system shall enable checks of isokinetic rates.

Sampling trains utilizing metering systems designed for higher flow rates than that described in APTD–0581 or APTD–0576 may be used provided that the specifications of this method are met.

2.1.8 Barometer. Mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg). In many cases, the barometric reading may be obtained from a nearby National Weather Service station, in which case the station value (which is the absolute barometric pressure) shall be requested and an adjustment for elevation differences between

State of West Virginia, County of Randolph, ss.

NOTICE OF PUBLIC HEARING

On Tuesday, November 29, 1994 beginning at 9:00 a.m., the Division of Environmental Protection, Office of Air Quality will hold a public hearing on proposed revisions to legislative rule 45CSR2 — "To Prevent and Control Particulate Air Pollution from Combustion of Fuel in Indirect Heat Exchangers."

The proposed revisions to 45CSR2 would primarily have the effect of relaxing the visible emission standards applicable to fuel burning units in West Virginia (including steam generating units and other indirect heat exchangers) to a level essentially the same as those established nationally by USEPA for new or modified fuel burning units.

Upon authorization and promulgation, this revised rule will be submitted to the U.S. Environmental Protection Agency for incorporation into the West Virginia Implementation Plan under the federal Clean Air Act.

The hearing will be held in the Conference Room of the Office of Air Quality located at 1558 Washington Street East, Charleston, West Virginia. The hearing is open to the public. Written and oral testimony by all interested parties will be accepted and made part of the record which will be closed at the conclusion of the public hearing.

Copies of the proposed legislative rule are available for public review in the Elkins-Randolph County Public Library, 416 Davis Avenue, Elkins, WV.

If you have any questions or comments concerning the proposed rule please contact:

G. Dale Farley
Chief, Office of Air Quality
Division of Environmental Protection
1558 Washington Street, East
Charleston, West Virginia 25311

10—27

I, James Hoffman, Publisher of THE INTER-MOUNTAIN, a newspaper published at Elkins, in said county, do hereby certify that the annexed advertisement was published on the following dates:

Oct. 22

19 94 as required by law.

Given under my hand this 27th day of October 1994.

James Hoffman
Publisher

Printer's Fee: $ 20.13

My C[...] ne this 27th day of October, 19 94.

Shirley A. Dresser
Notary Public

My Commission Expires the 15 day of April 2002.

State of West Virginia, County of Upshur, ss:

Mark Davis .... Advertising Manager Record Delta, a newspaper published at Buckhannon in the said county, do hereby certify that the annexed ..NOTICE OF PUBLIC HEARING ....

....

....

was published once a week for .. ONE WEEK(1) .... successive weeks in said Record Delta newspaper published as aforesaid, commencing on the . 28th ....

..day of October .... days of 19.94............

Given under my hand this ..31st day of Oct.... day of 19 .94 ....

... Mark Davis ... Advertising Manager

Printers fee $ ..14.65 ....

WEST VIRGINIA, UPSHUR COUNTY, TO-WIT:

Subscribed and sworn to before me this 31st day of Oct .. day of 19.94...

... Phyllis J. Neuharth .... Notary Public.

My Commission expires May 26, 2003..

OFFICIAL SEAL
NOTARY PUBLIC
STATE OF WEST VIRGINIA
PHYLLIS J. NEUHARTH
RT 2, BOX 95
FRENCH CREEK, WV 26218
My Commission Expires May 26, 2003

NOTICE OF PUBLIC HEARING

On Tuesday, November 29, 1994, beginning at 9:00 a.m., the Division of Environmental Protection, Office of Air Quality will hold a public hearing on proposed revisions to legislative rule 45CSR2-"To Prevent and Control Particulate Air Pollution from Combustion of Fuel in Indirect Heat Exchangers" The proposed revisions to 45CSR2 would primarily have the effect of relaxing the visible emission standards applicable to fuel burning units in West Virginia (including steam generating units and other indirect heat exchangers) to a level essentially the same as those established nationally by USEPA for new or modified fuel burning units. Upon authorization and promulgation, this revised rule will be submitted to the U. S. Environmental Protection Agency for incorporation into the West Virginia Implementation Plan under the federal Clean Air Act. The hearing will be held in the Conference Room of the Office of Air Quality located at 1558 Washington Street East, Charleston, West Virginia. The hearing is open to the public. Written and oral testimony by all interested parties will be accepted and made part of the record which will be closed at the conclusion of the public hearing. Copies of the proposed legislative rule are available for public review in the Gassaway Public Library, 100 Birch Street, Gassaway, WV. If you have any questions or comments concerning the proposed rule please contact:

G. Dale Farley
Chief, Office of Air Quality
Division of Environmental Protection
1558 Washington Street, East
Charleston, West Virginia 25311
10-28

AFFIDAVIT OF PUBLICATION
BECKLEY NEWSPAPERS INC.
BECKLEY, WEST VIRGINIA 25801

October 28, 1994

STATE OF WEST VIRGINIA
COUNTY OF RALEIGH, to wit:

I, Robert E. Zutaut being first duly sworn upon my oath, do depose and say that I am Advertising Manager of Beckley Newspapers Inc., a corporation, publisher of the newspaper entitled The Register-Herald, an Independent newspaper; that I have been duly authorized by the board of directors of such corporation to execute this affidavit of publication; that such newspaper has been published for more than one year prior to publication of the annexed notice described below; that such newspaper is regularly published daily, for at least fifty weeks during the calendar year, in the municipality of Beckley, Raleigh County, West Virginia; that such newspaper is a newspaper of "general circulation," as that term is defined in article three, chapter fifty-nine of the Code of West Virginia, 1931, as amended, within the publication area or areas of the aforesaid municipality and county; that such newspaper averages in length four or more pages, exclusive of any cover, per issue; that such newspaper is circulated to the general public at a definite price of consideration; that such newspaper is a newspaper to which the general public resorts for passing events of a political, religious, commercial and social nature, and for current happenings, announcements, miscellaneous reading matters, advertisements and other notices; that the annexed notice

of Public Hearing
(Description of notice)

was duly published in said newspaper once a week for 1 successive week (Class I), commencing with the issue of the 28 day of Oct., 1994, and ending with the issue of the 28 day of Oct., 1994, (and was posted at the ______ on the ______ day of ______); that said annexed notice was published on the following dates: 10/28/94 and that the cost of publishing said annexed notice as aforesaid was $ 19.69.

Signed [signature]
Robert E. Zutaut, Advertising Manager
Beckley Newspapers

Taken, subscribed and sworn to before me in my said county this 28 day of October 19 94

My commission expires March 27, 2001

[signature]
Notary Public of Raleigh County, West Virginia

R H

COPY OF PUBLICATION

NOTICE OF PUBLIC HEARING

On Tuesday, November 29, 1994 beginning at 9:00 a.m., the division of Environmental Protection, Office of Air Quality will hold a public hearing on proposed revisions to legislative rule 45CSR2-"To Prevent and Control Particulate Air Pollution from Combustion of Fuel in Indirect Heat Exchangers".

The proposed revisions to 45CSR2 would primarily have the effect of relaxing the visible emission standards applicable to fuel burning units in West Virginia including steam generating units and other indirect heat exchangers to a level essentially the same as those established nationally by USEPA for new or modified fuel burning units.

Upon authorization and promulgation, this revised rule will be submitted to the U.S. Environmental Protection Agency for incorporation into the West Virginia Implementation Plan under the federal Clean Air Act.

The hearing will be held in the Conference Room of the Office of Air Quality located at 1558 Washington Street East, Charleston, West Virginia. The hearing is open to the public. Written and oral testimony by all interested parties will be accepted and made part of the record which will be closed at the conclusion of the public hearing.

Copies of the proposed legislative rules are available for public review in the Raleigh County Public Library, PO Box 1876, Beckley, WV

If you have any questions or comments concerning the proposed rule please contact: G. Dale Farley, Chief, Office of Air Quality, Division of Environmental Protection, 1558 Washington Street, East, Charleston, West Virginia 25311.
10-28-Fri-1-RH

I, as an officer of the News-Tribune, a daily newspaper published at Keyser, Mineral County, West Virginia, hereby certify that the Notice of Public Hearing

in the case of Pollution Control for Indirect Heat Exchangers

vs. ______________________

a copy whereof is hereto annexed has been published for 1 consecutive day in said NEWS-TRIBUNE, the first publication being on the 28th day of, Oct. 19 94.

Given under my hand at Keyser this 28th day of Oct., 19 94.

Publisher

Publisher's Fee
$ 16.80

NOTICE OF PUBLIC HEARING

On Tues., Nov. 29, 1994 beginning at 9 a.m., the Division of Environmental Protection, Office of Air Quality will hold a public hearing on proposed revisions to legislative rule 45CSR2-"To Prevent and Control Particulate Air Pollution from Combustion of Fuel in Indirect Heat Exchangers."

The proposed revisions to 45CSR2 would primarily have the effect of relaxing the visible emission standards applicable to fuel burning units in West Virginia (including steam generating units and other indirect heat exchangers) to a level essentially the same as those established nationally by USEPA for new or modified fuel burning units.

Upon authorization and promulgation, this revised rule will be submitted to the U.S. Environmental Protection Agency for incorporation into the West Virginia Implementation Plan under the Federal Clean Air Act.

The hearing will be held in the Conference Room of the Office of Air Quality located at 1558 Washington Street East, Charleston, West Virginia. The hearing is open to the public. Written and oral testimony by all interested parties will be accepted and made part of the record which will be closed at the conclusion of the public hearing.

Copies of the proposed legislative rule are available for public review in the Keyser-Mineral County Public Library, 105 North Main Street, Keyser, WV.

If you have any questions or comments concerning the proposed rule please contact:

G. Dale Farley, Chief, Office of Air Quality
Division of Environmental Protection
1558 Washington Street, East
Charleston, West Virginia 25311

10: 28

NOTICE OF PUBLIC HEARING

On Tuesday, November 29, 1994 beginning at 9:00 a.m., the Division of Environmental Protection, Office of Air Quality will hold a public hearing on proposed revisions to legislative rule 45CSR2 - "To prevent and Control Particulate Air Pollution from Combustion of Fuel in Indirect Heat Exchangers".

The proposed revisions to 45CSR2 would primarily have the effect of relaxing the visible emission standards applicable to fuel burning units in West Virginia (including steam generating units and other indirect heat exchangers) to a level essentially the same as those established nationally by USEPA for new or modified fuel burning units.

Upon authorization and promulgation, this revised rule will be submitted to the U.S. Environmental Protection Agency for incorporation into the West Virginia Implementation Plan under the Federal Clean Air Act.

The hearing will be held in the Conference Room of the Office of Air Quality located at 1558 Washington Street, East, Charleston, West Virginia. The hearing is open to the public. Written and oral testimony by all interested parties will be accepted and made part of the record which will be closed at the conclusion of the public hearing.

Copies of the proposed legislative rule are available for public review in th Office of Air Quality, Northern Panhandle Regional Office, 1911 Warwood Avenue, Wheeling, WV.

If you have any questions or comments concerning the proposed rule please contact:

G. Dale Farley
Chief, Office of Air Quality
Division of Environmental Protection
1558 Washington Street, East
Charleston, West Virginia 25311

Intel., Oct. 31
N.R., Oct. 31

STATE OF WEST VIRGINIA,
COUNTY OF OHIO.

I, Bonnie Mattern *for the publisher of the*

WHEELING NEWS-REGISTER
~~WHEELING INTELLIGENCER~~ *newspapers published in the CITY OF WHEELING, STATE OF WEST VIRGINIA, hereby certify that the annexed publication was inserted in said newspaper on the following dates:*

October 31, 1994

commencing on the 31 *day of* October, *19* 94

Given under my hand this 1 *day of* November, *19* 94

Bonnie Mattern

Sworn to and subscribed before me this 1ND *day of* November *19* 94 *at WHEELING, OHIO COUNTY, WEST VIRGINIA*

Linda E. Miller
Notary Public

of, in and for OHIO COUNTY, WEST VIRGINIA.

My Commission expires August 9, 2002

OFFICIAL SEAL
NOTARY PUBLIC
STATE OF WEST VIRGINIA
LINDA E. MILLER

PUBLISHER'S CERTIFICATE

STATE OF WEST VIRGINIA,

COUNTY OF HARRISON

I, Deborah S. Veltri

Classified Office Manager of THE CLARKSBURG EXPONENT, a newspaper of general circulation published in the City of Clarksburg, County and State aforesaid, do hereby certify that the annexed

Notice of Public Hearing

was published in said THE CLARKSBURG EXPONENT one time, on the 27 day of October 19 94

The publisher's fee for said publication is $ 12.55

Deborah S Veltri

Classified Office Mgr. of The Clarksburg Exponent

SEAL

Subscribed and sworn to before me this 27 day of October, 19 94

Debra Kay Swiger

Notary Public in and/for Harrison County, WV.

My commission expires on the 25th day of August, 2003.

Form CA-14 E

OFFICIAL SEAL
NOTARY PUBLIC
STATE OF WEST VIRGINIA
Debra Kay Swiger
Route 1, Box 236A
Wallace, WV 26443
My Commission Expires August 25, 2003

NOTICE OF PUBLIC HEARING

On Tuesday, November 29, 1994 beginning at 9:00 a.m., the Division of Environmental Protection, Office of Air Quality will hold a public hearing on proposed revisions to legislative rule 45CSR2 - "To Prevent and Control Particulate Air Pollution from Combustion of Fuel in Indirect Heat Exchangers".

The proposed revisions to 45CSR2 would primarily have the effect of relaxing the visible emission standards applicable to fuel burning units in West Virginia (including steam generating units and other indirect heat exchangers) to a level essentially the same as those established nationally by USEPA for new or modified fuel burning units.

Upon authorization and promulgation, this revised rule will be submitted to the U. S. Environmental Protection Agency for incorporation into the West Virginia Implementation Plan under the federal Clean Air Act.

The hearing will be held in the Conference Room of the Office of Air Quality located at 1558 Washington Street East, Charleston, West Virginia. The hearing is open to the public. Written and oral testimony by all interested parties will be accepted and made part of the record which will be closed at the conclusion of the public hearing.

Copies of the proposed legislative rule are available for public review in the Office of Air Quality, North Central Regional Office, 517½ East Park Avenue, Fairmont, WV.

If you have any questions or comments concerning the proposed rule please contact:

G. Dale Farley
Chief, Office of Air Quality
Division of Environmental Protection
1558 Washington Street, East
Charleston, West Virginia 25311

NOTICE OF PUBLIC HEARING

On Tuesday, November 29, 1994 beginning at 9:00 a.m., the *Division of Environmental Protection, Office of Air Quality* will hold a public hearing on proposed revisions to legislative rule 45CSR2 - "To Prevent and Control Particulate Air Pollution from Combustion of Fuel in Indirect Heat Exchangers".

The proposed revisions to 45CSR2 would primarily have the effect of relaxing the visible emission standards applicable to fuel burning units in West Virginia (including steam generating units and other indirect heat exchangers) to a level essentially the same as those established nationally by USEPA for new or modified fuel burning units.

Upon authorization and promulgation, this revised rule will be submitted to the U. S. Environmental Protection Agency for incorporation into the West Virginia Implementation Plan under the federal Clean Air Act.

The hearing will be held in the Conference Room of the Office of Air Quality located at 1558 Washington Street East, Charleston, West Virginia. The hearing is open to the public. Written and oral testimony by all interested parties will be accepted and made part of the record which will be closed at the conclusion of the public hearing.

Copies of the proposed legislative rule are available for public review in the Parkersburg/Wood County Public Library, 3100 Emerson Avenue, Parkersburg, West Virginia.

If you have any questions or comments concerning the proposed rule please contact:

G. Dale Farley
Chief, Office of Air Quality
Division of Environmental Protection
1558 Washington Street, East
Charleston, West Virginia 25311

Oct.28 N

KATHY MILLER being first duly sworn, says that the "NOTICE OF PUBLIC HEARING-AIR QUALITY" hereto attached was printed in the Parkersburg News a DAILY newspaper published in the City of Parkersburg, Wood County, West Virginia, and posted at the front door of the Court House for ONE successive weeks, the first publication and posting thereon being on the 28th day of October 19 94, and subsequent publication on the ... day of ... 19..., the ... day of ... 19..., the ... day of ... 19..., the ... day of ... 19..., and the ... day of ... 19...

Printer's Fee $ 20.12

3 1/8 " x 103= 321.88 words @ .0625

Kathy Miller

Subscribed and sworn to before me this 28th day of OCTOBER 19 94.

Melani Zyla
Notary Public for Wood County, West Virginia

OFFICIAL SEAL
NOTARY PUBLIC, STATE OF WEST VIRGINIA
MELANI ZYLA
1629-19th STREET PARKERSBURG, WV 26101
MY COMMISSION EXPIRES MAR. 23, 2004

My commission expires 3-23-04

1994 OCT 31 P 3: 29
OFFICE OF AIR QUALITY
DIV. OF ENVIRONMENTAL PROTECTION

Parkersburg Printing Co. - 5/71

NOTICE OF PUBLIC HEARING

On Tuesday, November 29, 1994 beginning at 9:00 a.m., the Division of Environmental Protection, Office of Air Quality will hold a public hearing on proposed revisions to legislative rule 45CSR2 - "To Prevent and Control Particulate Air Pollution from Combustion of Fuel in Indirect Heat Exchangers".

The proposed revisions to 45CSR2 would primarily have the effect of relaxing the visible emission standards applicable to fuel burning units in West Virginia (including steam generating units and other indirect heat exchangers) to a level essentially the same as those established nationally by USEPA for new or modified fuel burning units.

Upon authorization and promulgation, this revised rule will be submitted to the U.S. Environmental Protection Agency for incorporation into the West Virginia Implementation Plan under the federal Clean Air Act.

The hearing will be held in the Conference Room of the Office of Air Quality located at 1558 Washington Street East, Charleston, West Virginia. The hearing is open to the public. Written and oral testimony by all interested parties will be accepted and made part of the record which will be closed at the conclusion of the public hearing.

Copies of the proposed legislative rule are available for public review in the Martinsburg-Berkeley County Public Library, 101 King Street, Martinsburg, WV and the Office of Air Quality's Eastern Panhandle Regional Office, P.O. Box 99, New Creek, WV.

If you have any questions or comments concerning the proposed rule please contact:

G. Dale Farley
Chief, Office of Air Quality
Division of Environmental Protection
1558 Washington Street, East
Charleston, West Virginia 25311

10:26(1t)

Certificate of Publication

This is to certify the annexed advertisement OFFICE OF AIR QUALITY

WV DIV.ENVIRONMENTAL PROTECTION 2128
OFFICE AIR QUALITY

HEARING PROPOSED REVISIONS
45CSR2

appeared for 1 consecutive days/weeks in The Journal Publishing Company a newspaper published in the City of Martinsburg, W. Va., in its issue beginning

10/26

OFFICIAL SEAL
NOTARY PUBLIC
STATE OF WEST VIRGINIA
CHERYL D. GEORGE
Box 505½ Jefferson Street
Martinsburg, W. Va 25401
My Commission Expires September 14, 1998

The Journal

Pamela K. McCauley

Fee $ 22.25

CHARLESTON NEWSPAPERS
P.O. Box 2993
Charleston, West Virginia 25330
Billing 348-4898
Classified 348-4848
1-800-WVA-NEWS
FEIN 55-0676079

INVOICE DATE	10/31/94
ACCOUNT NBR	037143002
SALES REP ID	0016
INVOICE NBR	159685001

Legal pricing is based upon 67 words per column inch at a rate of $.0725 per word
Each successive insertion is discounted by 25% of the first insertion rate ($.054375 per word)

ISSUE DATE	AD TYPE	PUB	DESCRIPTION REFERENCE NBR PURCHASE ORDER #	AD NUMBER	AD SIZE TOTAL RUN	RATE	GROSS AMOUNT	NET AMOUNT
10/28	LEGF	DM	PUBLIC HEARING 159685001	L214474	1X0563 5.63	4.85	27.31	27.31
			TOTAL INVOICE AMOUNT					27.31

State of West Virginia, **AFFIDAVIT OF PUBLICATION**

I, Sandra Legg of

THE DAILY MAIL, A DAILY REPUBLICAN NEWSPAPER,
published in the city of Charleston, Kanawha County, West Virginia, do solemnly swear that the annexed notice of:
PUBLIC HEARING
was duly published in said paper(s) during the dates listed below, and was posted at the front door of the court house of said Kanawha County, West Virginia, on the 29TH day of OCTOBER 1994. Published during the following dates: 10/28/94-10/28/94
Subscribed and sworn to before me this 1 day of November
Printers fee $ 27.31

Notary Public of Kanawha County, West Virginia

OFFICIAL SEAL NOTARY PUBLIC STATE OF WEST VIRGINIA SARAH J. WITHROW ... CHARLESTON, WV 25309 ... Expires April 28, 2003

NOTICE OF PUBLIC HEARING

On Tuesday, November 29, 1994 beginning at 9:00 a.m., the Division of Environmental Protection, Office of Air Quality will hold a public hearing on proposed revisions to legislative rule 45CSR2 - "To Prevent and Control Particulate Air Pollution from Combustion of Fuel in Indirect Heat Exchangers".

The proposed revisions to 45CSR2 would primarily have the effect of relaxing the visible emission standards applicable to fuel burning units in West Virginia (including steam generating units and other indirect heat exchangers) to a level essentially the same as those established nationally by USEPA for new or modified fuel burning units.

Upon authorization and promulgation, this revised rule will be submitted to the U.S. Environmental Protection Agency for incorporation into the West Virginia Implementation Plan under the federal Clean Air Act.

The hearing will be held in the Conference Room of the Office of Air Quality located at 1558 Washington Street East, Charleston, West Virginia. The hearing is open to the public. Written and oral testimony by all interested parties will be accepted and made part of the record which will be closed at the conclusion of the public hearing.

Copies of the proposed legislative rule are available for public review in the Library of the Office of Air Quality located at the address below.

If you have any questions or comments concerning the proposed rule please contact:
G. Dale Farley
Chief, Office of Air Quality
Division of Environmental Protection
1558 Washington Street, East
Charleston, West Virginia 25311

(214474)

NOTICE

NOTICE OF PUBLIC HEARING

On Tuesday, November 29, 1994, beginning at 9:00 a.m., the Division of Environmental Protection, Office of Air Quality will hold a public hearing on proposed revisions to legislative rule 45CSR2- "To Prevent and Control Particulate Air Pollution from Combustion of Fuel in Indirect Heat Exchangers".

The proposes revisions to 45CSR2 would primarily have the effect of relaxing the visible emission standards applicable to fuel burning units in West Virginia (including steam generating units and other indirect near exchangers) to a level essentially the same as those established nationally by USEPA for new or modified fuel burning units.

Upon authorization and promulgation, this revised rule will be submitted to the U.S. Environmental Protection Agency for incorporation into the West Virginia Implementation Plan under the federal Clean Air Act.

The hearing will be held in the Conference Room of the Office of Air Quality located 1558 Washington Street East, Charleston, West Virginia. The hearing is open to the public. Written and oral testimony by all interested parties will be accepted and made part of the record which will be closed at the conclusion of the public hearing.

Copies of the proposed legislative rule are available for public review in the Cabell County Public Library, 455 9th Street Plaza, Huntington, WV.

If you have any questions or comments concerning the proposed rule please contact:

G. Dale Farley
Chief, Office of Air Quality
Division of Environmental Protection
1558 Washington Street, East
Charleston, West Virginia 25311

.H-1486 10-28,94

AFFIDAVIT OF PUBLICATION

'94 DEC -1 A

OFFICE OF AIR QUALITY

STATE OF WEST VIRGINIA,
COUNTY OF CABELL, TO-WIT:

I, Connie Rappold being first duly sworn, depose and say that I am Legal Clerk for The Herald-Dispatch, a corporation, who publishes at Huntington, Cabell County, West Virginia, the newspaper: The Herald-Dispatch, a independent newspaper, in the morning seven days each week, Monday through Sunday including New Year's Day, Memorial Day, the Fourth of July, Labor Day, Thanksgiving and Christmas; that I have been duly authorized by the Board of Directors of such corporation to execute this affidavit of publication for an on behalf of such corporation and the newspaper mentioned herein; that the legal advertisement attached in the left margin of this affidavit and made a part hereof and bearing number LH-1486 was duly published in

The Herald-Dispatch

one time, ~~once a week for .... successive weeks~~, commencing with its issue of the 28th day of Oct., 19 94, and ending with the issue of the 28th day of October, 19 94, and was posted at the East door of the Cabell County Courthouse on the 28th day of October, 19 94: that said legal advertisement was published on the following dates: October 28, 1994

; that the cost of publishing said annexed advertisement as aforesaid was $38.86 ; that such newspaper in which such legal advertisement was published has been and is now published regularly, at least as frequently as once a week for at least fifty weeks during the calendar year as prescribed by its mailing permit, and has been so published in the municipality of Huntington, Cabell County, West Virginia, for at least one year immediately preceding the date on which the legal advertisement set forth herein was delivered to such newspaper for publication; that such newspaper is a newspaper of "general circulation" as defined in Article 3, Chapter 59, of the West Virginia Code, within the publication area or areas of the municipality of Huntington, Cabell and Wayne Counties, West Virginia, and ;

that such newspaper is circulated to the general public at a definite price or consideration; that such newspaper on each date published consists of not less than four pages without a cover; and that it is a newspaper to which the general public resorts for passing events of a political, religious, commercial and social nature, and for current happenings, announcements, miscellaneous reading matters, advertisements and other notices.

Connie Rappold

Taken, subscribed and sworn to before me in my said county this 28th day of October, 19 94

My commission expires 10-24-00

Ellen Kinsey

Notary Public
Cabell County,
West Virginia

OFFICIAL SEAL
NOTARY PUBLIC
STATE OF WEST VIRGINIA
ELLEN KINSEY
Herald Dispatch P.O. Box 2017
HUNTINGTON, WV 25720
MY COMMISSION EXPIRES OCT. 24, 2000

10M Form A-135 (867H)

SPEAKER'S LIST FOR PUBLIC HEARING

November 29, 1994

NAME	COMPANY AFFILIATION	ADDRESS
Carl Beard	Retired	5440 Longview Dr. - Cross Lanes -
Dave Flannery	Robinson & McElwee	Char. WV
David White		1801 Beechwood Dr S. Chas. WV 25303
Larry Myers	Monongahela Power	Fairmont, [illegible]
Wendy Radcliff	Environmental Advocate	10 McJunkin Road Nitro WV 25143
A.W. HADDER	VA. POWER	5000 DOMINION BLVD. GLEN ALLEN, VA. 23060

PUBLIC HEARING

November 29, 1994

NAME	COMPANY AFFILIATION	ADDRESS
Carl Beard	Retired	5440 Longview Dr, Cross Lanes.
David Long	American Electric Power Svc. Corp	1 Riverside Plaza, Columbus, OH 43215
C J Banner	APPALACHIAN POWER	ROANOKE, VA
A.W. HADDER	VA. POWER	RICHMOND, VA.
E.J. Robinson	Appalachian Power Co	Roanoke, VA
Wendy Radcliff	WV DEP	Nitro, WV
David Barnhart	Elkem Metals Co.	Alloy, WV
Christy Sims	Supreme Reporting	Chas, WV
Talmadge Hager	Elkem Metals Co	Alloy, WV
Jeff McKinney	Elkem	Pgh, PA
Bob Peters	FMC	So. Chas

PUBLIC HEARING

November 29, 1994

NAME	COMPANY AFFILIATION	ADDRESS
[illegible]	FMC	So Chas.
Ken [illegible]	FMC	S. Chas.
K. Beckett	Robinson & McElwee	Chas
D Flannery	"	"
B. Sweitzer	VIRGINIA POWER	MT. STORM
John Fey	Union Carbide Corp	So. Chas.
Ken Ward Jr.	Charleston Gazette	Chas.
K Schmidt	Robinson & McElwee	Charleston
Alan Zik	WCHS	1111 VIRST E Charleston

REGISTER

Date	Name	Address	Company Affiliation
11-22	Carl Beard	Charleston	Retired

PUBLIC HEARING

WEST VIRGINIA DIVISION OF ENVIRONMENTAL PROTECTION

OFFICE OF AIR QUALITY

* *

The following is a transcript of a public hearing held at the West Virginia Division of Environmental Protection, Office of Air Quality, 1558 Washington Street, Charleston, Kanawha County, West Virginia, on November 29, 1994, at 9:00 a.m., and taken by Christy L. Morris, Certified Court Reporter and Notary Public, pursuant to notice.

* *

PROCEEDINGS

MS. CHANDLER: Good morning. This public hearing will now come to order on the 29th day of November, 1994, in the conference room of the West Virginia Division of Environmental Protection, Office of Air Quality, located at 1558 Washington Street, East, Charleston, West Virginia, 25311.

The purpose of this public hearing is to hear discussions on the proposed revisions to legislative rule 45CSR2 -- "To Prevent And Control Particulate Air Pollution From Combustion Of Fuel In Indirect Heat Exchangers." This was filed in the Secretary of State's Office on October 21, 1994, and noticed in the State register on October 28, 1994.

In addition, this hearing was noticed in Class I legal advertisements throughout the State and various individuals and organizations.

This public hearing is being held pursuant to the provisions of 29A of the West Virginia Code and Section 110 of the Clean Air Act.

By way of introduction, my name is Jeanne Chandler. I am with the Public Information Office of the West Virginia Division of Environmental Protection. I will be the moderator for these proceedings this morning.

The 1994 changes in the administrative

procedures prohibit ex parte communication with the rule-making agency once the comment period has closed. It has prompted this agency to accept written comments at the close of today's hearing and no later.

This fact was noticed in the public announcement. The next opportunity to enter comments will be when the legislative rule-making review committee begins its hearing on the proposed revisions.

Oral comments will be taken as part of the record and written comments may be submitted at the end of the hearing. For those of you wishing to make formal oral comments, a sign-up sheet was provided at the front desk and if you haven't signed up at this time, please do so.

I will remind you again that the comment period will end at the close of today's hearing. It is right up here, now, if you need to sign up.

Also, if anyone needs copies of the revisions to the regulations, too, they are also available here for you to take.

The court reporter today is Ms. Christy Morris of Superior Court Reporting. Her address is 3719 Virginia Avenue, Charleston, West Virginia 25304. If anyone desires a transcript of today's hearing, please contact Ms. Morris at 925-2244.

45CSR2

TO PREVENT AND CONTROL AIR POLLUTION FROM
COMBUSTION OF FUEL IN INDIRECT HEAT EXCHANGES

STATEMENT OF CIRCUMSTANCES

The revisions proposed to 45CSR2 were initiated by a petition filed with the West Virginia Division of Environmental Protection on June 3, 1994, on behalf of the West Virginia Manufacturers Association and specific members of that organization.

The revisions proposed to 45CSR2 were developed by the staff of the West Virginia Division of Environmental Protection's Office of Air Quality as compromise provisions for public hearing or otherwise incidentally made to reflect enacted changes to the West Virginia Code.

The proposed rule consolidates previous rule 45CSR2 and a separate rule, 45CSR2A -- "Compliance Test Procedures for Regulation 2 -- 'To Prevent And Control Particulate Air Pollution From Combustion Of Fuel In Indirect Heat Exchangers'".

Upon authorization of this proposed rule, 45CSR2A will be repealed with the substance of 45CSR2A becoming an appendix of 45CSR2.

45CSR2

TO PREVENT AND CONTROL PARTICULATE AIR POLLUTION FROM COMBUSTION OF FUEL IN INDIRECT HEAT EXCHANGERS

SUMMARY

The purpose of 45CSR2, which became effective on September 1, 1974, is to establish particulate matter weight emission standards and visible emission standards for fuel burning units operated in West Virginia.

45CSR2 is a part of the West Virginia State Implementation Plan approved by the USEPA to assure attainment and maintenance of attainment with the National Ambient Air Quality Standards for particulate matter. The proposed revisions to 45CSR2 are for the following purposes:

1. To relax the visible emission standards applicable to fuel burning units (including steam generating units and other indirect heat exchangers) to a level essentially the same as those established nationally by USEPA for new or modified fuel burning units and to revise the provisions for visible emissions standards except in periods related to soot blowing, boiler start-ups and shut-downs;

2. To modify the authority, terminology, and West Virginia Code citations in the rule to conform to revisions enacted by the Legislature in 1994;

3. To update or modernize certain

definitions and delete rule provisions no longer applicable;

4. To combine 45CSR2 with the separate rule 45CSR2A, which establishes test procedures which must be employed to determine compliance with the weight emission limitations of 45CSR2 and to incorporate by reference USEPA's test method for determining visible emissions from a fuel burning unit; and

5. To replace the variance provisions of the rule with criteria for reporting, establishing, and remediating equipment malfunctions.

If the proposed rule revisions, in total or in part, are adopted by the DEP and authorized by the Legislature, the revised rule will be submitted to USEPA with a request to incorporate these revisions into the West Virginia State Implementation Plan for the federal Clean Air Act.

Mr. Farley would you like to make comments on this?

MR. FARLEY: Thank you. Ms. Chandler has outlined the nature of the proposed changes I think fairly well. I would like to make some brief comments here though, very cursory comments on the history of this rule and the petition and our response to the petition received in West Virginia Manufacturers Association with respect to particularly the opacity standards of the rule.

I would also like to alert people to a couple -- several corrections that I think are needed in the draft of the rule before you make any comments.

45CSR2 -- To Prevent And Control Particulate Air Pollution From Combustion Of Fuel In Indirect Heat Exchangers, or Reg. 2 as I will further refer to it from this point on, was adopted by the Air Pollution Control Commission in 1972 as a major element of West Virginia's Implementation Plan submitted to and approved by USEPA to bring about attainment with National Ambient Air Quality Standards in West Virginia for a particulate matter, obviously.

This rule establishes a particulate matter of emission standards and related compliance demonstration provisions for fuel burning units, primarily coal, oil and wood fire boilers and similar indirect heat exchangers. Fuel burning units are substantial contributory ambient particulate matter levels in a number of areas in West Virginia and many such units have very large potential emission rates.

The primary emission standards -- primarily within this rule, that is particulate matter of mass emission standards contained in 45CSR2, have not been revised since the Reg. was first adopted in 1972. And there is no proposal to change these emission standards within the rule revisions proposed today.

45CSR2, however, also established visible emission standards in terms of Ringlmann numbers or equivalent opacity as a standard in its own right as an indirect mechanism for the termination of compliance with the mass emission standards.

I might stop here for anyone who is not familiar with opacities or the concept of what an opacity is. Just based on questions I have had over the telephone.

Opacity is literally what I said. It is a visible emission standard, wherein certified emission observers or with the use of equipment, calibrated transmissometer. You actually measure the amount of light obscured as it passes through a point containing particles.

The old Ringlmann standard, which is primarily what is referenced in the rule, has with the passage of time become antiquated. It is something that is not commonly used in any federal rule-making today. That part of the proposal here is, I believe, that is pretty consistent throughout, to delete that reference in lieu of stated opacity standard.

When 45CSR2 was first enacted, and currently, this rule established one of the most stringent visible emission standards for fuel burning units (originally coal and oil-fired blowers) in the country.

Regulated industries, in particular, electric utilities in West Virginia have objected to 45CSR2 visible emission standards since the early 1970s. And previously petitioned the rule divisions and it raised numerous technical and economic arguments in support of its petition to change the rule, which was filed formally with the West Virginia DEP on June 3, 1994.

Since 45CSR2 has been in effect for more than 20 years and contains visible emission standards which have met provided by OAQ, the agency with relatively high competence of mass particulate emission standards, emission control effectiveness, OAQ has been and continues to have substantial reservations concerning relaxation in the existing visible emission standards.

A number of factors have led the OAQ to at least propose and solicit public and USEPA comment on proposed compromise changes to the existing rule and its opacity standards including the following factors:

There is a substantial amount of information available that is significantly high visible emissions, higher than the 10% opacity standards can be experienced by coal-fired boilers, even when compliance with the mass emission standards of 45CSR2 is being demonstrated.

The industries arguments concerning the relationships of stack diameter or light path length through plums has some technical merit with respect to the variability opacity even at identical particle loadings within a plume.

The current 10% opacity limit markedly contrasts, which is the basis of the petition, with the typical 20% average opacity limits of surrounding regional states, as well as the opacity limits established by USEPA for new units meeting more stringent particulate emission standard.

And as a last item there, based on evaluation this year continuous opacity monitoring data from utilities as well as a fairly lengthy prior history for some units, visible emission observations at a number of facilities, both utility and industrial. It is apparent that continuous compliance with the current VE limit of 10% opacity has not been achieved and it is probably not achievable on a continuous basis without major renovations and replacement of particulate matter of coal equipment.

Industry and utility estimates for the cost of these replacements and retrofits run at a hundreds of millions of dollars as per the petition which incurred in 1994.

Just as a lay of brief history, this matter first approached with the Office of Air Quality at the end of April -- I believe on April 26th, in a transmission from

Robinson and McElwee. And at that time, the focus of the proposed changes as you read the draft in the file, if you wish to do that, were targeted to utility plants.

There was not much modifications proposed to the rule as would reflect so-called type B and type C units, which are industrial, pulverized coal. Primarily what we are talking about is industrial pulverized coal and oil-fired units including stokers for the C category.

On June 3, the West Virginia Manufacturers and a number of its member companies as identified on the petition, formally filed a petition with the DEP for numerous changes to Regulation 2. After a number of discussions and redrafts, the current proposal was developed for consideration by the comment.

I might note that a number -- just a number of the provisions that kind of stand out as far as what was accepted or changed or proposed for change and some items that were proposed by the industry which were rejected.

First, as far as what is being changed, other than some of the things mentioned by Ms. Chandler with respect to the restructuring as a result of the DEP changes and so forth, we made the soot blowing provisions. The proposal now has soot blowing provisions which are not, as far as exertions or exceptions to the general newly proposed opacity standards, which are not automatic. A company would have to have case-by-case approval for this.

The major controversial change, I think, is actually relaxing the opacity standard from a 10% standard, which by interpretation as I understand it, is a non-average standard to a 20% 6-minute average standard with some allowances. I think a 6-minute period per hour, plus 27% opacity, which is in line with the federal resource performance standard for utility and other steam generators.

We have also proposed to adopt here the federal provisions related to start-up, shut-down and malfunctions with respect to the applicability or non-applicability of the DE standards for those periods and delete existing multi-tier -- I think there is two or three places in the rule, as the current rule, that deals with exception periods or potential exception periods for start-ups of the unit. I don't think the rule currently deals with shut-downs, per say.

We are establishing which was never done previously by reference, not incorporation by reference, a method for the determination of compliance with the opacity standards and that is incorporated by reference Method 9 of 40CSR60, which is the 6-minute average opacity approach.

Some of the things that were rejected and I expect will be a matter from the industry perspective comments today are inclusion of provisions for so-called equivalent opacity determinations. That is a mechanism that is allowed under federal rules wherein a regulated facility can demonstrate compliance of the mass standard and associate an opacity standard with that performance during those periods and get a source specific approval for a visible emission standard even higher than those currently proposed with the revision. That was rejected.

The Office of Air Quality believes that the relaxations that are already proposed here are substantial and that that is sort of a mechanism within the rule that is unacceptable.

Another controversial area was the provision for -- I will call it 95% compliance -- when a facility installs and uses continuous opacity monitoring equipment in lieu of periodic VE observations by an observer. I think the proposal that was put forward by the Manufacturers Association stems from policies reportedly adopted in Virginia and maybe by USEPA for compliance determination or for enforcement purposes and we do not believe it has any place in the rule per say.

In the initial proposal that was submitted on April 26th, I believe that was an actual proposal to relax the mass emission standard for utility plants from .05 to .1 pounds per MBtu and that was rejected for obvious reasons. We don't feel that is supportable and we feel that would be a nightmare for the State in going back and forth to complete state-wide attainment demonstration.

A couple things that I would just like to flag prior to anyone making comments. A couple of these notes are fairly vague at this point, but I am sure that we can elaborate more on this more when we respond to comments. Just structurally, the way the rule was rewritten with some deletions of tables and so forth, a paragraph in there, I didn't think we called it paragraph or subparagraph, 4.1.(a)(3) referenced a table for mass emission standard computation for type C stoker units.

It is obvious that the language in the table is somewhat disconnected and those need to be -- the table needs to be moved to the actual text or the table needs to be better referenced in the text and renumbered the best -- prior tables have been deleted to -- probably referenced to 45-2-A. If you look at the rule, it is pretty evident that that is not very well constructed.

One of the things that we stated we were going to do with the provisions for malfunctions was to delete the variants provisions of the Reg. The rule as it was filed did not have strike-throughs through for section 10, although there had been renumbering and you should take note that there should be strike-throughs what had been the old section ten, Variance, that should be deleted.

Just as a matter of consistency in subsection 6.2, the referenced date there within that text should apparently be September 1, 1974, rather than October 1, 1974, for consistency with subsection 6.1 and 7.1.

Then in a very vague comment, I will note that subsection 8.4, the second sentence needs some rewrite. I don't think it captures quite the thought that was needed there in terms of the event.

Just as a matter of note, prior to today, to my knowledge we have received only one set of written comments and those were received yesterday from the Ohio Valley Environmental Coalition. That will be made part of the record.

MS. CHANDLER: Thank you, Mr. Farley. The floor is now opened for other comments. We ask that you do state your names for Ms. Morris' benefit. So, we will start with the speakers list. Mr. Beard.

MR. BEARD: Pardon my voice. I have wondered a lot why I am here but for the record my name is Carl G. Beard, II. I am now retired. I was formerly the director of the Air Pollution Control Commission from September of '62 until January of '89.

Needless to say, I wouldn't be here if I wasn't opposed to these proposed changes to the Regs. that did and does work.

Now, let me point out something for the record, that is not in my prepared remarks. I have consulted with nobody about my testimony. I have not talked to Mr. Farley. The only people I have asked in this agency was concerning air quality and the ability to retrieve some of the old Regs. and bring myself up-to-date, or try as best I can, to compare the old Regs. to this new proposed regulation amendments so I can make some sense.

I will be the first to say that I have not had the opportunity to go through all of this. That is to say without qualification, I am opposed to the proposed regulation, proposed to a Reg. that does work.

Some of the things that Mr. Farley didn't talk about is air quality in West Virginia. The old TSP standard and the relatively new PM10 standard are being met in all of the state. That wasn't true in 1962 when I first came here. This place was filthy. I don't mean dirty; I mean filthy.

The Kanawha Valley by measurement was one of the dirtiest particulate areas in the nation. That is a big statement. It is even dirtier than the northern panhandle. The records of this agency will substantiate that, the old TSP measurements. And yet, when we started the agency with a director, a secretary and a $20,000 budget, and a five-member commission, that is the way things sort of stuck around until the mid-60s when we got our first grant.

How was Reg. 2 originally developed? There was a three-year air pollution study of the Kanawha Valley by the APCC and the United State Public Health Service. Extensive measurements were made. Part of that was a technical committee who studied each regulation that was developed. It consisted of Page Seekford, who was a Kanawha-Charleston health director; and Jean Scheuman, Public Health Service, deceased, so is Seekford; Leonard Nelson was president of West Virginia Tech; A.C. Hyde of Dupont-Belle plant; Ben Linsky, WVU. He taught air pollution. He is now deceased.

The man most responsible for the technical information on fuel combustion was James Duff, he was combustion engineer for this agency. Jim knew his stuff. He had 20 years experience in power plant operation with Union Carbide in South Charleston. Before that he was manager of an electric utility plant in Illinois.

I am sorry to say I can't remember the company name but his demonstration of professional knowledge to the Public Health Service and successor in EPA led to the recognition that was often called on for advice by other states PHS and EPA in areas far removed from West Virginia. I never met an engineer as knowledgeable as Duff about fuel combustion and air pollution control anywhere.

After the regulation was adopted, it was amended in the early 70s and made part of the State Implementation Plan.

As I noted to you, air quality in West Virginia from a particulate standpoint is now reasonably clean. But the things that Mr. Farley didn't mention to you, maybe he don't know, one common theme, as he noted, standards no more effective than USEPA. Why are the Feds so perfect? They have piddled around with visibility losses for over 20 years. And as far as I know, they haven't done anything.

Let's examine a couple of things. One, West Virginia has more periods of air stagnation than any other state east of the Rocky mountains. Remember that. The air is stagnant. They have very restrictive ventilation in its valleys and temperature inversions are common.

Here you have a tough air pollution problem to solve. As far as I know, we have more electric coal-fired generation in West Virginia than in any other state. That is fine in terms of coal produces and things to clean electric power, it sends it places elsewhere.

There was one report at one time that John Amos with its 2900 megawatts could supply the electric energy for every house in the state. I don't know whether that is true or not but it is daggone close. It is a huge plant located in Poca.

Two, EPA must adopt emission standards for all of the country. Therefore, EPA regulations are usually a compromise.

A few years ago, I was asked by the EPA to be a member of their national air pollution control technique advisory committee. This group is small. It is made up of environmentalists, industry, universities, local and state air pollution control commissions -- officials and it changes.

I just remember in passing that Don Tinnatem of MonPower was a member of this group after I left. How does the process work? I was inside and I watched it. This is an active group. We were in a position and we examined witnesses on proposed EPA regulations. Those proposed Regs. were developed by EPA who usually are assisted by EPA contractors.

As I noted, I was on the committee for four years. I was originally invited for three and they extended it for another year because they must have like what I did. I don't know. I complained enough about them.

Just because EPA adopts a standard, that doesn't make it necessary for what West Virginia should do. West Virginia should solve its own problems. It has solved its own problems on particulate matter. It is done. It is over. Why change what works?

A few years ago, USEPA, RTP and Region III joined together with Pennsylvania DER against West Virginia and Eastern Ohio. Pennsylvania was unable to attain or meet the Ambient Air Quality TSP standards in Western Pennsylvania. They claimed that the sulphur dioxide emissions from the Kammer and Mitchell plants of AEP and Weirton Steel plants were converted to sulphates; therefore, preventing were being transferred into Pennsylvania and preventing TSP attainment.

In a hearing in Washington, I testified along with some members of the staff and we clearly demonstrated that while sulphates are a problem, they did not interfere with the attainment of the particulate standards in the Kanawha Valley and the rest of West Virginia. Why? We had a good particulate regulation for combustion and the regulations were enforced.

The proof of the pudding is long history -- is the continued improvement of West Virginia's air quality. The irony is that while complaining about the sulfate problems in West Virginia -- in Western Pennsylvania, the director of Pennsylvania's state air control agency stated publicly that he didn't think it was necessary to have regulations more restrictive than USEPA's NSPS standards to achieve air quality standards -- ambient air quality standards in Pennsylvania.

When we completed our testimony in Washington, that was the last that I ever heard of Pennsylvania's complaint. They may have filed something in the last six years.

One of the complainants I understand in this petition is Virginia Power or West Virginia Power. The Mount Storm Plant of this company was constructed before the APCC had a regulation or legal authority to require construction permits. As a result, the fly ash control equipment on this new plant was grossly undersized. Whose fault it was? I don't know.

The plant was retrofitted with new fly ash control equipment that operated with no visible emissions. I submitted photographs of this to the United States Senate Public Works Committee when I testified several years ago about this marvelous achievement. How that coal can be used in a clean, not dirty way.

Let's get to the heart of these proposed changes. They would double, as Mr. Farley has stated, the visible emission limits. Why? There is no reason why. Something the Feds do is not all that great.

The particle size of these very fine emissions would probably be of the inhaleable size. The size that you and I and our children would breathe and we will probably be contaminated with sulfates. It is not good for you.

They will contribute these very fine particulates to increase loss of visibility in all of West Virginia but particularly in rural areas.

Since electric utility companies started building huge power plants, with tall stacks, visibility has markedly decreased in rural areas in this state, Virginia, North Carolina. I don't know about Pennsylvania because I haven't been up there. This major emission relaxation can only contribute to that problem.

I am troubled particularly -- and Dale, I don't know if I have the right versions of this thing, on page 9, section 4.2, 3 and etc. If this is a correct draft, 4.4 says the director may approve an alternative particulate matter weight emission standard not to exceed the product of .1, not .05 and the design heat instrument of the fuel burning unit on demonstration by the owner or operator of a whole list of things.

Now, it says he can do that without public notice, without a public hearing and he doesn't even have to get in touch or coordinate with the chief of air quality. This is tremendous power. If that is intended to be incorporated as changes, you might as well throw the regulation down the drain.

You know and I know and I am not speaking to Mr. Farley, I am speaking to every person in this room, in time those affected will come up with their very good smooth, arguments, Mr. Flannery will be glad to help you or some other law firm, accompanied by their appropriate consultants to remodeling experts, to convince anybody, my goodness alive, we should let them do it. This will double emissions. Amos is a huge plant.

On the matter of the addition of sulphur oxides to control to assist in the efficiency of precipitators, I suppose. If I recall correctly, Amos can already discharge 45 pounds per hour of sulphur dioxide today legally under Reg. 10 or whatever the current name is. They just want to add more fuel to the fire.

I don't know what Mr. Callaghan of the DEP, Director, would do regarding any petition. He apparently has allowed this monstrosity to have a hearing on but I can find nothing that is in the public interest. I can find an awful lot that is anti-public interest.

I didn't go through this thing with detail but on everything, every change that is being made it is more permissive -- it favors the polluter. The people will suffer. The polluter will prosper. That is what this means when you get down to the guts of it. As the old saying goes -- you have a good regulation. It has been proven --

regulations, I should say. The old saying goes "If it ain't broke, don't fix it." Why in the world do you even honor these people with a hearing?

MS. CHANDLER: Mr. Flannery.

MR. FLANNERY: I would be amiss if I didn't say that is a hard act to follow. My name is Dave Flannery. I am with the Charleston law firm of Robinson & McElwee and my partner, Kathy Beckett, and I appear today on behalf of the Manufacturers Association and a number of its members, along with four electric utilities that probably led this initiative in the early days; in particular, Appalachian Power, Ohio Power of the AEP System, Monongahela Power of the Allegheny Power System and Virginia Electric and Power. The comments are filed in addition on behalf of Elkem Metals, FMC Corporation, and Union Carbide.

This issue was first raised with Director Farley, I think it fair to say, on behalf of the electric utilities back in April. And it really wasn't until a month or so later that there was simply casual dialogue with the industrial sources and we realize that they, too, had the same level of concern about the issue that the utilities did. I simply offer that as a way of explanation for Chief Farley's comment that it was initially raised as a utility issue and only later expanded to include the industrials.

I have provided for the benefit of the record this morning a letter dated November 29th that contains the comments of these commentors. I will not go through that letter in detail. I would, however, like to put the letter in some perspective with my own slant on why it is that it is necessary to bring this issue on for hearing today and to underscore several of the points that are raised in the letter as a means of calling that for emphasis in the record.

First, this regulation -- it is true, it has been in effect for better than 20 years. Throughout much of that time, the regulated community has been explaining to the agency that this limitation was an unreasonable limitation that it couldn't be met.

This is not the first time there has been a hearing on this issue. It is not the first time that I have appeared before the Air Pollution Regulatory Authority of this State to comment on this particular regulation.

Indeed, my recollection is the last time I appeared on this issue was in 1977. At which point, I was ruled out of order but was promised in the course of that that the commission, at that time, would consider this issue and evaluate it and consider the stringency issues that have been pending over those years.

It is a fact, I believe, as Chief Farley says, that companies that have been subject to this regulation, have, in fact, not been able to comply with it loath the 20 years that it has been in existence.

Indeed, it is, I believe, the fact that nobody has, yet, forced these companies to comply with, this regulation. It has not been an enforcement initiative for the simple reason that there isn't a ready solution to it, I believe.

It is -- the passage of the 1990 Clean Air Act amendments and the requirements that are established under that Act, these companies must certify compliance with the soot requirement, with all of the soot requirements and this is certainly one that puts renewed emphasis on the need to address this issue.

And it is for that reason that the regulating community has approached the DEP and has said we really need to deal with this rule. We can't go on any longer in a situation where we are obligated to operate these facilities in the public interest. And on the other hand, having a regulation out there that nobody expects us to comply with and, indeed, frankly is impossible to comply with absent tearing down and starting all over again in many cases.

We are not talking about a real relaxation of this regulation. I think you can fairly characterize the proposal which the regulating community brings to the table today as a proposal to adjust the regulation to reflect what amounts to current performance of these facilities.

There is no proposal to change a mass emission requirement that is in this rule. For type A fuel burning units, the mass emission requirement of .05 continues to remain in effect. That is one-half the federal requirement. It is that regulation much to the credit of Mr. Beard that resulted in the clean-up of the Kanawha Valley and the northern panhandle and much of the State.

There were literally in excess of a billion dollars spent in the 1970s to install new precipitators on power plants, in particular, in order to meet the requirement of the .05 pound limit. And nothing that is at issue with these proposals in this hearing today is going to change that.

I do not believe there is basis for concern that if this change were adopted there would be an increase in emission or any threat of increased impact on ambient air quality or any threat of increased impact on public health or the environment.

There are many additional basis that are stated in the petition which -- the petition was filed with the DEP on June 3. As you will note from our letter and comments today, we have asked the entire petition to be incorporated into the record so that we are not obligated to have to repeat all that information today.

We strongly support the base change that is being proposed in this rule and that is to increase the 10% opacity requirement to a 20% opacity requirement, using language that is virtually identical to the change as it appears in federal regulation.

The question about whether we should care about the federal rules and whether they bind us in some way has already been an issue that has been resolved as a public policy matter in West Virginia. Our Legislature has historically spoken to that issue and mostly recently did so when it passed the DEP reorganization bill earlier this year.

And you will recall that that statute now provides that if this regulation is to be more stringent, there has to be a specific written reasons for that identifying what is reasonably necessary in order to protect the health of West Virginians taking into account scientific evidence and specific environmental characteristics of West Virginia.

And where there is a technical requirement that is involved there has to be a specific technical basis that is provided to explain why the director would do something more stringent from the federal requirement. We submit to you that there is no technical basis to support anything being different and believe that a change to a 20%

opacity requirement is entirely consistent with that.

We bring to your attention in the comments today three other areas where we believe the current proposal is more stringent than the federal requirement.

First, section 3.1 of the proposal does not contain a requirement and should contain a requirement that would exempt wet FGD units, flue-gas desulfurization, units from the applicability of the 20% opacity requirements. Those plumes, because they have water vapor in them related to the scrubber, have 100% opacity virtually the entire time and are currently exempted from the federal 20% opacity requirement.

There is also, in section 8.4, a provision which is more stringent than federal requirement in that it requires monthly reporting of start-up, shut-down notifications rather than quarterly.

There is also, under the federal requirement and it is addressed in section 9.1 of this proposal, a provision that says that during times of start-up, shut-down and malfunction one is exempted from both opacity requirements and mass emission requirements. 9.1 would extend that variance only with respect to mass emission.

We believe all three of those should be addressed and conform to the federal requirement if we are to satisfy the statutory mandate on our State program being consistent with the federal.

I also would note that with respect to the point that Chief Farley made about opposing our request that 95% compliance be established as the standard for your using continuous emission monitor data, that we are agreeable to that regulation -- that provision not being included in the rule.

But as you will see from our comments, we urge that that be included as an enforcement policy of the agency which is the mechanism that is in effect and utilized in Virginia.

We think that is a fair and reasonable approach to that and we suggested language in our comment that will establish that. We believe that has been accepted by EPA and should be found appropriate for everyone's purposes.

Section 4.4 was commented on by both Chief Farley and Mr. Beard and let me make a couple of comments about that. It, on its face, is a provision that sets up a mechanism whereby a company might petition the chief or the director I should say -- it would be Director Callaghan in that case -- to change the mass emission rate from .05 to .1.

As you will note in that section, it has some extremely significant hurdles in it. And the bottom line of which is that whatever is done there would have to be incorporated into a consent order and that consent order would have to be submitted to EPA and approved as consent orders normally are.

That, of course, has public comment, public hearing processes involved in it. It is certainly no one's intention that such a change as that would be run through without the full participation of the public in that process, so we wanted to underscore that.

We believe, however, that there is an opportunity in that division to allow it to be applied not only to the mass emission requirement which it currently is directed as but also to the opacity requirements that are in the rule. We recognize that Chief Farley really doesn't like that at all and that may well be an understatement but such a provision does exist in the federal program. It exists in the federal program with different words that are contained in Section 4.4 but we have a belief that if 4.4 is a good enough mechanism to deal with that rare case and we frankly know of none now that would be appropriate subject for that but if we ever get one of those cases. And 4.4 is appropriate to deal with the mass emission change, we certainly think it would be an appropriate mechanism to also to deal with opacity. There should be something in the rule to deal with that opacity change.

I would note that our comments contained a remark with respect to Section 10, dealing with variances. Chief Farley indicated in his opening comments this morning that that entire section should be deemed to have been deleted. I haven't fully assessed the implication of that comment, yet, but will be doing that after the hearing today and if there is any revision that is to be made to our comments in light of that announcement this morning, we will file a document with the agency before the close of business today to be within the comment period.

We considered this change to be a carefully measured moderate approach to deal with what we considered to be a critically acute issue that is definitely in need of fixing. We have a situation out there now where much of the regulated community is operating under a regulation that it simply can't comply with and this agency has known that for 20 years.

We need to address that Clean Air Act mandates of 1990 if nothing else forces us to do it. And while on its face, we are talking about doubly the numbers for opacity the fact that we are not changing the mass emission rate effectively means that there is going to be little or no increase in actual emission from any of these claims.

We thank you for an opportunity to comment.

MS. CHANDLER: Thank you, Mr. Flannery. Mr. White.

MR. WHITE: Thank you, Ms. Chandler, for the opportunity to comment on the proposed revisions to this regulation. My name is David White. I am a resident of South Charleston, West Virginia. I am here under my capacity as a resident of the State of West Virginia.

I would like to begin by clarifying a couple of issues that were addressed by the previous speakers. First, I would like to point out that in the existing regulation both the opacity standard and the mass emission standard are separate limitations and separate requirements.

The opacity standard is not merely as a surrogate for indicating compliance of the mass emission standard. There is no language specifically indicating that and there is good reason to separate those and fully enforce both provisions, not merely one as a surrogate to the other and I will address some of those issues in my prepared comments.

Secondly, I would like to point out that contrary to what Mr. Beard had indicated we are not meeting all standards in the State of West Virginia. We, currently in the State of West Virginia, exceed the National Ambient Air Quality Standard of 150 micrograms per cubit meter for PM10 or particulate matter of sub-10 microcron diameter in areas of the northern panhandle.

And since October of 1993, there has in fact been 9 separate exceedences of that 150 microgram per cubit meter standard rising as high as 278 micrograms per cubit meter on October 26th.

Having made those points, I would like to now turn to my prepared comments and these comments are addressed to Mr. David Callaghan, as Commission of the West Virginia Bureau of Environment and Director of the West Virginia Environment Protection, and Mr. G. Dale Farley, as Chief of West Virginia Office of Air Quality.

Messrs. Callaghan and Farley: Please accept the following comments regarding the filing of a revised Regulation 2 to the Office of the Secretary of State and the Legislative Rule-Making Review Committee as an agency-approved rule.

Initially, and this follows the comments previously made by Mr. Beard, the rationale for the approval documented by Mr. Callaghan in correspondence dated October 11, 1994, to the West Virginia Secretary of State of relaxing existing visible emission standards for fuel burning units is unclear.

The statement of circumstances prepared in that document does little to clarify the reason for recommending the adoption of language relaxing visible emission standards. It references the development by staff of the West Virginia Office of Air Quality of "compromise provisions" for public hearing. But with existing health based National Ambient Air Quality Standards already being compromised, further degradation of air quality is not warranted. Yet, both Mr. Callaghan and Mr. Farley have signed off on just such a recommendation.

The rationale and motive for the proposed changes submitted by Mr. David Flannery as representative for the Appalachian Power Company, the Monongahela Power Company, the Ohio Power Company, the Virginia Electric and Power Company, the Elkem Metals Company, the FMC Corporation, the Monsanto Chemical Company, the Union Carbide Corporation and the West Virginia Manufacturers Association are more readily apparent. Compliance with existing regulatory requirements would cost money.

At least thirteen separate Notices of Violations have been issued to those petitioners for violations of Reg. 2, and many more could have been and perhaps should have been issued. This is explicitly acknowledged by the petitioners when they state in their petition on June 3, 1994, to Mr. Callaghan that, "The opacity provision has remained largely unenforced by West Virginia."

The West Virginia Code mandates that if the director of Division of Environmental Protection is of the opinion that a person is violating the provisions of the Code or any regulations promulgated thereunder, "... he or she shall make and enter an order directing such person to cease and desist such activity." Chapter 22, Article 5, Section 5 of the Code.

Instead of fulfilling that nondiscretionary duty imposed by the Code, Mr. Callaghan has, perhaps at the recommendation of his staff in the Office of Air Quality, chosen to approve relaxation of existing standards. These actions serve neither as an effective means of achieving compliance with existing regulatory standards nor do they protect the health and welfare of the people of the State of West Virginia.

With areas within the State of West Virginia currently unable to comply with the existing National Ambient Air Quality Standard for particulate matter, it is inappropriate to be relaxing existing emission limits and allowing greater particulate matter emissions.

Particulate matter smaller in diameter than ten microns will often be limited more by an opacity limit than by a mass emission standard. The physical properties of sub ten micron particulate matter can display a disproportionately high effect on light diffraction, as compared to particulate matter of greater diameter.

These smaller diameter particles can have a greater impact on opacity than they would have on a mass emission standard. Therefore, the opacity standard may serve as a more effective limiting factor for the emission of particulate matter less than ten microns in diameter.

This is important because if this size of particulate matter below ten micros in diameter deposes the greatest health threat to the citizens of West Virginia and those downwind of facilities within our borders. This sub ten micron range is significantly more respirable and therefore potentially more harmful if inhaled.

Contrary to the contention of the petition submitted by Mr. Flannery to Mr. Callaghan on June 3, 1994, and again reiterated in his comments, any relaxation of opacity standards can only lead to increased emissions of particulate matter. This will serve to further exacerbate a situation in which air quality monitoring by the State of West Virginia has found unhealthful levels of particulate matter on nine separate occasions since October of 1993.

If current national standards are not being met, no relaxation of existing emission limits should be permitted. The National Ambient Air Quality Standards as promulgated by the United States Environmental Protection Agency are intended as a minimum baseline which all states are required by law to attain. The State of West Virginia is permitted by the federal Clean Air Act to impose even stricter standards to protect human health and environmental well being. However, even those minimum standards are not being met.

For the above enumerated reasons, I urge that any attempt to relax or weaken existing opacity standards, soot blowing limitations or enforcement capability embodied in the existing provisions of Regulation 2 be rejected in total and the proposed revisions be returned to the staff of the Office of Air Quality for revision appropriate to the duties and requirements imposed by the West Virginia Code. Thank you.

MS. CHANDLER: Thank you, Mr. White. Mr. Myers.

MR. MYERS: Good morning. My name is Larry Myers and I am the Director of Environmental Services for the Allegheny Power System. I am here this morning representing Monongahela Power Company, the Potomac Edison Company and West Penn Power Company.

We appreciate the opportunity to comment on the Office of Air Quality's proposed amendments to Regulation 45CSR2.

MonPower operates six power plants in West Virginia with a total generating capacity of 4949 megawatts, which are subject to this opacity regulation.

My oral comments this morning are an

abbreviated version of the written and more detailed comments being submitted by APS. APS' comments are also consistent with those being offered by Mr. Flannery of Robinson & McElwee on behalf of the West Virginia electric utilities and other industries.

APS fully supports the revision to existing Regulation 45CSR2 which proposes to increase the visibility emission limit from 10 to 20% opacity. Continuous compliance with the existing 10% opacity limit is not practical to achieve without the installation of additional costly particulate collection equipment.

While APS has previously objected to the severe stringency of the 10% opacity limit, it was recent changes to the opacity recordkeeping and reporting requirements developed by the EPA which has heightened the importance to revise the regulation.

It is important to note that the proposed revision to the regulation's opacity limit will not result in any increase of particulate emissions from the power stations. Our power stations are and will continue to be in compliance with the weight emission standards of .05 pounds per MBtu. Therefore, the proposed revision will not adversely affect the environment or health of West Virginia citizens.

I would also like to note that the proposed revision is consistent with that of West Virginia's neighboring states of Maryland, Pennsylvania, Virginia and Ohio which require a 20% opacity limit and EPA's federal New Source Performance Standards.

The proposed revision simply acknowledges the reality of present conditions and allows the state's power stations to operate in compliance with the regulation. Without these proposed revisions, additional particulate control equipment would have to be installed on our power stations at an additional estimated cost of $236,000,000 which would ultimately be passed on to our customers.

Two additional comments I would like to emphasize are on particular sections of the proposed regulation. First, in Section 3.1, a provision should be included which exempts units utilizing wet flue-gas desulfurization or (FGD) equipment from the 20% opacity limit. Due to the water vapor in the flue gas, it is not possible for these units to operate in compliance with the opacity limit. In fact, the EPA recognizes the unique operational circumstance of wet FGD units and exempts them from opacity monitoring requirements.

A related complication of opacity measurement on wet FGD units is the formation of secondary pollutants such as nitrates or sulfates which can actually occur after discharge from the stacks. Trying to measure opacity for compliance purposes after the vapor dissipates is neither an accurate assessment of the stack exit particulate emissions nor consistent with Method 9.

Second, in Section 3.2, it is recommended that West Virginia develop an enforcement policy regarding the compliance status of units which utilize continuous opacity monitors for determination of compliance with the opacity limit. The enforcement policy should require sources to be in compliance at least 95% of the operating time in order to be considered in compliance with the limit.

Again, we appreciate the opportunity to comment on the proposed amendments to the regulation and applaud the Office of Air Quality for making the much needed changes.

MS. CHANDLER: Thank you, Mr. Myers. Are there any other further oral comments? Would you please sign the register?

MS. RADCLIFF: My name is Wendy Radcliff. I am the Environmental Advocate with the Division of Environmental Protection. I do have written comments that I will submit to you before the end of the day but I do feel that I would like to express some comments that I made in the oral section also.

I would like to express a great deal of concern about the changing of the proposed Regulation 2 from a more stringent situation to perhaps a situation which would benefit some but not perhaps the public health and well-being of the citizens of West Virginia.

There were a number of statements that were made today, including one by Mr. Flannery, that stated that according to the reauthorization of the Division of Environmental Protection, there is specific line in the statute that suggests that in order to go more stringent than the EPA recommends that we have to cite specific technical information or information relative to particular area.

I believe that I would just like to reiterate some of what Mr. Beard stated in that we are in an area where the levels of stagnation as well as the number of electric coal-fired generation facilities in the State are greater than other states. As well as -- I think the point that could be well taken that many times the EPA does develop regulations on a national level having to adapt that to all 50 states.

All of us know there is certainly a different level of air quality in the State of Hawaii compared to the State of West Virginia. There is a great deal more air movement as well as situations with inversions and such. So, I do think we should keep that in mind in terms of developing this regulation that is currently in existence.

And when you think about changing that, that we should be very aware that this was a regulation that is being recommended that -- was done by the EPA that was relative to all 50 states. Whereas in West Virginia, we do have some unique qualities that I think should be addressed and have been addressed in the current regulation.

I also, you know, often when we propose regulations that are more stringent or even some that the manufacturing community doesn't agree with, often we hear about how much money it will cost companies to come into compliance. And in terms of statements that have been made today about that we haven't been able to meet constant compliance of this regulation since 1972 or '74, I heard two different dates. I have to question whether it is an inability to comply or whether it is an unwillingness to comply in terms of getting -- if this has been in the State since 1972 or '74, there should have been some movements and some upgrades to some of these facilities that could have met that.

As I stated before, I do have some written comments to submit to you, Ms. Chandler, before the end of the day but I would like to express a concern in the changing of Reg. 2. And I would like to thank Mr. Beard for coming out of retirement and speaking today. Thank you.

MS. CHANDLER: Thank you, Ms. Radcliff. Mr.

Hadder.

MR. HADDER: Good morning. I am A. W. Hadder, Manager of Air Quality for Virginia Power. I would just like to say that we do support the proposed revision to the regulation. We view this as being a very serious and necessary matter and it should be revised. We don't believe there is going to be any damage to the environment as a result of this revision.

We are particularly concerned about a new era that we are entering in as a regulated utility. We are going to see a big increase in competition over the years and we, right now, would be at a competitive disadvantage in West Virginia compared to utilities operating in other states with power standards. So, we do view this as a very serious matter and hope that the Commission will see fit to revise the regulation. Thank you.

MS. CHANDLER: Thank you Mr. Hadder. Any further comments? If there are no further comments, the hearing for 45CSR2 are now concluded.

(WHEREUPON, the hearing was concluded.)

REPORTER'S CERTIFICATE

STATE OF WEST VIRGINIA,

COUNTY OF KANAWHA, to wit:

I, Christy L. Morris, Certified Court Reporter and Notary Public duly certify and commissioned, do hereby certify that the foregoing is a true and accurate transcript of the proceedings had in the public hearing on the 29th day of November, 1994.

Given under my hand and notarial seal this 20 day of December, 1994.

Christy L. Morris - CCR
Certified Court Reporter
Notary Public

MY COMMISSION EXPIRES: 12/11/95

David White
1801 Beechwood Drive
South Charleston, WV 25303
November 29, 1994

Mr. David Callaghan
Commissioner
West Virginia Bureau of Environment
Director
West Virginia Division of Environmental Protection

Mr. G. Dale Farley
Chief
West Virginia Office of Air Quality
1558 Washington Street, East
Charleston, WV 25311-2599

Re : 45 CSR 2 - "To Prevent and Control Particulate Air Pollution from Combustion of Fuel in Indirect Heat Exchangers"

Dear Messrs. Callaghan and Farley:

Please accept the following comments regarding the filing of a revised Regulation 2 to the Office of the Secretary of State and the Legislative Rule-Making Review Committee as an agency-approved rule.

A. Initially the rationale for the approval documented by Mr. Callaghan in correspondence dated October 11, 1994 to the West Virginia Secretary of State of relaxing existing visible emission standards for fuel burning units is unclear. The statement of circumstances prepared in that document does little to clarify the reason for recommending the adoption of language relaxing visible emission standards. It references the development by staff of the West Virginia Office of Air Quality of "compromise provisions" for public hearing. But with existing health based national ambient air quality standards already being compromised, further degradation of air quality is not warranted. Yet both Mr. Callaghan and Mr. Farley have signed off on just such a recommendation.

B. The rationale and motive for the proposed changes submitted by Mr. David Flannery as representative for the Appalachian Power Company, the Monongahela Power Company, the Ohio Power Company, the Virginia Electric and Power Company, the Elkem Metals Company, the FMC Corporation, the Monsanto Chemical Company, the Union Carbide Corporation and the West Virginia Manufacturers Association are more readily apparent. Compliance with existing regulatory requirements would cost money. At least thirteen separate Notices of Violations have been issued to the petitioners for violations of Regulation 2, and many more could have been and perhaps should have been issued. This is explicitly acknowledged by the petitioners when they state in their petition of June 3, 1994 to Mr. Callaghan that, "The opacity provision has remained largely unenforced by West Virginia ..."

C. The West Virginia Code mandates that if the director of the Division of Environmental Protection is of the opinion that a person is violating the provisions of the Code or any regulations promulgated thereunder, "...

he or she *shall* make and enter an order directing such person to cease and desist such activity." Chapter 22, Article 5, Section 5. Instead of fulfilling that nondiscretionary duty imposed by the Code, Mr. Callaghan has, perhaps at the recommendation of his staff in the Office of Air Quality, chosen to approve relaxation of existing standards. These actions serve neither as an effective means of achieving compliance with existing regulatory standards nor do they protect the health and welfare of the people of the State of West Virginia.

D. With areas within the State of West Virginia currently unable to comply with the existing National Ambient Air Quality Standard for particulate matter, it is inappropriate to be relaxing existing emission limits and allowing greater particulate matter emissions. Particulate matter smaller in diameter than ten microns will often be limited more by an opacity limit than by a mass emission standard. The physical properties of sub ten micron particulate matter can display a disproportionately high effect on light diffraction, as compared to particulate matter of greater diameter. These smaller diameter particles can have a greater impact on opacity than they would have on a mass emission standard. Therefore, the opacity standard may serve as a more effective limiting factor for the emission of particulate matter less than ten microns in diameter. This is important because it is this size of particulate matter, below ten microns in diameter, that poses the greatest health threat to the citizens of West Virginia and those downwind of facilities within our borders. This sub ten micron range is significantly more respirable and therefore potentially more harmful if inhaled.

E. Contrary to the contention of the petition submitted by Mr. Flannery to Mr. Callaghan on June 3, 1994, any relaxation of opacity standards can only lead to increased emissions of particulate matter. This will serve to further exacerbate a situation in which air quality monitoring by the State of West Virginia has found unhealthful levels of particulate matter on nine separate occasions since October of 1993. If current national standards are not being met, no relaxation of existing emission limits should be permitted. The National Ambient Air Quality Standards as promulgated by the United States Environmental Protection Agency are intended as a minimum baseline which all states are required by law to attain. The State of West Virginia is permitted by the federal Clean Air Act to impose even stricter standards to protect human health and environmental well being. However, even those minimum standards are not being met.

For the above enumerated reasons, I urge that any attempt to relax or weaken existing opacity standards, soot blowing limitations or enforcement capability embodied in the existing provisions of Regulation 2 be rejected in total and the proposed revisions be returned to the staff of the Office of Air Quality for revision appropriate to the duties and requirements imposed by the West Virginia Code.

David White

David White

November 29, 1994

Date

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the copy center

FAX cover sheet

Date: 28 NOV 1994
To: MR. DALE FARLEY
Company: OFFICE OF AIR-WV DEP
FAX: (304) 558-3287
Phone: 304-558-4022

# of pages (including cover page) 11
From: JANET FOUT
Company: OHIO VALLEY ENVIRONMENTAL COALITION
Fax:
Phone: 304-525-6984

Comments: FOR THE PUBLIC RECORD FOR NOV 29 1994 PUBLIC HEARING.

OVEC

Ohio Valley Environmental Coalition

PO Box 970
Proctorville OH 45669

PO Box 422
Kenova WV 25530

November 28, 1994

Mr. Dale Farley, Chief
Office of Air Quality
WV-DEP
1558 Washington Street East
Charleston, WV 25311-2599

Re: Changes in proposed air regulations--November 29, 1994, hearing

Dear Mr. Farley:

The Ohio Valley Environmental Coalition opposes any weakening of current air quality regulations, especially the PM_{10} (particulate matter) standards for the following reasons:

1. A U.S. EPA study found that non-accidental death rates in three cities "tend to rise and fall in near lockstep with daily levels of particulates..." The study further concluded that as many as 60,000 U.S. residents per year may die from breathing particulates **at or below legally allowed levels.** Death rates began to increase when total suspended particulate levels were as low as a third of the current EPA standards (Schwartz and Dockery, 1992).

2. Those most likely to die from exposure to particulates include elderly or people currently suffering from respiratory illnesses such as asthma, emphysema, bronchitis, pneumonia and cardiovascular disease (Science News, April 1991).

3. Increases in airborne particulates have been linked to increased respiratory problems and hospital admissions for children (Science News, May, 1989).

It makes no sense to weaken current West Virginia PM_{10} standards to US EPA standards which already are not stringent enough to protect human lives and health.

Sincerely,

Janet Fout

Janet Fout, Project Coordinator

enclosures
c: Ken Ward, Charleston-Gazette

Increased Mortality in Philadelphia Associated with Daily Air Pollution Concentrations[1-4]

JOEL SCHWARTZ and DOUGLAS W. DOCKERY

SUMMARY Cause-specific deaths by day for the years 1973 to 1980 in Philadelphia, Pennsylvania, were extracted from National Center for Health Statistics mortality tapes. Death from accidents (International Classification of Disease, Revision 9 ≥ 800) and deaths outside of the city were excluded. Daily counts of deaths were regressed using Poisson regression on total suspended particulate (TSP) and/or SO_2 on the same day and on the preceding day, controlling for year, season, temperature, and humidity. A significant positive association was found between total mortality (mean of 48 deaths/day) and both TSP (second highest daily mean, 222 μg/m³) and SO_2 (second highest daily mean, 299 μg/m³). The strongest associations were found with the mean pollution of the current and the preceding days. Total mortality was estimated to increase by 7% (95% CI, 4 to 10%) with each 100-μg/m³ increase in TSP, and 5% (95% CI, 3 to 7%) with each 100-μg/m³ increase in SO_2. When both pollutants were considered simultaneously, the SO_2 association was no longer significant. Mortality increased monotonically with TSP. The effect of 100 μg/m³ TSP was stronger in subjects older than 65 yr of age (10% increase) compared with those younger than 65 yr of age (3% increase). Cause-specific mortality was also associated with a 100-μg/m³ increase in TSP: chronic obstructive pulmonary disease (ICD9 490-496), +19% (95% CI, 0 to 42%), pneumonia (ICD9 480-486 & 507), +11% (95% CI, −3 to +27%), and cardiovascular disease (ICD9 390-448), +10% (95% CI, 6 to 14%). These results are somewhat higher than previously reported associations, and they add to the body of evidence showing that particulate pollution is associated with increased daily mortality at current levels in the United States.
AM REV RESPIR DIS 1992; 145:600-604

Introduction

High levels of particulate air pollution have been associated with excess mortality in anecdotal reports for centuries. Evelyn attributed the rising death rate and increased rates of respiratory illness to the combustion of coal in London in 1661 (1), and Graunt, in a classic study of Bills of Mortality, attributed the high week-to-week variability in mortality to changes in the "airs" (2). Brimblecombe (3) has recently reanalyzed mortality data from this period and compared it with diary accounts of "Great Stinking Fogs." In the fall of 1679 a peak stinking fog period was associated with an increase in both total mortality and mortality from "tisick," a lung disease associated with asthma. The rise seemed greatest in the elderly. More recently, winter smog episodes characterized by high particulate and sulfur dioxide concentrations have been associated with substantial increases in daily mortality in the Meuse Valley, Belgium, in 1930, in Donora, Pennsylvania, in 1948, and in London, England, in 1952. The tracking of mortality increases and decreases during these episodes with the rise and fall of air pollution levels left little doubt that the relationship was causal. The increased mortality in London in 1952 was higher among the elderly, in deaths from respiratory disease, and from cardiovascular disease. More recently, excess mortality has been associated with a smog episode in West Germany (4). Particulate and SO_2 concentrations were lower than in the previous episodes, but high in comparison with concentrations currently observed in the United States and in Western Europe.

Studies of air pollution and mortality during nonepisode periods have shown correlations between increased daily air pollution and increased daily mortality across a wide range of concentrations, with no sign of a threshold (5–7). In London, the relation with particles held independent of sulfur dioxide, but not vice versa (5). Similar findings have been reported in New York City (8–10) and recently in Santa Clara, California (11). These studies have used optical measures of particulate concentration that are nonlinearly related to gravimetric particulate mass concentrations in a site-specific manner (12), making comparison with currently monitored particulate concentrations difficult. Studies using direct gravimetric measurement of particulate concentrations in the United States have been limited by the every-sixth-day sampling schedules for most particulate monitors. A recent report has found a significant association between total suspended particulates (TSP) and daily total mortality in Steubenville, Ohio, for the period 1974 to 1984 (13). Again, the TSP association was independent of SO_2, but not vice versa. This report presents an analysis of daily total and cause-specific mortality in Philadelphia, Pennsylvania, compared with daily TSP and SO_2 concentrations for 8 yr.

Methods

Daily deaths in the city of Philadelphia (population, 1,688,710 in 1980) (14) were extracted from mortality tapes from the National Center for Health Statistics for the calendar years 1973 to 1980. Deaths from accidental causes (International Classification of Disease Revision, ICD9 ≥ 800) were excluded, as were all deaths that occurred outside of the city. Daily counts of total mortality, mortality in persons younger than 65 yr of age, and mortality in persons 65 yr of age and older were

(*Received in original form April 8, 1991 and in revised form July 26, 1991*)

[1] From the U. S. Environmental Protection Agency, Washington, D.C., and the Environmental Epidemiology Program, Department of Environmental Health, Harvard School of Public Health, and Channing Laboratory, Harvard Medical School and Brigham and Women's Hospital, Boston, Massachusetts.

[2] Supported in part by Grants ES-00002 and ES-01108 from the National Institute of Environmental Health Sciences, by Contract RP-1001 with the Electric Power Research Institute, and by Cooperative Agreement CR-811650 with the Environmental Protection Agency.

[3] The views expressed in this report are those of the authors, and they do not necessarily represent those of the U.S. Environmental Protection Agency, the National Institute of Environmental Health Sciences, or the Electric Power Research Institute.

[4] Correspondence and requests for reprints should be addressed to Dr. Douglas W. Dockery, Environmental Epidemiology Program, Harvard School of Public Health, 665 Huntington Ave., Boston, MA 02115.

computed. Total mortality was also subdivided by cause of death. The choice of ICD code categories represents a trade off between specificity and sufficient cases to allow a separate analysis. The causes analyzed were pneumonia (ICD9 480–486 plus 507, ICD8 480–486), chronic obstructive pulmonary disease (COPD) (ICD9 490–496, ICD8 490–493 plus 519.3), cardiovascular disease (CVD) (ICD 390–448), and cancer (ICD 140–208). Cardiovascular disease accounted for 45.9% of the deaths in Philadelphia during this period, cancer for 21.8%, pneumonia for 3.0%, and COPD for 1.9%.

Daily mortality was matched to the 24-h samples (midnight to midnight) of TSP and SO_2 concentrations. All population-based monitors, defined by Environmental Protection Agency (EPA) sampler descriptions (15) within the city of Philadelphia, that is, not including the suburban communities, were included. Data were retrieved from the national aerometric data banks of the EPA (16). For each day, TSP and SO_2 from all available monitors were averaged to produce a citywide mean. For TSP, daily samples were routinely collected at two monitors (1501 East Lycoming and Community Health Services Building) supplemented by sampling every sixth day at several additional sites. SO_2 daily samples were collected at as many as 11 sites. On any given day, an average of more than seven monitoring sites contributed data to the citywide mean. For TSP, citywide means were available for 2,726 days (93.3% of 2,922 total days), and for SO_2, 2,706 days (92.6%).

This analysis sought to replicate the association between particulate air pollution and daily mortality that has been reported on data from Steubenville, Ohio (13). Age-stratified analyses were then performed, along with analyses of cause-specific mortality.

Daily mortality is a count of a rare event and was modeled by Poisson regressions. Daily mortality was fit to a model including seasonal indicators and weather variables that explained as much of the variation as possible. Air pollution variables were then added to this model. Therefore, a more exploratory approach was adopted with respect to model fitting with the season and weather terms since the goal was not to test specific hypotheses about weather but rather to conservatively estimate the association with air pollution.

During the period of study there was a decline in cardiovascular mortality rates in the United States. This was expected to result in a downward trend in mortality over time. There was also a slight drop in the population of Philadelphia during the period. To control for this, indicator variables for each year of the study were included in the models, as well as a continuous time variable to parameterize a continuous decline within year. The initial analysis of weather variables considered 24-h mean temperature and dew-point temperature, indicator variables for hot days, cold days, humid days, and hot and humid days, seasonal indicator variables, and interaction terms between season and the weather variables. Weather variables on the day of recorded death and the prior day were considered, and the square of temperature and dew point were also considered for each day. The definition of hot, cold, and humid days was initially set at the ninety-fifth percentile (fifth percentile for cold) and then varied to find the definition with the greatest explanatory power.

The Poisson model was estimated using the generalized estimating equations of Liang and Zeger (17, 18). In these models, as in a classic Poisson model, the logarithm of the expected number of deaths Y is given by: $\log[E(Y)] = X\beta$, where X is the matrix of covariates, β is the regression coefficients, and E denotes the expected value. In addition, an autoregressive covariance structure is assumed, modeling the serial correlation often found in long-time series. The approach of Liang and Zeger incorporates the covariance structure in the estimation of the regression coefficients as well as their variances, giving more efficient estimates of the parameters. Because of the computational complexity, models were initially developed using simple Poisson regression, and final models were then estimated using the methodology of Liang and Zeger.

Results

The distribution of air pollution, weather, and daily mortality in Philadelphia during the study period from 1972 to 1982 is shown in table 1. An average of 48 persons died each day in the city. Approximately 65% of the deaths were in those older than 65 yr of age. Except for cardiovascular and cancer disease, counts for the individual causes of death were low.

In initial analyses of weather factors, hot days (mean > 80° F), previous day's mean temperature, mean dew point, and winter temperature were significant predictors of daily mortality.

When TSP was included in the above model, particulates on both the current and the previous day were highly significant predictors of daily mortality, with approximately equal coefficients. The mean TSP of current and prior days was a stronger predictor than that of either the current or the previous day, and the 2-day mean was used in subsequent analyses. The coefficient of TSP ($\mu g/m^3$) was 0.000661 ± 0.000131. Current day and prior day SO_2 measurements (ppb) were also significant predictors of daily mortality. Again, the 2-day mean was the best predictor ($\beta = 0.00132 \pm 0.000290$). When both pollutants were considered together, TSP remained significant ($\beta = 0.000497 \pm 0.000179$), whereas SO_2 became insignificant and substantially reduced in magnitude ($\beta = 0.000565 \pm 0.000403$). To test the hypothesis that TSP was serving primarily as a vector to deliver SO_2 into the respiratory tract, we divided the sample into days below and days above the median (18 ppb). The coefficient of TSP during the low SO_2 days was 0.000707 ± 0.000238. When SO_2 was above 18 ppb, the coefficient of TSP was 0.000645 ± 0.000187. Hence, no evidence of an interactive effect was found. This parallels results from London (19).

The association with TSP was not strongly confounded by variables in season and weather. The estimated coefficient for TSP without controlling for these variables ($\beta = 0.000664 \pm 0.000129$) was only slightly different from the complete model estimates. Similarly, adjustment for day of the week slightly increased the estimate for TSP ($\beta = 0.000725 \pm 0.000135$).

The association of mortality with indicators of quintiles of TSP compared with the lowest quintile were evaluated.

TABLE 1

DISTRIBUTION OF DAILY MORTALITY COUNTS, WEATHER, AND AIR POLLUTION IN PHILADELPHIA, 1973–1980

	5%	10%	25%	50%	75%	90%	95%	Mean
Weather								
Temperature, °F	25	30	41	58	71	77	80	54.8
Dew Point, °F	8	15	28	44	59	68	70	42.8
Air pollutants								
TSP, $\mu g/m^3$	37	43	56	73	94	117	132	77.2
SO_2, ppb	6	8	12	18	27	38	48	21.0
Mortality, deaths/day								
Total	35	37	42	48	54	60	64	48.2
Age ≤ 65 yr	10	11	14	17	20	23	25	16.9
Age > 65 yr	21	23	26	31	36	40	44	31.3
Cause-specific mortality, deaths/day								
Cardiovascular	13	15	18	22	26	30	32	22.1
Cancer	5	6	8	10	13	15	18	10.5
Pneumonia	0	0	0	1	2	3	4	1.44
Chronic obstructive pulmonary disease	0	0	0	1	1	2	3	0.89

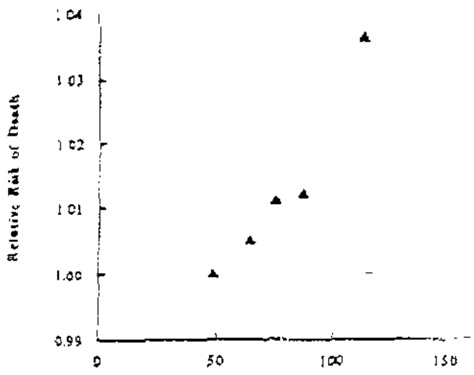

Fig. 1. Relative risk of death in Philadelphia by quintile of total suspended particulates controlling by regression for year of study, time trend, and weather

A strong indication of a dose-dependent increase in mortality was found (figure 1).

When mortality was considered separately for those older than 65 yr of age, the impact of TSP was substantially higher (β = 0.000910 ± 0.000161) than for the younger population (β = 0.000271 ± 0.000206). When mortality was analyzed separately by cause, the largest effect was seen for COPD (β = 0.00178 ± 0.00089), followed by pneumonia (β = 0.00102 ± 0.00070), and cardiovascular disease (β = 0.000921 ± 0.000183). In contrast to these causes, which had effect estimates higher than that of total mortality, the relative risk for cancer was substantially lower than for total mortality (β = 0.000361 ± 0.000258). These differential effects are illustrated in figure 2, which shows the relative risk of death for a 100-$\mu g/m^3$ increase in TSP, for total mortality, cause-specific mortality, and the age-stratified associations.

Discussion

As in previous reports of New York City mortality analyses (20, 21), hot days were associated with increased mortality in Philadelphia. During cooler periods, i.e., the winter months, increases in temperature were protective against mortality.

During the period of this study, the reference method for suspended particulate concentrations was TSP. The National Ambient Air Quality Standard for TSP was an annual geometric mean of 75 $\mu g/m^3$ and a 24-h mean of 260 $\mu g/m^3$. Annual geometric mean TSP concentrations (72 $\mu g/m^3$) were close to the standard, but there was only 1 day above the TSP standard during the study period, the two highest values being 380 and 222 $\mu g/m^3$. In 1984 (22), the reference method was changed to define an upper size cut for particulate matter of 10 μm aerodynamic diameter (PM_{10}). No PM_{10} data were collected during this period, but the EPA collected inhalable particulates every sixth day for the 1978 to 1982 period at six sites in Philadelphia with an upper size cut of 15 μm (PM_{15}). Ozkaynak and coworkers (23) reported that daily PM_{15} was equal to 61 ± 1% of TSP for these samples.

The finding of a significant association between TSP and daily mortality rates at commonly observed levels of exposure confirms the results that have been reported from Steubenville (13). It is also consistent with the analysis of Wyzga (24) who found coefficient of haze, an optical measure of particulates, was associated with daily mortality in Philadelphia in the 1960s. A more recent analysis (11) using coefficient of haze found a significant association with daily mortality in Santa Clara, California, during a period when particulate matter less than 10 μm (PM_{10}) concentrations rarely exceeded that of the ambient air quality standard.

A striking similarity of effect sizes is seen between this study and episode studies at high concentrations. It is generally accepted that particulate air pollution was responsible for the dramatic increase in mortality in London during the fog of December 1952 (25). In the London Administrative County, the death rate during the period December 6 to 9 was 2.2-fold elevated over the death rate during the period December 2 to 5. The mean concentration of particles (measured as British Smoke) was somewhat more than 1,200 $\mu g/m^3$ higher in the second period. At these high concentrations, TSP and British Smoke are essentially identical. Assuming the same relative risk model that was applied in this report and in the Steubenville analysis, that corresponds to a coefficient of slightly more than 0.0006, essentially identical to the results for Philadelphia that are reported here. The similarity of the slope estimates across such a large range of exposure, including a peak period where causality of the mortality relationship is not questioned, strongly suggests that association at lower concentrations is likewise causal.

The dose-response relationship indicated in figure 1 shows that this relationship is not restricted to high TSP days, which might be characterized by inversions and/or other high exposures, but rather continues across the range of TSP concentrations.

The independence of the mortality versus particulate association from confounding by SO_2, whereas the SO_2 association was substantially reduced upon inclusion of TSP, is also consistent with the findings from Steubenville (13), London (5), and New York (10).

If daily air pollution is affecting daily mortality at these concentrations, it must be by further compromising the health of persons who are already at significant risk of dying. This suggests that the effect size should be greater in the elderly. In this study the impact of an increase in TSP concentrations was about three times as great in persons older than 65 yr of age as in persons younger than 65. Although all persons with serious illness may be put at further risk of death by a respiratory insult, one would expect the increased risk to be greater in those whose major risk factor is respiratory disease. In Philadelphia, the TSP-associated in-

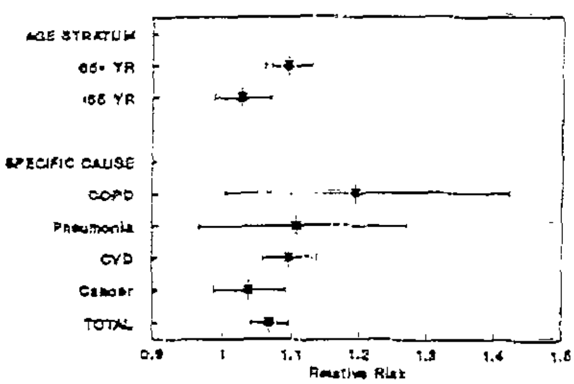

Fig. 2. Relative risk of mortality in Philadelphia associated with a 100 $\mu g/m^3$ increase in total suspended particulates (TSP) concentration after controlling by regression for year of study, time trend, and weather. Results for all-cause mortality, age-stratified mortality, and cause-specific mortality.

creased risk of COPD mortality was triple the increase in all-cause mortality. In contrast, the percentage increase in cancer mortality associated with particulate pollution was only half the percentage increase in all-cause mortality (figure 2). The pattern of increased mortality in Philadelphia is also consistent with the pattern in the London smog episode of 1952 (25). Total mortality was elevated 2.6-fold during the smog week, but bronchitis deaths were elevated 9-fold. The increase in total mortality during the episode was also higher for the elderly.

Only a small fraction of deaths have respiratory conditions defined as the primary cause. The physiologic reasons for the associations between total mortality and air pollution in the current or previous day are not obvious. Schimmel and Greenberg (9) have suggested that air pollution acts as an additional stress, similar to other environmental stresses such as heat waves, on subjects with preexisting respiratory or cardiovascular problems. Bates (26) has recently suggested three specific mechanisms by which respiratory conditions associated with acute air pollution exposures could contribute to cardiovascular mortality. First, acute bronchitis and bronchiolitis may be misdiagnosed as pulmonary edema. Second, air pollutants might increase lung permeability and precipitate pulmonary edema in people with myocardial damage and an increased left atrial pressure. Third, acute bronchiolitis or pneumonia induced by air pollution, in the presence of preexisting heart disease, might precipitate congestive heart failure.

Patients with COPD would be expected to be particularly at risk. Such patients almost universally suffer from ventilation-perfusion inhomogeniety. Hence, a disproportionate amount of their respiration occurs in a small part of their lungs, and it is in this portion where the particulate exposure will be concentrated (26). The combination of greater effective dose in the portion of the lung that remains functional and decreased reserve capacity should enhance any response to particulates in subjects with COPD.

If acute exposure to particulates increases mortality, one would also expect to find associations with elevated morbidity. In fact, particulate exposure has been associated with increased hospitalization for respiratory illness, and with other evidence of respiratory morbidity. Pope, in two recent studies (27, 28), demonstrated an association between inhalable particles and hospital admissions for respiratory illness in Utah. Bates and Sizto (29) have reported that sulfate particulates were associated with hospital admissions for respiratory conditions in southern Ontario. Gross and coworkers (30) found respirable particles associated with hospital admissions in Israel. A weaker association with emergency room visits was reported in Steubenville by Samet and colleagues (31). Wichmann and coworkers (4) reported increased hospitalization and ambulance calls during the European smog episode.

Exposure to particulates has also been associated with increases in respiratory symptoms in a diary study of patients with COPD (32). At lower levels of exposure, a series of analyses of data from the Health Interview Study have reported associations between particulate exposure and respiratory symptoms severe enough to restrict activity (33).

Although associations with illness in children are not directly relevant to health effects in adults, these can provide indirect support by demonstrating the association between low level particulate exposure and increased rates of respiratory illness. Schwartz and coworkers (34) have reported an association between PM_{10} concentrations and daily rates of lower respiratory symptoms in a diary study of school children in which PM_{10} concentrations were well below the ambient standard at all times. Dockery and colleagues (35) have also reported an association between annual average PM_{15} and acute bronchitis rates across six cities. The effect was much greater in children with a history of wheezing. These studies suggest that particulate pollution, even at low concentrations, exacerbates chronic respiratory conditions. This pattern is consistent with the increased relative risk of mortality associated with particulate pollution among persons with COPD in this study.

In summary, the association of particulate air pollution with daily total mortality in Philadelphia is quantitatively similar to results in other communities in the United States and in Europe. Moreover, the association is stronger among the elderly than among younger subjects, and it is stronger for respiratory causes of death compared with total mortality and cancers. Given the consistency of these findings, and the coherence of evidence from morbidity studies, the association reported here is likely to be ca..... Additional studies will remain useful in confirming these associations, particularly in communities with daily measurements of not only the mass concentration of particulates but also chemical characterization of their composition.

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cess to all Cal/EPA branches."

Native American tribes would be treated as states for the purpose of operating their National Pollution Discharge Elimination System (NPDES) permit and sewage sludge management programs under the Clean Water Act, according to a rule EPA proposed March 10. This rule would establish eligibility requirements for Native American tribes that elect to apply for authority over NPDES and state sludge management programs, similar to requirements of several states. A tribe granted this authority would apply it within its federal reservation. For more information contact Wendy Miller at (202) 260-3716.

New Jersey no longer will approve "bubble" permits, and those in force will not be renewed after they expire, according to state Department of Environmental Protection (DEP) rules issued March 2. Bubble permits allow industrial facilities in an area to "trade" emissions so that the *area* complies with volatile organic compounds (VOC) emission standards. For example, if the combined emission levels of facilities in an area—some above the limit, some below—equal less than the limit, the area (or bubble) is said to be in compliance for that industry. In the future, each facility must meet the standards. DEP estimates that eliminating bubble permits will reduce VOC emissions in the state by 5.5 tons/day. For more detail, see the *New Jersey Register* 1992 *24* N.J.R. 792.

Funding for clean coal technology research in Illinois has reached $1.1 billion, which has been spent or earmarked for spending by 1995. The funds come from the U.S. Department of Energy, the Illinois Department of Energy and Natural Resources, and private sources. To be eligible for funding, a project must use high-sulfur Illinois coal as its primary feedstock; use innovative technology that has commercial-scale prospects; offer economic benefits to Illinois; and meet all state and federal solid, liquid, and gaseous discharge and emission standards. Projects include mild coal gasification demonstration, combined-cycle power generation, conversion of NO_x to nitrogen, and desulfurization.

New York state proposed Superfund rules that redefine the "significant threat" waste sites pose to the environment. Under the new definition, a significant threat means that waste at a site will cause significant environmental damage or "is reasonably foreseeable to result in" environmental damage. Damage refers to injury to, or impairment of the use of, the environment. The goal of restoring sites to their conditions before disposal occurred also is being clarified. These moves have long been sought by the state's business community. Environmental groups also receive consideration: Previous regulations only "encouraged" public participation in setting up remedial processes at a site; in the future, public participation will be required. For more information and a copy of the revised regulations, contact Bruce Bentley, Department of Environmental Conservation, 50 Wolf Road, Albany, NY 12233; (518) 457-0849.

The District of Columbia, Maryland, and Virginia had been considering imposing "California rules" on automobile emissions. As of mid-March, their resolve seems to have faltered somewhat. District officials now ask whether the environmental benefits would be worth the estimated additional costs to consumers of $200–$1000 a car, not to mention additional administrative and enforcement costs to the city. The Virginia legislature sent the issue back for one year's study. Maryland was more "gung-ho" about imposing California rules, but became more cautious as a result of developments in the District and Virginia.

VIEWPOINT

"The massive destruction of the Amazon rain forest is neither willy-nilly nor accidental," charges economist Michael Drohan of The Pennsylvania State University (McKeesport, PA). "It has been a well-planned campaign . . . that is still being carried on despite an international crusade." One reason Drohan advances is that parts of the Amazon rain forest contain enormous untapped mineral wealth, particularly aluminum, copper, iron, manganese, nickel, and tin. "Smelting iron ore requires cutting down thousands of square miles of forest to supply charcoal for blast furnaces," Drohan points out. "Generating electricity to reduce bauxite to aluminum has demanded flooding enormous areas of the Amazon's main tributaries." Drohan adds, "The short-term windfalls from precious woods, land speculation, and ranching are high. Since in capitalistic economies, the short term is of paramount importance, the destruction of the Amazon rain forest is likely to continue." Drohan believes that the total destruction of the Amazon rain forest by the end of the century is entirely possible.

SCIENCE

Airborne particulates at levels considered safe by EPA may in fact help kill thousands of people in the United States annually, according to a new study published in the March *American Review of Respiratory Disease.* The study, based on eight years of mortality and pollution data from Philadelphia, found that for every 100-µg increase in total suspended particles (TSP) per m^3, death rates increased 10% for city residents over 65 and 3% for younger residents. Death rates began to increase when TSP levels were as low as a third of the current EPA standard. In some cases, say the researchers, the pollution hastens an imminent death, but for many it may be the difference between surviving or succumbing to a health crisis.

The first evidence that the ozone hole affects life has been reported by scientists from the University of California at Santa Barbara and the University of Hawaii. Studies in Antarctica's Bellingshausen Sea during 1990 found that phytoplankton exposed to higher levels of UV light suffered as much as a 12% decrease in their growth rate, which corresponds to as much as a 4% drop in annual phytoplankton production throughout the Antarctic region. The measurements were made during a six-week period in an area where the edge of the ozone hole swept back and forth over the region.

TECHNOLOGY

"Zapping" waste streams with a 1.5 million-V pulsed electron

3A
MONDAY, MAY 17, 1993

Huntington, WV
Herald-Dispatch

■ NEW YORK

Tiny pollutants can kill you, too

WHAT HAPPENED: Air pollution by extremely tiny particles can raise the risk of early death, even when the pollution falls within legally acceptable limits, a study found.

The research, which tracked more than 8,000 adults for about 15 years, linked the pollution chiefly to deaths from heart and lung disease.

BACKGROUND: The fine particles, small enough be inhaled into the lungs, resulted mostly from burning of fossil fuels for power generation, steel production, other industry, automobiles and home heating with wood, coal or oil, said chief author C. Arden Pope.

Pope, a visiting scientist in the environmental health department at the Harvard School of Public Health, said the result confirms prior studies.

In fact, it is in many ways more convincing than the prior results, commented Joel Schwartz, a senior scientist in the Office of Policy and Analysis at the Environmental Protection Agency.

Dust to Dust: A Particularly Lethal Legacy

Particulates – dust-sized air pollutants, including soot and sulfates – inflict much more harm than previously thought, according to a series of new studies. By correlating daily weather, air pollutants and mortality in five U.S. cities, a federal scientist has discovered that nonaccidental death rates tend to rise and fall in near lockstep with daily levels of particulates – but not with other pollutants.

Because the correlation held up even for very low dust levels – in one city, to just 23 percent of the federal limit on particulates – these analyses suggest that as many as 60,000 U.S. residents per year may die from breathing particulates at or below legally allowed levels, says epidemiologist Joel Schwartz of the EPA in Washington, D.C.

Confirmation of the new findings by other researchers would make airborne particulate levels the largest known "involuntary environmental insult" to which Americans are exposed and would strengthen the case for tightening the federal particulate standard, says Schwartz, who described his analyses last week in Arlington, Va., at the annual meeting of the Society for Occupational and Environmental Health.

"I've never thought that [airborne] particles were terribly important by themselves – at least not at these levels," says David V. Bates of the University of British Columbia in Vancouver. But Schwartz's analyses have won him over. Bates says the new studies represent a "tour de force" – one "with tremendous power."

Early last year, Schwartz and Allan H. Marcus of Battelle Memorial Laboratories in Research Triangle Park, N.C., published data on 14 London winters, showing a "likely causal" relationship between daily mortality and daily elevations in so-called "British smoke" – a roughly quantifiable gauge of airborne particulates. They focused on London because the city measures its particulate levels daily. Nearly all U.S. cities measure particulates only every sixth day – too infrequently, Schwartz says, to identify acute changes in mortality.

While analyzing the London data, Schwartz learned that Philadelphia and Steubenville, Ohio, had 10 years' worth of daily particulate readings. He looked at their weather, pollution and daily mortality, and again found a clear, statistically significant association between increased "total suspended particulates" one day and elevated mortality the next.

"Part of the reason nobody found this association before is simply because the statistical techniques required to do the analysis [for small populations or data sets] are quite difficult," says C. Arden Pope, an environmental economist at Brigham Young University in Provo, Utah. Schwartz "is to my knowledge the first to have applied them to mortality and air pollution data," Pope says, "and he did an excellent job."

In 1987, EPA switched from requiring the measurement of all particles suspended in the air to assaying only the respirable fraction – particles with a diameter of 10 microns or less. Schwartz identified two cities that had compiled daily logs of these "PM_{10}" data for roughly a year: St. Louis and Kingston, Tenn. He also correlated the type of daily "visibility" data compiled by airports with every-sixth-day particulate data for Detroit, producing a computed estimate of Detroit's daily particulate levels.

In analyzing the data for these three cities, Schwartz found exactly the same trend identified in London, Steubenville and Philadelphia. Daily particulate pollution correlated with mortality rates, while sulfur dioxide – a gaseous pollutant long suspected of affecting mortality – showed no effect. Moreover, the magnitude of the particulates' effect on mortality proved nearly identical in each U.S. city: a roughly 6 percent increase in deaths for every 100 micrograms of total particulates (or roughly 50 micrograms of PM_{10}) per cubic meter of air.

Such a uniform impact per given change in exposure – in five U.S. cities with vastly different sizes, climates and mixes of air pollutants – argues "very convincingly, both epidemiologically and statistically," that the observed correlations are real, Schwartz asserts.

His Philadelphia data also indicate that people who appeared to succumb to the particulates tended to be elderly and already quite sick, usually with respiratory disease. For every 100 micrograms of particulates per cubic meter of air, Schwartz found that the risk of dying increased by 32 percent from emphysema, 19 percent from other chronic obstructive lung diseases (such as bronchitis and asthma), 12 percent from pneumonia and about 9 percent from cardiovascular disease. Previous studies had linked increases in airborne particulates with children's respiratory symptoms and hospital admissions for bronchitis and asthma (SN: 5/6/89, p.277).

The new findings also suggest that particulates are more toxic than smog ozone, says Bart D. Ostro, chief of air pollution epidemiology at California's Department of Health Services in Berkeley.

But exactly how particulates might contribute to mortality remains unknown. "I have no idea what the mechanism is," says Bates, a chest physician and air pollution epidemiologist. "Nor has anyone else."

– J. Raloff

SCIENCE NEWS
APR 6, 1991
VOL 139 NUMBER 14
p212

SARASOTA HERALD-TRIBUNE/MONDAY, MAY 13, 1991

Air Pollution Blamed for 60,000 Deaths Yearly

The risk of death from air pollution is higher for the elderly and people with lung and heart disease, the study found.

Los Angeles Daily News

Air pollution in American cities ...s accounted for an estimated ...,000 deaths a year, making it ...nong the nation's top killers, ac...rding to researchers.

The risk of death is greatest ...nong the elderly and people with ...ng and heart disease, said Joel ...hwartz, of the Environmental ...rotection Agency, who worked ...ith another researcher on the air ...llution study made public Sun...y in Anaheim, Calif.

The study focused on particu...tes, or tiny airborne particles.

"There hasn't been much atten...n focused on particulates, and ...e standards are fairly loose," ...hwartz said, after presenting the findings at the 1991 International Conference of the American Lung Association in Anaheim.

"It comes out of electric power plants. It comes out of diesel trucks," Schwartz said. Factories, smoke, aerosols, dust and naturally occurring microorganisms are also to blame for airborne particles, he said.

The estimated 60,000 deaths a year account for 3 percent of all deaths nationwide, Schwartz said.

Those deaths linked to air pollution during the study occurred at levels of airborne particles below the standards set by the federal government, he said.

Schwartz said he expects the findings to push federal officials to change regulations. "Eventually, it will result in a tighter standard, but not next year," he said.

The study found that the number of deaths rose by 7 percent when the level of particles increased 100 millionths of a gram per cubic meter, he said. The death rate increased by 5 percent when sulfur dioxide increased 100 millionths of a gram, Schwartz said.

For people older than 65, the impact of particles in the air was three times greater than for people younger than 65, Schwartz said.

For people with asthma, bronchitis or chronic obstructive lung disease, the death rate was 20 percent greater when the level of particles increased 100 millionths of a gram per cubic meter, he said.

Schwartz said people should stay indoors when the pollution levels are high because that will filter out about two-thirds of the particles.

Philadelphia was chosen as a site for the study because it is typical of a large American city and one of the few that measure particle pollution levels daily, Schwartz said.

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November 29, 1994

G. Dale Farley, Chief
Office of Air Quality
West Virginia Division of
Environmental Protection
1558 Washington Street, East
Charleston, West Virginia 25311-2599

Re: Proposed 45 CSR 2 - "To Prevent and Control Particulate Air Pollution from Combustion of Fuel with Indirect Heat Exchangers"

Dear Chief Farley:

The following comments are offered on behalf of the following organizations regarding the October 21, 1994 proposed 45 CSR 2 "To Prevent and Control Particulate Air Pollution from Combustion of Fuel in Indirect Heat Exchangers."

Appalachian Power Company,
Elkem Metals Company,
FMC Corporation,
Monongahela Power Company,
Ohio Power Company,
Union Carbide Corporation,
Virginia Electric and Power Company,
and the
West Virginia Manufacturers Association

These companies and the trade organization have been actively working with the Division of Environmental Protection in an attempt to update Regulation 2 to reflect current practices with regard to agency implementation and current operations of indirect heat exchangers in the state.

On June 3, 1994 a Petition to Revise 45 CSR 2 was filed with the Division of Environmental Protection setting forth the interests and concerns of each of these organizations. These comments incorporate by reference that petition as it was filed. We approach the agency with these comments based upon the history of that petition and meetings with the agency subsequent to that filing. We urge your favorable consideration of the following comments and proposed revisions to this proposal.

Section 1.1. Scope. We agree with the incorporation of a cross-reference to the compliance determination methods and procedures previously contained in 45 CSR TP-2 "Compliance Test Procedures for Rule 2 - To Prevent and Control Particulate Air Pollution From Combustion of Fuel in Indirect Heat Exchangers."

Section 1.6. Incorporation by reference and determination of stringency. As set forth in the statute under W. Va. Code §22-1-3a,

> . . . legislative rules promulgated by the director. . . may include new or amended environmental provisions which are more stringent than the counterpart federal rule or program to the extent that the director first provides specific written reasons which demonstrate that such provisions are reasonably necessary to protect, preserve or enhance the quality of West Virginia's environment or human health or safety, taking into consideration the scientific evidence, specific environmental characteristics of West Virginia or an area thereof, or stated legislative findings, policies or purposes relied upon by the director in making such determination. In the case of specific rules which have a technical basis, the director shall also provide the specific technical basis upon which the director relied.

Examples of provisions in this proposal that are more stringent than the federal equivalent can be found under:

- Section 3.1 concerning the need for an exemption of wet FGD equipment from the 20% reporting requirement;

- Section 8.4 start-up and shutdown notification and reporting requirements be on a quarterly rather than monthly basis; and

- Section 9.1 concerning the need for the start-up, shutdown, and malfunction variance to apply to not only opacity requirements but also mass emission requirements.

Since no proper justification has been offered regarding these provisions, we do not believe DEP has the authority to make these regulations more stringent than the federal.

Section 2.6. Director. This definition should be revised to reflect the recently enacted W. Va. Code §22-5-2(3) to read,

"Director" means the director of the division of environmental protection or such other person to whom the director has delegated authority or duties pursuant to sections six or eight, article one, chapter twenty two of the West Virginia Code."

Section 2.12. Heat Input. We presume that the language of this definition was intended to reflect that which was previously found under 45 CSR TP-2. Specifically the typographical error found in 2.12.b should be revised to read consistent with the former rule as follows,

b. 'Total Design Heat Input (TDHI)' means the sum of the design inputs for all similar units located at one plant.

Section 2.14. Malfunction. The word "an" should be revised to correct the phrase "sudden and unavoidable failure."

Section 2.22. Pitobe. This term should be deleted and replaced with the term "pitot tube" to reflect the equipment used in sampling.

Section 3.1. Visible Emissions Standards. We strongly support the change to 20% opacity and the inclusion of an exception for one 6-minute period per hour of not more than twenty-seven (27) percent opacity. This brings this portion of the rule into conformity with federal requirements and the practice of our neighboring states.

We would urge, however, that a provision be included within the visible emission requirements for fuel burning units which would recognize those units utilizing flue-gas desulfurization [FGD] equipment. Application of FGD equipment to a fuel burning unit generates a plume that has 100% opacity by virtue of the water vapor present in the plume. It would not be possible to operate a unit equipped with wet FGD equipment in a way that could comply with such an opacity limitation. The federal regulation found under 40 CFR §75.14(b) specifically recognizes the unique operational circumstance of such FGD equipment and exempts such units from this opacity requirement. There is no justification for West Virginia to be more stringent than the federal requirement on this issue. Moreover, the provision simply makes no sense when applied to a stack that always has 100% opacity due to the FGD control equipment. We would urge that this regulation be revised to exempt wet FGD units from the regulation.

Additionally, we would also request that upon those occasions when condensate forms in the stack itself an exemption be provided.

Therefore, we would urge that Section 3.1. be revised as follows,

> No person shall cause, suffer, allow, or permit emission of smoke into the open air from any fuel burning unit which is darker in shade or appearance than No. 1 Ringelmann or twenty (20) percent opacity (6-minute average), except for one 6-minute period per hour of not more than twenty-seven (27) percent opacity. <u>This requirement shall not apply to units utilizing wet flue-gas desulfurization [FGD] equipment. Neither shall this requirement apply when condensate forms in the stack itself.</u>

Section 3.2. <u>Compliance with Visible Emission Standards</u>. We agree with the cross-reference to 40 CFR Part 60, Appendix A, Method 9 for use in determining compliance with the visible emission requirements of subsection 3.1. We would support the use of measurements from continuous opacity monitoring systems to determine compliance; however, such requirement should be accompanied by an enforcement policy that compliance with the visible emission requirements of subsection 3.1 at least 95% of the time as measured by its continuous opacity monitor will be determined to be compliance with the regulation. A similar policy is being used in Virginia based on an EPA-Region III policy. We urge that a similar enforcement policy be developed by DEP. Such an enforcement policy should provide as follows,

> Should continuous opacity monitoring devices be utilized, the owner or operator shall be in compliance with the visible emission requirements of Sub-Section 3.1 at least 95% of the time that the source is required to operate its continuous opacity monitor. If continuous opacity monitoring is utilized to determine compliance, it must be operated at all times (other than during maintenance activities on the continuous opacity monitoring device) that the fuel burning unit is in operation.

In its response to comments on this rule, we urge DEP to state its intent to develop such a policy.

Section 3.3. Soot Blowing. We support the provisions of proposed section 3.3. which provide for an exception to soot blowing operations; however, the requirement to obtain formal approval for specific visible emission standards applicable to fuel burning units for soot blowing creates an unnecessary administrative burden.

The proposed provision sets forth a time limitation of eight minutes per eight hour period, with visible emissions limited to an average forty percent (40%) opacity. It is presumed that the 40% limit is an average value. Since this regulation is otherwise based upon a six minute average, we would urge that the eight minute per eight hour period be revised to twelve minute intervals. There also exist operational circumstances where technological limitations would not allow soot blowing to occur within an eight minute time limit. The use of the twelve minute interval provides a more reasonable numerical value for which compliance could be assured and provides for consistent calculation using the required six minute average. We would also urge that this provision specifically include smoke emitted during the cleaning of a fire box.

Section 4.1.(a). Weight Emission Standards. We support the descriptions provided for type 'a', type 'b', and type 'c' fuel burning units, however, we would urge that cross-reference be provided to Table 45-2C as follows,

> For values between any two corresponding consecutive values listed in this Table (see Table 45-2C), linear interpolation is to be used for both columns.

Section 4.2. Addition of Sulfur Oxides. We support the inclusion of the provision that allows for written approval by the Director for the addition of sulfur oxides to a combustion unit exit gas stream. It is imperative, however, that the previous language which provided that the section shall not apply to combustion units in operation on September 1, 1974 be incorporated into this regulation. There is no justification for tightening requirement on the addition of sulfur oxides since such improves the collection efficiency of particulate control equipment in some important cases. Accordingly, the revised provision should read as follows:

The provisions of subsection 4.2 of this section shall not apply to combustion units in existence on September 1, 1974, or to any other unit that may be approved by the Director.

Section 4.4. Alternative Weight Emission Standards. We support the inclusion of this provision which sets forth those elements which must be addressed for the purpose of providing a demonstration supporting an alternative weight emission standard. We would, however, urge that this section be moved to Section 10 concerning variances and be expanded to include both alternative particulate matter weight emission standards as well as visible emission requirements.

Section 8.1. Testing. This provision addresses the testing requirements for Regulation 2. We support the cross-reference to the test methods which are set forth in the appendix to this series and reserve comment concerning the appendix to the latter portion of this letter.

Section 8.3. Reporting Operating Schedules and Fuel. We urge that the Director review and revise the forms that are utilized to implement this rule to assure their consistency with the rule in its revised form.

Section 8.4. Start-Up and Shut-Down Notification. This provision sets forth the notification requirements concerning the start-up or shut-down of a fuel burning unit. We would urge that this requirement be deemed to have been satisfied with respect to any unit for which approved continuous opacity monitoring data is submitted by that facility on a calendar quarter basis as opposed to a calendar month basis. We urge that this revision be incorporated based on the fact that such continuous opacity monitoring is already provided on a routine basis to the Agency pursuant to the federal regulation 40 CFR Part 75. We would urge that the reporting requirement be consistent with the federal counterpart. With regard to those fuel burning units that are not equipped with continuous opacity monitors, we urge that the reporting requirement be deemed to be satisfied through telephone call or letter as is reasonable.

Section 9.1. Start-Up, Shut-Down, and Malfunction Exemption. We strongly support the start-up, shut-down and malfunction exemptions for the opacity standards. We would urge, however, that the start-up, shut-down and malfunction exception be extended to cover Section 4 weight emission standards. It is our understanding that only under conditions of steady state operation is it appropriate to take TP-2 readings. By addressing start-ups and shut-downs in this manner, the regulation would be more like the agency's operation policy effective July 1, 1990 in that the exemption would be made applicable to both start-up and shut-down and would not require prior agency approval. This would bring West Virginia's regulation into conformity with federal requirements under 40 CFR §60.11(c) for opacity regulation.

Section 9.2. Good Air Pollution Control Practice. It is our understanding that the provisions under this section would require the operation of fuel burning units in a correct manner. This provision provides that, upon a determination by DEP that such operations do not represent good air pollution control practice for minimizing emissions, contact will be made with the company concerning its operations. We presume there is no requirement that the operator initiate contact with the agency concerning this section. If it is contemplated that this section establishes a reporting requirement, we strongly object based upon the fact that this regulation is unclear as to what data would be required of either COM equipped fuel burning units or for those units not equipped with COMs.

Section 9.3. Malfunction Reporting. This provision sets forth the reporting requirements concerning malfunctions. We would urge that for the purposes of clarification the opening sentence of this section be revised as follows,

> Except as provided in subsection 8.4 for startup and shutdown notification, and subsection 9.4 the owner or operator of a fuel burning unit subject to this rule shall report to the director. . ..

We would also urge that cross-reference be provided to Sections 3 and 4 with regard to the meaning of excess opacity or excess particulate matter emission rates. The requirement to provide a report of a malfunction as set forth in this section creates an additional and unjustified reporting burden. We object to the creation of another reporting obligation. If this regulation in final form requires reporting as proposed, we would suggest that for the purposes of providing a certified written report concerning the malfunction, that comparable certification language as found in 40 CFR Part 75 be deemed acceptable by the agency. We would also propose for inclusion in Section 9.3. a provision to be inserted at the end of the proposed regulation that would state that no violations of the requirements of sections 3 or 4 shall be deemed to have occurred if excess opacity or particulate matter emissions is due to a malfunction, as follows, No violations of the requirements of Sections 3 and 4 shall be deemed to have occurred if the excess opacity or particulate matter emissions is due to a malfunction.

Section 9.4. Alternative Excess Opacity Malfunction Reporting. We applaud the inclusion of this provision which sets forth an exception to the immediate reporting requirement set forth in 9.3. With regard to Section 9.4.b it is presumed that the forty percent limitation would be based upon an average.

Section 10. Variances. As commented previously with regard to Section 4.4, we would urge that this regulation provide for a variance under Section 10 for both weight emission standards and visible emission requirements upon an appropriate demonstration to the Director. We also urge that the reporting of conditions requiring a variance and the granting of such variances be conducted in a manner that is the least burdensome for both the operator and the agency. Extensive report writing and the unnecessary commitment of time will serve only to divert limited resources from all parties involved.

Section 11. Exemptions. We would urge that an exemption be provided for industrial boilers that have a heat input under 250 million B.T.U.s.

Appendix 4.1.a. We would urge that the provision concerning the temperature of the primary filter medium where sampling follows a wet scrubbing device be revised to cross-reference the applicable or approved federal reference methods as opposed to setting forth the specific requirement. Additionally, in the closing paragraph of section 4, we would propose that the cross-reference also be provided to Method 5B for the determination of nonsulfuricacid particulate matter from stationary sources. We would also urge that there be incorporated a provision which would allow other test methods to be utilized upon approval by the Director.

Appendix 7.1. We would urge that a provision be inserted that would allow the use of such other test methods as would be approved by the Director in addition to those listed within this provision.

Appendix 7.6.c. We applaud the inclusion of Method 5B within this provision to clarify what mechanism is to be used in the case of units with wet FGDs.

Section Numbers. The numerical assignment to sections within this proposed regulation should be revised to provide as follows:

Section 10 Variance.
Section 11 Exemptions.
Section 12 Inconsistency Between Regulations.

Additionally, there exist incorrect cross references within these sections as a result of the editorial error that will require revision. (See proposed §10.1).

Conclusion. We thank you for consideration of these comments and suggested revisions to the proposed 45 CSR 2.

Very truly yours,

David M. Flannery

David M. Flannery
On Behalf of:

Appalachian Power Company,
Elkem Metals Company,
FMC Corporation,
Monongahela Power Company,
Ohio Power Company,
Union Carbide Corporation,
Virginia Electric and Power Company,
West Virginia Manufacturers Association

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KATHY G. BECKETT
DIRECT DIAL NO. (304) 347-8344

November 29, 1994

G. Dale Farley, Chief
Office of Air Quality
West Virginia Division of
Environmental Protection
1558 Washington Street, East
Charleston, West Virginia 25311-2599

Re: Public Hearing Regarding <u>Proposed 45 CSR 2.</u>

Dear Chief Farley:

During the Public Hearing of November 29, 1994 concerning proposed changes to 45 CSR 2 - "To Prevent and Control Particulate Air Pollution from Combustion of Fuel with Indirect Heat Exchangers" it was stated by DEP that the proposed rule as published by the Secretary of the State's Office did not reflect DEP's intent to delete Section 10 of the existing regulation concerning variances.

To supplement our comments as filed during the Public Hearing concerning Section 10 - Variances, we offer the following in response to the announcement at the hearing that Section 10 would be deleted in its entirety.

We would urge that subsection 10.1 be maintained in the regulation to provide the Director authority to specifically permit operations for a limited 10 day period under unavoidable malfunction circumstances. This variance authority is not otherwise addressed in the regulation. The malfunction provisions in the proposed regulation do not address those malfunctions which would require a limited time extension to correct.

Additionally, as commented in our initial letter of November 29, 1994, alternative particulate matter weight emission standards and alternative opacity standards should be included in this section concerning variances to provide for variances under both steady state operations and during malfunctions, start-up, or shutdown operations, upon demonstration and approval by the Director.

We would support the removal of subsection 10.2 as is proposed by the DEP.

Thank you for incorporating this supplemental filing with our original filing.

Very truly yours,

Kathy G. Beckett

Kathy G. Beckett
On Behalf of:

Appalachian Power Company,
Elkem Metals Company,
FMC Corporation,
Monongahela Power Company,
Ohio Power Company,
Union Carbide Corporation,
Virginia Electric and Power Company,
West Virginia Manufacturers Association

Allegheny Power System

LARRY D. MYERS
Director, Environmental Services

Bulk Power Supply
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November 29, 1994

Mr. Dale Farley, Chief
Office of Air Quality
WV Division of Environmental Protection
1558 Washington Street, East
Charleston, WV 25311-2599

Dear Mr. Farley:

Amendment to West Virginia Regulation 45CSR2
"To Prevent and Control Particulate Air Pollution from
Combustion of Fuel in Indirect Heat Exchangers"

On October 21, 1994, the WV Office of Air Quality published a proposed rule as an amendment to existing regulation 45CSR2. The following comments are provided on behalf of Monongahela Power Company, The Potomac Edison Company and West Penn Power Company which comprise the operating companies of the integrated Allegheny Power System (hereinafter collectively referred to as APS). Monongahela Power operates six coal-fired power stations in WV with a total operating capacity of 4949 mw.

APS fully supports the revision to existing regulation 45CSR2 which proposes to increase the visible emission limit from 10 to 20% opacity. Continuous compliance with the existing 10% opacity limit is not practical to achieve without the installation of additional costly particulate collection equipment. While APS has previously objected to the severe stringency of the 10% opacity limit, it was recent changes to opacity recordkeeping and reporting requirements developed by the EPA which has heightened the importance to revise the regulation.

It is important to note that the proposed revision to the regulation's opacity limit will not result in any increase of particulate emissions from the power stations. Our power stations are and will continue to be in compliance with the weight emission standard of 0.05 lb/MBtu. Therefore, the proposed revision will not adversely affect the environment or health of WV citizens. I would also like to note that the proposed revision is consistent with that of WV's neighboring states of MD, PA, VA and OH which require a 20% opacity limit and EPA's federal New Source Performance Standards. The proposed revision simply acknowledges the reality of present conditions and allows the state's power stations to operate in compliance with the regulation.

Allegheny Power System

Bulk Power Supply

APS installed electrostatic precipitators on all WV power stations between 1967 and 1982 to control the emission of particulates. The precipitators are designed, installed, operated, and maintained to meet the weight emission standard of 0.05 lb/MBtu. According to stack tests, our stations are in compliance with the weight emission standard. Opacity is an inexact standard of measurement of the amount of particulate emissions. Although opacity is used as a surrogate measure of particulate emissions, the existing state opacity limit does not correlate with the weight emission limit. Accordingly, this proposed revision to the opacity limit is not a relaxation in particulate emissions, but a necessary correction to the opacity standard. Because our power stations utilize comparatively large diameter stacks and the measure of opacity, using continuous emission monitors, is dependent on the optical pathlength, it is possible that we could actually be emitting less particulate on a weight emission basis and still show a higher opacity than an equivalent source with a smaller diameter stack.

Increasing the opacity limit from 10 to 20% will not result in a violation of the weight emission standard. APS will continue to maintain compliance with the weight emission standard. APS does not intend to increase the size of it's units, the manner of operation of the electrostatic precipitators, or the potential to emit. Without a change in the opacity limit, APS would need to install additional particulate control equipment at several power stations in order to maintain continuous compliance. The cost to install this equipment is estimated to be over $236,000,000 which would ultimately be passed on to our customers.

WV's neighboring states, MD, PA, VA and OH, require a 20% opacity limit. Additionally, EPA's federal New Source Performance Standards (NSPS) include a 20% limit. WV law provides that WV regulations are to be no more stringent than federal regulations absent factors unique to WV. APS is not aware of any such unique factors present with opacity issues in WV. Therefore, APS believes the existing opacity limit is, at the least, unreasonably more stringent than our neighboring states, and, at the most, may be unlawful. The state legislature concluded that the state should not place itself in a competitive disadvantage absent compelling circumstances and should balance all interest involved, including employment, coal, etc.

APS's power stations are operated to reduce generation when the opacity limit cannot continuously be achieved. When stations reduce generation, that loss in production must be replaced with other more expensive generation which increases the cost to our customers. Moreover, units brought on-line to replace the lost generation are often power stations located out of state. Therefore, the existing WV opacity rule directly impacts the amount of WV coal burned at the WV stations. Employment in coal mining is also affected with shifts in generation of electricity from in-state to out-of-state. Coal severance taxes collected by the state are reduced with lower coal production and B&O taxes collected on generation of electricity are likewise reduced. Therefore, WV has been placing itself at a tremendous competitive disadvantage

acing itself at a tremendous competitive disadvantage
quiring more stringent standards than necessary.
Therefore, WV has been pl
versus other states by re

In conclusion, there is overriding support and rationale for the state to revise the opacity standard from 10 to 20%. The 20% opacity limit more accurately represents the existing weight emission standard and APS fully intends to continue compliance with the weight emission standard. This revision is in the best interest of our customers, the state tax receipts, the coal industry and the employment of the state. This change will enable the opacity standard to be in greater conformity to the weight emission limit, neighboring states opacity limits and WV statutes regarding stringency requirements. More importantly, the proposed revision does not reduce our protection of the environment and health of our citizens.

APS also offers the following comments on particular sections of the proposed regulation:

Sec. 3.1 A provision should be included which exempts units utilizing wet flue-gas desulfurization equipment from the 20% opacity limit. Due to the water vapor in the flue gas, it is not possible for these units to operate in compliance with the opacity limit. In fact, the EPA recognizes the unique operational circumstance of wet flue gas units and exempts them from opacity monitoring requirements [40CFR 75.14(b)]. A related complication of opacity measurement on wet FGD units is the formation of secondary pollutants such as nitrates or sulfates which can actually occur after discharge from the stack. Trying to measure opacity for compliance purposes after the vapor dissipates is neither an accurate assessment of the stack exit particulate emissions nor consistent with Method 9.

Sec. 3.2 It is recommended WV develop an enforcement policy regarding the compliance status of units which utilize continuous opacity monitors for determination of compliance with the opacity limit. The enforcement policy should require sources to be in compliance at least 95% of the operating time in order to be considered in compliance with the limit.

Sec. 3.3 In order to be consistent with the six minute averaging time and to simplify recordkeeping procedures, it is recommended the sootblowing exception be in terms of 4 six minute averages each day rather than 8 minutes per eight hour period.

Sec. 4.2 The use of flue gas conditioning with sulfur compounds is a generally accepted method of improving electrostatic precipitator performance. It is recommended the previous language in Sec. 4.3 which grandfathers such sources in operation effective September 1, 1974, be retained.

Sec. 8.4 In order to be consistent with the requirement for submission of opacity reports to the state on a quarterly basis, it is recommended the startup/shutdown reports be submitted with the quarterly report rather than monthly.

We appreciate the opportunity to comment on the proposed amendments to the regulation and the fact the Office of Air Quality is making the much needed revisions.

Respectfully,

L. D. Myers

Appalachian Power Company
PO Box 2021
Roanoke, VA 24022-2121
703 985 2300

AEP APPALACHIAN POWER

HAND DELIVERED

Mr. G. Dale Farley, Chief
West Virginia Division of Environmental Protection
Office of Air Quality
1558 Washington Street, East
Charleston, West Virginia 25311-2599

Re: Comments on Proposed
45 CSR 2

November 29, 1994

Dear Mr. Farley:

Appalachian Power Company (the Company) submits these comments in addition to those submitted by Mr. David Flannery and the work group industries on the proposed changes to 45 CSR 2, "To Prevent and Control Particulate Air Pollution..."

We applaud the Office of Air Quality's efforts in pursuing the changes to the regulation and in their work with the industries in this undertaking.

The Company is strongly affected by these regulations and urges the Office of Air Quality to carefully consider our comments and incorporate them into the revised regulation.

1. **Section 2.14** - The word "an" should be changed to "and" to reflect the conjunction of "sudden <u>and</u> unavoidable failure" when referring to malfunctions.

2. **Section 2.22** - "Pitobe" should be changed to "pitot tube" to reflect the equipment used in sampling.

3. The Company supports **Section 3.2** which allows compliance by either COMS or EPA Method 9. The Company requests that consideration be given to reinserting the 95% compliance time in Section 3.2 as found in earlier drafts of the proposed regulation. The revised section should include:

   "Should continuous opacity monitoring devices be utilized, the owner or operator shall be in compliance with the

> visible emission requirements at least 95% of the time that the source is required to operate its continuous opacity monitor. If continuous opacity monitoring is utilized to determine compliance, it must be operated at all times (other than during maintenance activities on the continuous opacity monitoring device) that the fuel burning unit is in operation."

4. We urge that the provision for sootblowing **(Section 3.3)** be revised to allow for a (minimum) twelve minute period of 40% average. Depending on the size of the boiler and the slagblowing methods, an eight-minute exception period may not be long enough to adequately clean the boiler. On the smaller units, slagblower cycle time is 8-10 minutes. For the larger Amos Plant, a 20-25 minute cycle time is typical, where cycle time is the time for one slagblower to enter and exit the boiler. Additionally, because opacity is reported in six minute averages, it is logical that a twelve minute exception period be used.

5. The Company requests that **Section 4.3** concerning sulfur oxide injection remain in the text, with the wording as follows:

    > **4.3 The provisions of Subsection 4.2 of this section shall not apply to combustion units in operation on or before September 1, 1974.**

    Appalachian Power presently injects at several of its units as an additional means of controlling opacity.

6. **Section 8.4** states that opacity reports shall be submitted on a monthly basis. We urge that this requirement be changed so that the reports (startup/shutdown, opacity, and quality of fuel used) are submitted quarterly, or in accordance with emissions reporting of 40 CFR 75. A monthly submittal schedule would be more stringent than the federal requirements for emissions. Submitting the opacity report in conjunction with the emissions report is logistically preferred.

Presently, opacity reports and startup/shutdown logs are submitted to the Office of Air Quality on a quarterly basis.

7. We support the opacity standards exceptions during startup/shutdown and malfunctions in Section 9. This provision should also include mass emission standards.

8. Malfunction reporting under **Section 9** should be revised to reference **Sections 3 and 4** for defining excess opacity or excess particulate emissions and to clarify this entire section in regard to what is reported.

9. **Section 9.3** should be revised to read:

> Except as provided in **Subsection 8.4** for startups and shutdowns and **Subsection 9.4** ...

Thank you for considering these comments.

Sincerely,

Robert J. Robinson

Robert J. Robinson
Environmental Affairs Director

RJR:d

ORAL COMMENTS ON BEHALF OF MONONGAHELA POWER COMPANY,
THE POTOMAC EDISON COMPANY AND WEST PENN POWER COMPANY

ON

PROPOSED AMENDMENTS TO WEST VIRGINIA REGULATION 45CSR2
"TO PREVENT AND CONTROL PARTICULATE AIR POLLUTION FROM COMBUSTION OF FUEL IN INDIRECT HEAT EXCHANGES"

NOVEMBER 29, 1994

PRESENTED BY: L. D. MYERS

Good morning. My name is Larry Myers and I am the Director of Environmental Services for the Allegheny Power System (APS). I'm here this morning representing Monongahela Power Company, The Potomac Edison Company and West Penn Power Company, the three operating companies of APS. We appreciate the opportunity to comment on the Office of Air Quality's proposed amendments to Regulation 45CSR2. Monongahela Power operates six power plants in West Virginia with a total generating capacity of 4949 Mw which are subject to this opacity regulation. My oral comments this morning are an abbreviated version of the written and more detailed comments being submitted. APS' comments are also consistent with those being offered by Mr. Flannery of Robinson & McElwee on behalf of the WV electric utilities and other industries.

APS fully supports the revision to existing regulation 45CSR2 which proposes to increase the visible emission limit from 10 to 20% opacity. Continuous compliance with the existing 10% opacity limit is not practical to achieve without the installation of additional costly particulate collection equipment. While APS has previously objected to the severe stringency of the 10% opacity limit, it was recent changes to opacity recordkeeping and reporting requirements developed by the EPA which has heightened the importance to revise the regulation.

It is important to note that the proposed revision to the regulation's opacity limit will not result in any increase of particulate emissions from the power stations. Our power stations are and will continue to be in compliance with the weight emission standard of 0.05 lb/MBtu. Therefore, the proposed revision will not adversely affect the environment or health of WV citizens. I would also like to note that the proposed revision is consistent with that of WV's neighboring states of MD, PA, VA and OH which require a 20% opacity limit and EPA's federal New Source Performance Standards. The proposed revision simply acknowledges the reality of present conditions and allows the state's power stations to operate in compliance with the regulation. Without these proposed revisions, additional particulate control equipment would have to be installed on our power stations at an additional estimated cost of $236,000,000 which would ultimately be passed on to our customers.

Two additional comments I'd like to emphasize are on particular sections of the proposed regulation. First, in Sec. 3.1, a provision should be included which exempts units utilizing wet flue-gas desulfurization (FGD) equipment from the 20% opacity limit. Due to the water vapor in the flue gas, it is not possible for these units to operate in compliance with the opacity limit. In fact, the EPA recognizes the unique operational circumstance of wet flue gas units and exempts them from opacity monitoring requirements [40CFR 75.14(b)]. A related complication of opacity measurement on wet FGD units is the formation of secondary pollutants such as ~~nitric oxides~~ NITRATES or ~~sulfur oxides~~ SULFATES which can actually occur after discharge from the stack. Trying to measure opacity for compliance purposes after the vapor dissipates is neither an accurate assessment of the stack exit particulate emissions nor consistent with Method 9. Second, in Section 3.2, it is recommended WV develop an enforcement policy regarding the compliance status of units which utilize continuous opacity monitors for determination of compliance with the opacity limit. The enforcement policy should require sources to be in compliance at least 95% of the operating time in order to be considered in compliance with the limit.

Again, we appreciate the opportunity to comment on the proposed amendments to the regulation and applaud the Office of Air Quality for making the much needed changes.

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DAVID M. FLANNERY
DIRECT DIAL NO. (304) 347-8352

JUN 07 94

June 3, 1994

Mr. David C. Callaghan
Director
Division of Environmental Protection
10 McJunkin Road
Nitro, WV 25143-2506

Re: Regulation of Particulate Emissions
From Indirect Heat Exchangers; 45 CSR 2.

Dear Director Callaghan:

Enclosed is a petition to review and revise 45 CSR 2.

These proposed revisions are being filed on behalf of our clients Appalachian Power Company, Monongahela Power Company, Ohio Power Company, Virginia Electric and Power Company and the West Virginia Manufacturers Association. I am authorized to state that Elkem Metals Company, FMC Corporation, Monsanto Chemical Company, and Union Carbide Corporation join in this request.

DEP is requested to undertake these modifications to avoid the significant and unnecessary expenditures that would be necessitated the existing version of this rule. Because these proposals do not change the mass emission limitations of this rule, we believe these changes can be approved as technical amendments.

Additionally, inasmuch as one such proposal involves adopting EPA approved test methods to measure opacity and mass emissions, we urge that TP2 (45 CSR TP-2) be repealed.

Your favorable action on these proposals is requested.

Very truly yours,

David M. Flannery

David M. Flannery

DMF/kjd

Enclosure
cc: Mr. G. Dale Farley

BEFORE THE WEST VIRGINIA
DIVISION OF ENVIRONMENTAL PROTECTION

Petition to Revise
45 CSR 2

"To Prevent and Control Particulate Air Pollution From Combustion of Fuel In Indirect Heat Exchanges"

On Behalf Of:

APPALACHIAN POWER COMPANY
ELKEM METALS COMPANY
FMC CORPORATION
MONONGAHELA POWER COMPANY
MONSANTO CHEMICAL COMPANY
OHIO POWER COMPANY
UNION CARBIDE CORPORATION
VIRGINIA ELECTRIC AND POWER COMPANY
and
WEST VIRGINIA MANUFACTURERS ASSOCIATION

Submitted by:

ROBINSON & MCELWEE

David M. Flannery
Kathy G. Beckett

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June 3, 1994

PETITION TO REVISE
45 CSR 2

"To Prevent and Control Particulate
Air Pollution From Combustion of
Fuel In Indirect Heat Exchangers"

1. Introduction.

The opacity and related regulatory requirements of Regulation 2 [45 CSR 2] are of critical importance to both the electric utility and manufacturing industry. These requirements have been a matter of concern to the regulated community since Regulation 2 was initially adopted. New continuous emission monitoring and reporting requirements as well as compliance certification requirements of the 1990 Clean Air Act Amendments have heightened concern with respect to the provisions of this regulation necessitating the filing of this petition.

1.1 The Petitioners.

This request to revise and amend Regulation 2 is filed on behalf of a group of electric utilities and manufacturers that own and operate Type 'a', 'b' and 'c' fuel burning units in West Virginia that are subject to the various requirements of 45 CSR 2. The companies that request modification of various provisions of Regulation 2 as will be set forth in greater detail in this petition are as follows:

Appalachian Power Company
Elkem Metals Company
FMC Corporation
Monongahela Power Company
Monsanto Chemical Company
Ohio Power Company
Union Carbide Corporation
Virginia Electric and Power Company
and
West Virginia Manufacturers Association

1.2. Overview of Regulation 2.

In its current form, Regulation 2 contains a broad series of regulatory requirements aimed at controlling particulate air pollution from the combustion of fuel in indirect heat exchangers. Regulation 2 establishes emission requirements of three types: opacity, weight emission and fugitive dust. Moreover the regulation sets forth a variety of other requirements related to registration, permitting, reports and testing, compliance programs, variances and exemptions. While the petitioners recognize that there are a number of aspects of Regulation 2 that are simply outdated and in need of revision for that reason alone, there are five specific aspects of the regulation that will be the focus of this petition and the request of the petitioners that these provisions be revised.

1.2.1. Opacity.

The primary area of concern to the petitioners are the requirements set forth in Section 3 (45 CSR 2-3) which establish an opacity requirement of 10% applicable to all fuel burning units. Two very limited exemptions are provided from the 10% opacity requirement. The first is applicable to soot blowing operations where opacity is allowed to a level of 20% for no more than eight minutes per fuel burning unit during any eight hour period. The second applies in the case of the start up of a fuel burning unit where opacity as high as 40% is allowed for Type 'a' and 'b' fuel burning units and as high as 60% for Type 'c' fuel burning units upon the specific application of the owner/operator of those units.

1.2.2. Weight Emission.

Weight emissions often times referred to as "mass\ emissions," are regulated in Section 4 of Regulation 2 (45 CSR 2-4) where weight emission standards are established on a plant wide basis for all fuel burning units at each plant. In the case of Type 'a' fuel burning units, a plant-wide limitation on the discharge of particulate matter in pounds per hour is established as being the product of 0.05 and the total design heat input of all units at the plant (not to exceed 1200 pounds per hour). For Type 'b' fuel burning units the limitation is established as being the product of 0.09 and the total design heat input of all such units (not to exceed 600 pounds per hour). For Type 'c' fuel burning units the plant wide emission limitation is set forth in a table provided in the regulations with a maximum of 300 pounds per hour of particulate matter.

1.2.3. Testing.

While Regulation 2 contains a variety of testing requirements in Section 8 (45 CSR 2-8), those requirements bear no apparent connection with the provisions contained at 45 CSR 2-TP nor the federal regulations applicable to determining compliance with the weight\mass emission requirements of the regulation. Regulation 2 does not address at all the testing procedure that should be made applicable to determining compliance with the opacity requirements of the regulation other than the reference to the antiquated "Ringelmann Smoke Chart."

1.2.4. Reporting.

Section 3.5 of Regulation 2 (45 CSR 2-3.5) allows an exemption from the normally applicable 10% opacity requirement, upon application to the Commission in the case of unit start up. The Office of Air Quality has in fact been operating under a policy that took effect on July 1, 1990 which requires the reporting of start up and shut down operations on a quarterly basis rather than in advance of the start up and shut down activity as the regulation states.

1.2.5. Gas Conditioning.

While Section 4.3 of Regulation 2 (45 CSR 2-4.3) allows units in existence as of September 1, 1974 to utilize sulfur oxide gas conditioning for the purpose of improving control equipment efficiency, there is no current authority to allow such to occur with respect to any later units.

1.3 Background of Development.

While Regulation 2 was originally adopted in 1966 for applicability to sources in the Kanawha Valley, the first statewide version of this rule was adopted by the West Virginia Air Pollution Control Commission on January 26, 1972 and became effective March 15, 1972. The regulation was next modified by the Air Pollution Control Commission on July 23, 1974 (effective September 1, 1974) principally for the purpose of adding provisions related to the utilization of sulfur oxides to improve control equipment efficiency. There have been no other substantive modifications to this regulation in the 20 years that have intervened.

2. Relationship of Regulation 2 to SIP.

2.1. Incorporation into SIP.

Regulation 2 (1972) became a principal component of West Virginia's first State Implementation Plan. The United States Environmental Protection Agency (EPA) acted to approve West Virginia's SIP on May 31, 1972 making that SIP federally enforceable and satisfying the requirements of the federal Clean Air Act.

2.2. Control Strategy for Attainment Demonstration.

The State Implementation Plan submitted by West Virginia to EPA for approval relied upon a control strategy for attaining compliance with the National Ambient Air Quality Standards for particulate matter that selected the Kanawha Valley as an example region and rolled back the emissions of all Kanawha Valley sources by a percentage that was determined to be sufficient to bring the particulate ambient air quality into compliance with the National Ambient Air Quality Standards. Having established the percentage reduction in mass\weight emissions that would be appropriate for the Kanawha Valley, the control strategy applied a similar set of emission limitations to comparable sources throughout the state.

For purposes of this petition, it is most significant that the control strategy for particulate matter relied exclusively on the mass\weight emission limitation requirements of Regulation 2 for making a demonstration of attainment and maintenance of National Air Quality Standards. Nowhere in the control strategy for particulate matter did West Virginia rely upon its opacity limitations for any part of this demonstration. Petitioners submit, therefore, that the proposals advanced in this petition should not in any way interfere with West Virginia's control strategy for attaining and maintaining National Ambient Air Quality Standards for particulate matter.

3. Comparison to Federal NSPS.

While EPA has not promulgated either opacity or mass emission limitations that are directly applicable to existing fuel burning units, EPA has adopted new source performance standards [NSPS] applicable to fuel burning units. Generally speaking, emission limitations for new sources are more restrictive than those for existing sources since it is much easier to design new control equipment into new sources than would be the case for existing sources. Such is, however, not the case with respect to the requirements applicable to Regulation 2. As can be seen by the following comparison between West Virginia's opacity requirements and those of the United States Environmental Protection Agency, West Virginia's opacity standard applicable to existing units is more restrictive by far than the opacity requirements which the federal government would apply to new sources including those sources that would be designed, constructed, and operated in the future.

COMPARISON OF OPACITY REQUIREMENTS TO EPA

	WV	U.S. EPA		
	All Units[1]	Utility[2] Old New Source	Utility[3] New Source	Industrial[4] New Source
Opacity	10%	20%	20%	20%
Opacity Exclusions (6 min/hr)	N/A	27%	27%	27%

1 45 CSR 2
2 40 CFR §60.42
3 40 CFR §60.42a
4 40 CFR §60.43b

4. <u>Historical Concerns Regarding Opacity Compliance</u>.

While West Virginia's 10% opacity requirement has been in effect since 1972 on a state-wide basis, it has been the subject of on-going concern. Numerous objections have been raised to this requirement by the regulated community over the years. The opacity provision has remained largely unenforced by West Virginia until recent months when reporting and certification requirements mandated by the federal Clean Air

Act Amendments of 1990 elevated the significance of this opacity requirement thus causing the regulated community and the agency to begin addressing the significance of compliance with this opacity requirement.

4.1. Historical Objections .

The original objection raised by industry to the 10% opacity requirement occurred during the rulemaking process in 1971 and 1972. The agency received a petition in 1974 from an electric utility company specifically petitioning to revise the opacity and other requirements of Regulation 2. The Commission took no action on that petition at the time.

In 1978, the Commission was again petitioned by representatives of the electric utility industry to address concerns over the stringency of the opacity requirement of Regulation 2. Attached and identified as Exhibit 1 is the statement that was filed with the Commission on December 7, 1978 on behalf of Appalachian Power Company and Ohio Power Company specifically requesting a relaxation of the 10% opacity requirement to the 20% opacity level that is contained within the federal program. Accompanying that statement was the technical report of H.J. Hall Associates, Inc. which, among other things, addressed the scientific basis behind the opacity limitation of West Virginia's regulation. As can be seen from page 46 of the excerpt from the transcript of the Commission proceedings held on December 7, 1978, a copy of which is attached and identified as Exhibit 2, the Commission obligated itself to conduct a hearing to address the potential for revision to the 10% opacity requirement. No other action on this request has been undertaken to date.

4.3. Compliance monitoring.

Another historical concern with respect to the implementation of the opacity requirements of Regulation 2 relates to the absence of any compliance monitoring mechanism specified in the regulation itself. As currently constituted Regulation 2 states the opacity limitation as either 0.5 Ringelmann or 10% opacity. While the regulation defines what constitutes a "Ringelmann Smoke Chart", there is nothing contained within the regulation that specifies how opacity itself will be read. In absence of a specific method to address opacity, it has been custom and practice to apply EPA Method 9 to read opacity for plumes after they have emerged from a stack. Regulation 2 has not addressed all the circumstances that would otherwise be applicable to the results of continuous opacity monitors which read opacity inside the stack itself. Each of these concerns compel revision to the regulation at this time.

4.3 Stack Diameter.

Because these fuel burning units subject to Regulation 2 utilize comparatively large diameter stacks and because the measure of opacity is dependent on the optical pathlength, it is possible that a unit could actually be emitting less particulate on a weight emission basis and still show a higher opacity than a comparable unit emitting a larger quantity of particulate through a smaller diameter stack.

This point is graphically illustrated on page 9 of the report of H.J. Hall Associates, Inc. which is found in Exhibit 1 to this petition. This report considers the relationship between opacity and mass emissions in the specific context of the facilities of American Electric Power in West Virginia. The report concludes that opacity is influenced by a number of factors other than mass emission rate. The factors include such things as stack diameter and the nature of the particulate matter being discharged. In particular, the report notes that stack diameter alone can cause opacity to vary from 10% to 20% for the same mass emission rate.

Using as an illustration the emissions from Appalachian Power Company's Amos Unit 3 as an example, Mr. Hall points out that the discharge of those emissions through three stacks having a diameter of 17.5 feet would meet a

10% opacity requirement while discharging precisely the same emissions through a single stack of 30.25 feet would result in an opacity of approximately 20% (twice the regulatory limitation that would otherwise apply).

4.6 Comparison to Other States.

At a time when West Virginia has a 10% opacity requirement applicable to all of its utility and industrial boilers, the petitioners find it significant that all of West Virginia's neighboring states require compliance with no more than a 20% opacity requirement -- the level that has been adopted by the federal government for new sources. This circumstance creates limitations on the operation of fuel burning units in West Virginia that are not applicable to neighboring states and causes West Virginia to suffer significant competitive disadvantage.

As will be seen in later discussions with respect to the electric utility industry the effect of a 10% opacity requirement at a time when 20% is mandated in other states is to shift load to units located in other states. This results in a loss of the opportunity to burn West Virginia coal that would otherwise be dedicated to these West Virginia utility boilers, not only depriving West Virginia of the sales of that coal but also the tax revenue and jobs that relate to its consumption.

In the case of industrial boilers, the stringency of the West Virginia opacity requirement results in higher costs of operation at the West Virginia facilities relative to facilities in neighboring states making those operations less competitive.

The following chart compares West Virginia's opacity standard with the opacity requirements of its neighboring states.

COMPARISON OF OPACITY REQUIREMENTS
TO OTHER STATES

STATE	OPACITY REQUIREMENT
West Virginia	10%
Kentucky	20%
Maryland	20%
Ohio	20%
Pennsylvania	20%
Virginia	20%

5. Start-up and Shut-down.

5.1. Comparison of Exemptions for Opacity and Mass Emissions.

As discussed previously there is a limited exemption contained in Section 3.5 of Regulation 2 related to the start-up of a fuel burning unit. No comparable provision is set forth in that section with respect to the shut-down of fuel burning units.

Similarly, Section 10.2 of Regulation 2 provides a variance from emission requirements of the regulation for start-up only of fuel burning units. The variance mechanism of Section 7.2 is initiated by application to the Director and may be granted for periods not to exceed 24 hours. There is little consistency between the two policies as set forth in Section 3 and Section 10 of Regulation 2 and petitioners will advance amendments to address this situation.

5.2. 1990 start-up policy.

In addition to the general objection of the regulated community to the 10% opacity requirement, there has been an on-going concern as to the applicability of the requirements of Section 3.5 of Regulation 2 to start-up operations involved with fuel burning units. Under the current requirements of this section, a limited exemption from a 10% opacity requirement may be allowed by the Commission upon specific application by an owner or operator in advance of the start-up of a unit. This requirement not only placed significant burdens on the regulated community but also upon the staff of the Commission and later DEP, resulting in the Commission issuing a policy effective July 1, 1990 directing that pre-notification of start-up and shut-down be suspended in favor of filing a report on start-up and shut-down activities on a quarterly basis. A copy of a typical letter containing this policy to the owner of a fuel burning unit is attached and identified as Exhibit 3. This policy has in fact been the operative document controlling the circumstances under which the regulated community has been complying with the reporting requirements of Regulation 2 with respect to opacity during start-up and shut-down operations. No effect has been undertaken at this time to correct Regulation 2 to bring it into conformity with this operating practice.

6. <u>Proposed Amendments</u>.

It should be apparent that over the years Regulation 2 has given rise to a significant number of issues that should be addressed at this time. These issues in part result from the historical concern which the regulated community has had with respect to the 10% opacity requirement and its enforceability. There is also a need to review and revise Regulation 2 to address the internal inconsistencies that exist in the regulation with respect to notification requirements, monitoring, reporting and testing. The regulation is also in need of review to update its terms given reorganization which has occurred in state government. Accordingly, petitioners urge that Regulation 2 be revised as follows and that 45 CFR 2-TP be repealed altogether as being inconsistent with the revisions that will be proposed to 45 CSR 2. Attached and identified as Exhibit 4 is a formal proposal to address these suggested revisions with deletions indicated with strike throughs and additions indicated with underlining.

6.1. <u>Opacity</u>.

To address concerns with respect to opacity requirements, amendments are suggested in several different areas of the regulation.

6.1.1. Normal Operations.

It is urged that all fuel burning units be subject to the same opacity requirement of 20% opacity determined on the basis of six minute averages except for a single six minute period per hour where opacity would not exceed 27%. This provision is taken directly from the federal regulations applicable to new sources.

6.1.2. FGD Exemption.

For fuel burning units that utilize flue-gas desulfurization [FGD] equipment to remove sulfur dioxide, it will be necessary to create an exemption from opacity requirements. Application of FGD equipment to a fuel burning unit generates a plume that has 100% opacity by virtue of the water vapor that is present in the plume. It would not be possible to operate a unit equipped with FGD equipment in a way that could comply with any opacity limitation. Such a provision would be consistent with EPA's regulation which appears at 40 CFR § 75.14(b). Petitioners urge that units equipped with FGD equipment be exempt from the requirement to comply with an opacity limitation.

6.1.3. Unit Outage Exemption.

Similarly, the opacity requirement of Regulation 2 should not be applied to the situation in which condensate forms in the stack when one or more of multiple units discharging into the same stack are taken out of operation. In this circumstance, it may not be possible to avoid creating condensate within the stack itself that would make it impossible to comply with an opacity limitation. Petitioners urge that the opacity limitation of Regulation 2 not be applied in this case.

6.1.4. Soot Blowing.

Under the current regulation, soot blowing is limited to 20% opacity for only eight minutes during any eight hour period. The petitioners believe that such a requirement is so restrictive as to be incapable of assuring compliance. Petitioners also note that no comparable requirement exists under the federal program. A modification to this requirement to establish the availability of a 40% opacity requirement for five six minutes periods (which may or may not be consecutive) during any eight hour period is both reasonable and necessary.

6.1.5. Testing.

To determine an appropriate methodology for achieving compliance with the opacity requirements of Regulation 2, the petitioners propose that new provisions be developed for inclusion within a new Section 3.4 of this regulation to address both external plume readings and instack opacity.

6.1.5.1. Method 9.

For conformity with the federal program, petitioners urge that the visible emission requirements of Regulation 2 be determined by reference Method 9 as set forth at 40 CFR Part 60, Appendix A. This methodology is well known to both the regulated community and the state. Its adoption will assure conformity with the federal program and provide all parties with important guidance as to how the regulatory requirements will be implemented.

6.1.5.2. Continuous Opacity Monitor.

While there is no mandate under the state program that continuous opacity monitors be employed, there clearly are a number of circumstances in which sources may elect to install such monitors. Petitioner propose that the new Section 3.4 for Regulation 2 provide for a mechanism to allow the Director to approve the installation of these new devices. In addition, the petitioners urge that the agency adopt a policy which considers compliance with the opacity requirements to be at least 95% of the time that a source is required to operate its COM. A similar policy, which is used in Virginia and is based on EPA - Region III policy, considers 95% compliance, based on COM data, as a guideline for determining when further investigation of a source's compliance status is needed.

6.1.6. Alternative Opacity Limit.

While it is believed that a 20% opacity requirement would be sufficient in most cases to allow fuel burning units to operate in compliance during normal operations, petitioners recognize that EPA has established a procedural mechanism that would allow alternative opacity limitations to be established in excess of 20% if an operator can make a demonstration that the fuel burning unit is in compliance with the applicable weight emission limitations. Petitioners urge that a new Section 3.5 be added to Regulation 2 modeled on the federal requirement that would provide for an alternative opacity limitation to be established in excess of 20% upon demonstration of a carefully prescribed set of conditions.

6.2. <u>Weight Emissions</u>.

6.2.1. Alternative Emission Standards.

While petitioners do not urge any immediate revision to the weight emission requirements of Regulation 2 as contained in Section 4.1 of that regulation, petitioner recognize that West Virginia's weight emission rates in many cases are significantly more restrictive than would be the case for comparable new fuel burning units subject to EPA's new source performance standards. To allow operators of fuel burning units a mechanism by which requests to address alternative weight emission limitations, it is proposed that a new Section 4.4 be added to Regulation 2. This section as proposed would give the Director the discretion to establish an alternative weight emission limitation upon demonstration by the owner of a fuel burning unit that an alterative limitation would assure attainment and maintenance of National Ambient Air Quality Standards for particulate matter and result in an emission limitation no greater than the product of 0.10 and the actual heat input of the fuel burning unit.

6.2.2. Testing.

While Section 8.1 of Regulation 2 contains a mechanism for conducting testing for compliance with weight emission requirements of the regulation, those testing requirements are outdated and inconsistent with both 45 CSR TP-2 and the test procedures that are mandated under the federal regulatory program.

A careful examination of the requirements of 45 CSR TP-2 indicates that that regulation, too, is inconsistent with the federal program in a number of particulars. To eliminate the potential for this inconsistency with the federal program, petitioners urge that Section 8.1 of Regulation 2 be revised to call for the utilization of EPA's compliance determination methodologies in all appropriate cases. For units utilizing wet flue gas desulfurization systems [FGD], EPA Method 5B is appropriate. In other applications EPA Methods 5 or 17 would be appropriate. We also believe it would be desirable to allow the Director to approve an operator's request to utilize alternative methods should those alternative methods meet with the Director's satisfaction. With these changes in place, it would be appropriate to repeal 45 CSR TP-2 as being unnecessary.

6.3. Start-up and Shut-downs.

As discussed previously Regulation 2 contains a number of inconsistencies between its handling of start-ups and shut-downs for both opacity and weight emission requirements. Petitioners urge, therefore, that the regulation be revised to address both the exemption for start-ups and shut-downs as well as applicable reporting requirements.

6.3.1. Exemption.

In order to bring West Virginia's regulation into conformity with federal requirements, we urge that opacity requirements not be applicable at all during periods of start-up and shut-down. A new Section 3.3 has been proposed to Regulation 2 to accomplish this objective. This requirement would be entirely consistent with provisions of the federal program applicable to new sources as set forth at 40 CFR §60.11(c).

It is also proposed that a comparable requirement be incorporated into Regulation 2 with respect to mass/weight emissions. Petitioners urge that a new Section 4.5 be added to the regulation that would exempt fuel burning units from the weight emission requirements during start-up and shut-down. Adoption of this provision would allow Section 10.2 of the current rule to be eliminated altogether. By addressing start-ups and shut-downs in this manner, the regulation would be made more like the agencies operation policy effective July 1, 1990 in that the exemptions would be made applicable to both start-up and shut-down and would not require prior agency approval.

6.3.2. Reporting.

Again in an effort to conform Regulation 2 to the agency's policy on start-ups and shut-downs effective July 1, 1990, the petitioners propose that Section 8.4 of Regulation 2 be revised to make it clear that an operator would be obligated to notify the Director after the occurrence of start-ups and shut-downs "within a reasonable time". It is believed that from time to time the Director would want to specify what constitutes a reasonable time for reporting. The agency's policy of July 1, 1990 currently requires the reporting to occur on a quarterly basis. It is also proposed that revised Section 8.4 provide that where an operator is reporting data through an approved continuous opacity monitor, it would not be necessary to provide a separate report of start-ups and shut-downs since the opacity monitor itself would identify that data.

6.4. Gas Conditioning.

The current provisions of Regulation 2 preclude the utilization of sulfur oxides to a combustion unit for purposes of improving control equipment efficiency in all cases other than units that were in existence on September 1, 1974. While petitioners presently know of no unit of more recent vintage that would necessarily need the benefit of sulfur oxides injection to improve control equipment efficiency, we believe it would be prudent for this option to be made available to the Director by this regulation. Petitioners therefore urge that Section 4.3 of this regulation be revised to authorize the director to approve the utilization of sulfur oxides to improve control equipment efficiency on units that have come into existence since September 1, 1974.

6.5. Clean-up Amendments.

6.5.1. Eliminate phase-in provisions.

There are a variety of provisions in the current version of Regulation 2 that were obviously placed in the regulation for purposes of bringing units into initial compliance with the regulations. Because these provisions are no longer useful, we urge their removal from the regulation. This is most applicable to the provisions contained in the current version of Sections 3.1 (related to fuel burning units which do not meet the mass emission requirements) Section 6.1 and 6.2 (related to registration requirements) Section 7.1 (related to permitting) and Sections 9.1 and 9.2 (related to compliance programs).

6.5.2. Conformity to Agency Reorganization.

Since Regulation 2 was last modified, there have been a number of changes to the manner in which air pollution regulation in West Virginia is to be undertaken. Effective June 10, 1994, all rulemaking authority for air pollution purposes has been transferred to the DEP director. We urge that these changes be incorporated into the current revision to this regulation.

6.5.3. Permit Requirements.

For reasons that the petitioners are unable to explain, the current version of Section 7.1 calls for the issuance of permits on the condition that emissions not cause or contribute to a violation of secondary air quality standards. We would suggest that this be made applicable to both primary and secondary ambient air quality standards. We would also urge that other changes be made to this section to eliminate the time period for processing permit applications since those time periods have now been revised in the statutes that control permitting on this issue.

7. Specific Facility Impact.

7.1. Appalachian Power Company and Ohio Power Company.

7.1.1 Units Involved

Appalachian Power Company, Ohio Power Company and Central Operating Company operate sixteen coal fired units within the State that are subject to Regulation 2 including the following: John E. Amos Units 1-3 located near St. Albans, Mountaineer Unit 1 on the Ohio River at New Haven, Philip Sporn Units 1-5 at New Haven, Kanawha River Units 1 and 2 at Glasgow and Mitchell Units 1 and 2 and Kammer Units 1, 2 and 3 located near Moundsville. The generating units account for 7,880,000 kilowatts of power. Although all units are restricted by Regulation 2, Amos Unit 3 is affected most critically by the 10% opacity limit.

7.1.2. Operational Constraints Imposed by Current Rule.

During the past five years, an average of $125,000 has been spent annually on maintenance repairs to the Amos Unit 3 ESP. $110,000 is expended annually to repair damage as a direct result of the high resistivity ash collected by the ESP.

Amos 3 ESP was designed to collect fly ash generated from burning 10,000 BTU/lb coal with a minimum sulfur content of 1% (2.0 lb SO_2/MMBTU). The present SO_2 emission regulation limits the SO_2 content of the coal to 1.6 lb SO_2/MMBTU. Fly ash from coal with sulfur contents less than 1% typically have high resistivities (> 2e10 ohm-cm).

Historically, coal with a sulfur content between 1.3 and 1.6 lb SO2/MMBTU results in better ESP performance. Amos has only one supplier whose coal deliveries are in a 1.3 to 1.6 lb SO2/MMBTU range. This represents 25% of the Amos coal supply. The plant administratively segregates storage piles or directly to the unit. The plant estimates that coal yard personnel spend 550 manhours per year segregating the piles for a cost of $20,000.

At times the unit is forced to curtail load because of the low opacity limit. In the period 1987-89, these load curtailments amounted to approximately 450,000 MWH of lost generation. In 1988, a more consistent supply of 1.3 coal was supplied to the unit. Although significantly reduced, force load curtailments were still required at times. However, with a coal strike occurring in 1993, obtaining 1.3 lb SO2/MMBTU was difficult and the unit was forced to burn below 1.3 coal. This resulted in 92,000 MWH of lost generation because of the higher sensitivity, which results in higher opacity. Even with renewed supply following the strike, Amos 3 continues to have load curtailments.

During 1993 alone, Amos Unit 3 was curtailed 112,000 megawatt-hours due to the 10% opacity limit. River and Sporn units were also curtailed, which meant a loss in B&O taxes to West Virginia of over $312,000. Additionally, unit curtailments mean West Virginia coal is not being burned. In the long term, this could result in loss of coal severance taxes due to out-of-state suppliers being utilized.

7.1.3 Costs Associated with Retrofit.

To achieve the 10% opacity limit the most economical alternative would involve repairs to the mechanical damage caused by years of intense rapping, and a new stand alone heated purge air system to be installed to protect the high voltage insulators from contamination and failure. The estimated cost is approximately $3.5 million. Also, an SO3 injection system would need to be installed to eliminate the opacity exceedances and load curtailments. The installed cost of an SO3 injection system is $2.4 million resulting in $5.9 million associated costs.

7.1.4 Result of Proposed Changes.

The proposed 20% opacity limit and associated exemptions will substantially eliminate non-exempt exceedances from the Philip Sporn Plant, Kanawha River Plant, Mitchell Plant, Kammer Plant and Mountaineer Plant without inhibiting the units ability to meet the particulate limitation. If the existing regulation is modified to emulate the federal limit of 20% then the opacity related curtailments and non-exempt exceedances at Amos are expected to be non-existent when consistently burning coals with above 1.3 lb SO_2/MMBTU.

7.2. Elkem Metals Company.

7.2.1. Units Involved.

Elkem has the following units that are regulated under Regulation 2 as Type 'b' fuel burning units:

Boiler No. 1: 422.6×10^6 BTU/hr. Maximum Design Heat Input [25.5 MW]

Boiler No. 2: 422.6×10^6 BTU/hr. Maximum Design Heat Input [25.5 MW]

Boiler No. 3: 514.5×10^6 BTU/hr. Maximum Design Heat Input [32.0 MW]

Boiler No. 4: 581.8×10^6 BTU/hr. Maximum Design Heat Input [48.0 MW]

7.2.2. Operational Constraints Imposed by Current Rule.

Elkem must operate its No. 4 Boiler at approximately 15 to 30 percent less than capacity in an attempt to achieve compliance. Weather conditions (i.e. hot and low humidity conditions) adversely affect the electrostatic precipitator, thus further adding the need to operate the boiler at reduced loads.

Boilers Nos. 1, 2 and 3 are not currently being operated at all due to the inability to meet the stringent conditions of Regulation No. 2. The units would require substantial work, approximately two million dollars each, to put them in a condition whereby the units could be operated to meet the 10% opacity requirement of Regulation 2. Even with this expenditure, it is not known if the boilers could consistently meet a 10% opacity requirement. It is believed that the boilers would most likely need to be operated at less than capacity even with the upgrades.

As stated above, the penalty to Elkem for operating its boilers at reduced load or not being able to operate Boiler Nos. 1,2, and 3 is estimated to be $2 million per year [not including upgrade costs.] The current regulation also adversely affects Elkem's competitiveness and flexibility in terms of utilizing additional ferroalloy furnaces at the plant.

Finally, Elkem must inject a flue gas conditioning agent into its No. 4 Boiler in an attempt to achieve compliance with the existing regulation. The use of the conditioning agent is another cost (approximately $200,000 per year) that is incurred by Elkem due to this overly stringent regulation.

7.2.3. Costs Associated with Retrofit.

Elkem is not aware of any technology that will allow start up or shut down of its boiler systems in compliance with the existing regulation. Therefore, we do not believe that feasible retrofit options exist for our situation, which is to have the ability of starting up a boiler with pulverized coal while utilizing an electrostatic precipitator for particulate abatement. Considering the above statement and considering other retrofit options, Elkem does not believe that it is economically feasible to retrofit its boilers in an attempt to ensure continuous compliance with the current regulation.

The cost of converting Boiler Nos. 1, 2 and 3 from "hot side" to "cool side" boilers, which would enhance our ability to comply with the current regulatory requirements would cost approximately $2 million per unit. It is noted that even after completing this work, Elkem does not believe that the boilers could comply with the current opacity requirement 100% of the time; nor could the units start up in compliance as per the existing regulation.

In summary, Elkem does not believe that a viable retrofit option exists that will ensure continuous compliance with the existing 10% opacity requirement or with the requirement for boiler start ups.

7.2.4. Result of Proposed Changes.

Adoption of the proposed change in the regulation will address actual conditions and abilities for boiler start up/shut down, soot blowing and for operational conditions that affect opacity (i.e. during load changes before combustion parameters are established and during times when additional pulverizers are being put into service).

The change in the regulation will allow boiler(s) to be started and shut down in compliance with regulatory requirements. Safety concerns make it is not feasible to start up our boilers in compliance with the existing regulation.

Finally, the change in the regulation will make Elkem more competitive in the marketplace because it will enhance operational flexibility for our plant, enable us to run our boiler(s) at capacity thus reducing energy costs, and will enhance the plant's ability to maintain a workforce of approximately 300 employees.

7.3. FMC Corporation.

7.3.1. Units Involved.

The FMC Corporation Steam Plant, located in South Charleston, West Virginia, has the following units that are regulated under West Virginia Air Regulation 2 as Type 'b' fuel burning units:

Boiler #13: 235 million BTU/hour Maximum Design Heat Input

Boiler #15: 160 million BTU/hour Maximum Design Heat Input

Boiler #16: 160 million BTU/hour Maximum Design Heat Input

7.3.2. Operational Constraints Imposed by Current Rule.

Boilers #15 and #16 have been retrofitted with burners that allow the use of natural gas as an alternate fuel. In order to comply with the opacity limits of Regulation 2, both boilers are started upon on natural gas and then switched to pulverized coal. Presently, a proposal is being considered that would also provide Boiler #13 with the equipment necessary to use natural gas as an alternate fuel.

The boilers at the Steam Plant were constructed around 1935. The last major modifications were in 1958. Using this older equipment, the time required to complete the soot blowing process exceeds the time period allowed in the regulation.

7.3.3. Costs Associated with Retrofit.

In 1993, FMC spent $165,000 to rebuild the precipitators in #13 boiler and has a program in place to continue with the necessary improvements to the system. Retrofitting #13 with natural gas burners is estimated to cost $200,000. The practice of using natural gas to ensure compliance with the opacity limits increases operating costs of the boiler units.

7.3.4. Result of Proposed Changes.

The proposed changes in the regulation more accurately reflect the actual conditions and abilities of FMC's boiler equipment and will allow the operation of the system within the proposed limits.

7.4. Monongahela Power Company.

7.4.1. Units Involved.

Monongahela Power Company (MPCo) operates and wholly or partially owns six coal-fired electric power generating stations in West Virginia with a total operating capacity of 4949 megawatts. A summary of MPCo units in West Virginia is set forth in Exhibit 3. Compliance testing demonstrates that all units meet the Regulation 2 mass weight emission limit of 0.05 lbs\MBTU. Continuous compliance with the corresponding 10% opacity limit, however, is not practical for these units and is the basis for this amendment request.

While continuous compliance with a 10% opacity limit is impractical at all of MPCOs units, Harrison Power Station experiences the most difficulty. In 1980, stack emission tests were conducted at Harrison Power Station, which demonstrated that the weight emission standard could be met while maintaining higher opacity levels. In 1981, Mr. Talbott of Brown, Harner & Busch, L.C., who was then counsel for MPCo, confirmed a February 3, 1981 conversation with Mr. Beard, the Director of the WV APCC, through his letter dated February 5, 1981. This letter indicates that the conversation consisted of Mr. Talbott's request that the APCC expedite the scheduling of a hearing for the purpose of having the Commission consider a change in the opacity provisions of Regulation 2. Furthermore, Director Beard advised, through this conversation, that his staff was working toward conducting such a hearing. Unfortunately, that hearing never took place. As a result of the testing which demonstrated compliance with the weight emission standard at higher opacity levels, the Harrison Power Station entered into a consent order to utilize washed coal and the station operates in order to reduce particulate emissions. Until 1993, the Harrison Power Station had not been subject to notices of violation for opacity exceedances. Now, in a changed climate of enforcement, submittal of monitoring reports, and in third-party suits, the issue again resurfaces.

Harrison Power Station will still be affected by the 10% opacity limit with or without SO_2 scrubbers. While MPCo maintains that opacity limitations should not apply to wet scrubber stations, the Office of Air Quality has not agreed with the position and has, in fact, issued a Notice of Violation for opacity exceedances at Pleasant Power Station which is a scrubbed station. There may also be occasions when the bypass will be utilized at scrubbed stations during which emissions will bypass the scrubbers creating the potential for an opacity exceedance. Therefore, all fourteen generating units are affected by this regulation and Harrison and Pleasants Power Stations will continue to be affected with or without SO2 scrubbers given the regulation as currently written.

7.4.2. Operational Constraints Imposed by Current Rule.

MPCo's stations are operated to reduce generation when the existing opacity standard cannot continuously be achieved. When stations reduce generation to comply with opacity, that loss in electrical production must be replaced with other more expensive generation. This is because all of MPCo's units are operated under economic dispatch thereby requiring the cheapest units be operated at all times. Displaced generation increases the cost of supplying electricity which is directly passed on to the customers through higher rates. These higher costs also reduce MPCo's ability to sell power to other utilities in the East.

Moreover, generating units brought on-line to replace the generation lost due to the 10% opacity limit could be company-owned units located out of state or, if cheaper, generating units owned by other utilities in other states. Therefore, this opacity rule can directly impact the amount of West Virginia coal that is burned at MPCo stations. Employment in coal mining is affected with shifts in generation of electricity from in state to out of state. Coal severance taxes collected by the state are reduced with lower coal production and taxes collected on generation of electricity are likewise reduced when generation is reduced. The Harrison Power Station alone has taken reductions in power generation of approximately 475,000 MW hours during the last two quarters alone due to the stringent West Virginia state opacity limit. It is not unusual for Harrison Power Station to be forced to take 100MW reductions per unit (at times, it is over 200MW). With three units, a 300 MW reduction in a 1920MW station is roughly a 15% reduction. These massive reductions in generation could be avoided with the approval of requested amendments to Regulation 2.

The Harrison Power Station typically consumes 4.6 million tons of coal per year. During the past two quarters, Harrison Power Station has taken opacity reductions in generation amounting to approximately 475,000 megawatt-hours. This reduction in generation corresponds with the operational procedure at Harrison to maintain the opacity limit established through testing.

To operate ~~to~~ achieve a 10% opacity limit would necessitate even greater reductions in generation. Operating without these reductions, Harrison Power Station could burn an additional 225,000 tons of coal per year. The direct increase in coal and related employment would be 190 people per year (National Coal Association). Taxes generated on individual incomes, tangential employment incomes, and coal severance corporate income taxes is obvious and beneficial to the state. For example, coal severance tax is 5% of gross value of coal. The loss of 225,000 tons of coal per year times the average price per ton paid at Harrison of $38 for coal equals $427,500 tax loss in coal severance taxes alone. Likewise, West Virginia levies of B & O gross receipts tax on electricity production at the average rate of $2.60 per megawatt hour. By losing 15% generating capacity, sales decline $105,000,000 per year (Mann-Witt study). Loss in B & O tax revenues alone are approximately $1,235,000 over a 6 month time period due to loss production. Therefore, West Virginia places itself at a tremendous competitive disadvantage by invoking more stringent standards than necessary and forcing generation out of state.

7.4.3. Costs Associated with Retrofit.

MPCo installed electrostatic precipitators on all West Virginia units between 1967 and 1982. Throughout the years, MPCo has performed maintenance in order to maintain and operate the electrostatic precipitators as efficiently as possible. Projects have included replacement of the rappers and rapper control systems and replacement of the automatic voltage control systems on all MPCo precipitators, as well as collecting plate alignment, wire replacements, structural and insulation repairs as needed.

The majority of MPCo's precipitators were designed and installed and are operated to meet the weight emission standard established by Regulation 2. According to the most recent stack tests, our units are in compliance with the weight emission standard. Opacity is an inexact standard of measurement of the amount of particulate emitted into the air. Although opacity is used as a surrogate measure of the amount of particulate emitted into the air, the state opacity requirement obviously does not comport with the weight emission limits established by the state. Accordingly, this request to revise the opacity limit is not a relaxation in particulate emissions but a necessary revision to correct the opacity standard.

In order to maintain 100% compliance with the established weight emission standard and the overly stringent opacity limit of 10% as it now stands, it would be necessary to install additional pollution controls, possibly baghouses at four of MPCo's WV stations. The estimated total cost of the baghouses would be over $236,000,000, which would ultimately be passed on to MPCo's customers. Baghouses can not be installed at Harrison and Pleasants Power Stations because they are equipped with SO_2 scrubbers.

7.4.4. Result of Proposed Changes.

Increasing the opacity limit from 10% to 20% and making related modifications to Regulation 2 will not result in a violation of the weight emission standard. MPCo will continue to maintain compliance with the established weight emission standard (0.05 lbs/MBTU). MPCo does not intend to increase the size of its units, the manner of operation of the electrostatic precipitators, or the potential to emit at its facilities.

Opacity is an inexact standard of measurement of the amount of particulate emitted into the air. Although opacity is used as a surrogate measure of the amount of particulate emitted into the air, the state opacity requirement obviously does not comport with the weight emission limits established by the state. Accordingly, this request to revise the opacity limit is not a relaxation in particulate emissions but a necessary revision to correct the opacity standard.

7.5. Union Carbide Corporation.

7.5.1. Units Involved.

The Union Carbide Corporation, South Charleston Plant currently has three boilers that are burning a mixture of fuel (primary coal, about 90%, but also some gas and organic by-product fuel) and a fourth boiler that is gas-fired. Numbers 15 and 16 Boilers operate on mixed fuel, share a common stack and have a steam load capacity of 160 MBTU/HR each. Number 25 Boiler operates on mixed fuel and has a steam load capacity of 290 MBTU\HR. Number 13 Boiler operates strictly on fuel gas and has a steam load capacity of 90 MBTU\HR. Both 13 and 25 Boilers have their own stacks.

7.5.2. Operational Constraints Imposed by Current Rule .

It is impracticable to run these or any other comparable fuel burning unit other than gas-fired and operate below the 10% opacity limit on a consistent basis. To run a fuel burning unit under 10% opacity would require that it must be operated at 8% opacity or lower. This is practically impossible to achieve due to the load swings created by the demands of the specialty chemical plant operation. This type of operation is a dynamic system that requires time for operating response. Setting the opacity limit at 20% for these units would provide that time.

It is also impracticable to maintain compliance under 20% opacity on a consistent basis while blowing soot or cleaning a fire box. When cleaning a fire box, the doors are opened creating a draft effect. The physical process of blowing soot or cleaning a fire box does not adapt to the constraints set forth by the current version of Regulation 2. A more reasonable limit while doing these normal operations is 40%. This is particularly needed in the case of these units since these are not automated, but rely on manual type operations. A 40% opacity provision for soot blowing should apply for a period or periods aggregating thirty 30 minutes per unit every eight hours.

Start-ups and shut-downs should be excluded from the opacity requirements to allow for normal operation dusting. The shutdown exclusion is needed for operational safety reasons. The fans must be left on to purge any remaining fuel-gas from the system and to purge any possible fuel gas leaks. The control devices must be turned off during the shut-down process to avoid potential explosions. The fans must be left on to purge any remaining fuel-gas from the system and to purge any possible fuel-gas leaks which are an ignition source. The start-up exclusion is needed for some of the same reasons. During the "ramp-up" period when system is being purged prior to lighting off the boiler, the large volume of air exchange can result in stack dusting. As the units come on line the first hours are critical in lining out the system. This includes the steam header pressure through-out the plant and adjusting the coal feed to achieve a system balance.

The provisions of Section 8.4 should be revised to allow for notification of start-ups and shut-downs to be submitted no less frequently than on a calendar quarter basis in accordance with current agency policy.

7.5.3. Costs Associated with Retrofit.

We have an electrostatic precipitator (ESP) control device on each of our coal burning boilers. The ESPs were designed to meet weight emission standards for Regulation 2. We recently, May 1993 through May 1994, spent $270,000 making considerable upgrades to our boiler operations and have a program in place to continue these upgrades. Even with these improvements, compliance with the 10% opacity requirement of Regulation 2 on a consistent basis is troublesome as long as we continue to burn West Virginia coal.

7.5.4. Result of Proposed Changes.

Union Carbide currently operates its boilers using a mixture of fuel gas, bituminous coal and other by-product organic fuel. Conversation to all fuel gas would result in an operating cost increase of $4,500,000 per year and would be extremely detrimental to the South Charleston Plant.

7.6. Virginia Power.

7.6.1. Units Involved.

Virginia Electric and Power Company [Virginia Power] owns and operates one power station in West Virginia, the Mt. Storm Power Station. Mt. Storm is located in Grant County, and has three tangentially-fired, coal burning units. Units 1 and 2, which are identical and share a common stack, are each rated at 551 MW. They began commercial operation in September 1965 and July 1966, respectively. Unit 3 is rated at 552 MW and began commercial operation in December 1973.

Although the results of particulate testing performed in recent years demonstrated compliance with the 0.05 lb/MBTU mass emission limit, the Mt. Storm units have had difficulty operating continuously below the 10% opacity limit. In an attempt to improve precipitator performance and maintain compliance, many modifications have been made to all three precipitators in the last decade.

As a result of the modifications to the Unit 3 precipitator in 1992, Unit 3 is now able to operate at opacity levels below 10% over 90% of the time. In addition, the Unit 3 scrubber, which is scheduled to commence operation this fall, will provide an additional 70% reduction in particulate emissions. Since the scrubber will rarely be completely bypassed, we expect the scrubber to provide the additional reductions necessary to enable continued compliance with the opacity requirements of Regulation 2.

The modifications to the precipitators associated with Units 1 and 2 have not resulted in as dramatic of an improvement in performance as have the modifications to Unit 3. It is not certain whether scrubbers for these units will be part of Virginia Power's Phase II compliance plan necessary to comply with Phase II of Title IV of the CAAA. Based on recent particulate testing and other studies completed, we believe that substantial additional precipitator modifications would be necessary to enable continuous compliance with the current version of Regulation 2. However, additional testing will be necessary to confirm that these modifications would adequately improve precipitator performance as Virginia Power believes.

7.6.2. Operational Constraints Imposed by Current Rule.

Although the precipitators have undergone many upgrades over the years, Mt. Storm has had difficulty operating at opacity levels consistently below 10%. In the fall of 1993, the opacity problem suddenly worsened at Mt. Storm for unknown reasons. DEP issued a temporary variance to Virginia Power to provide time to diagnose and correct the problem. Although the causes of the elevated opacity were never identified with certainty, we suspect that Mt. Storm's temporary reliance on alternate coal supplies due to the coal-miner's strike and the installation of NOx controls on Unit 1 may have contributed to the elevated opacity levels. In an attempt to diagnose the cause of the elevated opacity, Virginia Power completed a particulate testing program and an EPA-based computer model study to predict precipitator performance.

Numerous load curtailments were necessary at Mt. Storm during the fall and winter months of 1993 as a direct result of attempting to comply with the 10% opacity limit. Daily load curtailments averaged approximately 69 MW for a total of approximately 293,000 MWH lost during those months. The cost of replacement power due to these load curtailments was approximately $7.9 million. These load curtailments not only hurt Virginia Power and its customers but also hurt the state of West Virginia due to lost tax revenues (approximately $762,000). In addition, these curtailments reduced the consumption of West Virginia coal which constituted 56% of the coal burned at Mt. Storm during 1993 the reduction amounted to 116,897 tons.

The causes for the elevated opacity levels disappeared early this year as suddenly and mysteriously as they appeared, however, even now we cannot continuously maintain opacity levels below 10% on either stack. In particular, it is difficult for the units to operate below 10% opacity during periods of startup, shutdown and unit operational problems. In addition, the NOx controls on Unit 1 recently made operational to comply with Title IV of the CAAA are believed to be at least partially responsible for contributing to the elevated opacity levels.

Two particulate test programs were undertaken in the last two years in an attempt to identify causes for elevated opacity levels. During testing performed in the fall of 1992, we attempted to develop a relationship between particulate emissions and opacity in order to project particulate emission at opacity levels above 10%. In order to develop this relationship, testing was performed during normal operation and operation at elevated opacity levels. Testing during normal operation demonstrated compliance with both the particulate and opacity limits.

The second part of the test program involved taking precipitator fields out of operation in order to increase opacity up to about 10%. Based on the relationship developed using this test data, we were unable to demonstrate that the unit could consistently maintain compliance with the particulate limit at opacity levels higher than about 12%. However, there is some reason to believe that the relationship between particulate and opacity observed through this test program was invalid. Taking precipitator fields out of service may have resulted in increased particulate emissions that would not necessarily have resulted even at increased opacity levels with all fields in service.

As a result of the increased opacity problems in the fall of 1993, a second test program was conducted on Units 1 and 2. The primary focus of this test program was to identify the impact of the NOx controls on opacity. Results of this testing showed elevated opacity levels (15-29%) with corresponding particulate emissions below 0.05 lb\MBTU in 11 out of 12 test runs. A possible explanation for low mass emissions and elevated opacity levels is the emission of an unusually high percentage of fine particles resulting at least in part from the NOx controls. (Results from the testing showed 47% of the particles to be less than 1 micron in size and 80% less than 1.6 microns in size.) The emission of higher levels of fine particulates causes more light to be obscured due to greater surface area per unit mass. In addition, it should be noted that the exit stack diameter is a major factor affecting visible emissions, since visible emissions vary directly as a function of optical path length. The combined stack serving Units 1 and 2 has an unusually large diameter.

Results from the two test programs appear to conflict with each other. While the 1992 testing suggests Mt. Storm must stay below about 12% opacity in order to ensure particulate emissions below 0.05 lb\MBTU, the 1993 testing revealed very low mass emission at significantly elevated opacity levels.

With the approval of DEP, Virginia Power plans to conduct further particulate testing on Units 1 and 2 at Mt. Storm in another attempt to project particulate emissions at opacity levels greater than 10%. The proposed testing program will consist of a full compliance particulate test on the combined stack of Units 1 and 2 during full load operation. Throughout the testing, samples will be taken in order to obtain size distribution of the particulate matter.

Based on the results of the particulate testing and the particle size distribution, it will be possible to develop curves relating particulate emissions to opacity. Using this relationship, it will be possible to determine the opacity level for units 1 and 2 necessary to keep particulate emissions below the required mass emission rate. In order to determine overall station compliance, we will perform particulate testing on Unit 3 once the scrubber is in operation.

In addition to the particulate testing, Virginia Power hired Clean Air Engineering to use an EPA-based computer model to predict Unit 1 and 2 precipitator performance while burning several different types of coal. The computer model results indicate that the existing precipitators are capable of achieving compliance with the existing West Virginia particulate limit (0.05 lb/MBTU), but not necessarily with the opacity limit (10%). Based on the model results, Clean Air Engineering identified four possible problems which may contribute to precipitator problems. These include the following:

- High dust resistivity due to acid condensation in regions with low gas temperatures (below 275 F).

- A relatively large number of submicron diameter particles.

- A large amount of unburned carbon (potentially due to the Unit 1 NOx controls).

- Possible reentrainment of fly ash caused by low resistivity ash.

7.6.3. Costs Associated with Retrofit.

Virginia Power has made numerous improvements to the precipitators at Mt. Storm over approximately the last 13 years. These improvements are in addition to the replacement of the original three-field precipitators on Units 1 and 2 with five-field precipitators in 1973.

During the 1981-1986 time period, each of the precipitators associated with all three units have had two control upgrades to automatic voltage controls. The present controls are state-of-the-art technology which enable maintenance of optimum power levels in the precipitator electrical fields. In 1988, new rapper and vibrator controls were installed to provide greater flexibility in programming of the frequency and force with which the plates and discharge electrodes are cleaned.

During the 1993 Planned Maintenance Outages, the Unit 1 and 2 precipitators underwent extensive modifications to the design of the precipitator rapping scheme. The original design provided rapping to groups of ten plates per pair of rappers. This was the common design throughout the industry at the time that these precipitators were constructed. However, it has been the experience of all precipitator manufacturers that this design is improved by reducing by half the number of plates rapped. The modification of Units 1 and 2 involved dividing each group of ten plates into two groups of three and a single group of four plates per rapper. This tripled the original number of rappers and reduced the maximum number of plates rapped concurrently to four. For each precipitator, this modification was very extensive due to the structural steel work required to support the collecting plates with this type of configuration, as well as the removal of the 240 original rappers and the installation of 720 new rappers.

In addition to the modification to the Units 1 and 2 precipitators, additional instrumentation was added near the precipitator inlets. This instrumentation provides more accurate information with regard to temperature and excess air entering

the precipitator and enables better tuning of these parameters in order to maximize precipitator collection efficiency.

During the spring 1992 Planned Maintenance Outage, Unit 3 received extensive precipitator modifications. The modifications included doubling the number of rappers, which reduced the original groups of nine plates per rapper pair, to groups of four and five plates per pair. Also, the inlet and center electrical fields were each divided in half and the power supplies to the respective fields were doubled in number. The end result was a six electrical field precipitator which was a 100% increase from the original three field precipitator.

The costs associated with the modifications completed since 1981 total at least $9 million. Furthermore, Virginia Power has estimated that it would cost an additional $25.6 million in capital costs for additional precipitator fields and dual flue gas conditioning (SO_2 and NH_3) for Units 1 and 2 to meet the 10% opacity limit consistently during normal operation. Even with these improvements, we believe it would be difficult if not impossible to meet a 10% opacity limit during some periods of startup, shutdown and unit trips.

7.6.4. Result of Proposed Changes.

The results of the proposed particulate testing program will determine how the adoption of the proposed modifications to Regulation 2 will impact the compliance status of Mt. Storm Units 1 and 2. If the results of the testing show the units can go up to 20% opacity with corresponding particulate emissions at or below 0.05 lb\MBTU, then these units will be able to achieve a 98% compliance percentage based on historical information.

If, however, the results of the testing program show Units 1 and 2 would be restricted to an opacity level less than 20% in order to achieve corresponding particulate emissions below 0.05 lb\MBTU, then Virginia Power's course of action will depend on the ability to consistently meet the projected opacity level. If the projected opacity level is closer to 10%, then it may be necessary for Virginia Power to take advantage of the proposed amendment to the regulation which would allow a particulate emissions limit up to 0.1 lb/MBTU based on a modeling demonstration that no violation of the NAAQS will occur. Otherwise, if Virginia Power believes it is possible to maintain compliance consistently with the predicted opacity level associated with 0.05 lb\MBtu then that opacity level will become the limit for the Mt. Storm Unit 1 and 2 stack.

CONCLUSION

The statutes applicable to DEP provide strong evidence that the legislature desires for environmental programs in West Virginia to be no more stringent than federal requirements absent factors unique to West Virginia. No such unique factors exist with respect to the revisions being advanced by petitioners. The state legislature has examined this issue several times over the past years and concluded that the state should not place itself in a competitive disadvantage absent compelling circumstances and should balance all interests involved, including employment, coal, and tax revenue among others.

There is compelling technical and economic support for these proposed modifications to Regulation 2 including increasing the opacity limit to 20%. A 20% opacity limit more accurately represents the existing weight emission standards. While petitioners are committed to compliance with the established mass emission rate of Regulation 2, the opacity requirement and other proposed modifications are needed to avoid unnecessary and substantial expenditures. These revisions are not only in the best interest of the petitioners, their ratepayers and stockholders, but also the state's tax revenue, the coal industry, and employment opportunities in the state. These changes will also bring the opacity standard into greater conformity to the mass emission limit as well as, neighboring states opacity limits.

Submitted this 3rd day of June, 1994.

APPALACHIAN POWER COMPANY
ELKEM METALS COMPANY
FMC CORPORATION
MONONGAHELA POWER COMPANY
MONSANTO CHEMICAL COMPANY
OHIO POWER COMPANY
UNION CARBIDE CORPORATION
VIRGINIA ELECTRIC AND POWER COMPANY
and
WEST VIRGINIA MANUFACTURERS ASSN.

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STATEMENT OF ROBERT W. REEVES ON BEHALF OF APPALACHIAN POWER COMPANY AND OHIO POWER COMPANY BEFORE THE WEST VIRGINIA AIR POLLUTION CONTROL COMMISSION AT ITS HEARING REGARDING PROPOSED AMENDMENTS TO REGULATION II.

December 7, 1978

Mr. Chairman, Members of the Commission, Director Beard.

My name is Robert W. Reeves. I am Head, Environmental Engineering Division, American Electric Power Service Corporation with offices in Canton, Ohio. I am speaking today on behalf of Appalachian Power Company and Ohio Power Company regarding the Commission's consideration of Regulation II as that applies to utility boilers in West Virginia.

By way of background and for the benefit of the new members of the Commission, I believe it is necessary to review the commitments which AEP has made in West Virginia to comply with Regulation II as it now exists.

Following the revision of Regulation II by this Commission in 1971, it became necessary for Appalachian and Ohio Power to enter into compliance programs to bring all six of their power plants into compliance with an emission limitation of .05 pounds per million BTU. The compliance programs were the subjects of many hearings before this Commission in which AEP voiced its considerable concern over the stringency of that emission limitation. Under the terms of those compliance programs it was necessary for AEP to retrofit the Mitchell and Amos Plants which had begun operation at about the same time that Regulation II was adopted. Those retrofits were necessary even though the Mitchell and Amos Plants had been constructed with pollution control equipment designed to achieve compliance with the emission requirement of Regulation II which existed from 1966 and 1971. In addition, those compliance programs called for the installation of new electrostatic precipitators at both the Philip Sporn and Kammer Plants. In addition a major upgrading of the precipitators at the Kanawha River Plant was undertaken. All of these programs have been completed with the exception of the precipitators retrofit for Units 1 through 4 of the Philip Sporn Plant which is scheduled for completion no later than July 1, 1979. Also a part of the Company's efforts to comply with Regulation II was the shutdown of the Cabin Creek Plant in 1977.

AEP's commitment to comply with this regulation alone, has or will involve at the Sporn Plant $113,600,000; at the Amos Plant $109,400,000; at the Kanawha River Plant $4,300,000; at the Mitchell Plant $98,300,000; at the Kammer Plant $75,100,000; and in order to bring the new Mountaineer Plant in compliance with Regulation II $37,300.000. Thus, not counting any value associated with the shutdown of the Cabin Creek Plant, AEP has made a total commitment of $438,000,000.

This enormous commitment of resources was in spite of the fact that we believed that the .05 pound emission limitation was far more restrictive than was necessary in order to attain primary and secondary ambient air quality standards or to satisfy the requirements of the United States Environmental Protection Agency for an approvable state implementation plan. Without intending to reargue the merits of the .05 pound emission limitation, we believe that the Commission should now examine the opacity provision of Regulation II to avoid the possibility of yet another retrofit of one or more of these plants which we believe have already been installed with the best availability control technology. In this connection I call your attention to the fact that the Commission proposes to ratify the requirement which is contained in §2.02 of proposed Regulation II which imposes a 10% opacity requirement on all fuel burning units whose maximum design heat input is equal to or more than one million BTU's per hour. The effect of this provision is to place a second and perhaps more restrictive emission limitation upon power plants which may be independently enforceable by the Commission.

Our experience with opacity from power plant stacks indicates that a situation may exist in which one or more of our plants could be in full compliance with the .05 pound emission limitation or mass emission rate and yet be in violation of the 10% opacity requirement. We have been fortunate so far in the operation of our plants in that we believe we have had success in achieving both the opacity and the mass emission requirements of Regulation II. To the extent that this has been accomplished, however, we think it is becuase our control equipment has been performing better than design or that the characteristics of the stacks involved have been such that 10% opacity has been achieved. Our concern is that over time the precipitator performance at our plants may drop off to the extent that while they will still be in compliance with the .05 pound mass emission rate they may not be capable of assuring continued compliance with the 10% opacity requirement.

For example, I call your attention to the situation we are presently experiencing at the Tanners Creek Plant of Indiana and Michigan Electric Company, one of the operating companies of AEP. All four units at Tanners Creek are equipped with electrostatic precipitator control equipment designed and operated at essentially the same collection efficiency. All four units are required to comply with exactly the same mass emission rate. However, because of differences in the construction of the boilers and the configuration of the stacks, three of the units at Tanner's Creek have no visible plume while the fourth unit has a plume of approximately 20% opacity. The significance of this experience is that all four of these units, including the one with 20% opacity, are operating at mass emission rates well below the level of .05 pounds.

We are not alone in our observation that compliance with a mass emission standard will not assure compliance with an opacity standard. I have attached to my statement a report dated June 23, 1976 which was prepared by H. J. Hall Associates, Inc., a nationally recognized authority in this field. This report considers the relationship between opacity and mass emissions in the specific context of AEP plants in West Virginia. The report concludes that opacity is influenced by a number of factors other than mass emission rate including such things as stack diameter and the nature of the particulate matter being discharged. In addition the report notes a very serious problem in that precipitator vendors will not guarantee compliance with an opacity standard.

It should be noted that the problems associated with the use of opacity as an independently enforceable emission restriction has been recognized by EPA since 1971 when it first established new source performance standards for power plants. At that time EPA established an opacity standard of 20% and a mass emission rate of .1 pounds. I note that in the Federal Register of September 19, 1978 that even though EPA is contemplating a reduction in the mass emission rate for power plants to .03 pounds they propose to leave the opacity standard at the 20% level. EPA's new source performance standards make it very clear that it is the mass emission rate - not opacity - which should control the determination of whether a source is in compliance with new source performance standards. °40 C.F.R. §60.11(e)!. We believe that this is an appropriate technique with which to establish the relationship between mass emission and opacity limitations. It is clear based upon the EPA experience that opacity does not have a linear relationship with mass emission rates.

In this connection we are concerned that when this Commission initially adopted a 10% opacity requirement it did so on the basis of a linear reduction of the EPA new source performance standard. That is, when this Commission elected to adopt a mass emission rate of .05 pounds (or 1/2 the EPA new source performance standard of .1 pounds) it also elected to adopt an opacity standard of 10% (which was likewise 1/2 of the opacity standard of 20%).

We believe that the overwhelming weight of technical authority, including the recently proposed rulemaking of EPA, demonstrates conclusively that it is not appropriate to reduce opacity in the same ratio as mass emissions are reduced.

We strongly urge this Commission to amend the opacity provisions of Regulation II as they apply to utility boilers to eliminate the 10% opacity requirement as an independently enforceable emission limctation. We suggest instead that the Commission adopt the approach which has been followed by EPA in recognizing the mass emission rate as being the basis upon which to establish compliance. We believe that this action is consistent with the Commission's belief that the SIP should not be any more stringent than is necessary to attain primary and secondary standards and be approvable by EPA. With the continued existence of the .05 pound mass emission rate applicable to utility boilers, there is no reason to believe that EPA would disapprove this amendment to West Virginia's Implementation Plan.

Failure to amend the 10% opacity restriction raises a very serious concern about whether it will be necessary for us to face once again further precipitator retrofits in West Virginia involving hugh commitments of capitol without sound economic or environmental justification. It is even questionable given the present and anticipated financial and economic conditions that we could raise the capitol necessary to carry out such retrofit.

I appreciate the opportunity to have presented these remarks to you today and I will be glad to answer any questions that you may have regarding my statement.

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SCIENTIFIC CONSULTANTS
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TECHNICAL REPORT HAR 76-132

SUMMARY ANALYSIS - PRECIPITATOR DESIGN, COSTS, STACK EMISSIONS AND OPACITY FACTORS AT STEAM ELECTRIC GENERATING PLANTS OF THE AEP COMPANY IN WEST VIRGINIA

Prepared For

American Electric Power Service Corp.
Canton, Ohio

June 23, 1976

H. J. Hall

ABSTRACT AND SUMMARY

Technical Report HAR 76-132

This report principally covers analyses on electrostatic precipitator design, costs, stack emissions and opacity factors at steam electric generating plants of the American Electric Power Company in West Virginia. Comparisons among the pertinent factors are made for systems designed to achieve outlet stack particulate emissions at 0.05#/10^6BTU and at 0.1#/10^6BTU heat input.

The important results and conclusions may be summarized as follows:

1. AEP has six (6) plant sites, comprising 19 boilers and 9 separate stacks, currently operating in West Virginia. Among them, about 1300 people are employed. Plant sites are designated Amos, Cabin Creek, Kammer, Kanawha, Mitchell and Sporn; they are located in Putnam, Kanawha, Marshall, and Mason Counties. Present plants have a total generating capacity of 6,875,000 KW, of which over 65% is at Amos and Mitchell. A new plant under construction is rated for 1,300,000 KW (Kilowatts). A typical average home may consume about 550 KW HR electric energy per month. The AEP system energy capacity in West Virginia amounts to about 5,000,000,000 KW HR per month.

2. Among the 50 States in the USA, allowable particulate emissions vary from as low as 0.05 lbs per million BTU heat input for coal-fired utility boilers in West Virginia and New Mexico to as high as 0.8 lbs per million BTU heat input for existing plants in North Dakota. The tendency seems to be for a limit of about 0.1 lb per million BTU for large boilers in most all States. Only 4% of the States have regulations limiting particulate emissions to less than this figure at 0.05 $\#/10^6$BTU. The Federal EPA standard for new installations is also 0.1$\#/10^6$BTU.

3. Precipitator design criteria typically require reliable collection efficiencies at 99.4% and at 99.7%, minima, in order to meet particulate emission regulation of 0.1 and 0.05 $\#/10^6$BTU, respectively. It is very difficult and costly to achieve, continuously, collection efficiencies at 99.7% or more on large boilers in the 800-1300 megawatt (MW) class--especially so when burning low sulfur coals in big, base-loaded plants such as Amos. To go from 0.1 $\#/10^6$BTU to 0.05 $\#/10^6$BTU requires outlet dust emissions to be cut in half and this has to be done on the finer particles which are more difficult to collect. Thus, a diminishing return and cost-benefit effect occurs where the incremental performance of added precipitator sections

decreases as overall performance requirement increases. Further, as the size and complexity of the equipment increase to achieve very high performance, so also do potential operating problems and maintenance requirements increase.

4. As shown in Table 2, present operating plant data supplied by AEP plant managers to the APC Board of W.Va. are summarized. All plants except Kammer and Mitchell are achieving present SO_2 emission limits prescribed by Regulation X. (Fig. 1). The required outlet stack emissions and corresponding calculated probable opacity for particulates at 0.1 #/10^6BTU and at 0.05 #/10^6BTU are indicated. Conditions under which opacity calculations were made are listed at bottom of Table 2. Opacity data are based on the scientific principles of light scattering or absorption by fine particles as measured by an optical instrument called a Transmissometer approved by the Federal EPA. For the larger stack diameters (30-33 ft) at Amos and Mitchell, stack opacity estimates are in the range 33-38% for 0.1 #/10^6BTU emission and 18-22% for 0.05 #/10^6BTU emission. Plants capable of meeting West Virginia's 10% opacity at 0.05 #/10^6BTU would be Cabin Creek, Kammer 3 and possibly Kammer 1, 2, Kanawha 1, 2 and Sporn 5 under favorable

conditions. About 50% of emission regulation 0.05 #/10^6BTU would be required to achieve 10% opacity at Amos and Mitchell plants as tests have corroborated. Except for the smaller diameter stacks, we conclude that the West Virginia regulation 0.05 #/10^6BTU particulate emission is inconsistent with meeting a 10% opacity.

5. Emission, costs and opacity factors with new backfit precipitators having guaranteed efficiencies up to 99.8+% for Amos 1, 2, Kammer, Mitchell, Sporn plants and a new 1301 plant, are reviewed in Table 3 (Section 2.3). Cost figures are actual data from AEPSC records for equipment designed for 1% sulfur coal or less. AEP design practice (Section 2.7, para. 4) is conservative and also costly in West Virginia. Basic guarantees on performance are more than adequate to meet the 0.05 #/10^6BTU emission regulation. In fact, capability is in the range 0.024 to 0.032 #/10^6BTU. At these levels, 50 to 60% of the regulation, stack opacity estimates are in the range 5-10% for all plants. New large precipitator installations scheduled in the AEP system, W. Va., cost $7-12/sq. ft. collecting plate area. For backfit cases, the total Air Pollution Control project cost ranges 2.24 to 3.77 times the installed precipitator cost, per se.

6. Costs vs particulate emissions with present SO_2 regulations are discussed in Section 2.4 and Tables 4, 5. For the actual systems being installed, noted to be conservative, the overall costs increase about 25% in going from 0.1 #/10^6BTU to 0.05 #/10^6BTU emissions. Generally, however, for normal design practice these cost increases could range up to 30+%. Current program costs for maximum emission 0.05 #/10^6BTU at various AEP plants in West Virginia are as follows:

Plant & New PPTRS	Total Cost $ Million	MW
Amos 1, 2	88.46	1600
Kammer 1, 2, 3	61.82	675
Mitchell 1, 2	84.53	1600
Sporn 1-4	74.94	620
Sporn 5	38.71	450
Total	348.46	4945

Average Cost $70.6 per KW

An additional $5.21 million will have been spent in 1976 for upgrading existing precipitators at Amos 3 and Kanawha 1, 2. (not including costs of SO_3 conditioning system previously installed at Kanawha 1, 2). Thus, total current project costs in West Virginia come to $353,670,000. These expenditures involve 7 existing plants comprising 8 separate stacks. Cabin Creek has not been considered since no current work is scheduled due to a projected shut-down in 1977.

7. The effects of burning medium to high sulfur coals (2-4%) on precipitator size, cost, performance and stack opacity are discussed in Section 2.5 and Table 6. Thus, if West Virginia were to relax SO_2 regulations, much smaller precipitators at much lower costs would be possible to meet particulate emissions required. For the five (5) backfit installations above (Table 7) total project costs would be reduced about in half to $179.4 million compared to $348.5 million with low S coals at particulate emissions 0.05 #/10^6BTU. For 0.1 #/10^6BTU emissions, the comparable program cost would be about #132.4 million with higher sulfur coals. This is over $215 million less than present commitments for the 5 plants to meet existing W. Va regulations for SO_2 emissions and the 0.05 #/10^6BTU particulate emission.

8. Opacity factors and methods of determination are reviewed in Section 2.6. The Ringelmann method used by W. Va. and others is imprecise, unscientific and unsatisfactory for any reliable determination of stack opacity. It is shown (Appendix A) that, due to the large number of factors involved, many of which are uncontrollable, it is possible for the opacity determination to vary from 14% to 87% with a 32.5 ft diameter stack at a contant

geometric mean particle size of 2.5 micron diameter at a mass emission rate of 0.05 grains per standard cubic foot of gas. It is concluded that the use of Ringelmann opacity measurements by regulatory bodies to determine the degree of particulate emissions is contrary to the laws of nature. As shown in Section 2.63, actual stack opacity, calculated by Transmissometer method, can be reduced to 11-13% for 0.05 #/10^6BTU emission with three separate stacks, compared to 18-22% opacity with a single stack at Amos 3. If a Ringelmann observer looked at the 3 stacks in line, he would be expected, if accurate, to see about 29-34% opacity at the same dust emission rate of 0.05 #/10^6BTU.

9. At present, precipitator or other equipment vendors do not guarantee an opacity. In view of the number of variables involved, this is not surprising. Certainly, in the case of a Ringelmann determination, it would hardly be expected.

10. Section 2.7 briefly reviews the State-of-the-Art for particulate emissions control in pulverized-coal-fired power plants. For large plants, the conventional scrubber can be eliminated from serious consideration. To date, experience with bag filters is limited to very small boilers in the 80 MW class. However, new developments in the reliable application of fabric filters in the

power industry are being followed with interest, particularly for high resistivity ash associated with low Sulfur coals. Although systems have been sold at least up to 375 MW size, no large installation has yet been operated; bag life has yet to be proven; costs are uncertain. The electrostatic precipitator has been the universally accepted method for fly ash collection world wide. With proper design and reasonable maintenance, modern systems are capable of achieving reliable high performance above 99%. Many are reported in operation in the range 99.4-99.8%. There is a paucity of good data on the continuity of high performance for several years following initial installations. It is very difficult and costly, especially following the air-heater with high resistivity ashes of varying chemical composition, to maintain, continuously, performance at or above 99.7% in large base-loaded plants. The AEP plants at Amos and Mitchell, 800-1300 MW, are among the largest in the country.

11. Typical boiler start up factors related to particulate emissions in the AEP system are reviewed in Section 2.10.

H J Hall

H. J. Hall

4 August 1976
Princeton, N.J.

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LIST OF ILLUSTRATIONS

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ELECTROSTATIC PRECIPITATION
AIR POLLUTION CONTROL
SYSTEMS & EQUIPMENT
AEROSOL PHYSICS

23 June 1976

TECHNICAL REPORT HAR 76-132

SUMMARY ANALYSIS - PRECIPITATOR DESIGN, COSTS, STACK EMISSIONS AND OPACITY FACTORS AT STEAM ELECTRIC GENERATING PLANTS OF THE AEP COMPANY IN WEST VIRGINIA

I. INTRODUCTION

1.1 This report is an update and extension of a 1974 review[1] of some of the factors in the above title. Extensive, new and more reliable cost data are now available.

1.2 The principal objectives are:

1. To discuss effects on relative precipitator costs, overall APC project costs and opacity factors with stack particulate emissions at 0.05 and 0.1#/10^6BTU heat input:

   a. With present SO_2 emission regulations in W. Va.

   b. With possible increased SO_2 by burning higher sulfur coals conservatively considered by Mr. Maynard Smith to have no adverse effects on primary ambient SO_2 concentration levels.

   c. Special cases of Amos 3 and Kanawha 1, 2 problems now in process of improvement.

2. To consider pertinent state-of-the-art factors for the control of air pollutants by either precipitators, fabric filters or wet scrubbers, and to comment on statements made by the EPA in the Technical Document[2] issued May 1976.

II. RESULTS AND DISCUSSION

2.1 LOCATIONS AND PERSONNEL

1. Data for 6 plants in W. Va are indicated in Table 1.

2. Putnam, Kanawha, Marshall and Mason Counties are involved.

3. Locations vary slightly between 81° and 82° Longitude and 38° to 40° Latitude.

4. Total personnel employed = 1298 of which 30.2% are at Amos and about 22.7% are at Sporn. The others are at Cabin Creek, Kammer, Kanawha and Mitchell plants.

2.2 OPERATIONS AND EMISSIONS FACTORS--SUMMARY

1. Data for 9 existing installations and (1) proposed new 1300 MW plant are shown in Table 2.

2. All plants except Kammer and Mitchell are achieving present SO_2 emission limits prescribed by Regulation 10. (Fig. 1).

3. The required outlet stack emissions and corresponding calculated probable opacity for particulates at 0.1#/10^6BTU and at 0.05#/10^6BTU are indicated. For the larger stack diameters (30-33 ft diam) at Amos and Mitchell, it is seen that stack opacity estimates are in the range 33-38% for 0.1#/10^6BTU emission and 18-22% for 0.05#/10^6BTU emission. Plants capable of meeting W. Va 10% opacity at 0.05#/10^6BTU would be Cabin Creek, Kammer 3 and possibly Kammer 1, 2, Kanawha 1, 2, and Sporn 5 under favorable conditions.

4. The required nominal precipitator efficiencies in the last 2 columns are estimated on the basis of actual <u>average</u> coal, ash properties currently being <u>used</u>. All new precipitator installations scheduled are designed for performance well above these levels.

5. Except for the smaller diameter stacks, we conclude that the regulation 0.05#/10^6BTU particulate emission is generally inconsistent with meeting a 10% opacity. Although somewhat greater leeway might be expected with Ringelmann evaluations, under certain conditions, it is most improbable that 10% opacity could be expected at Amos and Mitchell at 0.05#/10^6BTU emissions. About one-half said concentration would be required as tests have corroborated.

2.3 EMISSIONS, COSTS AND OPACITY FACTORS WITH NEW BACKFIT PRECIPITATORS

1. General data are summarized in Table 3.

2. Emissions capability of the various systems with installed SCA in full operation are vendor guarantee values (except Kammer est.) for actual equipment contracted. Thus, the outlet emissions capabilities shown are based on guarantee performance with conservative inlet loadings for typically worst ash conditions. The Kammer case is based on guarantee performance 99.4% with 12.5% of installed capacity out of service.

3. We conclude as follows:

   a. AEP design practice is conservative and also costly in West Virginia. Basic guarantees on performance are more than adequate to meet the 0.05#/10^6BTU emission regulation. i.e. Dry bottom boilers - 99.7-99.75% with 12½% installed capacity out of service; Kammer Cyclone Boilers - 99.4% with 12½% installed capacity out of service.

   b. Opacity estimates are generally 5-10% in all plants for system capability. Note, however, that this takes outlet emissions 50 to 60% of the regulation 0.05#/10^6BTU.

   c. Large new precipitator installations cost \$7-12/sq ft plate area. For backfit cases the total APC project cost ranges 2.24 to 3.77 times installed precipitator cost, per se.

2.4 COSTS VS PARTICULATE EMISSIONS, PRESENT SO_2 REGULATIONS

1. Data for (5) large backfits and (1) new installation of precipitators are summarized in Table 4.

2. For the actual systems being installed, noted to be conservative, the overall costs increase about 25% in going from 0.1#/10^6BTU to 0.05 #/10^6BTU emissions. Generally, however, for normal design practice these costs increases could range up to ~ 30-34%.

3. Total APC project costs in W. Va. for the (5) existing plants are thus $276,950,000 for 0.1 #/$10^6$BTU compared to $348,458,000 for 0.05 #/$10^6$BTU--all for meeting required SO_2 emissions with low S coals. The difference amounts to about $71,500,000, a substantial, significant amount--about enough to do the air pollution control systems work on another new plant in excess of 1000 MW capacity.

4. In addition to above costs, monies for upgrading Amos 3 and Kanawha 1, 2, as shown in Table 5, will have been spent in 1976. The Kanawha 1, 2 figure does not include the cost of the SO_3 conditioning system previously installed to meet performance requirements. The new work of Table 5 is to secure long term reliable performance at Kanawha at emissions less than 0.05#/10^6BTU.

5. We summarize current program costs for maximum emissions 0.05#/10^6BTU at various AEP plants in W. Va. as follows:

Plant	$ million	MW	
New PPTRS			
Amos 1, 2	88.46	1600	
Kammer 1,2,3	61.82	675	
Mitchell 1,2	84.53	1600	
Sporn 1-4	74.94	620	
Sporn 5	38.71	450	
	348.46	4945	$70.6/KW

Upgrading existing PPTRS		
Amos 3	0.91	1300
Kanawha	4.30	450
	5.21	1750

Total Projects Costs in W. Va. $353,670,000 involving 7 existing plants comprising 8 separate stacks. Cabin Creek has not been considered in this report since no current work is scheduled due to a projected shut down in 1977.

2.5 Effects of Medium to High S Coals on PPTR Size, Cost, Performance and Opacity

1. These data are summarized in Table 6. Much smaller precipitators can be used to achieve high performance and low opacity capability. This is reflected in reduced costs as shown.

2. As shown in the following Table 7, relative costs for higher S coals are about one-half those for low S coals meeting existing SO_2 regulations.

TABLE 7

COMPARISON COST ESTIMATED LOW AND HIGH S COALS APC FOR (5) AEP PLANTS: AMOS 1,2; KAMMER 1,2,3; MITCHELL 1,2; SPORN 1-4; SPORN 5. COSTS IN $ MILLIONS

	PPTR COSTS INSTALLED		OA Project Costs	
	0.1 #/10^6BTU	0.05	0.1 #/10^6BTU	0.05
1. Low-W.Va. SO_2 Regs.	99.75	122.67	276.95	348.46
2. Higher S 2-4% Table 6	46.52	63.02	132.38	179.40
Relative Cost Case 1 over Case 2	2.1	1.94	2.1	1.94

3. With 2% S coal, Amos 3 should have little difficulty meeting 0.05#/10^6BTU emission on a long term basis. Performance both at Amos 3 and Gavin with medium sulfur coals have shown precipitator capabilities in the 99.8% range.

2.6 OPACITY FACTORS

2.61 Ringelmann Method

1. A number of factors affecting the Ringelmann determination are summarized in a recent paper[4] and attached as Appendix A. The authors indicate that it is possible for the opacity determination to vary from 14% to 87% with a 32.5 ft diameter stack at a constant geometric mean particle size of 2.5 micron dia. at a mass emission rate of 0.05 gr/SCF. They conclude that the use of opacity measurements by regulatory bodies to determine the degree of particulate emissions is contrary to the laws of nature.

2.62 Transmissometer Method

1. This is the method used in all opacity calculations reported in this paper. It is more scientific and depends upon the physical laws of light scattering or absorption by fine particles. Systems typically use a light source at a wavelength of 0.55 micron for max output. This is compatible with visible light which is in the range 0.4-0.7 micron wavelength.

2. The fundamental factors affecting opacity (1-transmission) in stacks are:

   a. Stack diameter - the longer the path length the greater the opacity.
   b. Particle concentration by wgt
   c. Particle specific surface - total surface/unit wgt
   d. Index of refraction of the particles, color
   e. Particle shape

3. Thus, the number of particles below 1 to 2 micron size are the most significant in determining opacity. Particles of equivalent diameter comparable to the wavelength of light used offer the greatest scattering power and hence highest opacity. Note that a transmissometer in a flue or stack is unaffected by condensibles existing as a gas at the measurement temperature.

4. Opacity is related logarithmically to the variables cited.

5. Since specific surface varies inversely with particle size and density for a given weight concentration, this can have considerable effect on opacity determinations. Most fly ashes have average particle densities in the range 2-3 gm/cc. However, in some cases; particularly very high performance precipitators, Much of the outlet ash may consist of small cenospheres which float on water (density <1). Thus, for a given weight emission, a high concentration of cenospheres will increase the total specific surface and hence the opacity. In any given plant, fairly good correlation between opacity and weight emission can be established for specified conditions, but such a correlation may not apply to some other plant with different coals, grinding, boiler operations, etc.

6. Probable accuracy of opacity data given in this report is estimated ±15% for conditions used. Limited data to date indicate my calculated opacity values on fly ash to be within about 10% of values determined by a Lear Siegler instrument--generally on the conservative side. As more data become available further refinements in calculation can be made for various operating conditions.

7. Fine particle agglomeration occurs variably in a precipitator and these effects are difficult to assess without in situ measurements of particle size outlet distributions. In high performance pptrs, the dust emissions are largely controlled by rapping losses of precipitated dust which can exhibit some agglomeration, thus reducing apparent opacity. It is well known, for example, that the use of certain conditioning agents such as SO_3, NH_3, etc. may alter particle surface properties and promote a agglomeration tendencies. Stack opacities being reduced from ~60% to ~20% have been noted in some cases, without reducing weight emissions by that much.

2.63 Stack Diameter Effects on Opacity

1. To illustrate these effects, the case of Amos 3 is an appropriate example. We compare opacity obtained with a single 30.25' dia stack vs opacity resulting from three (3) stacks of 17.5' dia each so that exit gas velocity is the same in each case and particulate loading is also held constant:

	OUTLET EMISSIONS			
	Single 30.25' Stack		(3) 17.5' dia Stacks	
Item	0.1 #/10^6BTU	0.05	0.1 #/10^6BTU	0.05
1. Gas Flow/Stack, 1000 ACFM	4300	4300	1433.3	1433.3
2. #/hr per Stack, Particulate	1190	595	396.7	198.4
3. gr/ACF per stack	0.0322	0.0161	0.0322	0.0161
4. Est. Opacity % per stack				
nominal min	33	18.1	20.6	10.9
nominal max	38.4	21.5	24.4	13.1

2. We see that the individual 17.5' dia. stacks exhibit opacities close to the 10% regulation for 0.05#/10^6BTU emission, where as the corresponding opacity with the single large stack is about 20%.

3. It is interesting, further, to examine the effect on a Ringelmann observer looking at the plumes from the 3 stacks aligned--i.e. one behind the other. In this case, he would see typically 50-57% opacity at 0.1#/10^6BTU and about 29-34% opacity at 0.05#/10^6BTU emission. Corresponding Ringelmann numbers would be 2.5-3 and 1.5 to 2, respectively.

4. Fig. 2 illustrates, graphically, the opacity as a function of stack diameter for the cases discussed.

2.64 Vendor Opacity Guarantee

1. At present, equipment vendors do not guarantee an opacity. In view of the number of variables involved--particularly those associated with particle size, density, color, shape, agglomeration effects, etc., this is not altogether surprising. Certainly, in the case of a Ringelmann determination, it could not be expected.

2. Vendors guarantee a certain outlet gas particulate concentration by weight as measured by a specified method.

3. In some cases, where adequate information is available, conceivably a vendor might guarantee an average opacity not to exceed a specified figure as measured by a specified instrument or method such as a Transmissometer-Lear Siegler, for example. However, since boiler operation, coal-ash properties, ESP operation and maintenance, etc. are outside control of vendor, it is very difficult to make realistic opacity guarantees except perhaps under very limited conditions.

2.7 STATE-OF-ART PARTICULATE CONTROL - Power Plants

1. Meeting most State and Federal particulate emission requirements of ~ 0.1#/10^6BTU heat input typically requires fly ash recovery in excess of 99% by weight. Lowest requirements of 0.05#/10^6BTU emissions exist in two States--West Virginia and New Mexico. To meet this, particulate recovery has to be typically in excess of 99.5% by weight. Variations occur due to coal-ash properties, type of boiler, etc. In the AEP system, for conservative design, control equipment is typically specified on the basis of 10,000 BTU/lb, 20% ash for Eastern Bituminous Coals; and 7500 BTU/lb, 15% ash for Western Coals. Thus for dry bottom boilers at 80% carry over, 99.4% efficiency at 0.1 #/10^6BTU and 99.7% efficiency at 0.05#/10^6BTU are typically required. This may not appear to be a significant difference in performance--only 0.3%. In fact, it is a significant factor in terms of size, cost and reliability of equipment because it means that the collector dust loss has to be reduced in half or by 50%--and this has to be done on the finer particles which are the most difficult to collect. The incremental performance of added size sections decreases as overall collection efficiency increases. There is a diminishing return effect on increasing pptr size.

2. Possible methods of accomplishing above performance encompass basically three: electrostatic precipitators, fabric filters, or wet scrubbers. Technical and economic considerations favor the ESP for high performance on fine particles <3 micron size, particularly at very high gas flows frequently required in large power plants. An 800 MW plant delivers about 3 million cubic feet per minute of flue gas for treatment at ~300 F+; about 4.3 million ACFM at 750F if a "Hot" pptr is used. To achieve over 99% with a venturi scrubber on 1 micron particles requires prohibitive power requirements and cost. In addition, horrendous problems of reliability and wet sludge handling and disposal are introduced.

For large plants, the conventional scrubber can be eliminated from serious consideration. The fabric filter, assuming a 2 yr bag life and proper maintenance, might be considered costwise competitive with the ESP up to 300-400 MW size under some conditions (particularly high ash resistivity cases). It can deliver efficiencies 99.5-99.7+% with dry collection; it is unaffected by high ash resistivity factors. Power requirements are substantial (3-6"H_2O pressure drop) and equipment is large. Problems can occur with abrasive ashes, fine particle blinding, dewpoint excursions, corrosion, excessive pressure drop, and maintenance. To date, the experience here in power boilers using pulverized coal rests on the Sunbury station PPL where two 80 MW boilers have bag filters showing average bag life 2 yrs+. Recently, a few other sales have been made including boilers in the 375 MW range. Practice seems to indicate fairly low treatment rates order 2 cfm/sq ft bag. A recent estimate[5] on cost for an 800 MW plant showed $ 11.00/sq ft bag system installed. Caution on costs is indicated since no large plant has yet been built, and the 2 yr bag life assumed has yet to be proven. New developments in the reliable application of bag filters in the power industry are being followed with interest, particularly for high resistivity ash associated with low S coals.

3. The ESP, which is capable of high performance, dry collection, lowest power requirements, applicability to ultra fine particles and large gas flows, has been the universal method for fly ash collection world wide. With proper design and reasonable maintenance, modern systems are capable of achieving, reliably, high performance above 99%. Many are in operation in the range 99.4-99.8%. It is difficult and costly, especially following air heater with high resistivity ashes, to maintain, continuously, performance at or above 99.7%.

4. It may be of interest to note AEP's recent policy in the design of new precipitators generally guaranteed for at least 99.7% in most cases.

   a. Careful, specific and detailed specifications giving limits on certain critical parameters.

   b. 14% redundancy -- extra capacity above that nominally required.

   c. Technical considerations first priority over cost, per se.

   d. Objectives high continuous performance without excessive maintenance or forced boiler outage due to ESP failure.

   e. Designs based on worst coal-ash properties expected. Often with either Eastern or Western coals or combinations thereof.

   f. Conservative basic precipitator sizing.

   g. Gas flow rate design typically 10% above max calculated expectation.

   h. Refinements and features to minimize maintenance requirements for reliability.

   i. Use of "European" type designs to minimize wire breakage and to enhance reliability

   j. Judicious use of gas conditioning, where appropriate, to alleviate performance variability with changing coal-ash properties in low sulfur fuel combustion.

   k. Use of both cold and hot precipitators according to technical and economic evaluations.

2.8 STATE AIR POLLUTION REGULATIONS

1. Appendix B summarizes Codes and Standards 1975 among the 50 States of the USA.

2. One is struck by the variability and special conditions attached to the Codes; it is necessary to read every word and carefully.

3. It is noted that delivery schedules for SO_2 scrubber equipment and construction time tables look like 3 to 4 years; this is comparable with large precipitator project schedules.

4. Particulate emissions vary from as low as 0.05 #/10^6BTU heat input for coal fired utilities in West Virginia and New Mexico to as high as 0.8#/10^6BTU for existing plants in North Dakota. The tendency seems to be for a limit of about 0.1#/10^6BTU for large boilers. W. Va. limits 1200 #/hr total emission from all units in one plant site.

5. Total hourly amounts of SO_x from a plant are limited in several states such as W.Va. which uses 45,000 #/hr SO_2 max in Kanawha Valley.

6. In New Mexico, fine particulate of <2 microns equivalent aerodynamic diameter cannot exceed 0.02#/10^6 BTU at all coal fired plants.

2.9 Ambient Particulate and SO_2 Data in West Virginia

1. Tables 8 and 9 summarize most recent data in the Kanawha Valley obtained from the National Monitoring Network for year 1974.[3]

2. It is interesting that the second highest SO_2 conc recorded is less than ½ National 24 hr standard.

2.10 Boiler Start-Up Factors

1. Common recommended practice in the ESP industry is to energize the pptr only after the flue gas temperature leaving the precipitator has obtained a value above the dewpoint within pptr for prevailing conditions. Levels of 250F-270F are reasonable in most cases. For very low S coals, much less than 1%, lower temperatures can be used. The reasons are to avoid sticky ash deposits on electrodes which can seriously impair performance capability, and to prevent excess water collection in hoppers which, with fly ash, can cuase hopper pluggage and severe maintainance problems as well as possible over-filling and shorting out the precipitator.

2. Recently, I understand that some manufacturers have tentatively recommended immediate pptr operation at stable coal fire without deleterious effects. Each case must be examined carefully.

3. Oil lighters and warm up with good combustion should not normally require pptr operation for stack appearance. Precipitator energization in some cases may start with first use of coal. Recommended practice is to use minimum amount of pptr, say 1 or 2 sections, as required--progressively energizing as additional mills are put in service and gas temperature gets to satisfacoty levels. Temporary operation at higher than normal rapping is also sometimes employed.

4. Typical Plant Practice in AEP system, W. Va. is summarized as follows:

Plant		Compliance Time or PPTR Energization From Start Up
(1) Sporn		est~ 5 hrs
(2) Kammer		5 hrs hot restart to 250F gas 7 hrs cold start AH out
(3) Mitchell		2-3 hrs inlets on - not complianc
	Unit 1	6 hrs one side PPTR on 250F gas 12 hrs other side PPTR on 250F gas
	Unit 2	6 hrs one side PPTR on 250F gas 8 hrs other side PPTR on 250F gas
(4) Kanawha		5.5 hrs warm restart - 265Fout weekend outage gas 12.5 hrs cold start - 265F out ga

Estimate can live with Ringelmann 2 to 3 during startup

(5) Cabin Creed		3 hrs hot restart 5 hrs cold start

Safely meet Ringelmann 2 during start

(6) Amos 1, 2		est~ 5 hrs new pptr fully on 270F can use existing pptr at stable coal fire
(7) Amos 3		est~ 5+ Hrs 1st field at stable coal fire

Data items 1-5 from Plant Managers; items 6,7 from Bob Mata, AEPSC. Al Moore estimates Amos plant could cope reasonably well with 4 hour exemption on start up.

2.11 Comment on EPA Technical Document[2]

Reference Section Technical Feasibility of Complaince with Regulation II.

1. A simplistic, generalized view is expressed; it can be misleading and dangerous in making comparisons among various methods of particle collection.

2. Pg. 20--Many cases of low S coal ashes, the resistivity is not primarily determined by the sulfur content of the coal as stated. Important and often overriding are the chemical properties of the ash. Some West Virginia 1% S coals, for example, are extremely poor actors in a precipitator--those with high silica + alumina, low Sodium and Potassium, and marginal iron content.

3. Pg. 20--"Keeping temperature constant, the only way to increase pptr efficiency is to increase its size as indicated above"--this is not so. SO_3 conditioning or other conditioning and electrical energization factors are also important methods of increasing performance with high resistivity ashes.

4. Pg. 21--discussion implies that hot pptrs allow large reductions in size over cold pptrs on high resistivity ash--this is not so. Assume a poor ash, cold side pptr with a conservative SCA 750 Ft^2/1000 ACFM on an 800 MW boiler having gas flow 3,000,000 ACFM @ 300F+. This takes collecting area 2,250,000 ft^2. for say 99.7% collection. A hot pptr for same performance would have about 480 SCA, conservative design. At 750 F, gas flow would be about 4,300,000 ACFM and the collecting area 2,065,000 sq ft or about 8.2% smaller size. Add to this case, extra cost of heat insulation, and the overall cost may not be much different than the cold side, or it could be higher depending upon site conditions, flue runs, possible requirement for higher cost steel.

5. Pg. 21--The reliability, energy cost, water pollution, etc. problems in scrubbers for large plants leaves much to be desired.

H. J. Hall *HJ Hall*

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1. H. J. Hall. Design and Cost Analyses for Electrostatic Precipitators and Air Pollution Control Systems for Particulate Emissions of 0.05 and 0.1 #/10 BTU Heat Input in Steam Electric Generating Plants (W.Va.), American Electric Power Company. Technical Report HAR 74-67, 10 Sept. 1974.

2. Technical Document Supporting the Administrator's 4 March 1976 Reafformance of His Original Approval of the West Virginia State Implementation Plan, May 1976.

3. Monitoring and Air Quality Trends Report, 1974. EPA-450/1-76-001, Feb 1976 issue.

4. Alexander Weir, Jr., et al. Factors Influencing Plume Opacity. Environmental Science and Technology, Vol. 10, No. 6, June 1976, page 539.

5. J. M. Genco, et al. The Use of Nahcolite Ore and Bag Filters for SO_2 Emission Control. JAPCA, Dec 1975, page 1244.

TABLE 1

GEOGRAPHICAL LOCATIONS AND PERSONNEL---AEP PLANTS IN W. VA.

	PLANT	SITE	COUNTY	LONGITUDE	LATITUDE	MANAGER	TEL (304)	No. Employ
1.	Amos	St. Albans	Putnam	81°49'18'	38°28'26"	J. A. Moore	755-5301	392
2.	Cabin Creek	Cabin Creek	Kanawha	81°28'43"	38°11'55"	G. E. Briers	595-2811	81
3.	Kammer	Cresap	Marshall	80°49'00"	39°50'30"	C. E. Shay	845-6220	208
4.	Kanawha	Glasgow	Kanawha	81°25'16"	38°12'20"	J. A. Bennett	595-3480	125
5.	Mitchell	Cresap	Marshall	80°49'00"	39°50'00"	C. E. Shay	845-6220	197
6.	Sporn	New Haven	Mason	81°55'02"	38°58'02"	E. H. Gloss	882-3111	295
							Total	1298

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TABLE 2 - SUMMARY STEAM PLANT OPERATING FACTORS AND EMISSIONS FACTORS - AEP SYSTEM in WEST VIRGINIA

	PLANT	TOTAL MW	RATED INPUT 10^6 BTU/HR	RATED STEAM 1000 # PER HR	STACK HGT FT.	STACK DIAM FT.	STACK GAS TEMP F	STACK 1000 ACFM	W.VA ALLOW # SO_2/10^6 BTU	PRESENT COALS AVERAGE VALUES BTU/LB	% S	% ASH	REQD OUTLET LOADINGS 0.1 #/10^6 BTU #/HR	gr/ACF	0.05 #/10^6 BTU #/HR	gr/ACF	EST. STACK OPACITY % AVG FOR EMISSIONS REQD 0.1 #/10^6 BTU MIN	MAX	0.05 #/10^6 BTU MIN	MAX	NOM. PPTR E. 0.1 #/10^6 BTU
1.	AMOS 1,2	1600	14,040	10,560	903	33	310	5600	1.6	11400	0.89	16.1	1404	0.0293	702	0.0146	32.7	38.2	18.0	21.3	99.12
2.	AMOS 3	1300	11,900	9720	903	30.25	310	4300	1.6	11400	0.89	16.1	1190	0.0322	595	0.0161	33.0	38.4	18.1	21.5	99.12
3.	CABIN CREEK 81,82,91,92	180	2184	1800	260	16	370	1100	1.6	11700	0.65	11.3	218.4	0.0232	109.2	0.0116	14.1	16.8	7.3	8.9	98.75
4.	KAMMER 1,2	450	4312		601	16.7	337	1877	2.7	11700	4.3	14.8	431.2	0.0268	215.6	0.0134	20.2	25.4	10.6	13.6	97.37
5.	KAMMER 3	225	2156		601	11	337	938	2.7	11700	4.3	14.8	215.6	0.0268	107.8	0.0134	14.6	18.5	7.6	9.7	97.37
6.	KANAWHA 1,2	450	3900	2670	325	19.16	309	1453	1.6	11600	0.82	16.6	390	0.0313	195	0.0157	21.8	25.8	11.6	13.9	99.13
7.	MITCHELL 1,2	1600	14040	10,578	1200	33	328	5642	2.7	11250	3.6	17.5	1404	0.029	702	0.0145	32.4	37.8	17.8	21.2	99.20
8.	SPORN 1-4	620	5244	3720	600	21.5	280	1703	3.2	11220	1.27	16	524.4	0.0359	262.2	0.018	27.1	31.9	14.6	17.5	99.12
9.	SPORN 5	450	3916	2923	601.5	15.08	280	1273	3.2	11220	1.27	16	391.6	0.0359	195.8	0.018	19.9	23.6	10.5	12.6	99.12
10	1301 NEW	1300	11,900	9720		30.25 EST		4730 EST	1.2	10,000 (Design)	0.7	20	1190	0.0294	595	0.0147	30.5	35.8	16.6	19.8	99.38

NOTES: 1. OPERATING DATA supplied by Plant Managers in Recent Letters to APC BOARD W.VA.

2. OPACITY CALCULATIONS FOR CONDITIONS MEETING OUTLET EMISSIONS AS NOTED ARE BASED ON:
   a. TRANSMISSOMETER INSTRUMENT OPTICAL
   b. LIGHT COLORED FLY ASH
   c. ASH INDEX REFRACTION ~1.5
   d. AVERAGE OUTLET ASH SPECIFIC SURFACE TYPICAL
      DRY BOTTOM BOILER 2.36 - 2.86 m^2/gm
      CYCLONE BOILER (KAMMER) 3.1 - 4.0 m^2/gm
   e. NO SIGNIFICANT PARTICLE AGGLOMERATION EFFECTS ASSUMED

3. NOM. REQD PPTR EFFICIENCY BASED ON AVERAGE INLET PARTICULATE LOADING USING PRESENT AVERAGE COAL BTU/LB, 80 % TOTAL CARRY OVER DRY BOTTOM, AND 30% CARRY OVER FOR CYCLONE (KAMMER) AND AVG ASH CONTENTS AS SHOWN

4. Nominal Allowable S content of coals to meet SO_2 emissions are:
   AMOS, CABIN CREEK & KANAWHA ~1.0 % S
   KAMMER & MITCHELL ~1.6 % S
   SPORN ~1.9 % S ; NEW 1301 ~0.7 % S

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PRINCETON, N.J.
HAR 76-13
11 June 1976
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TABLE 3 - SUMMARY - NEW PRECIPITATOR DESIGN, EMISSIONS, COSTS, OPACITY FACTORS--AEP PLANTS IN W. VA.

PLANT	Sched Compl Date	MW Total	PPTR Design Basis--Totals: 1000 ACFM	1000 ft² inst. Area	SCA inst	Eff % Max	Nom Outlet Emission Capability #/10⁶BTU	gr/ACF	Cost Data $1000: PPTRS erected	OA Proj (3)	Ratio Cost OA/PPTR	PPTR Cost $/Ft²	$/ACFM	Est. Opacity nominal %: Min	Max
1. Amos 1, 2	4/78	1600	6000	4389.76	731.6	99.85	0.024	0.0068	32,158	88,455	2.75	7.33	5.35	8.8	10.6
2. Kammer 1,2,3, (5)	8/78	675	3000	2776	925.3	99.63	0.031	0.0081	27,640	61,823	2.24	9.96	9.21	6.6 Kam 1,2 4.7 Kam 3	8.5 6.0
3. Mitchell 1,2	4/78	1600	6000	4389.76	731.6	99.85	0.024	0.0068	31,837	84,532	2.66	7.26	5.31	8.8	10.6
4. Sporn 1-4	2/80	620	2400	1696.94	707.6	99.8	0.032	0.0084	20,756	74,940	3.62	12.20	8.64	7.1	8.6
5. Sporn 5	9/77	450	1750	1264.8	722.7	99.8	0.032	0.0084	10,276	38,708	3.77	8.12	5.87	5.0	6.1
6. New 1301	(4)	1300	4870	4390	900	99.83	0.027	0.0079	31,278		2.0 est.	7.13	6.43	9.3	11.2

NOTES: (1) Dry Bottom Boilers except Kammer -- 1 to 6% S, 20% ash coal, 10,000 BTU/lb min assume 80% carryover for inlet nominal 16#/10⁶BTU.
(2) Stack gas flow assumed ~97% of design PPTR at full load, max conditions.
(3) Overall project cost includes interest during construction. These data plus pptr erected costs are actual figures supplied by Jack Barton, AEPSC.
(4) Not yet fixed, probably after 1980 -- PPTR costs actual based on Firm 1975 prices when purchased. Design adequate for 0.7% S coal. OA proj. cost not yet determined.
(5) Kammer is cyclone boiler design for 1% S coal + flux with PPTR for >50% C in ash Estimates based on max inlet particulate 8.3#/10⁶BTU.

TABLE 4

COST ESTIMATES FOR MAJOR NEW PRECIPITATORS AT 0.1 AND 0.05 #/10^6BTU EMISSIONS--AEP PLANTS IN WEST VIRGINIA
(Base Data Ref. Table 3)

PLANT	MW GROSS	\$1000 PPTR COST ERECTED 0.1 #/10^6 BTU	\$1000 PPTR COST ERECTED 0.05 #/10^6 BTU	\$1000 OA PROJECT COST 0.1 #/10^6BTU	\$1000 OA PROJECT COST 0.05 #/10^6BTU
1. Amos 1,2	1600	25,500	32,158	70,000	88,455
2. Kammer 1,2,3	675	22,850	27,640	51,200	61,823
3. Mitchell 1,2	1600	25,250	31,837	67,150	84,532
4. Sporn 1-4	620	16,200	20,756	58,600	74,940
5. Sporn 5	450	7,950	10,276	30,000	38,708
6. New 1301	1300	37,800	45,400 est 1980	75,600	90,800 est 1980
Total items 1-5 existing plants	4945	97,750	122,667	276,950	348,458
Total 6 Plants	6245	135,550	168,067	352,550	439,258
OA Relative Costs		1.0	~1.25	1.0	~1.25
Average ratio OA Project Cost/ PPTR Cost including one new plant				2.61	
For 5 existing plants				2.74	

PPTR design basis conservative, including 14% redundancy on pptr size nominally required for guarantee performance. This is typically 99.4% for 0.1#/10^6BTU and 99.7% for 0.05#/10^6BTU in Dry bottom boilers. Kammer design is based on conservative 99.4% at max 0.05#/10^6BTU with extra 14% installed capacity above this.

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TABLE 5

ADDITIONAL PROJECT COSTS FOR UPGRADING PERFORMANCE AT AMOS 3 AND KANAWHA 1, 2 PLANTS, AEP

		$1000 Mat	$1000 Lab
AMOS 3			
1.	Replace all wires-barb in all sections	93	160
2.	Navco plate rappers - lower pptrs	80	25 est
3.	Koppers New air rap - upper pptrs added extra rappers on trailing edges of plates all sections	120	25
4.	Replace wire rappers P-55 air	52	10
5.	Hopper chain baffles	5	10
6.	Hopper heating installation	68	104
7.	Air supply	69	
8.	TR control improvements	66	19
9.	Air Heater By-Pass already instld		
		553	353

Total cost items 1-8 $906,000

Scheduled completion 1976 - most have now been done.

KANAWHA 1, 2

1. Double electrical energization and TR sets
2. Double number rappers
3. Reinforce plate suspensions and support for new TR sets
4. New control room and electrical work
5. New hopper level indicators and hopper heating

Total Project Cost -- $4,300,000.

Scheduled completion -- Jan 1977

13 week outage for Unit 2 start 16 Aug 1976
13 week outage for Unit 1 start 15 Oct 1976

This program meets State compliance date of mid Oct 1976.

TABLE 6. SUMMARY TYPICAL EFFECTS OF HIGHER S COAL ON PPTR SIZE, COST, PERFORMANCE, OPACITY

PLANT	(a) Coal % S	(b) Nom. SCA installed 0.1 #/10^6 BTU	(b) Emissions 0.05	(c) Estimated Costs PPTR Installed in 1000 Dollars 0.1 #/10^6 BTU	0.05	(c) Estimated Costs OA Project - $1000 0.1 #/$10^6$ BTU	0.05	Nom outlet emission capability max (d) Eff %	(d) #/10^6 BTU	(e) Eff%	(e) #/10^6 BTU	Typical max Opacity % (f) Expected case (d)	case (e)
1. Amos 1,2	2.0	342	456	15,040	20,000	41,400	55,000	99.86	0.0224	99.6	0.064	9.9	26
2. Amos 3	2.0	342	456	Performance capability of existing PPTR is adequate to meet 99.4% with 5 fields and 99.7% with 6 fields with 2% S coal				99.86	0.0224	99.6	0.064	10.3	27
3. Kammer 1,2	4.0	308	410	9,200	12,270	20,600	27,400	99.5	0.030	99.1	0.054	8.2	14.3
4. Kammer 3	4.0	308	410									5.8	10.2
5. Mitchell 1,2	4.0	256	353	11,150	15,400	29,600	40,800	99.86	0.0224	99.6	0.064	9.9	26
6. Sporn 1-4	3.5	256	353	7,510	10,350	27,150	37,400	99.86	0.0334	99.6	0.064	6.1	14.5
7. Sporn 5	3.5	256	353	3,615	5,000	13,630	18,800	99.86	0.0224	99.6	0.064	4.3	11.8

NOTES:
(a) Rec by Maynard Smith as realistic without adversely affecting ambient AQ Stnds.
(b) Includes 14% redundancy for reliability; 99.4% eff @ 0.1#/10^6BTU & 99.7% eff @ 0.05#/10^6BTU for dry bottomm--all except Kammer--80% carryover, 10^4BTU/lb, 20% ash coals all cases. Kammer cyclone boilers, 30% carryover and 98.4% eff @ 0.1#/10^6BTU; 99.2% eff @ 0.05#/10^6BTU.
(c) Based on actual cost data shown in Table 3 -- prorated for change in PPTR size.
(d) Nom. max eff. capability of installed system with typical worst coal properties expected-- Design instld max SCA (column 3)
(e) Nom. max eff capability as above with SCA design installed as shown column 2
(f) Opacity data for operating conditions as in Table 3 for gas flow

18 June 1976
HJ Hall

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TABLE 8

SUMMARY - AMBIENT PARTICULATE DATA IN NATIONAL AQCR #234, KANAWHA VALLEY, FOR THE YEAR 1974 as of 27 Sept 1975.[3]

Station and Location	SUSPENDED PARTICULATES No. Valid Values	No. Daily > 24 Hr Stnds Sec	Pri	Highest 24 Hr Values 1st μg/m³	2nd	Annual Geom Mean μg/m³
50 0280002 F01 Charleston	55	13	5	371	360	106
3 F03 Charleston	53	1		159	129	51
4 F01 Charleston	110	52	17	418	417	151
5 F01 Charleston	56	8		193	189	93
8 F01 Charleston	40			116	113	54 ?
0760001 F02 Kanawha Co.	42	9	1	357	253	89 ?
2 F02 Kanawha Co.	58	1		249	127	44
1340001 F02 Nitro	54	2		168	168	66
1560002 F02 Putnam Co.	56			128	118	45
3 F02 Putnam Co.	56			149	131	56
1760001 F01 So. Charleston	18	4		200	174	84 ?
2 F02 So. Charleston	21	2		215	200	
3 F01 So. Charleston	60			129	114	42
5 F02 So. Charleston	14	1		208	145	
6 F02 So. Charleston	14	7	1	268	196	

National 24 hr primary stnd = 260 μg/m³
secondary stnd = 150 μg/m³

Annual geometric mean primary stnd = 75 μg/m³
secondary stnd = 60 μg/m³

TABLE 9

SUMMARY - AMBIENT SO_2 DATA IN NATIONAL AQCR #234, KANAWHA VALLEY, FOR YEAR 1974 AS OF 27 SEPT 1975.[3]

Station and Location	No. of Valid Values	Highest 24 Hr Values, μg/m³ 1st	2nd	Arithmetic Annual mean μg/m³
50 0280004 F01 Charleston	6105	252	172	44 ?
7 F02 Charleston	57	270	141	55
8 F01 Charleston	37	102	86	24 ?
0760002 F02 Kanawha Co.	55	210	178	46
1340001 F02 Nitro	52	168	160	29
1560002 F02 Putnam Co.	50	128	86	30
3 F02 Putnam Co.	52	136	102	33
1760002 F02 So. Charleston	16	63	60	
3 F02 So. Charleston	56	148	115	23
4 F02 So. Charleston	4	84	63	
5 F02 So. Charleston	15	141	115	
6 F02 So. Charleston	13	136	115	

National 24 Hr standard = 365 μg/m³ 2nd highest/yr.

Annual Arithmetic mean stnd = 80 μg/m³ (.03 PPM)

3 hr standard = 1300 μg/m³

All data full 4 quarters except ? which are for 2 or 3 Quarte

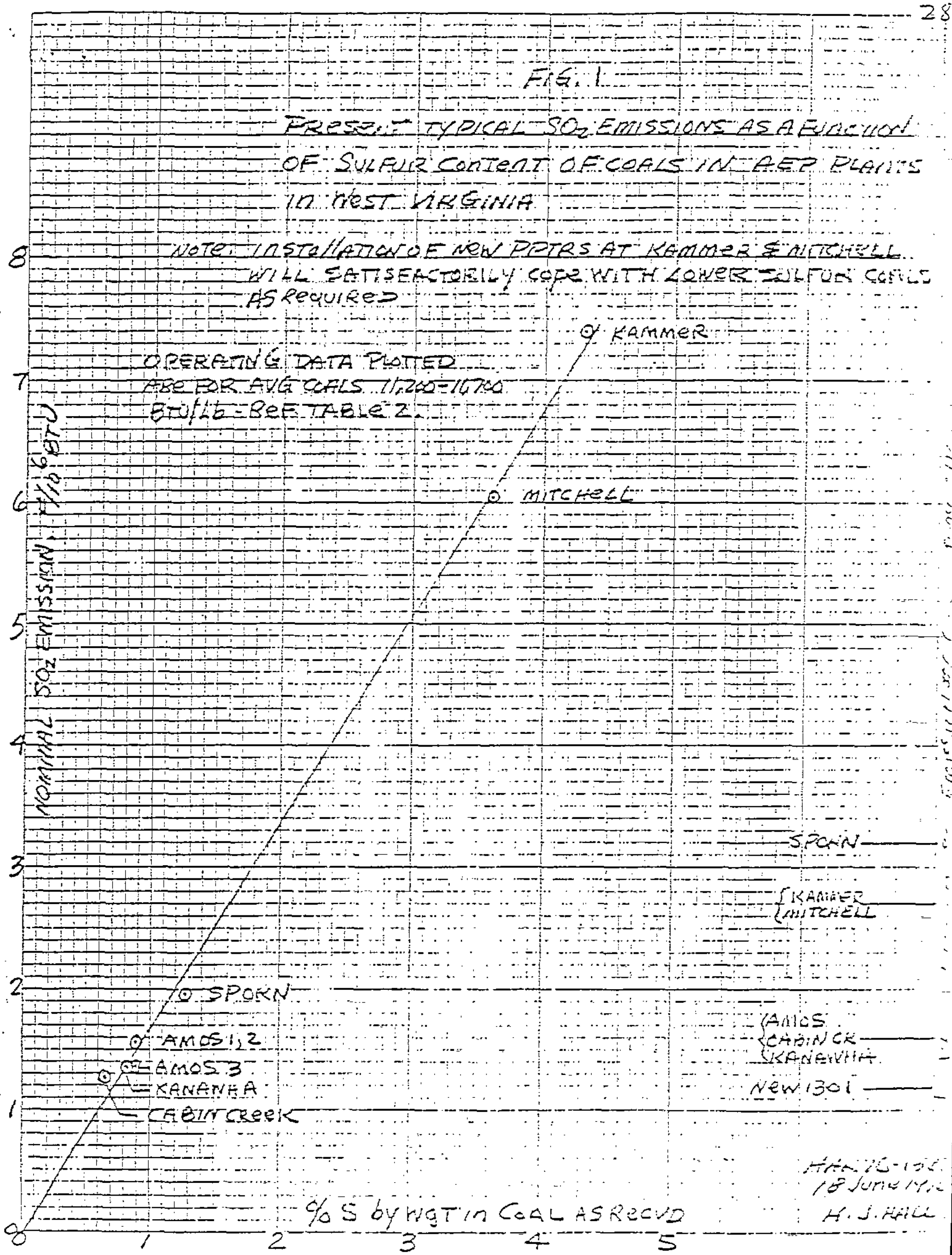


FIG. 1
PRESENT TYPICAL SO2 EMISSIONS AS A FUNCTION OF SULFUR CONTENT OF COALS IN AEP PLANTS IN WEST VIRGINIA
NOTE: INSTALLATION OF NEW PPTRS AT KAMMER & MITCHELL WILL SATISFACTORILY COPE WITH LOWER SULFUR COALS AS REQUIRED
OPERATING DATA PLOTTED ARE FOR AVG COALS 11,200-11,700 BTU/LB - SEE TABLE 2.
KAMMER
MITCHELL
SPORN
AMOS 1,2
AMOS 3
KANAWHA
CABIN CREEK
SPORN
KAMMER
MITCHELL
AMOS
CABIN CK
KANAWHA
NEW 1301
NOMINAL SO2 EMISSION, #/10^6 BTU
% S by WGT in COAL AS RECVD
0
1
2
3
4
5
6
7
8
18 June
H. J. HALL

FIG. 2

NOMINAL MINIMUM STACK OPACITY AS A FUNCTION OF STACK DIAMETER FOR AMOS 3 PLANT, AEP

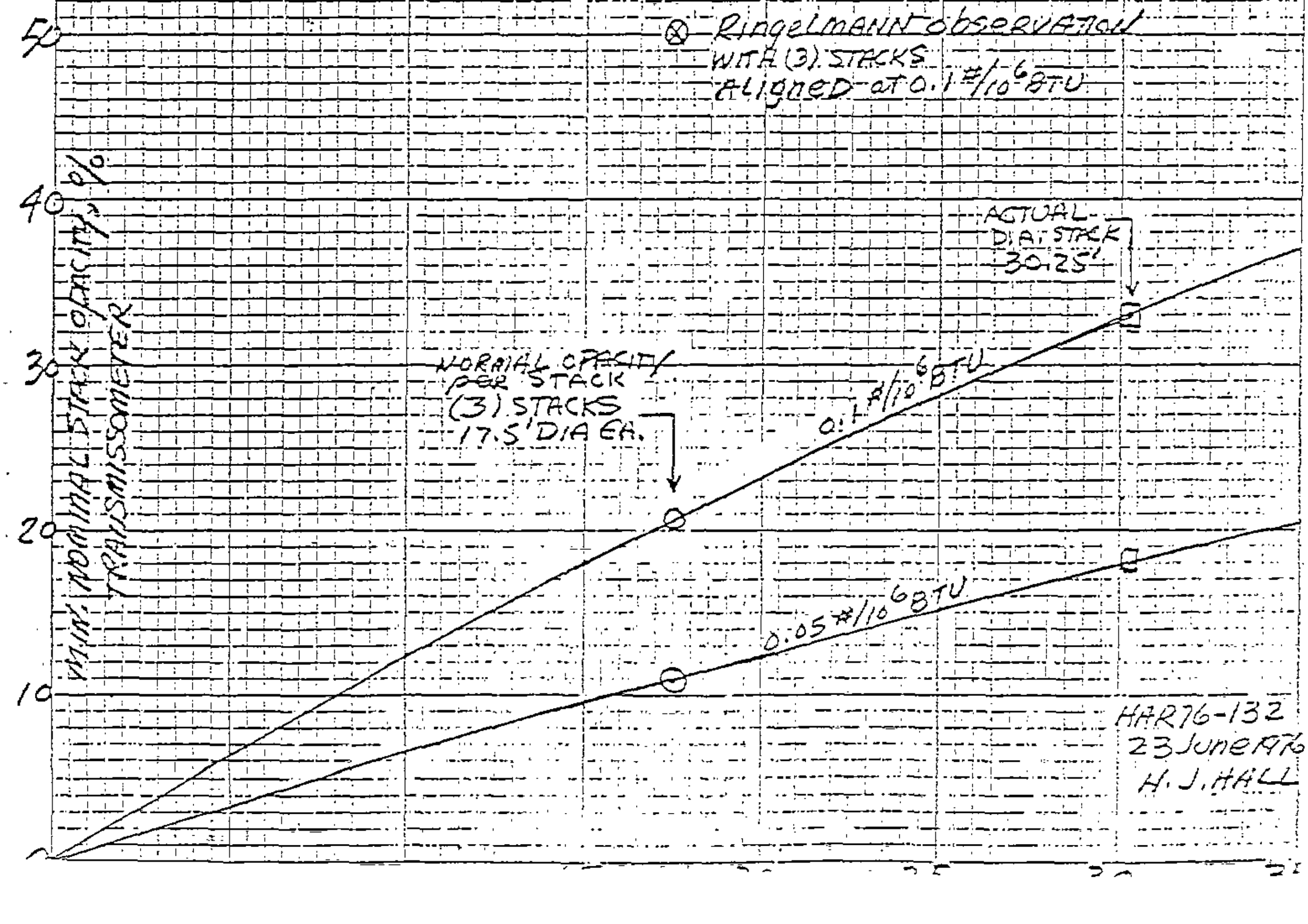
RATED HEAT INPUT 11,900 x 10^6 BTU/HR

DATA FOR CONSTANT PARTICULATE CONC.

0.0322 gr/ACF @ 0.1 #/10^6 BTU EMISSION

0.0161 gr/ACF @ 0.05 #/10^6 BTU EMISSION

(3) STACKS OF 17.5' DIA. EACH WOULD HAVE SAME GAS EXIT VELOCITY AS INSTALLED SINGLE STACK OF 30.25' DIA.



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H. J. HALL

FEATURE

Factors influencing plume opacity

Previously unrecognized uncontrollable variables such as the angle of the sun, the time of day and the geographic location of the power plant greatly influence smoke plume opacity

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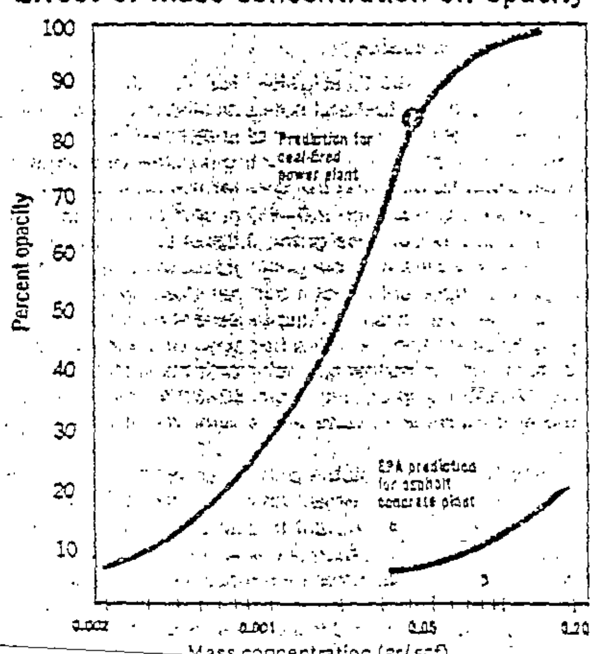
Numerous experiments on the removal of particulate matter with electrostatic precipitators and wet scrubbers have been conducted at the 1580 MW coal-fired Mohave Generating Station at South Point, Nev. It was established that opacity is not a function of particulate grain loading alone, but is influenced by a number of other independent variables, some of which are beyond the control of the operator of the stationary source. Thus, mass emissions cannot be determined by opacity measurements alone.

The experimental data, including plume opacity observations by trained smoke observers, were obtained in conjunction with 11-ft and 32.5-ft diameter stacks and fly ash particles of similar shape having 0.95 and 2.5 μ mean diameters. Mass emissions of particulate matter ranged from 0.004–0.40 gr/scf. The data indicate that it is possible for opacity to vary from 14–87% with a 32.5-ft diameter stack at a constant mean particle diameter of 2.5 μ and a constant mass emission rate of 0.05 gr/scf.

FIGURE 1
Effect of mass concentration on opacity



This paper presents the quantitative effect of a number of independent variables on opacity. It also shows that the use of opacity measurements by regulatory agencies to determine the degree of particulate emissions is contrary to the laws of nature, regardless of the laws of man.

Variables affecting opacity

There are a number of variables that affect opacity other than the mass emissions of particulate matter. These variables can be divided into two categories: Those variables that are a function of the control equipment and can be "controlled" by the operator or the designer; and those variables beyond the control of the operator (see box).

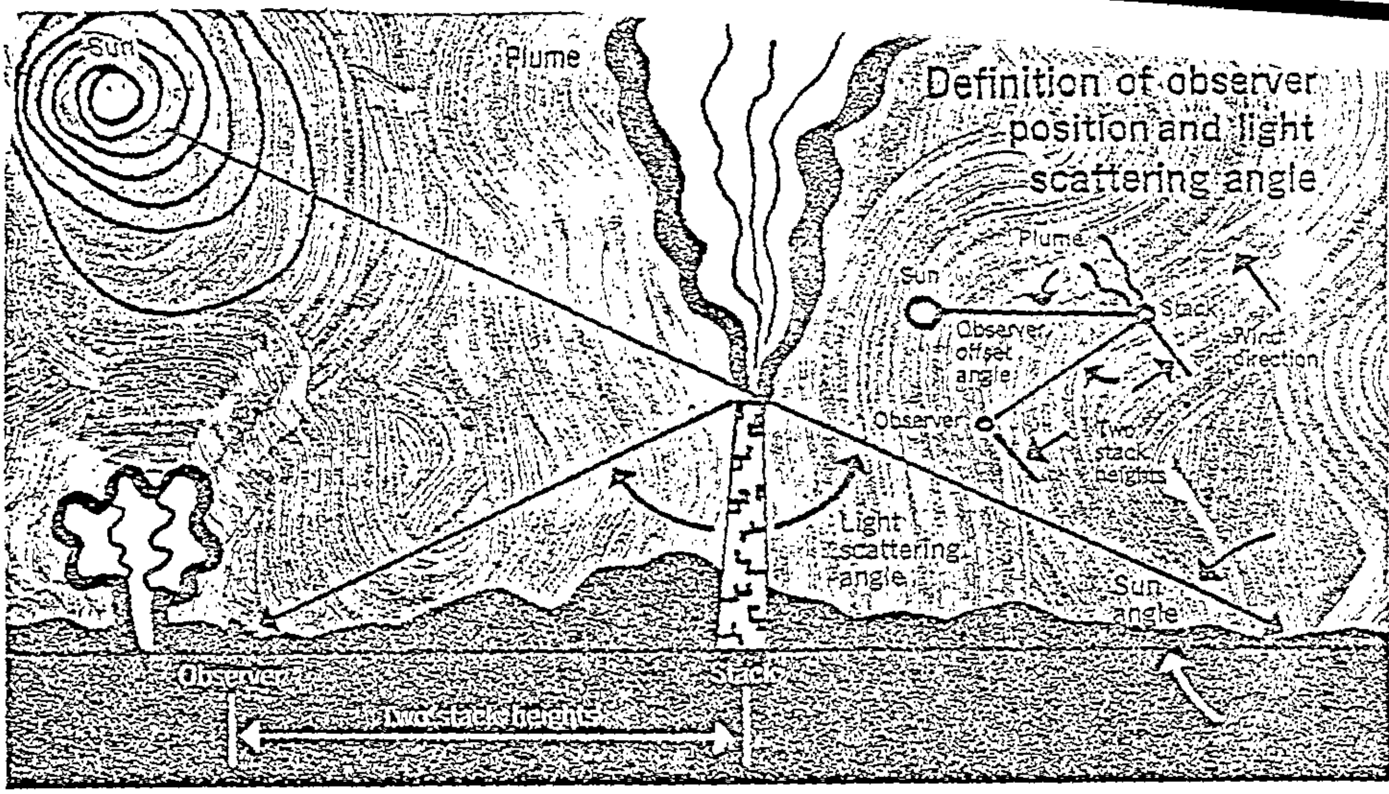
Control equipment could be installed to influence plume opacity as a result of controllable variables, but opacity standards would still reflect the influence of five other "controllable" variables in addition to mass emissions.

Light-scattering theory (see Reference 1 Additional reading) predicts opacity values within a reasonable degree of accuracy over a range of mass emissions (from 0.004–0.4 gr/scf) and large variations in mean particle sizes compared with the observations of trained observers.

In this paper the theory is used to quantitatively determine the effects of changes in a single parameter on opacity, while all other factors are held constant. Several arbitrarily selected conditions were used as a basis for conducting this parametric study. In the figures that follow, the opacity that corresponds to this nominal set of conditions is indicated as a black dot on a curve generated by variations in a single parameter. By using the Halow-Zeek equation and making certain assumptions, the opacity corresponding to the arbitrarily selected conditions (see Table 2 for "black dot" values) is 85%.

Controllable variables

Mass concentration of particulate emissions was the first parameter considered. A Functional Opacity-Mass Relationship for an Asphalt Concrete Plant was recently reported by the EPA in the *Federal Register*. These EPA data have been replotted in Figure 1, which also shows the predicted opacity-mass relationship beginning with the "black dot" conditions typical at the Mohave Generating Station. Note that for the coal-fired power plant, as the grain loading approaches a large value, the opacity



asymptotically approaches 100%. Conversely, as the grain loading approaches zero, the opacity asymptotically approaches zero. In coal-fired power plants, opacity is thus *not* a simple linear function of mass emissions as EPA published for asphalt-concrete plants.

Figure 1 indicates that at a grain loading of 0.05 gr/scf, the EPA data suggest an opacity of 6%, while at the same grain loading the opacity at the coal-fired power plant would be 85%, as indicated by the black dot. This large difference is accounted for by the influence of variables other than the concentration of mass emissions.

One important independent variable is the diameter of the stack, which fixes the path length that light traverses during penetration of a smoke plume. The larger the diameter, the greater the path length over which light is scattered by smoke particles, and the greater the apparent plume opacity.

The size of the particulate matter in the smoke plume is another variable that has a pronounced effect on opacity. If 50% of the particles by weight are larger than a given size (and the remaining 50% by weight smaller than a given size), then the characteristic size is called the mean particle size. At a given grain loading, the smaller the mean particle size, the greater the number of particles in a given volume of gas and the greater the degree of light scattering and resultant opacity.

Deviation from the mean size is another important variable. Particle size distribution can be measured with a sampling device called a cascade impactor that separates the particles into different sizes. By weighing the amount of particles collected for each size range, the weight fraction of particles can be determined as a function of particle size. Most particle size distributions for coal-fired power plants can be plotted as a straight line on log probability paper, corresponding to a gaussian distribution of the ratio of particle diameter to the mean particle diameter. Thus, the geometric standard deviation from the mean particle size can be defined as the ratio of the particle size at 84 wt % to the mean size, or also the ratio of the mean size to the particle size at 16 wt %. If all the particles *are the same size*, the geometric standard deviation is one, but increases as more particles are found in size categories different from the mean size.

For mean particle diameters of 2.5 μ and larger, the smoke plume opacity is minimum at a geometric standard deviation of one, *and increases* as the deviation increases. This is because of a larger percentage of small particles fall between 0.2–2.0 [illegible] for light scattering). For a mean opacity is a maximum at a geometric standard deviation of one since all the particles are within the optimum light-scattering size range. As the deviation increases, an increasing fraction of particles fall outside the optimum light-scattering size range, and the opacity decreases. Therefore, for the small particles (0.95 μ) opacity *decreases* as the deviation from the mean particle size is *increased*, while for large particles (2.6 μ) the converse is true.

Stack gas temperature is also an important factor. One convenient measure for mass emissions of particulate matter, which is reported in the literature and frequently used for comparisons between different coal-fired power plants, is grain loading, or grains of particulate matter per standard cubic foot. If such a measure is used, then variations in the temperature of the stack gas will influence the relationship between standard cubic feet and actual cubic feet of stack gas. The higher the stack gas temperature, the higher the ratio of actual to standard cubic feet, and the lower the particle concentration per cubic foot, thus decreasing the opacity.

Uncontrollable variables

One of the important variables that is determined by the characteristics of the fuel and not controllable by a power plant operator is the density of the particles emitted. The less dense the particulate matter, the greater the number of particles at a specified grain loading and the greater the opacity. Variations in particle density between 2.0–4.0 g/cm^3 can occur for coal-fired power plants because of the different chemical nature of the ash, which varies with the geologic location where the coal is mined. It is important to point out that standard techniques of measuring particle density by displacement may not be valid for many types of fly ash particles because of surface inclusions and/or formation of hollow ash spheroids during the combustion of coal. Variations in opacity from 60–90%, owing to normal variations in particle density alone, would not be considered unusual.

Still another uncontrollable particle property that influences opacity at a given mass emission rate is the particle index of refraction. Typical power plant fly ash particles have an index of refraction of about 1.5. Mohave fly ash particles have an index of refraction of 1.6 (measured by microscopic examination with selected immersion oils). A *range in refractive index from* 1.4–1.6 corresponds to a difference in opacity from 77–95%.

The color of the plume and the color contrast ratio between the plume and the sky is another uncontrollable variable related

TABLE 1.

Effects of geographic location and calendar date on opacity

	Kauna Point, Hawaii	Key West, Florida	Grentley Harbor, Alaska
Latitude	19° 02'N	24° 33'N	65° 16'N
Angle of Sun at time of maximum opacity			
June 21	85.5°	89.0°	48.0°
Dec. 21	47.5°	42.0°	1.0°
Percent opacity under "black dot" conditions at maximum opacity			
June 21	86.4%	86.8%	68.5%
Dec. 21	67.5%	64.5%	14.5%

Note: The opacity at sunrise or sunset is 14.0% at all three locations.

to the type of fuel burned. Even if all factors such as mass emissions and particle size are the same, the opacity of a "black" plume against an overcast background will be different from the opacity of a "white" plume against an overcast background. If the overcast is white, the "black" plume will have a higher apparent opacity than the "white" plume. If the overcast is black or dark grey, the opposite situation will prevail.

Plume color is caused by the nature of the particulate matter in the plume. Silica or glass-like particles produce "white" plumes while carbon or light-absorbing particles produce "black" plumes. Because of combustion temperatures achieved in coal-fired power plant boilers, the particles in the plume are generally glass-like in nature, and the plume is generally "white" in color.

Data have been obtained for a white plume viewed against a blue sky background. If the sky were a white overcast color, a white plume would tend to disappear and could only be seen by a brightness difference between the plume and the overcast. There are no data upon which to base a prediction of the opacity of a white plume on an overcast day. Similarly, a white plume on a clear day viewed against a dark background (such as a forest-covered mountain) will produce a different opacity than the same white plume viewed against a blue sky. The color of the background thus has a significant effect on the opacity of a white plume.

Seasonal variations in ambient airborne particulate matter (caused by wind or other factors) tend to change the color of the sky. Daily variations in sky color resulting from sunrise/sunset effects, photochemical smog or changes in weather conditions all influence the opacity of a white plume without any change in the mass emissions of the plume itself. Such factors are difficult to quantify since no data for white plumes are available for correlating Ringelmann number to color contrast ratio as a function of background color.

Another uncontrollable factor related to the type of fuel burned is the water vapor content of the flue gas. While it is generally recognized that water is one of the products of combustion emitted by oil-fired power plants, it is not always recognized that large quantities of water also result from the combustion of coal. Specifically, the combustion of a coal containing 10% ash would [illegible] five times (by weight) as much water as ash being formed. If a wet scrubber were used to remove the ash, additional water would be introduced in the gas so that the gas would be saturated with water vapor at 120–130 °F leaving the scrubber. While not adding water, an electrostatic precipitator will not remove any water vapor from the gas.

Ambient temperature and humidity conditions can result in the condensation of some of this water vapor and there are no presently available scientific methods with which an observer can distinguish between the degree of opacity caused by the presence of the condensed water vapor and the opacity caused by the presence of fly ash. This factor is interrelated with the variables of wind direction, velocity, and turbulence and no attempt has been made to quantify it in this report.

Unlike previously discussed variables that were quantitatively related to opacity, variables such as stack and wind velocity are more difficult to quantify. Although it is not difficult to measure either stack or wind velocity or wind direction, plume opacity is measured by a human observer, and the appearance of the plume in the atmosphere is subject to atmospheric conditions such as turbulence and velocity. Haythorne and Rankin, describing the effects of these variables, said: "The velocity of the exhaust gas and the external wind conditions also will have obvious effects. In a still atmosphere the particulates may build up increasing opacity. In a high wind particles may be dispersed so that there may be no opacity at all even though the same volume of particulates is emitted." It is also obvious that the wind direction will have an influence on the opacity with observations parallel with the flow of the plume giving higher values than observations made perpendicular to the flow. This "path length effect" is similar to the effect of stack diameter presented previously.

Because of the many combinations of stack velocity, wind velocity, wind direction, and atmospheric turbulence that exist, no attempt has been made to quantify these interrelated variables.

Variables influencing plume opacity

Controllable factors

- Mass emission of particulate matter
- Mean particle size
- Deviation from the mean size
- Stack diameter
- Stack gas temperature
- Stack velocity and other factors influencing plume dispersion

Uncontrollable factors

(Related to type of fuel burned or process involved)

- Particle density
- Particle index of refraction
- Water vapor
- "Color" of the plume

(Related to human observer, ambient weather conditions and movement of earth about the sun)

- Wind speed
- Wind direction
- Wind turbulence
- Ambient air temperature and humidity
- "Color" of the sky
- Distance of observer from stack
- Non-level terrain
- Observer offset angle
- Time of day
- Day of year
- Longitude of stack
- Latitude of stack
- "EPA allowable" human error
- Sun angle

The position of the sun

An important category of uncontrollable factors that influences plume opacity is the position of the sun and the observer with respect to the plume.

The degree of plume opacity seen by an observer depends critically on the scattering angle through which incident light is eflected and refracted from the particles in the smoke plume. This "scattering angle" and other geometric relationships are presented in Figure 2. The maximum opacity would be seen when looking at the sun through the plume and the minimum opacity would be seen when the plume is observed with the sun directly behind the observer. The closer to the stack that the observer stands, the more he must tilt his head upward toward the sky and the greater the opacity (because of the decreased light-scattering angle). A remote observation, on the other hand, gives a low reading and is another reason why an opacity measurement is not a reliable indicator of mass emissions.

Another variable affecting plume opacity is non-level terrain. Occasionally, the sun is in such a position relative to the stack that power plant equipment obscures a view of the plume at a distance of two stack heights from the base of the stack. Alternatively, coal-fired power plants are sometimes located near the edge of a cliff or near elevated terrain. In these cases, an observer must usually make an observation at a location elevated or depressed with respect to the base of the stack. This influence on the light-scattering angle has been calculated for an observer at two stack heights from the base of the stack.

The variation in opacity with changes in the elevation of the observer are more pronounced at low sun angles in the winter than at high sun angles in the summer. Also, the opacity increases as the observer position is depressed with respect to the base of the stack. Depending on sun angle, aircraft observations would normally indicate a lower opacity than would be seen on the ground. The effects of distance from the stack would be a severe problem, however, in making airborne observations.

If opacity changes when an observer moves closer to the stack at a fixed sun angle, then the opacity obviously must also change when the sun angle changes as the sun moves across the sky relative to a fixed observer position. If all opacity readings are made with the sun directly behind an observer who is two stack heights from the stack, then on June 21st at latitude 35°, the sun angle varies between 0° at sunrise or sunset and 79° at the time of maximum opacity. The opacity correspondingly varies between 18% at sunrise or sunset and 85% at the maximum sun angle when all other variables are held constant.

This sun angle effect is illustrated in greater detail in Figure 3, where the variation in opacity, as seen by a perfect observer, is plotted as a function of the time of day. Figure 3 is computed from data presented in the Nautical Almanac and Sight Reduction Tables for Air Navigation to obtain the angle of the sun as a function of the time of day. Knowledge of the latitude, longitude, and time zone in which the power plant is located was also required to obtain the sun angle data. Figure 3 is plotted for the location of the Mohave Generating Station at South Point, Nev.

Since a perfect observer always has the sun directly behind him, he would thus begin the day east of the stack and traverse a circular path at two stack heights from the stack before ending his day west of the stack. Note that this assumes no obstructions within the circular path around the stack, which probably never occurs at an actual power plant.

If the perfect observer returned to the Mohave site every day of the year, and only made an observation at the time of maximum opacity (the highest sun angle), and if all other variables were held constant for the entire year, the records of the perfect observer would be such that the opacity would vary between 54% on December 21st and 85% on June 21st. Naturally, the daily variations in opacity between sunrise and sunset would occur throughout the year, with the opacity at sunrise/sunset being 14%. The wintertime daily variation in opacity would be less than the summertime daily variation.

Obstructions between the observer and the stack (for ex- ...) might require that observations be made when the sun is not directly behind the observer (see Figure 2). By using solid geometry to calculate the scattering angle when the sun angle and observer offset angles are known, the effects of making an observation when the sun is not directly behind the observer can be calculated.

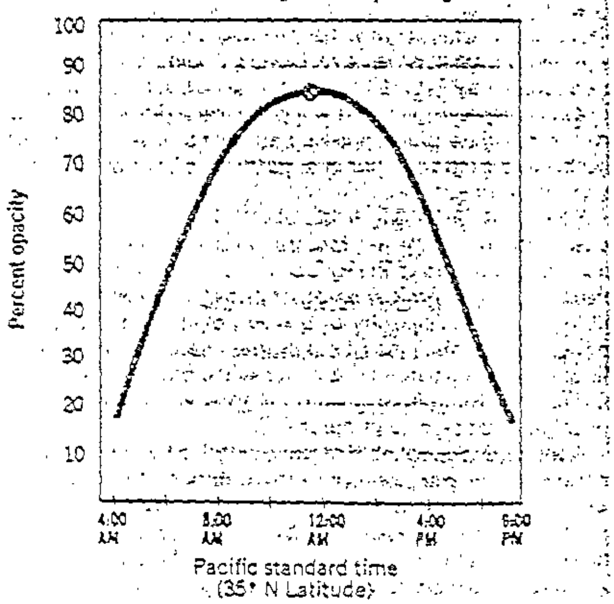
The lower the sun angle, the more pronounced the effects of observer offset angle. If an observer looks at the smoke plume when he is in the wrong position with respect to the stack and the sun, the impression received would always indicate an opacity that is greater than the correct value. This is especially pronounced when the sun angle is low and is more likely to occur in the winter than in the summer.

It was previously indicated that observations should be made with the wind at right angles to the direction of observation, since the EPA has established that the observation point should be "perpendicular to the plume." However, it also should be noted that this set of circumstances—wind at right angles; sun at observer's back—will only occur under certain specific conditions.

A smoke inspector who wished to make visual measurements when the opacity of the plume was at its maximum value would chose the time when the angle of the sun was at its maximum value for that day. This time occurs when the sun crosses the meridian of longitude of the observer and is referred to as "Local Apparent Noon" by navigators and astronomers. However, the time of "Local Apparent Noon" seldom coincides with twelve o'clock on the observer's watch. For an observer who is located in the exact center of the time zone, this coincidence only occurs four times a year (on April 15, June 15, September 1, and Christmas Day). On the other 361 days of the year, maximum opacity occurs either before or after twelve noon "Local Standard Time" on the observer's watch.

This irregular variation of the time of occurrence of maximum opacity throughout the year at any given location is caused by differences in the speed of rotation of the earth around the sun, tidal action and other factors. However, the time of maximum opacity occurrence can be calculated for any given day by use of information presented in the Nautical Almanac and knowledge of the local longitude.

FIGURE 3
Effect of time of day on opacity



The effects of latitude

The angle of the sun at the time of maximum opacity is a function of the latitude of the power plant or other source of smoke plume, with greater angles (and greater opacity) occurring at the lower latitudes.

If a power plant is located at different areas within the continental U.S.—*all other factors remaining constant*—the opacity values for a power plant in the south will always be higher than those seen by the same observer under identical conditions and at an identical power plant in the north. This effect is the result of higher sun angles in the southern latitudes. If national opacity standards were applicable, a power plant in Alaska would obviously have less difficulty meeting the regulations than an identical power plant in Florida.

Figure 4 indicates quite clearly that visual opacity is not an indication of the amount of pollutants being emitted from a stationary source. With all other variables being constant (grain loading, particle size and density, and stack diameter) opacity can vary from 14–87% depending on the geographic location and time of day. If power plants located in Hawaii and Alaska are considered, these effects are even greater.

Table 1 presents the opacities that would exist if power plants were located at Kauna Point, Hawaii; Key West, Fla.; and Grantley Harbor, Alaska. The opacity at the time of maximum opacity on June 21st in Alaska is almost the same as the opacity on December 21st in Hawaii (63.5% vs. 67.5%). However, the opacity in Hawaii increases to a maximum of 86.4% in the summer, while in Alaska the opacity decreases to 14.5% in the winter. The winter opacity in Alaska, even at the maximum daily opacity, is just slightly greater (14.5% to 14.0%) than the opacity at sunrise or sunset.

The opacity *in summer* at Key West would be slightly greater (86.8–86.4%) than in Hawaii even though the latitude is greater. This is because the maximum sun angle in summertime occurs when the latitude is equal to the declination of the sun (23° 26.5′N in 1975). The latitude of Key West (24° 33′N) is closer to this value than the latitude of Kauna Point (19° 02′N).

FIGURE 4

Effect of geographic location and time of day on opacity

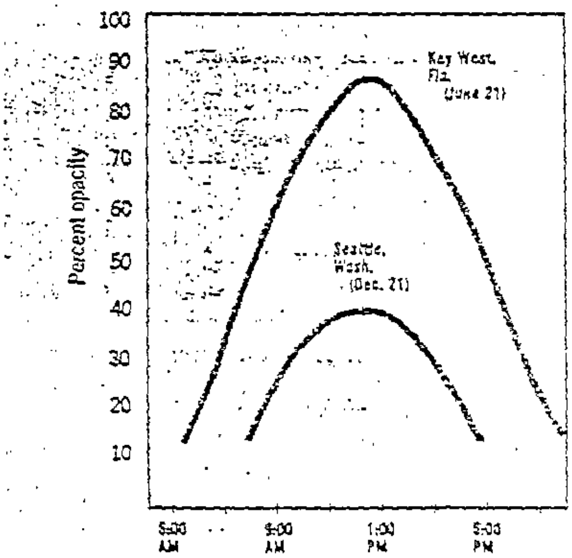


TABLE 2

Relative effects of variables on opacity

Independent variable	"Black dot" value	Typical range of variation	Resultant change in opacity with all other variables held constant
Particulate grain loading	0.05 gr/scf	0.01–0.20 gr/scf	25–98%
Stack diameter	32.5 ft	10–35 ft	37–87%
Mean particle size	2.6 μ	0.9–10 μ	96–34%
Deviation from the mean size	3.0	1.5–5.0	70–80%
Particle index of refraction	1.5	1.4–1.6	77–95%
Particle density	2.2 g/cc	1.5–5.0 g/cc	93–51%
Stack gas temperature	270 °F	130 °–350 °F	91–82%
Stack velocity	90 ft/s	70–130 ft/s	—
Water vapor content of stack gas	10%	6–14%	—
Color of the plume	White	White to black	—
Wind speed	Zero	Zero to 70 mph	—
Wind direction	Perpendicular to observation direction	±180°	—
Wind turbulence	Zero	Zero to ±30%	—
Ambient air temperature and humidity	70 °F, 15% R.H.	−10 °F to 130 °F 0–100% R.H.	—
Color of the sky	Blue	Blue to overcast	—
Distance of observer from stack	2 H_s	0.5–50 H_s	92–74%
Effect of nonlevel terrain	Level	±20% H_s	84–86%
Sun angle	79°	0–90°	18–87%
Time of day	11:30 AM (PST)	4 AM to 7 PM	18–85%
Day of year	June 21 at maximum sun angle	January 1 to December 1 at maximum sun angle	55–85%
Geographic location—longitude	114° W. Long. time of max. sun angle	±15° of Lat. time of maximum sun angle	83–85%
Observer offset angle	0°	0–60°	85–88%
Geographic location—latitude	35° N. Lat. at max. sun angle	25° N. Lat. to 48% N. Lat. max sun angle	79–88%
Allowable human error	Zero	Zero to ±15% opacity	70–100%

Summing up

The prediction of plume opacity by using light-scattering theory and measurements in the stack gas at Mohave were in agreement with the observations made by trained observers. A parametric study of the effects of independent variables on plume opacity by using the same light-scattering theory has shown that plume opacity can vary from 14–87% depending only on the geographic location of the source and the time of day, with all other factors such as particulate matter emissions remaining the same. This implies that the EPA New Source Performance Standard for plume opacity (20%) is not consistent with the particulate matter emissions standard (0.1 lb/10^6 Btu) for all power plant locations or times of day and days of the year.

The relative effects of the 24 variables are tabulated in Table 2. As can be seen, there is an extremely wide variation in possible values of opacity, even when the mass emission of particulate matter remains unchanged. It is concluded that opacity measurements are not indicative of the mass emissions of particulate matter, and that mass emissions cannot be accurately determined from opacity observations. The use of an opacity standard to enforce a mass emission limitation is therefore difficult to justify on a technical basis.

Additional reading

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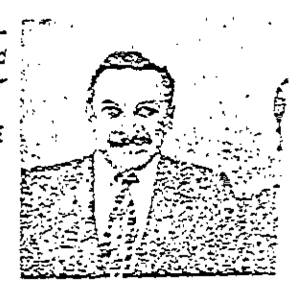
Alexander Weir, Jr. (center) *principal scientist for air quality;* Dale G. Jones (r) *research scientist; and* Lawrence T. Papay (l) *director of research and development are employed by Southern California Edison Company.*

Seymour Calvert (l) *is founder and president of Air Pollution Technology, Inc. and* Shiu Chow Yung *is a chemical engineer with this San Diego, Calif., firm.*



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Codes and Standards

State emission regulations slowly tighten

Original schedules for Clean Air Act compliance for sulfur oxides have slipped, however. Check all state discharge limits here

This year, state standards for fossil-plant emissions reflect the same conflicting tendencies that were evident in 1974. Fuel shortages, the economic recession and environmental considerations are all influencing changes.

The setbacks in nuclear-plant timetables put the spotlight on fossil-fired plants, where the major controversy involved sulfur-oxide emissions. Methods of preventing high SO_x concentrations, effectiveness of the methods, relation of stack SO_x concentrations to air standards, and the date for achieving goals were chief topics in contention.

State standards had originally intended compliance with U S EPA-set primary air-quality standards for health by 1975. But as 1974 drew to a close, the inability of existing plants to meet the states' SO_x emission standards became clearer. Several states have, at least temporarily, backed off on SO_x standards for both new and old plants. Secondary standards compliance may be deferred from 1975 to as distant a time as 1980, although as a general rule new plants will still have to meet much stricter demands than existing plants.

SO_x removal is unsettled

Methods for SO_x reduction were enmeshed in a controversy that pitted state and federal courts, EPA, FPC, state environmental and public-service agencies, utilities and environmental groups against each other. Courts both upheld and condemned scrubbers and intermittent controls, with nearly every decision slated for appeal. By early 1975, the scrubber, which had won several victories in courts and state environmental agencies, appeared destined for the key spot in new-plant thinking on SO_2 removal from flue gas.

Delivery schedules for SO_2 scrubber equipment and construction timetables look like 3 to 4 years, however, so we may see continued bending of the rules and permissions for what have become expedients—tall stacks, and intermittent controls that call for low-sulfur fuel during critical weather conditions.

For particulate emissions, most states specify in lb/10^6 Btu heat input. The values are from as low as 0.05 lb/10^6 Btu for utility stations in West Virginia and New Mexico (0.005 for oil-burning equipment in the latter state) to as high as 0.8 for existing plants in North Dakota. The tendency seems to be for a limit of about 0.1 for large boilers.

Instead of limiting emissions in terms of heat input, several states including Alaska, Arkansas, Maryland, Michigan, Oregon and Washington, limit the stack gas loading, in weight per cubic foot or cubic meter. Utah's regulations are simpler, calling only for removal of 85% of particulates in coal burning. Hawaii regulations limit only opacity readings.

Stacks and plumes are still in

Stack-height effect is included in several state regulations on particulates. Georgia, South Carolina, Indiana and Texas are some of the states. Texas penalizes oil- or gas-fired plants with stacks below a minimum height. Minnesota has removed some particulate restrictions based on stack height, on the other hand. Plume rise, another factor besides stack height that does not bear directly on fuel or combustion, enters calculations in Indiana and Iowa.

Most states give emission limits as the weight of sulfur oxides, figured as SO_2 per 10^6 Btu heat input. A few, such as Alaska, Texas, Louisiana and Washington, give a ppm limit on sulfur compounds in the emission. Louisiana calls for the more restrictive of stack concentration or air concentration beyond the plant premises. Wyoming, Arkansas and Delaware have limits only on ambient air, but Wyoming is preparing to establish limits on SO_x emissions.

In Indiana's case, ground-level concentration requirements exist, in addition to federal standards; the allowable ground-level concentrations depend on stack height and plume rise, too.

Hawaii and Delaware directly regulate only fuels. Utah requires that units emitting large amounts of SO_x install control equipment to remove 80% of sulfur.

Total hourly amounts of SO_x from a plant are limited in several states, such as West Virginia. Stack height figured in Georgia, Texas and Indiana regulations, but a 1974 decision in a federal appeals court seems to rule out reliance on tall stacks except as a last resort.

Possibilities for stack-gas-cleaning equipment, such as scrubbers, got increasing recognition in state regulations. Several states that had set limits on sulfur in solid and liquid fuels will now permit higher sulfur percentages provided stack-gas-cleaning equipment removes enough sulfur.

The apparent feasibility and development level of stack-gas-cleaning equipment, as reflected in state rules, vary greatly. Oregon's regulations merely hint that the equipment may exist, while at the other end of the scale, Texas mandates the application of proven technology when available, and Utah requires control equipment. Most states, however, do not mention such equipment, but instead either prefer a fuel restriction or leave it up to the plant how to reduce SO_x.

Zoning a state to create areas in which particulate or SO_x emissions get different limits is found in both large and small states. California is perhaps the prime example, with no statewide regulations. Instead, each of 47 air-pollution control districts sets its own standards. States as small as Delaware and New Jersey have set different limits in metropolitan areas vs rural areas. Alabama puts counties into two categories, with significant difference in SO_x limits. Georgia, Illinois, Indiana, Kentucky, Massachusetts, Maine, Minnesota, New York, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia and Wisconsin are other states with different treatment for specific areas. This is nearly always for SO_x emissions, although several states differentiate for particulates, too.

More curbs on NO_x emissions

Nitrogen oxide regulations appear a little more frequently this year. At least two states—Idaho and Indiana—have adopted regulations, and Wyoming has extended its NO_x restrictions to solid fuel. Minnesota has removed some restrictions on existing units.

In general, NO_x regulations closely follow the federal standards (0.2 for gas, 0.3 for oil and 0.7 for coal, all in lb NO_x/10^6 Btu), but there are exceptions. North Carolina allows 0.6, 0.6 and 1.3, and Massachusetts limits all fuels for new installations to 0.3.

For coal, a few other states allow 0.9, while Maryland (0.5 for new) and New Mexico (0.45 for new) have gone below the federal figure. A few states have different zonal treatment for NO_x, too. Indiana and Texas are examples.

The entire regulatory picture can be expected to change further during 1975, so your best course is to keep in continual contact with your state authorities during the year.

Alabama

Alabama Air Pollution Control Commission, 645 South McDonough St, Montgomery, AL 36104.

Particulates. Allowable emission rate for fuel-burning equipment rated 250×10^6 Btu/hr heat input and above for both Category-I (primarily urban) and Category-II (primarily suburban) counties and for both new and existing sources is 0.12 lb/10^6 Btu.

Sulfur oxides. Fuel-burning installations in Category-I [Category-II] counties are restricted to 1.2 [1.5] lb SO_x (measured as SO_2)/10^6 Btu heat input. This may be changed to 1.8 [4.0] this year. All new sources are subject to regulations for Category-I counties. Total heat input for all similar fuel-combustion units at a plant is used for determining the max allowable emission of SO_x from a stack or stacks. Units constructed and operated to conform with the new source performance standards are not considered similar to other units at a plant. Category I and II classifications are reviewed annually.

Nitrogen oxides. New installations rated 250×10^6 Btu/hr heat input or greater cannot emit more than 0.2 (gaseous fuels), 0.3 (liquid), or 0.7 (solid) lb NO_x (calculated as NO_2)/10^6 Btu. Total heat input from all similar combustion units at a plant is used to determine the max allowable emission of nitrogen oxides from a stack or stacks.

Alaska

Dept of Environmental Conservation, Pouch O, Juneau, AK 99801.

Particulates. Emissions from fuel-burning equipment are limited to 0.05 grains/cu ft of exhaust gas, corrected to standard conditions (70 F dry gas at 14.7 psia) except for those sources (1) in operation prior to 7/1/72, and (2) burning coal or municipal waste. Emissions from these two categories are limited to 0.1 grains/cu ft.

Sulfur oxides. Sulfur-compound emissions from industrial processes or fuel-burning equipment may not exceed 500 ppm, expressed as SO_2.

Nitrogen oxides. No source emission standards are stated in the regulations.

Arizona

Arizona Dept of Health Services, Div of Environmental Health Services, Bur of Air Quality Control, 1740 W Adams St, Phoenix, AZ 85007.

Particulates. Tests to determine particulate emissions are performed in accordance with generally recognized standards, such as ASME PTC-21 and PTC-27. Allowable emission rate, Y (lb/10^6 Btu), for fuel-burning equipment rated 4000×10^6 Btu/hr heat input and above is calculated by the equation, $Y = 17.0X^{-0.568}$, where X is the maximum equipment-capacity rating in 10^6 Btu/hr heat input. Below 4000×10^6 Btu/hr, the equation is $Y = 1.02X^{-0.231}$.

Sulfur oxides. New [old] fuel-burning installations with a total rated capacity of 5500×10^6 Btu/hr heat input or greater are limited to 0.80 [1.0] lb SO_2/10^6 Btu (max 2-hr avg) for both coal and oil. Existing plants burning oil with over 0.9% sulfur (severe restrictions on this) are limited to 2.2 lb SO_2/10^6 Btu (max 2-hr avg).

Nitrogen oxides. New installations rated 250×10^6 Btu/hr heat input or greater cannot emit more than 0.2 (gaseous fuels), 0.3 (liquid fuels), or 0.7 (solid fuels) lb NO_x (calculated as NO_2)/10^6 Btu (max 2-hr avg).

Arkansas

State of Arkansas, Dept of Pollution Control & Ecology, 8001 National Drive, Little Rock, AR 72209

Particulates. Emissions of particulate matter from any premises on which equipment—that is, any device capable of causing an emission—is located is limited to the following: (1) Suspended particulate matter above background cannot exceed an avg of 75 micrograms (μg)/cu meter for any 24-hr period or 150 μg/cu meter for any 30-min avg as computed from dispersion formulas or ambient-air sampling determined by the state. (2) Particulate fallout contributed from such premises above background can not exceed 15 tons/sq mile/month. (3) The number of particles larger than 60-micron diam downwind of the premises can not exceed 120/sq cm for 24 consecutive hours.

Sulfur oxides. Emissions are limited to those that will not cause maximum concentrations, beyond the premises on which the source is located, in excess of 0.2 ppm SO_2 for any 30-min avg. Maximum concentrations are determined, at the option of the state, by ambient-air sampling or by calculations based on appropriate dispersion equations and stack concentrations.

Nitrogen oxides. No source emission standards are stated in the regulations.

California

Resources Agency, Air Resources Board, 1709 11th St, Sacramento, CA 95814.

In California, the Air Resources Board has the primary responsibility for regulating emissions from motor vehicles and for overseeing activities of 47 local air-pollution-control districts. It does not establish law, but adopts regulations to implement mandates of the state's legislature.

The board monitors air quality, controls agricultural burning, researches improved methods of controlling air pollution, develops the Implementation Plan for Achieving & Maintaining Ambient Air Quality Standards, and subvenes funds to local districts.

Local districts are responsible for enforcing emission standards pertaining to stationary sources of pollution, including approval of construction of new sources. They adopt their own rules and regulations, including those that are equal to or more stringent than some required by state law.

The Air Resources Board has subdivided the state into 13 air basins. The districts within the basins are represented on coordinating councils, which develop basinwide plans for control of air pollution. The districts are accountable to the board for implementation of the plans. The board may intervene in any situation in which it finds the local district is not fulfilling its responsibility.

Colorado

Air Pollution Control Commission, Colorado Dept of Health, 4210 East Eleventh Ave, Denver, CO 80220

Colorado adopted early this year the US Environmental Protection Agency's "Standards of Performance for New Stationary Sources," *Federal Register*, 12/23/71. These standards are outlined here:

Particulates. (1) Emissions are limited to 0.1-lb particulate/10^6 Btu heat input (max 2-hr avg). (2) Opacity is limited to 20%, but 40% is permissible for not more than 2 min in any hour. (3) Where the presence of uncombined water is the only reason for failure to meet the requirements of (2), such failure is not a violation.

Sulfur oxides. (1) Emissions are limited to 0.8 [1.2] lb SO_2/10^6 Btu heat input (max 2-hr avg) when liquid [solid] fossil fuel is burned. (2) Where different fossil fuels are burned, the allowable emissions are determined by:

$$(0.8y + 1.2z) \div (x + y + z)$$

where x, y and z are heat input from gaseous, liquid and solid fossil fuel, respectively, as percentages of total heat input.

Nitrogen oxides. (1) Emissions are limited to 0.2 (gaseous fossil fuel), 0.3 (liquid fossil fuel) or 0.7 (solid fossil fuel, except lignite) lb NO_x (expressed as NO_2)/10^6 Btu heat input. (2) Where different fossil fuels are burned, allowable emissions are determined by:

$$(0.2x + 0.3y + 0.7z) \div (x + y + z)$$

Equation nomenclature is as defined above.

Particulate-emission regulations for existing units with capacities greater than 500×10^6 Btu/hr heat input are the same as those for new sources described above. SO_2 emissions for existing units are governed by ground-level and source-emission concentrations. SO_2 ground-level emissions above 0.25 ppm (5-min avg), 0.1 ppm (1-hr avg), or 0.05 ppm, more frequently than once in any 8 hours, 4 days, or 90 days, respectively, are not permitted outside the premises on which the source is located. Source-emission concentrations are limited to (1) 500 ppm SO_2 from any opening, and (2) 5 tons/day SO_2 from any air-contamination source. The source-emission concentrations do not apply to any air-contamination source with SO_2 emissions at concentrations of less than 150 ppm. Existing sources not in compliance with the source-emission standards for SO_2 by 7/1/75 must be designed to meet those regulations by 1/1/78. Sources designed or contracted for after 1/1/75 must meet the standards when they begin operation.

Connecticut

Dept of Environmental Protection, State Office Bldg, Hartford, CT 06115.

Particulates. Emissions for new [existing] equipment are restricted to 0.1 [0.2] lb/10^6 Btu heat input. All compliance tests must be conducted with a heat input equal to the equipment manufacturer's or designer's guaranteed input, whichever is larger.

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. (1) Emissions from fuel-burning equipment rated above 250 × 10^6 Btu/hr heat input are limited to 0.2 (gas-fired), 0.3 (oil-fired), 0.7 (new coal-fired), or 0.9 (existing coal-fired) lb NO_x (expressed as NO_2)/10^6 Btu heat input. Testing methods for determining particulate, SO_2, SO_x and NO_x emissions are outlined in "Standards of Performance for New Stationary Sources,"-- Federal Register, 12/23/71, pp 24888, 24890, 24893 and 24891, respectively.

Delaware

Dept of Natural Resources & Environmental Control, Air Pollution Control Div, Tatnall Bldg, Dover, DE 19901.

Particulates. Emissions from fuel-burning equipment with heat input of 1 × 10^6 Btu/hr or greater shall not exceed 0.3 lb/10^6 Btu.

Sulfur oxides. Sulfur content of fuel used in New Castle County by fuel-burning equipment is limited to 1% by weight (0.3% for distillate oil). In Kent and Sussex Counties, sulfur content of distillate oil is limited to 0.3%, with no restriction on residual oil. Higher sulfur content is allowed if emission controls give results equivalent to above limits on fuel. In any event, the emission of SO_2 from fuel-burning equipment shall not cause ambient-air-quality standards to be compromised.

Nitrogen oxides. Regulation, which affects only fuel-burning equipment in New Castle County rated 500 × 10^6 Btu/hr input and greater, states that, after 1/1/76, emissions will be limited to 0.2 lb/10^6 Btu for gaseous fuels and 0.3 lb/10^6 Btu for other fuels (calculated as NO_2). Regulation applies only to boilers for the production of steam. NO_x emissions from fuel-burning equipment are not restricted by regulation in Kent or Sussex Counties.

Florida

Dept of Pollution Control, 2562 Executive Center Circle East, Montgomery Bldg, Tallahassee, FL 32301

Particulates. Existing and new sources larger than 250 × 10^6BTU/hr heat input are subject to the same laws as Colorado, parts (1) and (2).

Sulfur oxides. New sources larger than 250 × 10^6 Btu/hr heat input are subject to the same laws as Colorado, part (1). Existing sources (plants operating, under construction and those licensed for construction before the effective date of the state air-pollution laws, but not reactivated plants that have been shut down for more than one year) greater than 250 × 10^6 Btu/hr heat input are required to clean up discharges as rapidly as possible, but are limited to emissions of 1.1 (liquid fuel) or 1.5 (solid fuel) lb SO_2/10^6 Btu heat input until 7/1/75.

Nitrogen oxides. New sources larger than 250 × 10^6 Btu/hr heat input are subject to the same laws as Colorado, part (1). At present there is no NO_x emission limit for existing sources, but one may be adopted by 7/1/75.

Georgia

Air Quality Control Section, Environmental Protection Div, Dept of Natural Resources, 270 Washington Street SW, Atlanta, GA 30334.

Particulates. Emission limits from fuel-burning equipment in operation or under construction on or before 1/1/72 and rated less than 10 × 10^6 Btu/hr heat input are P = 0.7; for similar units rated 10-2000 × 10^6 Btu/hr, P = 0.7 × $(10/R)^{0.202}$; here P = allowable weight of emissions in lb/10^6 Btu heat input and R is heat input to equipment in 10^6 Btu/hr. Equipment on which construction began after 1/1/72 is subject to these limits: for equipment with less than 10 × 10^6 Btu/hr heat input, P = 0.5 lb/10^6 Btu heat input; for equipment with 10 to 250 × 10^6 Btu/hr heat input, P = $0.5(10/R)^{0.5}$ lb/10^6 Btu heat input; for equipment greater than 250 × 10^6 Btu/hr heat input, P = 0.10 lb/10^6 Btu heat input. In addition, from any site located within or up to 1 mile from the limits of a city of 50,000 or more population: for stack height h under 120 ft, P (in this case, the max allowable particulate emission in lb/hr) = 0.48h; for h from 120 to under 300 ft, P = $900(h/300)^3$; for h from 300 ft up, P = $900(h/300)^2$. If several stacks are at the same site, the height used is the average stack height weighted by stack emission.

Sulfur oxides. Emission limits for new or old fuel-burning equipment are: S = $4000F(h/300)^n$. S is SO_2 emission in lb/hr; n = 3 for stacks under 300 ft high and n = 2 for stacks 300 ft high or higher; and h = stack height, in ft. Averaging for stack height is same as for particulates. F = 0.8 when two or more fuel-burning sources, each with heat input exceeding 500 × 10^6 Btu/hr and burning fuel with more than 1% sulfur (by weight), are located in an urban area (within the limits or within 5 miles of the limits of a city of 50,000 population or over, with all other sites considered as "rural"); F = 1 for all other fuel-burning sources in an urban area; F = 2 for rural fuel-burning sources with less than 10,000 Btu/hr heat input; F = 3 for rural fuel-burning sources with 10,000 or over Btu/hr heat input.

New fuel-burning sources rated more than 250 × 10^6 Btu/hr heat input that are constructed or modified extensively after 1/1/72 are subject to the same laws as Colorado's for new sources. No fuel-burning sources (new or old) below 100 × 10^6 Btu/hr heat input shall burn fuel containing more than 2.5% sulfur (by weight). All above 100 × 10^6 Btu/hr heat input are limited to maximum of 3% sulfur (by weight).

Nitrogen oxides. New fuel-burning sources, constructed or modified extensively after 1/1/72 are subject to the same laws as Colorado.

Hawaii

State of Hawaii, Dept of Health, P.O. Box 3378, Honolulu, HI 96801

Particulates. Visible emissions from existing stationary sources can not be darker than 40% opacity, except for periods of not more than 3 min in any hour during startup or when equipment malfunctions. Under these variable short-term operating conditions, 60% opacity is permitted. New sources cannot have emissions darker than 20% opacity; 60% opacity is permitted for not more than 3 min in any hour for the reasons stated above.

Sulfur oxides. Fuel oil for steam-generating facilities rated above 25 MW or 250 × 10^6 Btu/hr heat input is limited to max sulfur content of 0.5%, effective 6/1/74.

Nitrogen oxides. No source emission standards are stated in the regulations.

Idaho

Dept of Environmental Protection & Health, Statehouse, Boise, ID 83707

Particulates. For sources of 250 × 10^6 Btu/hr or over, constructed, modified or installed after 12/5/74, and not having a permit to construct issued before that date, particulates are limited to 0.10 lb/10^6 Btu heat input.

For sources constructed or with permit to construct before 12/5/74, fossil-fuel-burning equipment rated greater than 10,000 × 10^6 Btu/hr heat input is limited to 0.12 lb/10^6 Btu heat input. Permissible emissions from equipment rated between 10 and 10,000 × 10^6 Btu/hr heat input is determined by:

$$\text{Log } Y = 0.2300 \log X - 2.0111$$

where X = total heat input, 10^6 Btu/hr, and Y = maximum allowable emissions, lb/10^6 Btu heat input

Heat input is calculated as the aggregate higher heating value of all fuels whose combustion products pass through the stack. When two or more units are connected to a single stack, the combined heat input of all units connected to the stack is used to determine the allowable stack emission. When a single fuel-burning unit is connected to two or more stacks, the allowable emission from all the stacks combined cannot exceed that permitted for the same unit connected to a single stack.

Sulfur oxides. For units with permit to construct issued before 12/5/74, sulfur in residual fuel oil is limited to 1.75% by weight, sulfur in distillate fuel oil is limited to 0.3% [0.5%] by weight in ASTM Grade 1 [Grade 2], and sulfur in coal is limited to 1.0% by weight.

For sources of 250 × 10^6 Btu/hr or over constructed, modified or installed after 12/5/74, and not having a permit to construct issued before that date, SO_2 is limited to 0.80 lb/10^6 Btu heat input for liquid fossil fuel and to 1.2 lb/10^6 Btu heat input for solid fossil fuel. If combinations of fossil fuels are burned simultaneously, the formula is:

$$[Y(0.80) + Z(1.2)] \div 100$$

in which Y is percent of total heat input from liquid fossil fuel and Z that from solid fossil fuel.

Nitrogen oxides. For sources of 250 × 10^6 Btu/hr or over constructed, modified or installed after 12/5/74, and not having a permit to construct issued before that date, nitrogen oxides (calculated as NO_2) are limited to 0.20 lb/10^6 Btu heat input for gaseous fossil fuel, to 0.3 lb/10^6 Btu heat input for liquid fossil fuel, and to 0.70 lb/10^6 Btu heat input for solid fossil fuel except lignite. If different fossil fuels are burned simultaneously, the formula is:

$$[X(0.20) + Y(0.30) + Z(0.70)] \div 100$$

in which X, Y, Z are percents of total heat input from gaseous, liquid and solid fossil fuel, respectively.

No source emission standards are given for other fossil-fuel-fired steam generators.

Illinois

Illinois Environmental Protection Agency, 2200 Churchill Rd, Springfield, IL 62706

Particulates. Emissions from existing and new fuel-combustion sources rated 250 × 10^6

Btu/hr heat input or greater are restricted to 0.1 lb/10^6 Btu heat input in any one hour, except if an existing emission source (1) is designed for or is proved capable of restricting emissions to less than 0.2 lb/10^6 Btu heat input, and control of the source is not allowed to degrade more than 0.05 lb/10^6 Btu from either the design point or performance test findings, or (2) is in full compliance with a variance granted by the state. In both these cases, emissions may not exceed 0.2 lb/10^6 Btu heat input. These rules for existing fuel-combustion sources will apply as of 5/30/75. Particulate emissions shall be determined by ASME PTC-27 (latest revision).

Sulfur oxides. Emissions from existing sources located in the Chicago, St. Louis and Peoria major metropolitan areas (MMA), and burning solid fuel exclusively, will be restricted to 1.8 lb SO_2/10^6 Btu heat input in any one-hour period on or after 5/30/75. Existing sources burning solid fuel exclusively outside these areas cannot exceed the following: (1) 6 lb SO_2/10^6 Btu heat input on or after 5/30/75, and (2) 1.8 lb SO_2/10^6 Btu heat input for all fuel-combustion sources within other MMAs that have an annual-arithmetic-average SO_2 level greater than 0.02 ppm for any year ending prior to 5/30/76, or 0.015 ppm for any year ending on or after 5/30/76. Existing sources burning liquid fuels exclusively are limited to emissions of 1 lb SO_2/10^6 Btu heat input for residual oils and 0.3 for distillate oils.

When combinations of fuels are burned in existing units the following formula applies:

$$E = S_sH_s + 0.3H_d + S_rH_r$$

where E is allowable SO_2 emission rate, lb/hr; S_s and S_r are applicable solid-fuel and residual-oil standards, respectively, in lb SO_2/10^6 Btu heat input; and H_s, H_r and H_d are actual heat inputs from solid fuel, residual oil and distillate oil, and any of their gaseous derivatives (such as gasified coal), respectively, in 10^6 Btu/hr.

Emissions from all existing combustion sources owned or operated by one person and located within a 1-mi radius from the center point of any such source cannot exceed the emission limits determined by the following equations:

$$E = 20{,}000\,(H_s/300)^2$$

and

$$H_s = (P_1H_1 + P_2H_2 + \ldots + P_nH_n) \div (P_1 + P_2 + \ldots + P_n),$$

where E = total SO_2 emissions from all fuel-combustion sources owned within a 1-mile radius, lb/hr; P_n = emissions from source "n", % of total; and H_n = height of stack "n" above grade, ft.

Emissions from new sources rated above 250 × 10^6 Btu/hr heat input are restricted to 1.2 (solid fuel exclusively), 0.8 (residual oil exclusively) and 0.3 (distillate oil exclusively) lb SO_2/10^6 Btu heat input. SO_2 emissions are measured in the manner prescribed in Method 6, "Standards of Performance for New Stationary Sources," *Federal Register*, 12/23/71, p 24890.

Nitrogen oxides. Allowable emissions from existing fuel-combustion sources, greater than 250 × 10^6 Btu/hr heat input, for any 1-hr period in the Chicago and St. Louis MMAs are determined by:

$$E = [0.3(P_g + P_l) + 0.9\,P_s]Q \div (P_g + P_l + P_s)$$

where E is allowable NO_x emissions, lb/hr; P_g, P_l and P_s are actual heat inputs derived from gaseous, liquid and solid fuels, respectively, in % of total; and Q is total heat input, in 10^6 Btu/hr. Exceptions to this rule are boilers with cyclone burners firing solid or liquid fuel, and horizontally opposed burners firing solid fuel. NO_x emissions from new fuel combustion sources throughout the state, rated 250 × 10^6 Btu/hr heat input and above, are dictated by the same equation as above—except that the coefficient of P_s is 0.7, not 0.9.

Indiana

Air Pollution Control Div, Indiana State Board of Health, 1330 West Michigan St, Indianapolis, IN 46206

Particulates. Maximum allowable emissions from existing fossil-fuel-fired indirect heat exchangers are calculated in accordance with the following formula for all areas of the state except near Indianapolis and the Indiana portion of the Chicago AQCR:

$$C_{max} = 76.5\,P_tQ_m^{0.75}n^{0.25}/ah_s$$

where C_{max} = max ground-level concentration, not to exceed 50 micrograms (μg)/cu meter for a 30-60-min time period; P_t = particulate emission, lb/10^6 Btu heat input; Q_m = total plant capacity, 10^6 Btu/hr heat input; n = number of stacks; a = plume-rise factor (a value between 0.67—for units rated less than 1000 × 10^6 Btu/hr heat input—and 0.8); h_s = stack height, ft. If a number of stacks of varying heights exist, the height used should be calculated by weighting each stack in proportion to its emission rate. Particulate matter from all fuel combustion for indirect heating sources cannot be greater than 0.8 lb/10^6 Btu heat input.

For Indianapolis and the Indiana portion of the Chicago AQCR:

$$P_t = 0.87Q_m^{-0.16}$$

Note that where Q_m is greater than 10,000, P_t cannot exceed 0.2.

Emissions in all areas of the state, for new sources rated 250 × 10^6 Btu/hr heat input and above, are regulated in accordance with "Standards for Performance of New Stationary Sources," *Federal Register*, 12/23/71.

Sulfur oxides. New sources with over 250 × 10^6 Btu/hr heat input are regulated in accordance with Federal New Source Performance Stds 40 CFR Part 60, but also must meet maximum ground-level concentration requirements, C_{max}, which must not exceed 200 μg/cu meter in Lake County, and 500 in Dearborn, Marion and Warrick counties. Limit is 900 elsewhere. $C_{max} = 90S_tQ_m \times 0.75n \times 0.25/ah_s$, where S_t is heat input in lb SO_2/10^6 Btu; Q_m is total combustion-equipment capacity rating in 10^6 Btu/hr; n is number of stacks; a is plume rise factor = 0.7; h_s is stack height in ft. For multiple stacks, n is an average, weighted for SO_2 emission rates. All new stacks must be 2½ times the height of the tallest obstruction that is within 500 ft and has major effect on air movement. Minimum new-stack height is 50 ft. Exceptions to stack-height rules are possible.

For existing sources and for new sources with 250 × 10^6 Btu/hr heat input or less, maximum total SO_2 emission is the lesser of $E_p = 17.0Q_{in}^{-0.33}$ or $E_p = 17.0Q_m^{0.67}$, where $E_p = E_m \times Q_m$; E_m is heat input in lb SO_2/10^6 Btu; Q_m is total equipment capacity rating in 10^6 Btu/hr; E_p is allowable SO_2 emission in lb/hr. The value of E_m shall not exceed 6.0 lb SO_2/10^6 Btu heat input, and need not be reduced below 1.2. Allowable maximum hourly ground-level concentrations are the same as for new sources. In Lake, Dearborn, Marion and Warrick counties, the smaller values for total SO_2 emissions and for allowable ground-level concentrations hold regardless of capacity of existing equipment.

Sources in Lake County must comply by 5/31/75. Noncomplying sources in Dearborn, Marion and Warrick counties may delay compliance until 5/31/78 if they install interim controls, including monitoring, reporting and burning low-sulfur fuel during adverse meteorological conditions. Sources in the rest of the state must maintain at least two weeks' supply of low-sulfur fuel.

Nitrogen oxides. For new equipment of 250 × 10^6 Btu/hr heat input or over, the limits on nitrogen oxides, calculated as NO_2, are: gas firing, 0.20 lb/10^6 Btu heat input, oil firing, 0.30 lb, and coal firing 0.70 lb. This applies to all existing stationary sources in Lake County as well.

Iowa

Iowa Air Pollution Control Commission, Dept of Environmental Quality, P O Box 3326, 3920 Delaware Ave, Des Moines, IA 50316.

Particulates. Max emissions from indirect heating or power-generation sources are calculated from the equation given for Indiana. For plants rated 4000 × 10^6 Btu/hr heat input and above, the plume-rise factor is 1.0. Outside [inside] any standard metropolitan statistical area, max allowable emission from each stack (irrespective of height) serving existing equipment is 0.8 [0.6] lb/10^6 Btu heat input. New equipment in all locations must meet the 0.6-lb/10^6 Btu heat-input limit.

Sulfur oxides. Emissions will be limited to 6 (solid fuels) and 2.5 (liquid fuels) lb SO_2/10^6 Btu heat input (max 2-hr average) as of 7/31/75, and to 5 (solid) and 2.5 (liquid) lb SO_2/10^6 Btu heat input (max 2-hr average) as of 7/31/78.

Nitrogen oxides. No source emission standards are stated in the regulations.

Kansas

Bureau of Air Quality & Occupational Health, Dept of Health & Environment, Topeka, KS 66620.

Particulates. All fuel-burning equipment burning coal at 350,000 Btu/hr or over heat input, or No. 5 or heavier oil or No. 4 or lighter oil at 10^6 Btu/hr heat input, or gas (or No. 4 or lighter oil on standby basis) at 100 × 10^6 Btu/hr heat input is subject to regulations. Emission limit for 10^6 Btu/hr heat input or less is 0.60 lb/hr/10^6 Btu. From 10^6 to 10,000 × 10^6 Btu/hr heat input, the allowable emission limit is $A = 1.026/I^{0.233}$, where A is in lb/hr/10^6 Btu and I is the total heat input in 10^6 Btu/hr. For 10,000 × 10^6 Btu/hr and above, the allowable limit is 0.12 lb/hr/10^6 Btu.

Sulfur oxides. For equipment with heat input of 250 × 10^6 Btu/hr or more, sulfur emission is limited to 1.5 lb/10^6 Btu/hr heat input.

Nitrogen oxides. Gas- or oil-fired equipment with heat input of 250 × 10^6 Btu/hr or more is limited to 0.30 lb nitrogen oxides/10^6 Btu/hr heat input. For coal-fired equipment with heat input of 250 × 10^6 Btu/hr or more, the limit is 0.90 lb of nitrogen oxides (calculated as NO_2)/10^6 Btu/hr heat input.

Kentucky

Div of Air Pollution, Kentucky Dept for Natural Resources & Environmental Protection, Capital Plaza Tower, Frankfort, KY 40601.

Particulates. Allowable emissions in lb/10^6 Btu from existing indirect heat exchangers in Priority I, II, and III regions vary exponentially between the following limits: for 10 × 10^6 Btu/hr heat input or less: 0.56, 0.75, 0.80, respectively; for 10,000 × 10^6 or more: 0.11, 0.15, 0.18.

New sources with 250 × 10^6 Btu/hr heat input or more are restricted to emissions of 0.10 lb/10^6 Btu heat input in all geographic regions. Smaller new sources follow the existing Priority I curve. Stack tests for particulate matter on existing plants are made in accordance with ASME PTC-27 or by state-approved methods.

Sulfur oxides. Emissions from existing indirect heat exchangers in Priority I regions must be limited to 0.8 (liquid fuel) and 1.2 (solid fuel) lb SO_2/10^6 Btu heat input (max 2-hr average) for maximum rated capacity of 250 × 10^6 Btu/hr heat input or more, by 7/1/77. In Priority II regions, the limits are 1.5 (liquid fuel) and 2.0 (solid fuel) for max rated capacity of 500 × 10^6 Btu/hr heat input or more, by 7/1/78. In Priority III regions, the limits are 2.0 (liquid fuel) and 3.5 (solid fuel) for max rated capacity of 1000 × 10^6 Btu/hr heat input or more, by 7/1/79. Allowable emissions from new sources are those given above for existing sources in Priority I regions. In addition, no indirect heat exchanger can be modified or constructed to discharge more than 500 tons/day of SO_2 or, collectively with all others emitting over 100 tons/day of SO_2 in a circle of 10 miles diameter, more than 750 tons/day.

Nitrogen oxides. Existing indirect heat exchangers in Priority I regions rated 300 × 10^6 Btu/hr heat input or more are limited to 0.3 (gas and liquid fuels) or 0.9 (solid fuels) lb NO_x (expressed as NO_2)/10^6 Btu heat input (max 2-hr average). New sources rated at 250 × 10^6 Btu/hr heat input or more are limited to 0.2 (gas fuels), 0.3 (liquid fuels) or 0.7 (solid fuels) lb NO_x (expressed as NO_2)/10^6 Btu heat input (max 2-hr average).

Louisiana

Air Control Commission, State Office Bldg, P.O. Box 60630, New Orleans, LA 70160

Particulates. Emissions from new and existing fuel-burning equipment are limited to 0.6 lb/10^6 Btu heat input. If the quality of emissions from existing sources is higher than standards, this level of quality must be maintained, unless it can be demonstrated to the state that a change in quality will not be contrary to the regulations. Particulate emissions are determined by ASME PTC-27 or EPA test methods, described in the *Federal Register*, 8/17/71, pp 15708-15722.

Sulfur oxides. Emissions are limited to the most restrictive of the following criteria: (1) 2000 ppm sulfur compounds (by volume) measured as SO_2 at standard conditions, or (2) the maximum concentrations, listed below, attributable to such emissions at any point beyond the premises on which the source is located. Maximum permissible concentrations are 0.03 ppm SO_2 annual arithmetic mean, and 0.14 ppm SO_2 max 24-hr concentration, not to be exceeded more than once each year. SO_2 emissions may be determined by several methods, including EPA test methods published in the *Federal Register*, 8/17/71, pp 15708-15722.

Nitrogen oxides. No source emission standards are stated in the regulations.

Maine

Dept of Environmental Protection, Augusta, ME 04330

Particulates. Emissions from new fuel-burning equipment rated 150 × 10^6 Btu/hr heat input and above are limited to 0.3 lb/10^6 Btu heat input (max 2-hr avg). Existing equipment must meet these codes by 6/1/75. Test procedures include methods 1-5 in "Standards of Performance for New Stationary Sources," *Federal Register*, 12/23/71.

Sulfur oxides. Emissions can be regulated by the use of low-sulfur fuels and/or pollution-control equipment. Sources in the Metropolitan Portland AQCR must burn the equivalent of 1.5%-sulfur fuel (or better) after 11/1/74. Central Maine, Down East, Aroostook County and Northwest Maine AQCRs must burn the equivalent of 2.5%-sulfur (or less) fuel. Some variances have been granted in the Portland AQCR.

Nitrogen oxides. No source emission standards are stated in the regulations.

Maryland

Dept of Health & Mental Hygiene, Environmental Health Admin, 610 North Howard St, Baltimore, MD 21201

Particulates. New residual-oil-fired equipment rated 51 to 250 × 10^6 Btu/hr heat input is limited to 0.02 grains/scf (dry); new residual-oil- [coal-]fired units above 250 × 10^6 Btu/hr heat input are limited to 0.01 [0.03] grains/scf (dry). Existing residual-oil-fired units in Areas III and IV have the same limits as new units. Existing coal-fired units in Areas III and IV rated more than 250 × 10^6 Btu/hr heat input are limited to 0.03 grains/scf (dry).

Sulfur oxides. Emissions can be regulated by using low-sulfur fuels or by stack-gas desulfurization equipment. All sources must burn fuel with a maximum 1% sulfur content or use stack-gas cleanup equipment that will limit SO_2 emissions to 0.5 lb S/10^6 Btu heat input. Residual-oil sulfur limit of 0.5% will become law 7/1/80.

Nitrogen oxides. New units rated more than 250 × 10^6 Btu/hr heat input are limited to 0.2 (gaseous fuel), 0.3 (liquid fuel) and 0.5 (solid fuel) lb NO_x (calculated as NO_2)/10^6 Btu heat input (max 2-hr avg). In Areas III and IV, existing sources rated 250 × 10^6 Btu/hr heat input or greater must meet emission levels that are attainable through the use of reasonably applied control technology. There is no requirement for existing sources in Areas, I, II, V and VI.

Massachusetts

Dept of Public Health, Div of Environmental Health, Bureau of Air Quality Control, 600 Washington St, Boston, MA 02111

Particulates. Existing fossil-fuel utilization facilities are limited to 0.15 lb/10^6 Btu heat input, except in towns and cities near large population centers—called "critical areas of concern" by state officials— where the limit is 0.12. (The list of designated critical areas is too long to present here.) New sources larger than 250 × 10^6 Btu heat input must reduce emissions to 0.05 lb/10^6 Btu heat input, except for units with equipment designed to control or reduce SO_2. These sources can discharge 0.1 lb. All sources must be in full compliance with all particulate-control laws by 1/31/74. Emission testing is to be done in accordance with method 5 presented in "Standards of Performance for New Stationary Sources," *Federal Register*, 12/23/71.

Sulfur oxides. Emissions from residual-oil- or coal-fired equipment are restricted to the equivalent of the uncontrolled burning of fuel containing 0.28 lb sulfur/10^6 Btu heat-release potential in the following towns and cities: Arlington, Belmont, Boston, Brookline, Cambridge, Chelsea, Everett, Malden, Medford, Newton, Somerville, Waltham and Watertown. All other sources in the state burning resid or coal are limited to fuels with 0.55 lb sulfur/10^6 Btu heat-release potential. Distillate-fired sources must not have a greater air polluting effect than if fuel with 0.17 lb sulfur/10^6 Btu were burned uncontrolled. All sources must comply with sulfur-oxides control laws by 1/31/74.

Nitrogen oxides. Emissions from new fossil-fuel utilization facilities greater than 250 × 10^6 Btu/hr heat input (except gas turbines and diesel engines) are limited to 0.3 lb NO_x/10^6 Btu heat input as of 1/31/74. Testing must be conducted in accordance with method 7, "Standards of Performance for New Stationary Sources," *Federal Register*, 12/23/71, or a state-approved equivalent.

Michigan

Dept of Public Health, 3500 North Logan, Lansing, MI 48914

Particulates. Allowable emissions from pulverized-coal fired equipment rated less than 1 × 10^6 lb steam/hr vary from about 0.18 to 0.3 lb/10^3 lb flue gas. Actual limit for any specific unit is found from a curve, the formula for which is not given in the regulations, but which is obtainable from the address above. Operators of larger pulverized-coal-fired equipment are required to file an application with the state for an allowable-emission limit. Operators of other fuel-burning equipment rated above 300,000 lb steam/hr also must file with the state for an allowable-emission limit. Equipment using other than pulverized coal, and rated from 100,000 to 300,000 lb steam/hr, is restricted to between 0.65 and 0.45 lb/10^3 lb flue gas (actual value determined by linear interpolation); up to 100,000 lb/hr the limit is 0.65. Note that in calculating your boiler emissions, state requires you assume 50% excess-air firing.

Sulfur oxides. Power plants rated 500,000 lb steam/hour and less—that is, the steam capacity of all plant equipment as of 8/17/71—must burn the equivalent of 2%-sulfur fuel by 7/1/75 and 1.5%-sulfur fuel by 7/1/78. Larger plants must burn 1.5%-sulfur fuel by 7/1/75 and 1.0%-sulfur fuel by 7/1/78. These figures translate to 1.6 lb SO_2/10^6 Btu heat input for 1%-sulfur coal, 2.4 for 1.5%-sulfur coal, 3.2 for 2%-sulfur coal, 1.1 for 1%-sulfur oil, 1.7 for 1.5%-sulfur oil and 2.2 for 2%-sulfur oil. The state assumes solid fuels have a heating value of 12,000 Btu/lb; liquid fuels, 18,000 Btu/lb.

Nitrogen oxides. No source emission standards are stated in the regulations.

Minnesota

Minnesota Pollution Control Agency, 1935 West County Road B-2, Roseville, MN 55113.

Particulates. Max allowable emissions for stationary sources in Duluth and the Minneapolis/St. Paul AQCR are 0.4 lb/10^6 Btu heat input. Elsewhere, the max is 0.6.

Sulfur oxides. In the Minneapolis/St. Paul AQCR, coal and oil can have no more than 2% sulfur. Sources larger than 250 × 10^6 Btu/hr heat input cannot burn coal or oil containing more than 1.5% sulfur. Outside this region, sources larger than 250 × 10^6 Btu/hr heat input are limited to 2%-sulfur coal. All sources in the state using stack-gas cleanup in lieu of low-sulfur fuel are limited to 1.75 lb SO_2/10^6 Btu heat input.

Nitrogen oxides. For existing sources, there is no restriction on NO_x emissions from steam-generating units. New sources larger than 250 × 10^6 Btu/hr heat input are subject to Federal Stationary Source Stds.

Mississippi

Air & Water Pollution Control Commission, P.O. Box 827, Jackson, MS 39205

Particulates. Fossil-fuel-burning equipment rated 10 to 10,000 × 10^6 Btu/hr heat input is limited to between 0.6 and 0.19 lb/10^6 Btu heat input, respectively. If your equipment capacity lies between these points, find the allowable emission rate by plotting a straight line on log-log graph paper from the coordinate 0.6, 10 to 0.2, 10,000. Above 10,000 × 10^6 Btu/hr heat input, the max emission rate is 0.2 lb/10^6 Btu heat input.

Sulfur oxides. (1) Max emission from indirect heat-transfer equipment ~~used for~~ producing power is 4.8 lb SO_x (measured as SO_2)/10^6 Btu heat input. (2) Emissions in any calendar year cannot exceed those recorded in 1970, unless a variance is granted by the state. (3) Emissions from modified fuel-burning equipment used for power generation and rated below 250 × 10^6 Btu/hr heat input are limited to 2.4 lb SO_x/10^6 Btu heat input.

Nitrogen oxides. No source emission standards are stated in the regulations.

Missouri

Missouri Air Conservation Commission, Dept of Natural Resources, P.O. Box 176, Jefferson City, MO 65101.

The following regulations apply throughout the state except in the City of St. Louis and in St. Charles, St. Louis, Jefferson, Franklin, Clay, Cass, Buchanan, Ray, Jackson, Platte and Greene Counties. For codes in these areas, write to the above address.

Particulates. Emission limits from fuel-burning equipment (existing or under construction as of 2/24/71) rated 100, 500, 1000, 2500, 5000, 7500 and 10,000 and more × 10^6 Btu/hr heat input are 0.4, 0.3, 0.26, 0.23, 0.20, 0.19 and 0.18 lb/10^6 Btu, respectively. For intermediate capacity ratings, use linear interpolation. For new sources, the permissible emission rates are 0.275 lb/10^6 Btu heat input for 100 × 10^6 Btu/hr heat input, 0.159 for 500, 0.126 for 1000 and 0.1 for 2000 or more. Compliance with these regulations is determined at steady-state conditions using ASME's PTC-27 or any other method approved by the state.

Sulfur oxides. Source emissions in excess of 1000 lb SO_2/hr are not permitted unless they do not cause or contribute to concentrations and frequencies exceeding the following limits in ambient air at any occupied place beyond the premises on which the source is located: 0.25 ppm (1-hr avg) once in any four-day period, 0.07 ppm (24-hr avg) once in any 90-day period.

Nitrogen oxides. No source emission standards are stated in the regulations.

Montana

Montana State Dept of Health & Environmental Sciences Air Quality Bureau, Cogswell Bldg, Helena, MT 59601

Particulates. Maximum allowable emission rate from new [existing] fuel-burning equipment rated 100 × 10^6 Btu/hr heat input is 0.35 [0.4] lb/10^6 Btu; 1000 × 10^6 is 0.2 [0.28]; 10,000 × 10^6 and above is 0.12 [0.19]. Allowable emissions for unit ratings between the capacities noted above can be found by plotting a curve on log-log graph paper with the data given. Use the ordinate for maximum emissions in lb/10^6 Btu of heat input and the abscissa for heat input in 10^6 Btu/hr. Heat input is defined as the aggregate heat content (using the higher heating value) of all fuels burned. When two or more fuel-burning units are connected to a single stack, the combined heat input of all units connected to the stack is used in calculating the allowable emission rate. When a single fuel-burning unit is connected to two or more stacks, the allowable emission from all stacks combined cannot exceed that permitted for the same unit connected to a single stack.

Hearings are scheduled on whether to reduce the particulate limit to 0.10 lb/10^6 Btu heat input. If passed, the effective date is expected to be immediate for new operations and 6/30/77 for existing operations.

Sulfur oxides. Gaseous fuel cannot be fired in fuel-burning installations if it contains more than 50 grains of sulfur compounds/100 cu ft, calculated as hydrogen sulfide at standard conditions. Liquid and solid fuels cannot be fired if they contain more than 1 lb sulfur/10^6 Btu, unless (1) they are blended with low-sulfur fuels and the resulting mixture has an equivalent sulfur content of less than 1 lb sulfur/10^6 Btu, or (2) a stack-gas cleanup system is utilized. This system must be capable of reducing sulfur emissions to the equivalent of burning acceptable fuels in an uncontrolled manner.

Nitrogen oxides. No source emission standards are stated in the regulations.

Nebraska

Dept of Environmental Control, P.O. Box 94653, State House Station, Lincoln, NE 68509

Nebraska adopted the U S Environmental Protection Agency's "Standards of Performance for New Stationary Sources," *Federal Register*, 12/23/71, which are outlined here:

Particulates. (1) Emissions are limited to 0.1 lb particulates/10^6 Btu heat input (max 2-hr avg). (2) Opacity is limited to 20%, but 40% is permissible for not more than 2 min in any hour. (3) Where the presence of uncombined water is the only reason for failure to meet the requirements of (2), such failure is not a violation.

Sulfur oxides. (1) Emissions are limited to 0.8 [1.2] lb SO_2/10^6 Btu heat input (max 2-hr avg) when liquid [solid] fossil fuel is burned. (2) Where different fossil fuels are burned, the allowable emissions are determined by:

$$(0.8y + 1.2z) \div 100$$

where y and z are heat input from liquid and solid fossil fuel, respectively, as percentages of total heat input.

Nitrogen oxides. (1) Emissions are limited to 0.2 (gaseous fossil fuel), 0.3 (liquid fossil fuel) or 0.7 (solid fossil fuel, except lignite) lb NO_x (expressed as NO_2)/10^6 Btu heat input. (2) Where different fossil fuels are burned, allowable emissions are determined by:

$$(0.2x + 0.3y + 0.7z) \div 100$$

Equation nomenclature is as defined above, plus x for gaseous fuel. There are no limits for existing sources.

Nevada

Bureau of Environmental Health, Dept of Human Resources, 1209 Johnson St, Carson City, NV 89701.

Particulates. Max allowable emission rate from new and existing fuel-burning equipment rated up to and including 10 × 10^6 Btu/hr heat input is 0.600 lb/10^6 Btu; above 10 × 10^6 to and including 100 × 10^6, 0.352; above 100 × 10^6 to and including 1000 × 10^6, 0.207; above 1000 × 10^6 to and including 10,000 × 10^6, 0.0909; above 10,000 × 10^6 to and including 100,000 × 10^6, 0.0246. Between 10 × 10^6 and 4000 × 10^6 Btu/hr, allowable emission rate Y in lb/10^6 Btu is $Y = 1.02X^{-0.231}$; X is the max equipment rating in 10^6 Btu/hr heat input. For X over 4000 × 10^6 Btu/hr, the equation is $Y = 17.0X^{-0.564}$. Heat input is the aggregate heat content of all fuels whose products of combustion pass through a stack or stacks, or the equipment manufacturer's or designer's guaranteed max input, whichever is greater. Total heat input of all fuel-burning units in a plant or on the premises must be used in determining max allowable particulate emission rate.

Sulfur oxides. Sulfur emission, in terms of the sulfur part of sulfur compounds in stack gas, from new and existing fuel-burning equipment rated 10 × 10^6 Btu/hr heat input, is 7 lb sulfur/hr; 100 × 10^6, 70; 1000 × 10^6, 400; 10,000 × 10^6, 1050; 100,000 × 10^6, 10,500. For interpolation between capacities above, a source with max heat input under 250 × 10^6 Btu/hr is permitted a max sulfur emission rate of Y = 0.7X, with X the max equipment rating in 10^6 Btu/hr; for max heat input over 250 × 10^6 but below 5000 × 10^6 Btu/hr, Y = 0.4X; for max heat input over 5000 × 10^6 Btu/hr, Y = 0.105X.

Nitrogen oxides. No source emission standards are stated in the regulations.

New Hampshire

Air Pollution Control Agency, State Lab Building, Hazen Drive, Concord, NH 03301.

Particulates. Max allowable emission rate from new [existing] fuel-burning equipment rated 50 × 10^6 Btu/hr heat input is 0.4 [0.46] lb/10^6 Btu; 100 × 10^6, 0.35 [0.4]; 500 × 10^6, 0.10 [0.34]; 1000 × 10^6, 0.10 [0.28]; 2500 × 10^6, 0.10 [0.24]; 5000 × 10^6, 0.10 [0.22]; 7500 × 10^6, 0.10 [0.20]; 10,000 × 10^6 and above, 0.10 [0.19]. Allowable emissions for unit ratings between the capacities noted above can be found by plotting a curve on log-log graph paper with the data given. The ordinate is max emissions in lb/10^6 Btu of heat input; the abscissa is heat input in 10^6 Btu/hr. For all new equipment larger than 250 × 10^6 Btu/hr heat input, the max emission rate is 0.10 lb/10^6 Btu. When two or more fuel-burning units are connected to a single stack, the combined heat input of all units connected to the stack is used in calculating the allowable emissions. When a single fuel-burning unit is connected to two or more stacks, the allowable emission from all stacks combined cannot exceed that for the same unit connected to a single stack.

Sulfur oxides. Gaseous fuel cannot be fired in fuel-burning installations if it contains more than 5 grains of sulfur/100 cu ft, calculated as hydrogen sulfide at standard conditions. No 2 oil cannot contain more than 0.4% sulfur by weight, No. 4 oil cannot contain more than 1% sulfur by weight, and residual oils are restricted to 2% sulfur by weight until 5/31/75, with review on the limit before then. New [existing] fuel-burning installations using solid fuel cannot burn coal with a maximum sulfur content greater than 1.5 [2.8] lb/10^6 Btu gross heat content, provided that the weighted average of all coal received during a trimonthly period does not exceed 1 [2] lb sulfur/10^6 Btu gross heat content. Fuels with higher sulfur content can be burned if control apparatus continuously restricts sulfur emissions to levels permitted by the regulations for uncontrolled burning of the fuel being burned.

Nitrogen oxides. No source emission standards are stated in the regulations.

New Jersey

Dept of Environmental Protection, Div of Environmental Quality, John Fitch Plaza, P O Box 2807, Trenton, NJ 08625

Particulates. Maximum allowable emission rate from new and existing fuel-combustion equipment with a heat input rate of 200 × 10^6 Btu/hr is 20 lb/hr; 1000 × 10^6, 100; 5000 × 10^6, 500; 10,000 × 10^6, 1000. Allowable emissions for heat-input rates between those noted above are found by linear interpolation. Heat input rate is the sum of the heat-input rates of all fuel-burning equipment discharging through a single stack.

In measuring emissions, solid particles must be drawn by isokinetic procedures from the stack, and the weight of the solid particles determined gravimetrically after removing uncombined water. Specifications for the sampling train, as well as the sample procedures, are available from the above address.

Sulfur oxides. Liquid fuels cannot be fired in fuel-burning installations if they contain more than 0.2% (No. 2 and lighter oils) or 0.3% (No. 4 and heavier oils) sulfur by weight. Exemptions are fuel-burning installations in Atlantic, Cape May, Cumberland, Hunterdon, Ocean, Sussex and Warren counties. Facilities in these areas are permitted to burn 0.3%-sulfur No. 2 oil, 0.7% No. 4 oil and 1% No. 5 and No. 6 oils. Liquid fuels of higher sulfur content can be burned if control apparatus continuously restricts sulfur emissions to levels permitted by the regulations for uncontrolled burning of the fuel being burned.

Sulfur content of bituminous and anthracite coal, for facilities existing as of 5/6/68, is limited to 0.2% by weight, except if: (1) Control equipment will maintain emissions below 0.3 lb SO_2/10^6 Btu heat input; or (2) rated capacity of a single boiler exceeds 200 × 10^6 Btu/hr heat input or a group of boilers at one location have a combined rating greater than 450 × 10^6 Btu/hr heat input. These facilities may be authorized to burn bituminous coal containing 1% sulfur by weight or anthracite coal containing 0.7% sulfur. If coal of this quality cannot be burned successfully, the state may grant a variance to burn solid fuel containing up to 1.5% sulfur by weight.

Also exempt from the 0.2% sulfur (in coal) rule are existing (as of 5/6/68) fuel-burning installations in Atlantic, Cape May, Cumberland, Hunterdon, Ocean, Sussex and Warren counties. These facilities can burn bituminous coal with up to 1% sulfur by weight and anthracite coal with up to 0.7% sulfur.

For new installations, the sulfur content of coal is limited to 0.2% by weight unless cleanup equipment can maintain emissions below 0.3 lb SO_2/10^6 Btu heat input.

Nitrogen oxides. No source emission standards are stated in the regulations.

New Mexico

Environmental Improvement Agency, P.O. Box 2348, Santa Fe, NM 87501

Particulates. Maximum allowable emission rate from existing coal-fired boilers (under construction or in operation as of 1/23/70), rated above 30 × 10^6 Btu/hr heat input, is 0.5 lb/10^6 Btu until 12/31/73. Then, the limits for new sources (listed below) must be met. •Maximum allowable particulate emission rate, E (lb/10^6 Btu heat input), for fuel-burning sources rated less than 1000 × 10^6 Btu/hr heat input is determined from the formula: $E = 0.96135\ I^{-0.22471}$, where I is the total heat input in 10^6 Btu/hr. For units rated from 1000 × 10^6 to 20,000 × 10^6 Btu/hr heat input, the formula is $E = 0.52431\ I^{-0.14647}$. After 12/31/74, particulate emissions from all coal-burning equipment are limited to 0.05 lb/10^6 Btu heat input; fine particulate emissions of less than 2 microns equivalent aerodynamic diameter cannot exceed 0.02 lb/10^6 Btu heat input. Particulate emissions from oil-burning equipment cannot exceed 0.005 lb/10^6 Btu heat input.

Particulate emissions from oil- and coal-fired boilers are determined by ASME PTC-27. Fine particulates must be collected and measured at stack conditions in a manner such that no condensation of gaseous material is included with the sample.

Sulfur oxides. Maximum allowable emission rate from new coal-burning equipment rated above 25 MW or 250 × 10^6 Btu/hr heat input is 0.34 lb SO_2/10^6 Btu. After 12/31/74, emissions from existing (in operation or under construction as of 9/1/71) coal-burning equipment rated above 25 MW or 250 × 10^6 Btu/hr heat input must be restricted to 1 lb SO_2/10^6 Btu. SO_2 emissions from new and existing oil-burning equipment are restricted to 0.34 lb/10^6 Btu heat input.

Stack-gas sampling must be performed in a manner that prevents interference with and contamination of the reactive elements of the sampling method. The sampling procedures need not be isokinetic, but must yield representative gas samples.

Nitrogen oxides. New gas-burning equipment is restricted to emissions of 0.2 lb NO_2/10^6 Btu heat input. Existing (in operation or under construction as of 1/10/72) gas-burning sources will be limited to 0.3 lb NO_2/10^6 Btu heat input after 12/31/74. New and existing oil-burning installations are limited to discharges of 0.3 lb NO_2/10^6 Btu heat input. New coal-burning equipment rated above 25 MW or 250 × 10^6 Btu/hr heat input is restricted to emissions of 0.45 lb NO_2/10^6 Btu. Existing (under construction or in operation as of 9/1/71) coal-burning equipment rated above 25 MW or 250 × 10^6 Btu/hr heat input will be limited to 0.7 lb NO_2/10^6 Btu as of 12/31/74.

Stack-gas sampling must be performed in a manner that prevents interference with and contamination of the reactive elements of the sampling method. The sampling procedures need not be isokinetic, but must yield representative gas samples.

New York

Dept of Environmental Conservation, 50 Wolf Rd, Albany, NY 12233

Particulates. Maximum allowable emission rate from coal-fired boilers rated 10 × 10^6 to 10,000 × 10^6 Btu/hr is determined by the formula, $E = 1.02p^{0.219}$, where E is the allowable emission rate in lb/10^6 Btu heat input and p is the total heat input in 10^6 Btu/hr. Individual combustion installations rated 300 × 10^6 Btu/hr heat input or less operating prior to 6/1/72 may exceed these values if they fall into the following categories: (1) Spreader stokers are restricted to a maximum of 0.6 lb/10^6 Btu heat input; (2) fuel-combustion systems other than spreader stokers, rated below 100 × 10^6 Btu/hr heat input, are limited to 0.6 lb/10^6 Btu; 200 × 10^6, 0.45; 300 × 10^6, 0.3. Intermediate values are calculated by linear interpolation.

Oil-fired combustion sources and new coal-fired equipment (construction-permit application filed after 8/11/72) are restricted to 0.1 lb/10^6 Btu heat input (max 2-hr average). Exemptions can be granted if emissions do not cause air-quality standards to be exceeded. Distillate-oil-burning sources to 250 × 10^6 Btu/hr input are exempted.

When two or more different fuels are burned simultaneously in a single furnace, the permissible emission rate is the sum of the permissible emission rates for each fuel multiplied by the heat input (Btu) derived from that fuel.

Sulfur oxides. For new installations in most of the state, applying for permit after 3/15/73, with total rated heat input over 250 × 10^6 Btu/hr, oil limit is 0.75% sulfur by weight, and coal limit is 0.60 lb sulfur/10^6 Btu gross heat content. This does not apply to New York City, Nassau, Rockland or Westchester counties. In New York City, limit on oil is 0.30% sulfur by weight, and 0.20% sulfur by weight for distillate; limit on solid fuel is 0.20 lb sulfur/10^6 Btu gross heat content. In Nassau, Rockland and Westchester, limit for oil is 0.37% sulfur by weight, and for solid fuel 0.20 lb sulfur/10^6 Btu gross heat content.

For existing installations in the Suffolk county towns of Babylon, Brookhaven, Huntington, Islip and Smithtown, the limit for oil is 1.0% sulfur by weight, and for solid fuel 0.6 lb sulfur/10^6 Btu gross heat content. In Erie and Niagara counties, the limit for oil is 2.2% sulfur by weight, dropping to 1.1% on 10/1/75; for solid fuel the maximum [average] is 1.7 [1.4] lb sulfur/10^6 Btu gross heat content. In Erie and Niagara counties, the average value for sulfur in solid fuel, found for each emission source, is the result of dividing total sulfur content by gross total heat content of all solid fuel received during any consecutive 3-month period. For the rest of the state, the limit for oil is 2.0% sulfur by weight, and the maximum [average] for solid fuel is 2.5 [1.9] lb sulfur/10^6 Btu gross heat content.

Gaseous fuel is limited to 50 grains of sulfur compound (expressed as H_2S)/100 dry standard cu ft of gas.

Fuels with sulfur content in excess of the above may be used if it can be demonstrated that the resulting max and 3-month average emission of sulfur compounds (expressed as SO_2) will not exceed product of total heat input multiplied by allowable rate of sulfur dioxide emission, S (in lb/10^6 Btu):

$$S = (2YA + 2ZB)/(Y + Z)$$

where Y [Z] is percent of total heat input from liquid [solid] fossil fuel, A is 0.55 times the sulfur content of the oil in percent by weight permitted above, and B is the sulfur content of the coal in lb sulfur/10^6 Btu permitted above.

Until 6/30/75, installations burning coal continuously since 12/31/67 in New York City, Nassau, Rockland, Suffolk and Westchester counties will be permitted to burn at the same rate without respect to the fuel's sulfur content. Installation of control equipment may also allow a plant exception from fuel sulfur content restrictions.

Installations with heat input of over 250 × 10^6 Btu/hr applying after 3/15/73 for construction permit or environmental certificate to burn any oil or coal must have equipment on each stack to monitor and record sulfur-compound emissions continuously.

Any plant changing from oil or gas to coal must buy coal with sulfur content in lb/10^6 Btu not higher than the product of 0.55 times max sulfur content (in percent by weight) of oil permitted for the plant.

Sources rated at 250 × 10^6 Btu/hr total heat input or less may be allowed to use oil with sulfur content of 3.0% by weight and/or solid fuel with sulfur content of 2.8 lb/10^6 Btu gross heat content, provided analysis shows no violation of federal standards or degradation of air quality.

Nitrogen oxides. Emissions are limited to 0.2 (gaseous fuel), 0.3 (liquid fuel) and 0.7 (solid fuel) lb NO_x (expressed as NO_2)/10^6 Btu heat input for stationary combustion installations rated over 250 × 10^6 Btu/hr total heat input and for which construction application was made after 8/11/72. Gas turbines and stationary engines are exempt.

North Carolina

Dept of Natural & Economic Resources, Div of Environmental Management, Air Quality Section, P O Box 27687, Raleigh, NC 27611.

Particulates. Maximum allowable emission rate from all fuel-burning sources rated 100 × 10^6 Btu/hr heat input is 0.33 lb/10^6 Btu; 1000 × 10^6, 0.18; 10,000 × 10^6 and greater, 0.1. Allowable emissions for unit ratings between the capacities noted can be found by plotting a curve on log-log graph paper with the data given. Use the ordinate for maximum emissions in lb/10^6 Btu and the abscissa for heat input in 10^6 Btu/hr. Heat input is defined as the aggregate heat content of all fuels burned.

Sulfur oxides. Fuel-burning installations constructed after 7/1/71 are limited to emissions of 1.6 lb SO_2/10^6 Btu heat input. Sources constructed before 7/1/71 are limited to 2.3 lb SO_2/10^6 Btu heat input until 7/1/80, when the emission level drops to 1.6 lb—unless it can be demonstrated that ambient air-quality standards in the area are not likely to be contravened.

Nitrogen oxides. New and existing oil- and gas-fired boilers rated 250 × 10^6 Btu/hr heat input and above are limited to 0.6 lb NO_2/10^6 Btu heat input. Coal-fired boilers in the same size range are restricted to 1.3 lb NO_2/10^6 Btu heat input.

North Dakota

Dept of Health, Div of Environmental Engineering, State Capitol Bldg, Bismarck, ND 58501

Particulates. Maximum allowable emission rate from existing plants is 0.8 lb/10^6 Btu heat input. However, as technology develops and control equipment becomes compatible with existing plants, compliance with the standards for new plants (see below) will be required. Maximum allowable emission rate, E (lb/10^6 Btu heat input), for new installations (under construction or in operation as of 7/1/70) is, $E = 0.811H^{-0.131}$, where H is heat input in 10^6 Btu/hr.

The total heat input of all fuel-burning units at the source of emission is used in finding the maximum allowable discharge rate. Discharges are measured in accordance with ASME PTC-27.

Sulfur oxides. Emissions from new and existing fuel-burning installations are limited to 3 lb SO_2/10^6 Btu heat input.

Nitrogen oxides. No source emission standards are stated in the regulations.

Ohio

Environmental Protection Agency, P O Box 1049, Columbus, OH 43216

Particulates. Maximum allowable emission rate from new and existing fuel-burning equipment in Priority I regions is found from Ohio EPA's curve P-1, which can be plotted on log-log graph paper from the following points: 0.4, 1 × 10^6; 0.4, 10 × 10^6; 0.1, 1000 × 10^6; 0.1, 100,000 × 10^6. The first number given is the ordinate, representing the maximum allowable emission rate in lb/10^6 Btu heat input; the second number is the abscissa, representing total heat input in 10^6 Btu/hr. Curve P-2, expressing the maximum allowable emission rate from new and existing fuel-burning equipment in Priority 2 and 3 regions, can be plotted from the following points: 0.6, 1 × 10^6; 0.6, 10 × 10^6; 0.15, 1000 × 10^6; 0.15, 100,000 × 10^6. By 7/1/75, however, fuel-burning equipment in Priority 2 and 3 regions must meet the emission rates specified by curve P-1.

Heat input is defined as the aggregate heat content of all fuels burned in a single unit. The value used in the calculations is the manufacturer's or designer's guaranteed maximum input, whichever is greater. The total heat input of a plant or premises which are united either physically or operationally is used in calculating the maximum allowable particulate emissions from any single fuel-burning unit. Particulate emissions are measured in accordance with ASME PTC-27.

Sulfur oxides. Maximum allowable emission rate of sulfur compounds (measured as SO_2) for new and existing fuel-burning equipment in Priority 1 regions is 1 lb SO_2/10^6 Btu heat input; in Priority 2 regions, 1.6; in Priority 3 regions, 3. By 7/1/75, however, all fuel-burning equipment in Priority 2 and 3 regions must meet Priority 1 standards. New regulations may appear in 5/75.

Nitrogen oxides. Maximum allowable emission rate from existing stationary sources in Priority I regions, and new sources (those on which construction started after 2/15/72) throughout the state, rated 250 × 10^6 Btu input and above, is 0.2 lb NO_x (measured as NO_2)/10^6 Btu input for gas-fired boilers, 0.3 for oil-fired, 0.9 for coal-fired.

Oklahoma

Air Quality Service, Environmental Health Services, Dept of Health, NE 10th & Stonewall Sts, Oklahoma City, OK 73105

Particulates. Maximum allowable emission rate from new and existing fuel-burning equipment rated up to 10 × 10^6 Btu/hr heat input is 0.6 lb/10^6 Btu; 100 × 10^6, 0.35; 1000 × 10^6, 0.2; 10,000 × 10^6 and above, 0.1. Allowable emissions for unit ratings between the capacities noted above can be found by plotting a curve on log-log graph paper with the data given. Use the ordinate for maximum emissions in lb/10^6 Btu of heat input and the abscissa for heat input in 10^6 Btu/hr. When one source is connected to two or more stacks, the heat input of the single source is used in determining the maximum total emission from all stacks combined.

Sulfur oxides. Maximum allowable emission rate from new gas-burning equipment (that on which construction started after 1/23/72) is 0.2 lb SO_x (measured as SO_2)/10^6 Btu heat input (max 2-hr avg). New oil-fired units are restricted to 0.8 lb SO_x (measured as SO_2)/10^6 Btu heat input. New solid-fuel-burning equipment is limited to 1.2 lb SO_x (measured as SO_2)/10^6 Btu heat input. Where different fossil fuels are burned, the allowable emissions are determined by:

$$(0.8y + 1.2z) \div 100$$

where y and z are heat input from liquid and solid fuel, respectively, as percentages of total heat input.

All units rated 250 × 10^6 Btu/hr heat input that are required to limit SO_x emissions must be outfitted with continuous monitoring instruments, except where only gaseous fuel with less than 0.1% sulfur is burned.

Nitrogen oxides. New installations rated 50 × 10^6 Btu/hr heat input and above cannot emit more than 0.2 (gaseous fuels), 0.3 (liquid fuels) and 0.7 (solid fuels) lb NO_x (calculated as NO_2)/10^6 Btu heat input (max 2-hr avg).

Oregon

Dept of Environmental Quality, Air Quality Control Div, 1234 SW Morrison, Portland, OR 97205

Particulates. Maximum allowable emission rate from existing fuel-burning equipment (in operation prior to 6/1/70) is 0.2 grains/standard cu ft; for new sources, 0.1 gr/scf.

Sulfur oxides. Sulfur content of residual fuel oils is limited to 2.5% (by weight) until 7/1/74, when the limit drops to 1.75%. No. 1 distillate is restricted to 0.3% sulfur (by weight); No. 2 to 0.5%; coal to 1%.

With prior approval, fuels used in a manner or with control that allows SO_2 emissions to be demonstrably equal to or less than those from combustion of above-mentioned fuels can be exempted from the limits.

Maximum allowable emission rate from new sources (those installed, constructed or modified after 1/1/72), rated 150 × 10^6 to 250 × 10^6 Btu/hr heat input, is 1.4 [1.6] lb $SO_2/10^6$ Btu heat input (max 2-hr avg) when liquid [solid] fuel is burned. Units rated more than 250 × 10^6 Btu/hr heat input are restricted to 0.8 [1.2] lb $SO_2/10^6$ Btu heat input (max 2-hr avg) when liquid [solid] fuel is burned.

Nitrogen oxides. No source emission standards are stated in the regulations.

Pennsylvania

Dept of Environmental Resources, Bureau of Air Quality & Noise Control, P.O. Box 2063, Harrisburg, PA 17120

Particulates. Maximum allowable emission rate from new and existing combustion units rated 2.5 × 10^6 to 50 × 10^6 Btu/hr heat input is 0.4 lb/10^6 Btu. From 50 × 10^6 to 600 × 10^6 Btu/hr heat input, the emission rate, A (lb/10^6 Btu heat input), is determined by the equation: $A = 3.6E^{-0.56}$, where E is the heat input in 10^6 Btu/hr. Units rated 600 × 10^6 Btu/hr heat input and greater are limited to 0.1 lb/10^6 Btu heat input. In addition to these regulations, EPA's "Standards of Performance for New Stationary Sources," *Federal Register*, 12/23/71, also are enforceable by the state, since they were adopted by reference. The EPA standards are outlined above (see Nebraska).

Sulfur oxides. The sulfur-oxide regulations are divided into three categories:

(1) The following rules apply to all combustion units in all air basins except those units subject to the provisions of Section 2. Maximum allowable emission rate from units rated 2.5 × 10^6 to 50 × 10^6 Btu/hr heat input is 3 lb SO_x (expressed as SO_2)/10^6 Btu heat input. From 50 × 10^6 to 2000 × 10^6 Btu/hr heat input, the emission rate, A (lb $SO_x/10^6$ Btu heat input) is determined by the equation: $A = 5.1E^{-0.14}$, where E is heat input in 10^6 Btu/hr. Units rated 2000 × 10^6 Btu/hr and greater are restricted to 1.8 SO_x (expressed as SO_2)/10^6 Btu heat input.

(2) For all combustion units in the Allegheny County, Beaver Valley, Monongahela Valley and Southeast Pennsylvania air basins, the maximum allowable emission rates for units below 50 × 10^6 and above 2000 × 10^6 Btu/hr heat input are one-third those presented in Section 1. Between 50 × 10^6 and 2000 × 10^6 Btu/hr heat input, the applicable equation is $A = 1.7E^{-0.14}$.

(3) All combustion units not covered under Sections 1 and 2 must restrict emissions to 4 lb SO_x (expressed as SO_2)/10^6 Btu heat input.

In addition to these regulations, EPA's "Standards of Performance for New Stationary Sources," *Federal Register*, 12/23/71 also are enforceable by the state, since they were adopted by reference. The EPA standards are outlined above (see Nebraska).

Nitrogen oxides. Although no state regulations exist, EPA's "Standards of Performance for New Stationary Sources," *Federal Register*, 12/23/71, are enforceable by the state, since they were adopted by reference. The EPA standards are outlined above (see Nebraska).

Rhode Island

Div of Air Pollution Control, Dept of Health, 204 Health Bldg, Davis St, Providence, RI 02908.

Particulates. Max allowable emission rate from equipment with heat input over 250 × 10^6 Btu/hr is 0.10 lb/10^6 Btu heat input. For equipment of 10^6 to 250 × 10^6 Btu/hr, max allowable emission rate is 0.20. Heat input is the aggregate heat content of all fuels whose products of combustion pass through a stack or stacks. The heat-input value used is the manufacturer's or designer's guaranteed max input. Total heat input of all fuel-burning units on a plant or premises determines the max allowable amount of particulate matter emitted. Permission is required before constructing, installing or modifying any potential source of pollution with over 10^6 Btu/hr heat input. Separate applications must be made for each potential source and each pollution-control device or part of it.

Sulfur oxides. Fuel must not contain more than 0.55 lb sulfur/10^6 Btu heat-release potential, unless an approved stack-gas cleaning process limits emissions to 1.1 lb sulfur compounds (as sulfur dioxide)/10^6 Btu gross heat input.

Nitrogen oxides. Max allowable emission rates from oil- [gas-]fired equipment over 100 × 10^6 Btu/hr input are 0.3 [0.2] lb NO_x (calculated as NO_2)/10^6 Btu heat input.

South Carolina

Bureau of Air Quality Control, Dept of Health & Environmental Control, 2600 Bull St, Columbia, SC 29201.

Particulates. Max allowable emission rate for new and existing sources is presented in a graph with three variables: permissible emission, equipment capacity and stack height. Max emission rate for new sources (after 2/10/71) to about 340 × 10^6 Btu/hr heat input is 0.6 lb/10^6 Btu heat input, independent of stack height. Taller stacks allow this rate to be maintained for larger ratings before decrease occurs for each stack-height class.

Sulfur oxides. Sources in Charleston County larger than 10 × 10^6 Btu/hr heat input are limited to 2.3 lb $SO_2/10^6$ Btu heat input. Sources in Aiken and Anderson counties of 1000 × 10^6 Btu/hr heat input and larger are limited to 2.3 lb $SO_2/10^6$ Btu heat input. All sources elsewhere are limited to 3.5 lb $SO_2/10^6$ Btu heat input. Variances for higher SO_2 discharges are available on case-by-case basis, with maintenance of ambient air standards the objective.

Nitrogen oxides. No source emission standards are stated in the regulations.

South Dakota

Dept of Environmental Protection, Office Bldg No. 2, Pierre, SD 57501.

In South Dakota, the US Environmental Protection Agency enforces its "Standards of Performance for New Stationary Sources," *Federal Register*, 12/23/71. These standards are outlined above (see Nebraska).

For units rated under 250 × 10^6 Btu/hr heat input, particulate emissions are limited to 0.3 lb/10^6 Btu heat input; SO_2 discharges to 3 lb $SO_2/10^6$ Btu heat input. NO_x limits for gas- and oil-fired boilers are the same as those for units rated over 250 × 10^6 Btu/hr heat input.

Tennessee

Air Pollution Control Board, Dept of Public Health, 256 Capitol Hill Bldg, Nashville, TN 37219.

Particulates. Maximum allowable emission rate for existing (as of 4/3/72) installations rated 1 × 10^6 to 10 × 10^6 Btu/hr heat input is 0.6 lb/10^6 Btu; 10,000 × 10^6 and above, 0.1. Allowable emissions for unit ratings between the capacities noted above can be found by plotting a curve on log-log graph paper with the data given. Use the ordinate for maximum emissions in lb/10^6 Btu of heat input and the abscissa for heat input in 10^6 Btu/hr. Limits for units rated 4000 × 10^6 Btu/hr heat input and below took effect 8/9/73, those above 4000 × 10^6 heat input become law 7/1/75. Emissions from new installations are governed by the curve formed by the following points: 1 × 10^6, 0.6; 10 × 10^6, 0.6; 250 × 10^6 and above, 0.1.

If one or more sources in a county are in conformity but the ambient-air-quality standard is being exceeded, a lower standard may be set for each source. If repairs or modifications costing 20% or more of the cost of the installation are made in a 12-month period, the installation must meet standards for new installations.

Sulfur oxides. After 6/30/75, the following limits apply to sources of all size in existence before 4/3/72, and they have applied since 1/1/73 to sources constructed after 4/3/72 and not exceeding 250 × 10^6 Btu/hr heat input: In Polk, Sullivan, Roane and Maury counties, 1.6 lb sulfur oxides (calculated as SO_2)/10^6 Btu heat input (max 2-hr average); in Humphreys County, 3.0; in the rest of the state, 4.0.

For sources larger than 250 × 10^6 Btu/hr heat input and constructed after 4/3/72, the limit is 0.80 [1.2] lb sulfur oxides (calculated as SO_2)/10^6 Btu heat input (max 2-hr average) when liquid [solid] fossil fuel is burned. Where different fossil fuels are burned simultaneously, the allowable emissions are determined by proration:

$$(Y[0.80] + Z[1.2])/\div 100$$

in which Y is percent of total heat input from liquid fuel, and Z that from solid fuel.

In addition, any fuel-burning installation of over 1000 × 10^6 Btu/hr must demonstrate that the installation will not interfere with attainment or maintenance of primary and secondary ambient air standards, will not give air quality concentrations in excess of 50% of the primary ambient air quality standard, and will not increase air quality concentrations above those of 1972 or of the first year of operation for any installation that began after 1/1/72.

Nitrogen oxides. Air-contaminant sources, rated 250 × 10^6 Btu/hr heat input and above, that were constructed after

4/3/72, must meet the regulations stated for Nebraska. Note that, in calculating NO_x concentrations, sample should be corrected to 15% excess air.

Texas

Air Control Board, 8520 Shoal Creek Blvd. Austin, TX 78758.

Texas adopted the US Environmental Protection Agency's "Standards of Performance for New Stationary Sources," *Federal Register*, 12/31/71. These standards are outlined above (see Nebraska) and hold for new sources and modified sources (sources with increase in pollutant or change in pollutant type). New and modified sources are those contracted for after 9/1/71.

Particulates. Max allowable emission from an existing solid-fossil-fuel-fired generator is 0.3 lb/10^6 Btu heat input (max 2-hr average). Max allowable emission from an existing oil- and gas-fired steam generator of over 2500 $\times$ 10^6 Btu/hr heat input is 0.1 lb/10^6 Btu heat input (max 2-hr average). For existing oil- or gas-fired steam generators of 2500 $\times$ 10^6 Btu/hr heat input or less, allowable emission rate E in lb/hr must not exceed $E = 0.048q^{0.62}$, where q is the stack effluent flow rate in acfm. In addition, for this size range of oil- or gas-fired steam generators, the allowable emission level must be reduced for low stacks by multiplying it by the square of the ratio of effective stack height to standard effective stack height. Effective stack height,

$$h_e \text{ (in ft)} = h + 0.083v_eD_e \times (1.5 + 0.82[(T_e - 550)/T_e]D_e),$$

with h the stack height above ground level in ft, v_e the stack-exit velocity in ft/sec, D_e the stack-exit inside diameter in ft, and T_e the stack-exit temperature in deg R. Standard effective stack height $H_e = 1.05q^{0.35}$, with q the stack effluent flow rate in acfm.

Sulfur oxides. Max allowable emission of SO_2 from an existing solid-fossil-fuel-fired steam generator is 3.0 lb/10^6 Btu heat input. New proven technology for removing SO_2 from emissions of these steam generators must be applied when available. For ~~existing~~ liquid-fuel-fired steam generators, SO_2 must not exceed 440 ppm by volume, and emission concentrations must be reduced if stack height is below certain values. The reduction method is the same as that under "Particulates" above, except that $H_e = 0.49q^{0.50}$.

Nitrogen oxides. In the Dallas-Ft Worth and Houston-Galveston AQCRs, there are limits for steam generators of over 600,000-lb/hr steam capacity. For opposed-fired units, the limit on NO_x calculated as NO_2 is 0.7 lb/10^6 Btu heat input (max 2-hr average); for front-fired units, 0.5; for tangentially fired units, 0.25.

Utah

Utah State Div of Health, 44 Medical Drive, Salt Lake City, UT 84113

Particulates. All coal-fired steam generators are required to maintain a minimum of 85% control of particulate emissions, based on source emissions at maximum operating capacity while control devices are not operating—that is, unless this degree of control exceeds maximum opacity limits of No. 2 Ringelmann (40% black). Under these circumstances, tighter control must be employed. Oil-fired boiler emissions only are restricted by 40% opacity limit.

Sulfur oxides. All new installations capable of emitting more than 250 tons/year of SO_x from a stack or stacks must install control equipment to limit discharges of sulfur to 20% or less of the input sulfur. Liquid fuels are limited to a maximum sulfur content of 1.5% (by weight); solid fuels, to 1%.

Nitrogen oxides. No source emission standards are stated in the regulations.

Vermont

Air & Solid Waste Programs, Agency of Environmental Conservation, P O Box 489, Montpelier, VT 05602.

Particulates. Maximum allowable emission rate from new and existing fuel-burning equipment (including gas turbines) rated 10 $\times$ 10^6 Btu/hr heat input and less is 0.5 lb/10^6 Btu heat input; 300 $\times$ 10^6 and above, 0.1. Allowable emissions for unit ratings between the capacities noted above can be found by plotting a curve on log-log graph paper with the data given. Use the ordinate for maximum emissions in lb/10^6 Btu of heat input; the abscissa expresses heat input in 10^6 Btu/hr. Note, units rated 1000 $\times$ 10^6 Btu/hr heat input and greater that were constructed after 7/1/71 are limited to 0.06 lb/10^6 Btu heat input.

Sulfur oxides. Fuels are limited to 1.5% sulfur (by weight). Higher-sulfur fuels can be used if the stack-gas cleanup system employed is capable of reducing sulfur emissions to the equivalent of burning acceptable fuels in an uncontrolled manner.

Nitrogen oxides. Maximum allowable emission rate from new installations (constructed after 7/1/71)—including gas turbines—larger than 250 $\times$ 10^6 Btu heat input is 0.3 lb NO_x/10^6 Btu.

Virginia

Air Pollution Control Board, Room 1106, Ninth St Office Bldg, Richmond, VA 23219

Particulates. Maximum allowable emission rate, E (lb/10^6 Btu heat input), from existing (as of 8/11/72) fuel-burning equipment is found for unit sizes between 25 $\times$ 10^6 and 10,000 $\times$ 10^6 Btu/hr heat input from the equation $E = 0.8425\ H^{-0.2314}$, where H is the total heat input in 10^6 Btu/hr. Over 10,000 $\times$ 10^6 Btu/hr heat input, max allowable discharge rate is 0.1 lb/10^6 Btu heat input.

Heat input is the aggregate heat content of all fuels whose products of combustion pass through a stack or stacks. The heat input value used is the equipment manufacturer's or designer's guaranteed maximum input, or maximum continuous heat input, or maximum continuous heat input determined by test, whichever is greater.

The total heat input of all fuel-burning units at a plant or on premises normally operated simultaneously is used for determining the maximum allowable amount of particulate matter that may be emitted. Emission tests are made in accordance either with ASME's PTC-27 or with a state-approved substitute standard.

In AQC Region 7, units rated less than 87 $\times$ 10^6 Btu/hr heat input are limited to 0.3 lb/10^6 Btu heat input. From 87 $\times$ 10^6 to 10,000 $\times$ 10^6, the equation for calculating maximum allowable emissions is: $E = 0.8425H^{-0.2314}$. Above 10,000 $\times$ 10^6, the limit is 0.1 lb/10^6 Btu heat input.

Sulfur oxides. Maximum allowable emission rate in lb/hr of SO_x is calculated by multiplying 2.64 by total capacity rating in 10^6 Btu/hr heat input. For AQC Region 7, the multiplier is 1.06.

Nitrogen oxides. Virginia has basically a standby regulation, not to be implemented until air-quality standard for NO_x is exceeded. In such case, existing fuel-burning equipment throughout the state, rated above 250 $\times$ 10^6 Btu/hr heat input, cannot emit more than 0.4 (gaseous fuels), 0.7 (liquid fuels) and 0.9 (solid fuels) lb NO_x (expressed as NO_2)/10^6 Btu heat input. Where gaseous and liquid fuels are burned simultaneously in power-generating facilities, the emission limit is calculated by proration.

Washington

Air Resource Div, Dept of Ecology, P.O. Box 829, Olympia, WA 98504.

Particulates. Maximum allowable emission rate from existing combustion sources is 0.2 grains/standard cu ft (dry) until 7/1/75, when the limit drops to 0.1, present limit for new sources. This standard is for flue-gas samples corrected to 7% oxygen.

Sulfur oxides. Maximum permissible concentration from existing sources (in operation or under construction as of 2/24/72) is 2000 ppm SO_2 until 7/1/75, when the limit drops to 1000 ppm. All new sources must meet the 1000-ppm limit when they go into operation. The regulations are for dry samples corrected to 7% oxygen.

Nitrogen oxides. No source emission standards are stated in the regulations.

West Virginia

Air Pollution Control Comm, 1558 Washington St East, Charleston, WV 25311.

West Virginia classifies fuel-burning sources in three categories: (a) any fuel-burning unit which has as its primary purpose the generation of steam or other vapor to produce electric power for sale; (b) any fuel-burning unit not classified as (a) or (c), such as industrial pulverized-fuel-fired furnaces, cyclone furnaces, gas-fired and liquid-fuel-fired units; (c) any fuel-burning unit, hand-or stoker-fired, not classified as Type (a).

Particulates. (a) Max allowable emission rate in lb/hr from all Type (a) fuel-burning units located at one plant is calculated by multiplying 0.05 by the sum of the design heat input, in units of 10^6 Btu/hr, of all sources at the plant. No more than 1200 lb/hr of particulates can be discharged to the atmosphere from all such units, however.

(b) Max allowable emission rate in lb/hr from all Type (b) fuel-burning units located at one plant is calculated by multiplying 0.09 by the sum of the design heat input, in units of 10^6 Btu/hr, of all sources at the plant. No more than 600 lb/hr of particulates can be discharged to the atmosphere from all such units, however.

(c) Max allowable emission rate in lb/hr from all Type (c) fuel-burning units located at one plant when the sum of the design heat inputs of all sources at the plant is 10^6 Btu/hr is 3.4 lb/hr; for 20 $\times$ 10^6 Btu/hr, 5.6 lb/hr; for 40 $\times$ 10^6, 9.0; for 60 $\times$ 10^6, 11.7; for 80 $\times$ 10^6, 14.4, for 100 $\times$ 10^6, 16.6; for 200 $\times$

10^6, 26.4; for 400 × 10^6, 42.2; for 600 × 10^6, 54.0; for 3333 × 10^6, 300.

Sulfur oxides cannot be added to the flue-gas stream to improve efficiency of particulate-control equipment.

Sulfur oxides. Max allowable emission rate, effective 6/30/75 [6/30/78] from all Type (a) fuel-burning units at one plant in Priority I and II regions is calculated by multiplying 2.7 [2] by the sum of design heat inputs, in 10^6 Btu/hr, of all sources at the plant. The 6/30/78 regulation also limits total SO_2 discharges from the plant to 45,000 lb/hr. In the Kanawha Valley AQCR, the multiplier is now 1.6, with 45,000 lb/hr discharge limit. For all Priority III regions except Kanawha Valley, a 3.2 multiplier is applicable from 6/30/75 to 6/30/78, when it drops to 2.0, with max discharge from a plant of 45,000 lb/hr of SO_2.

Max allowable emission rate, effective 6/30/75 [6/30/78], from all Type (b) and (c) fuel-burning units at one plant in Priority I and II regions is calculated by multiplying 3.1 [2.3] by the sum of the design heat inputs, in 10^6 Btu/hr, at the plant. The 6/30/78 regulation also limits total SO_2 discharges from the plant to 8000 lb/hr. In the Kanawha Valley AQCR, the multiplier is 1.6 now, with a 5500-lb/hr discharge limit. For all Priority III regions except Kanawha Valley, a 3.2 multiplier is applicable from 6/30/75 to 6/30/78, when it drops to 2.3, with a max discharge limit from a plant of 8000 lb/hr of SO_2.

Nitrogen oxides. No source emission standards are stated in the regulations.

Wisconsin

Dept of Natural Resources, Air Pollution Control Section, P O Box 450, Madison, WI 53701.

Particulates. All installations not over 250 × 10^6 Btu/hr heat input, with construction or modification starting after 4/1/72, are limited to 0.15 lb/10^6 Btu heat input to any stack; this range of size in the SE Wisconsin Intrastate AQCR is not allowed to burn coal. For installations over 250 × 10^6 Btu/hr with construction or modification start after 4/1/72, limit is 0.10 lb/10^6 Btu heat input to any stack.

For installations with construction or modification start before 4/1/72, the limit for all installations is determined by use of Fig. 2 of ASME Std No. APS-1, with max emission irrespective of stack height being 0.60 lb/10^6 Btu heat input to any stack. By 7/31/75, installations in subregion 1 of the Lake Michigan Intrastate AQCR must meet a limit determined in same way, but with max emission irrespective of stack height being 0.30 lb/10^6 Btu heat input to any stack.

In the SE Wisconsin Intrastate AQCR, installations must also meet, by 7/31/75, limits of 0.15 lb/10^6 Btu heat input to any stack; installations in that AQCR not exceeding 250 × 10^6 Btu/hr are not allowed to burn coal.

Sulfur oxides. Max emission rate of new or modified installations (on which construction began after 3/31/72) is 0.8 [1.2] lb SO_2/10^6 Btu heat input for liquid [solid] fuels. In the SE Wisconsin Intrastate AQCR, standby fuel is limited to 1.5% sulfur by weight (as fired) for coal, 1.0% for residual oil and 0.7% for distillate oil.

Nitrogen oxides. New or modified installations (on which construction began after 3/31/72) rated 250 × 10^6 Btu/hr heat input or more cannot emit more than 0.2 (gaseous fuels), 0.3 (liquid) or 0.7 (solid) lb NO_x (expressed as NO_2)/10^6 Btu heat input.

Wyoming

Div of Air Quality, Dept of Environmental Quality, State Office Bldg West, Cheyenne, WY 82002.

Particulates. Maximum allowable emission rate from existing (under construction or in operation as of 2/22/72) fuel-burning equipment rated 1 × 10^6 to 10 × 10^6 Btu/hr heat input is 0.6 lb/10^6 Btu; 10,000 × 10^6 and above, 0.18. Allowable emissions for unit ratings between the capacities noted above can be found by plotting a curve on log-log paper with the data given. Use the ordinate for maximum emissions in lb/10^6 Btu of heat input and the abscissa for heat input in 10^6 Btu/hr. Maximum allowable emission rate from new sources is 0.1 lb/10^6 Btu heat input (max 2-hr avg). Heat input is the aggregate heat content of all fuels whose products of combustion pass through a stack or stacks. The heat-input value used is the equipment manufacturer's or designer's guaranteed maximum input, whichever is greater. The total heat input of all fuel-burning units at a plant or on premises is used for determining the maximum allowable amount of particulate matter which may be emitted. The amount of particulate matter emitted is measured by a source test method approved by the state and consistent with Section 60.85, Appendix, Method 5, *Federal Register*, Vol 36, No. 247, 12/23/71.

Sulfur oxides. The following was proposed in 1974 and may be approved by 4/75. For new sources, begun since 1/1/74, coal-[oil-]fired equipment is limited to 0.2 [0.8] lb/10^6 Btu heat input for units of 250 × 10^6 Btu/hr or more. For existing coal-burning sources with individual-unit heat input between 250 × 10^6 and 750 × 10^6 Btu/hr, limit is 1.2 lb/10^6 Btu heat input. For individual coal-burning units between 750 × 10^6 and 5000 × 10^6 Btu/hr, the limit is 0.5 lb/10^6 Btu. For individual coal-burning units with heat input of 5000 × 10^6 Btu/hr or more, the limit is 0.3 lb/10^6 Btu.

Prior to approval of these standards, the only ones are for ambient air: 0.02 ppm SO_x annual arithmetic mean; 0.1 ppm SO_x max 24-hr concentration, not to be exceeded more than once a year; 0.5 ppm SO_x max 3-hr concentration, not to be exceeded more than once a year.

Nitrogen oxides. Emission is measured by method described in App, Method 7, *Federal Register*, Vol 36, No. 159, 8/17/71 or equivalent method and is calculated as NO_2. Limit for new [existing on 2/22/72] gas-fired equipment is 0.20 [0.23] lb/10^6 Btu heat input. Limit for new oil-fired equipment with heat input of 10^6 Btu/hr or more is 0.30 lb/10^6 Btu; for smaller new oil-fired equipment, 0.60. Limit for existing oil-fired equipment with heat input of 250 × 10^6 Btu/hr or more is 0.46 lb/10^6 Btu heat input; for smaller existing oil-fired equipment, 0.60. Limit for new [existing] solid-fossil-fuel-fired equipment (except that burning lignite) is 0.70 [0.75] lb/10^6 Btu heat input. Internal-combustion engines with less than 200 × 10^6 Btu/hr input are exempt from these NO_x emission requirements.

MR. TENNANT: Mr. Chairman, I believe the Clean Air Act also requires that this be done.

CHAIRMAN DOUGLASS: I hate to cut this discussion off, but again it isn't germane to the regulation at the present time. Again, you will not find my views too adverse. I think we need to look and evaluate this at some future date. Are there any -- you have any further comments, or do you have any comments particularly to this? None? Okay, we thank you.

(Witness stands aside.)

CHAIRMAN DOUGLASS: Next we'll call upon Mr. Robert W. Reeves, American Electric Power Company.

(Witness sworn.)

THEREUPON

ROBERT W. REEVES

appearing in behalf of American Electric Power Service Corporation, having been first duly sworn to tell the truth, testified as follows:

MR. REEVES: Before I make my statement, I would like to have Mr. David Flannery, our counsel for the company, make a comment regarding some previous statements.

(Witness stands aside.)

CHAIRMAN DOUGLASS: Do you need to be sworn, Mr. Flannery?

MR. DAVID FLANNERY: I intend to present no evidence, Mr. Chairman, and for that reason, I'm not sure it would be necessary for me to be sworn, but if you'd like me to, I'd be glad to do so.

CHAIRMAN DOUGLASS: Just in order that it can be considered, if you wouldn't mind being sworn.

MR. FLANNERY: I'd be glad to do so.

(Witness sworn.)

THEREUPON

D A V I D M. F L A N N E R Y

appearing in behalf of American Electric Power Service Corporation, having been first duly sworn to tell the truth, testified as follows:

CHAIRMAN DOUGLASS: Proceed.

MR. FLANNERY: Mr. Chairman, your statement a moment ago raised some concern in our minds about the statement which Mr. Reeves is prepared to present inasmuch as his testimony will deal very extensively with this

Commission's 10 percent opacity requirement which is now applicable to the utility boilers. His statement presents considerable evidence that this Commission has never heard about that opacity standard and how it impacts on the operation of American Electric and its subsidiaries in West Virginia.

We prepared that statement after reviewing the regulation because the regulation appeared to us to open up this issue, and let me explain. In your Section 11, it makes it very clear that this regulation is intended to supersede entirely the previous version of Regulation II that was in effect. At least the Commission in its action today will endorse that 10 percent opacity standard if it does nothing else.

So my point is that we don't want to be out of order and yet your regulation suggests that we may be in order by commenting on 10 percent opacity. You've suggested we may file a petition with you and consider that issue later, and if the Commission is disposed to consider it in a later hearing, we certainly will be prepared to file this petition and proceed. Let me remind the Commission that we have already done so in that we filed a petition in either 1974 or 1975 to have this issue raised and the petition was not entertained by the Commission. And this hearing is the first time since Regulation II was amended in 1971 that it has been considered by the Commission for further amendments, with the very minor exception of that one change for the sulphur trioxide gas situation."

Now so for that reason, we would ask the Commission to allow Mr. Reeves to go ahead and present his statement on opacity, and if the Chair rules that out of order, we'd appreciate it if you'd note our objection and allow us to vouch the record by offering Mr. Reeves' statement as a written summission and we certainly will be prepared to file a petition to have this issue raised at a more appropriate hearing. I think it would be appropriate, Mr. Chairman, for some ruling on that before Mr. Reeves proceeds with his testimony.

CHAIRMAN DOUGLASS: Of course, Mr. Flannery, the regulation upon the books now will be superseded, and I don't understand your statement in reference to Section 11, because the amendments we have proposed would be the new regulation. You say you consider we've opened it up and superseded the regulations.

MR. FLANNERY: The language that you've suggested in Section 11, Mr. Chairman, says to me, as a legal matter, that whatever appears in Regulation II (1974) will not exist any longer and that if one wants to know what the law is in West Virginia with respect to emissions from power plants, one need only look at Regulation II (1978), assuming that's ultimately adopted by the Commission. That being the case, the 10 percent opacity requirement is as much in the '78 regulation as it is in the '74 regulation.

MR. BEARD: Mr. Chairman, could I comment?

CHAIRMAN DOUGLASS: Mr. Beard.

MR. BEARD: On the face of it, the regulation -- in the hearing notice on the face of the regulation, the front page, "Public hearings will be held concerning proposed amendments to the West Virginia Air Pollution Control Commission's Regulation II..." Now the regulation that Mr. Flannery is so concerned about, the original regulation has 10 percent opacity and has been approved by EPA. It's part of West Virginia's SIP. Anything that you do today will still have to be approved by EPA. It was not our intent for either Mon Power or AEP -- there is no language in here concerned with power plants. We're talking about industrial fuel boilers.

Now these people are trying to raise an issue that's not an issue. They have petitioned you before and you've denied them. I think that this is not the forum or not the time.

CHAIRMAN DOUGLASS: Be at ease a moment.

(WHEREUPON, a discussion was held off the record.)

CHAIRMAN DOUGLASS: The hearing will come back to order, please.

At this time, the Chair will recognize legal counsel, Larry Kopelman. Mr. Kopelman.

MR. KOPELMAN: Mr. Chairman, as a result of Mr. Flannery's comments, I'd like to point out and try to clarify as best I can what the intent of the notice that was published in the paper was, the intent of the notice that was published on the front of these proposed amendments to each regulation. The intent of the Commission as for these hearings was to consider proposed amendments to each regulation and not the regulation in toto. The Section 11 language which is an addition, as indicated by the underlines in the proposed amendments, is also proposed language. I would suggest that that language is in error. I would suggest that the regulations are not being repromulgated in toto but the Commission is considering only the amendments to each regulation that were proposed and those proposed changes are, deletions are struck and additions are underlined in the proposed regulations that were noted and submitted for public approval and public comment.

If the Chair chooses to go further at this time to listen to and take testimony on any topic, it's their choice, if the Commission would so choose. If you would choose to consider Regulation II or any regulation in toto at some later date, that is again your choice. But I would suggest that the Chair make it perfectly clear that there was a technical error in Section 11, that the entire regulation is not being repromulgated, that the amendments to the regulation are, of course, for specific consideration today and not the entire regulation.

CHAIRMAN DOUGLASS: Thank you, Mr. Kopelman, and the Chair rules in this fashion, that I would consider it not within the powers of this Commission at this time to consider amendments other than what is underlined. As a technical point, we can also look at Section 11, and it is underlined, and this could be struck by the

Commission and, therefore, bring us into compliance with the comments that we have made in view of the questions or technicalities that have been raised here.

So in view of this, and the Commissioners have discussed the question that has already been raised by Mr. Tennant and which you alluded that Mr. Reeves would, also, point his comments, that the Commission will obligate itself to a hearing on this topic hopefully early next year, or no later than mid-summer, and the only reason for setting it back at this late a date is the fact that we must get the implementation plan and some other technicalities out of the way. Once the Commission's schedule is changed, the Commissioners have obligated themselves here to meet, which I, as their spokesman, say that we will hold a hearing on this topic.

MR. FLANNERY: Thank you. Well, Mr. Chairman, may I interpret that remark in the context with the remarks that you made earlier, that you would desire those who have an interest in this development to file a petition requesting the Commission to amend it, or does the Commission intend to move on its own to set that hearing?

CHAIRMAN DOUGLASS: My commitment is, and the

Commissioners' [illegible] is, we will move on our [illegible] this time in view of the testimony and comments of Mr. Tennant and yourself. So, therefore, the comments of Mr. Reeves, if they are in this direction, would not be germane really to this hearing.

MR. FLANNERY: Mr. Chairman, will you allow Mr. Reeves' comments to be lodged in the record for whatever benefit they may be in a later review of this record:

CHAIRMAN DOUGLASS: I have no objections.

Yes, Mr. Beard.

MR. BEARD: Mr. Chairman, the Commission realizes that there are a number of pieces of control equipment that are presently on line that you've got an outstanding order against one plant of Mon Power and another is on a consent order, and you're going to hear this sometime late summer? You're going to make a change in this thing? I stand amazed.

MR. FLANNERY: Mr. Chairman, let me assure the Commission that at least on behalf of AEP that our petition will relate to the opacity standards, and the company already has installed in all but one plant and will have installed in the remaining plant by July 1, 1979, control equipment to achieve compliance with the .05 pounds emission limitation, so that nothing that the Commission will today I'm sure will affect those kinds of commitments. We're talking about the possibility of the Commission's opacity requirements imposing yet further requirements for control technology on our operations, and again at an appropriate time, we'll discuss that. By no means is the company going to call off its plans for commitments amounting to in excess of $400 million for control equipment in West Virginia just to comply with this regulation. That money is substantially spent.

Thank you.

MR. BEARD: Mr. Chairman.

CHAIRMAN DOUGLASS: Mr. Beard.

MR. BEARD: Are you opening this thing up? Then you'll have to take in VEPCO, too, to just the opacity limitations? Is this the matter of discussion at some future hearing at some future date?

CHAIRMAN DOUGLASS: This is my understanding and this is the question that has been raised.

MR. FLANNERY: Mr. Chairman, I'm here representing Appalachian and Ohio Power, and our objections will go to opacity. Other speakers have objected to other portions of it, and I don't mean my remarks to bind them.

MR. BEARD: What's the Chair's ruling then?

CHAIRMAN DOUGLASS: I'll look at the Commissioners and see if I get any dissent. Okay, the Commissioners say opacity would be what we would look at.

MR. BEARD: Okay, we'll drag forth our expert witnesses, too, and we'll have a full-blown hearing sometime at a future date.

CHAIRMAN DOUGLASS: All right.

MR. FLANNERY: Thank you, Mr. Chairman.

CHAIRMAN DOUGLASS: Good enough.

(Witness stands aside.)

CHAIRMAN DOUGLASS: At this time, then we will call upon Mr. James Christie, Grafton Coal Company. Mr. Christie.

(Witness sworn.)

THEREUPON

J A M E S R. C H R I S T I E

appearing in behalf of Grafton Coal Company, having been first duly sworn to tell the truth, testified as follows:

MR. CHRISTIE: I feel kind of strange coming up here after the lengthy proceeding we just had because my comments were going to be directed again towards particulates and standards.

Because of what has happened, I will reserve those comments for a later time.

I would like to say, though, that Grafton Coal Company is not a utility. We don't work for the utilities, and we do have an interest in the standard itself of .05, and I would like to request that the Commission, during the hearing on Regulation II, will also look into the matter of the standard itself. I have reasons for asking this because of what has happened in particular in the last month to the coal industry as a result of orders the power companies' standards are setting on ash and et cetera, and the .05 to the coal industry is important. So we feel that besides the opacity being examined, we would also like for the standard of .05 be examined.

CHAIRMAN DOUGLASS: Inasmuch as you are endeavoring to open this regulation up even further, in order to get this formally before the Commissioners, since they have not ruled on it, if you would desire to file a letter with the Commission with this request, we can consider it. They would make that decision whether they would open it up further.

MR. CHRISTIE: Okay, it is very important to the coal industry, and I believe to the ratepayers, especially northcentral West Virginia who are affected by the higher cost of coal, low ash, or precipitator, in the event Monongahela Power elects to do so.

CHAIRMAN DOUGLASS: Okay, are there questions? Mr. Christie, excuse me, I didn't mean -- I'm not cutting you off. Do you have further comments?

MR. CHRISTIE: No, I have no further comments. Thank you.

CHAIRMAN DOUGLASS: Okay, are there any questions or comments from any of the Commissioners? There appears to be none. Thank you, sir.

(Witness stands aside.)

CHAIRMAN DOUGLASS: Next we'll call upon Mr. Richard A. Porter, West Virginia University, Morgantown.

(Witness sworn.)

THEREUPON

R I C H A R D A. P O R T E R

Exhibit 3

MONONGAHELA POWER COMPANY
ESP DESIGN AND MAINTENANCE

Unit	Generating Capacity (MW)	Manuf.	Inst. Date	SCA (1)	Avg. Gas Velocity	Residence Time	Design Flow	Rapper Controls	AVC (2)	Plate Spacers	Misc.	Capital Cost (3)
Alb. 1	70	Buell	1975	397	3.5 ft/s	8.6 sec.	375,000 acfm @ 360° F	mid 1970's	1909			$1,820,369.78
Alb. 2	76	Buell	1075	397	3.5 ft/s	8.6 sec.	375,000 acfm @ 360° F	mid 1070's	1090			$1,804,011.89
Alb. 3	140	Buell	1075	397	4.1 ft/s	8.8 sec.	675,000 acfm @ 305° F	1991	1900		plate & wire mod 1909 chemical additive test '88	$2,001,570.09
Fm. 1		UOP	1007	100	N/A	N/A	N/A	1080	1091	1st field '90 2nd field '92		
Fm. 2		UOP	1060	100	N/A	N/A	N/A	1909	1991	1st field '92		
Fm. 1	552	Delco	1081	237	5.48 ft/s	7.12 sec.	2,000,000 acfm @310° F	1002	1002			$16,090,734.35
Fm. 2	555	Delco	1082	237	5.48 ft/s	7.12 sec.	2,000,000 acfm @310° F	1082	1082			$17,328,487.49
Har. 1	640	Am. Std.	1072	180	5.0 ft/s	4.0 sec.	2,070,000 acfm @ 270° F	early 1070's	1993			$2,907,008.41
Har. 2	640	Am. Std.	1073	180	5.0 ft/s	4.0 sec.	2,079,000 acfm @ 270° F	early 1070's	1093			$2,915,336.40
Har. 3	640	Am. Std.	1974	180	5.0 ft/s	4.0 sec.	2,070,000 acfm @ 270° F	early 1070's	1993	1st field 1992		$3,294,257.08
Pl. 1	623	UOP	1978	311	5.4 ft/s	6.7 sec.	2,400,000 acfm @ 270° F	1989-1992	1992	comp. 1991	collecting plate repair 1998 wire & support insulators replaced '88	$11,510,510.25
Pl. 2	623	UOP	1980	311	5.4 ft/s	6.7 sec.	2,400,000 acfm @ 270° F	1989-1990	1992	3rd & 4th fields/1992 2B 2nd field 1990 2A & 2B 1st field '89 2A & 2B	collecting plate repair 1988 wire & support insulators replaced '88	$11,061,035.72
Riv. 5	48	Buell	1075	307	4.2 ft/s	13.3 sec.	300,000 acfm @ 430° F	1075	N/A	N/A	chemical additive test 05	$1,407,012.87
Riv. 6	93	Buell	1075	307	3.8 ft/s	13.2 sec.	525,000 acfm @ 430° F	1075	N/A	N/A	N/A	$1,860,384.02
Wl 1	55	Buell	1075	365	N/A	12.8 sec.	320,000 acfm @ 500°F	1993	early 00's			$2,021,420.69
Wl 2	188	Buell	1078	365	N/A	12.4 sec.	1,100,000 acfm @ 850°F	1992	early 00's		structural & insulation replacements 1998	$4,013,322.30

1. SCA - specific collection area = ft^2 plate area per 1000 acfm gas flow.
2. AVC - Automatic Voltage Controls.
3. Cost includes installation & capital improvements but excludes fly ash handling.

5/26/04 - YFC/dls

DRAFT 6/1/94

45 CSR 2

TITLE 45
LEGISLATIVE RULES
~~AIR POLLUTION CONTROL COMMISSION~~
DIVISION OF ENVIRONMENTAL PROTECTION

SERIES 2
REGULATIONS
TO PREVENT AND CONTROL PARTICULATE AIR
POLLUTION FROM COMBUSTION OF FUEL IN INDIRECT HEAT EXCHANGERS

§45-2-1. General.

1.1 Scope. --Series 2 establishes emission limitations for smoke and particulate matter which are discharged from fuel burning units.

1.2 Authority. --W.Va. Code ~~§16-20-5~~ §§22-5-1 et seq.

1.3 Filing Date. -- ~~July 31, 1974~~

1.4 Effective Date. -- ~~September 1, 1974~~

§45-2-2. Definitions.

2.1. "Air Pollution", 'statutory air pollution', shall have the meaning ascribed to it in ~~Section Two of Chapter Sixteen, Article Twenty of the Code of West Virginia, as amended.~~ W.Va. Code §22-5-2.

2.2. "Air Pollutants" shall mean solids, liquids, or gases which, if discharged into the air, may result in a statutory air pollution.

~~2.3. "Commission" shall mean the West Virginia Air Pollution Control Commission.~~

2.3 ~~2.4~~. "Director" shall mean the director of the West Virginia ~~Air Pollution Control Commission.~~ Division of Environmental Protection.

2.4 ~~2.5~~. "Person" shall mean any and all persons, natural or artificial, including the state of West Virginia or any other state, the United States of America, any municipal, statutory, public or private corporation organized or existing under the laws of this or any other state or country, and any firm, partnership, or association of whatever nature.

2.5 ~~2.6~~. "Fuel Burning Unit" shall mean and include any furnace, boiler apparatus, device, mechanism, stack, or structure used in the process of burning fuel or other combustible material for the primary purpose of producing heat or power by indirect heat transfer. For the purpose of this regulation, all fuel burning units are classified in the following categories:

(a) Type 'a' shall mean any fuel burning unit which has as its primary purpose the generation of steam or other vapor to produce electric power for sale.

(b) Type 'b' shall mean any fuel burning unit not classified as a Type 'a' or Type 'c' unit such as industrial pulverized-fuel-fired furnaces, cyclone furnaces, gas-fired and liquid-fuel-fired units.

(c) Type 'c' shall mean any hand-fired or stoker-fired burning unit not classified as a Type 'a' unit.

2.6 ~~2.7~~ "Similar Unit(s)" shall mean all Type 'a', or all Type 'b', or all Type 'c' fuel burning units located at one plant.

2.7 ~~2.8~~. "Fuel" shall mean any form of combustible matter (solid, liquid, vapor, or gas) that is used as a source of heat.

2.8 ~~2.9~~. "Particulate Matter" shall mean any material except uncombined water that exists in a finely divided form as a liquid or solid.

2.9 ~~2.10~~. "Smoke" shall mean small gasborne and airborne particulate matter arising from a process of combustion in sufficient number to be visible.

2.10 ~~2.11~~. "Ringelmann Smoke Chart" shall be the Ringelmann's Scale for Grading the Density of Smoke published by the United States Bureau of Mines, or any chart, recorder, indicator, procedure or device which is a standardized method for the measurement of smoke density which is approved by the Director ~~Commission~~ as the equivalent of said Ringelmann's Scale.

2.11 ~~2.12~~. "Plant" shall mean and include all fuel burning units, source operations, equipment, and grounds utilized in an integral complex.

2.12 ~~2.13~~. "Fugitive Particulate Matter" shall mean any and all particulate matter generated by any operation involving or associated with the combustion of fuel in fuel burning units which, if not confined, would be emitted directly into the open air from points other than a stack outlet.

2.13 ~~2.14~~. "Fugitive Particulate Control System" shall mean any equipment or method used to confine, collect, or dispose of fugitive particulate matter, including, but not limited to, hoods, bins, duct work, fans, and air pollution control equipment.

<u>2.14</u> ~~2.15~~. "Air Pollution Control Equipment" shall mean any equipment used for collecting or confining particulate matter for the purpose of preventing or reducing the emission of this air pollutant into the open air.

<u>2.15</u> ~~2.16~~. "Stack", for the purposes of this regulation, shall mean, but not be limited to, any duct, control equipment exhaust, or similar apparatus, which vents gases and/or particulate matter into the open air.

~~2.15 2.17. "Kanawha Valley Air Basin" shall mean that area starting at the junction of the Gauley and New Rivers and terminating at the center of the Winfield Locks and extending a distance of three (3) statute miles, measured horizontally, with no reference to terrain, on each side of the center line of the Kanawha River.~~

§45-2-3. Emissions of smoke and/or particulate matter prohibited and standards of measurement.

3.1. Visible emission requirements for fuel burning units ~~not meeting the requirements of Section 4, Weight Emission Standards~~.

No person shall cause, suffer, allow, or permit emission of smoke into the open air from any fuel burning unit which is ~~in excess of the Ringelmann limitations specified in the following tables for the designated areas and time periods: (See Table 45.2A at the end of this regulation.)~~ <u>darker in shade or appearance than No. 1 Ringelmann or twenty (20) percent opacity (6-minute average), except for one 6-minute period per hour of not more than twenty-seven (27) percent opacity. This requirement shall not apply to units utilizing flue-gas desulfurization [FGD] equipment. Neither shall this requirement apply when condensate forms in the stack itself as the result of changed operating conditions such as with multiple unit stacks when one or more units are not in service.</u>

3.2. The provisions of Sub-Section 3.1 of this section shall not apply to smoke emitted during the cleaning of a fire box or soot blowing the shade or appearance of which is less than ~~the~~ <u>No. 2</u> Ringelmann <u>or forty (40) percent opacity</u> ~~number specified in the following table,~~ for ~~a period or periods aggregating~~ no more than <u>five six minute periods (which may or may not be consecutive)</u> per fuel burning unit in any eight (8)-hour period~~:~~<u>.</u> ~~Sub-Sections Ringelmann Number~~

~~3.1(a) 3~~
~~3.1(b) and (c) 2~~

~~3.3. Visible emission requirements for fuel burning units that meet the requirements of Section 4, Weight Emission Standards.~~

~~No person shall cause, suffer, allow, or permit emission of smoke into the open air from any fuel burning unit which is darker in shade or appearance than 0.5 Ringelmann or ten (10) percent opacity.~~

~~3.4. The provisions of Sub-Section 3.3 shall not apply to smoke emitted during the cleaning of a fire box or soot blowing the shade or appearance of which is less than No. 1 Ringelmann or twenty (20) percent opacity for a period or periods aggregating no more than eight (8) minutes per fuel burning unit for any eight (8) hour period.~~

3.3 ~~3.5~~ During periods of start-up and shut-down of a fuel burning unit, the visible emission requirements of Sub-section 3.1 of this section shall not apply. ~~Realizing that with present technology the provisions of this section may, in some cases, be too restrictive to be applied to the building of a new fire in a fuel burning unit, the Commission may, upon specific application by the owner and/or operator of a fuel burning unit(s), grant exemptions to these provisions. However, in no case shall these exemptions exceed the limitations set forth in the following table: (See Table 45-2B at the end of this regulation.)~~

~~If such an exemption to the provisions of this section is desired, an application in writing shall be made to the Director. From time to time the Commission shall review such exemptions to determine if they are still warranted. If the Commission revises or terminates an exemption the owner and/or operator of the affected fuel burning unit(s) shall be notified by certified mail. Such revisions or terminations shall not become effective for at least ninety (90) days after the receipt of notification by the owner and/or operator.~~

3.4 Compliance with the visible emission requirements of Sub-Section 3.1 of this section shall be determined in accordance with 40 CFR Part 60, Appendix A, Method 9 unless the source elects to determine compliance in accordance with continuous opacity monitoring devices approved by the Director. Should continuous opacity monitoring devices be utilized, the owner or operator shall be in compliance with the visible emission requirements of Sub-Section 3.1 at least 95% of the time that the source is required to operate its continuous opacity monitor. If continuous opacity monitoring is utilized to determine compliance, it must be operated at all times (other than during maintenance activities on the continuous opacity monitoring device) that the fuel burning unit is in operation.

3.5 Notwithstanding any other provision of this regulation the owner and/or operator of a fuel burning unit(s) may petition the Director to make appropriate adjustment to the visible emission requirement of Sub-Section 3.1.

The Director will grant such a petition upon a demonstration by the owner and/or operator of such unit(s), that:

1. such unit(s) have been tested and been found to comply with the requirements of Section 4 Weight Emission Standards;

2. at the time of such test(s) such unit(s) and associated air pollution control equipment was operated and maintained in a manner to minimize the visibility of emissions;

3. such test(s) were performed under conditions established or approved by the Director; and

4. at the time of such test(s) such unit(s) and associated air pollution control equipment were incapable of being adjusted while operating at full load to meet the applicable visible emission requirement.

On the basis of such a demonstration, the Director will establish a visible emission requirement for such unit(s) at a level at which such unit(s) will be able to meet the visible emission requirement at all times during which the source is meeting the requirements of Section 4, Weight Emission Standards.

§45-2-4. Weight emission standards.

4.1.(a) No person shall cause, suffer, allow, or permit the discharge of particulate matter into the open air from all fuel burning units located at one plant, measured in terms of pounds per hour in excess of the amount determined as follows:

(1) For Type 'a' fuel burning units, the product of 0.05 and the total design heat inputs for such units in million British Thermal Units (B.T.U.'s) per hour, provided however that no more than twelve hundred (1200) pounds per hour of particulate matter shall be discharged into the open air from all such units;

(2) For Type 'b' fuel burning units, the product of 0.09 and the total design heat inputs from such units in million B.T.U.'s per hour, provided however that no more than six hundred (600) pounds per hour of particulate matter shall be discharged into the open air from all such units; and

(3) For Type 'c' fuel burning units, in excess of the values listed in the following table, provided however that no more than three hundred (300) pounds per hour of particulate matter shall be

discharged into the open air from all such units. ~~(See Table 45.2C at the end of this regulation.)~~
~~TABLE 45-2C~~

~~TABLE FOR TYPE 'C' UNITS~~

Total Design Heat Input for All Type 'c' Fuel Burning Units Located at One Plant in Millions of B.T.U.'s Per Hour	Total Allowable Particulate Matter Emission Rate for All Type 'c' Fuel Burning Units Located at One Plant in Pounds Per Hour
10	3.4
20	5.6
40	9.0
60	11.7
80	14.4
100	16.6
200	26.4
400	42.2
600	54.0
3,333	300.0

For values between any two corresponding consecutive values listed in this table, linear interpolation is to be used for both columns.

(b) Subject to the provisions of this regulation, allowable emission rates for individual stacks shall be determined by the owner and/or operator and registered with the Director ~~Commission~~ at the request of, and on forms provided by, the Director. Such rates shall be subject to review and approval by the Director.

The approved set of individual stack allowable emission rates shall become an official part of the compliance schedule and/or any permits concerning such source(s), and shall not be changed without the prior written approval of the Director.

(c) If the number of fuel burning units, located at one plant, each of which is meeting the requirements of this regulation, is expanded by the addition of new unit(s), the total allowable emission rate for the new unit(s) shall be determined by the following formula. However, the maximum allowable emission rates given in Sub-section 4.1(a) are not to be exceeded.

$$R_e = \left(1 - \left(\frac{H_{et} - R_{et}}{H_{et}}\right)\right) H_e$$

Where, R_e is the total allowable emission rate in pounds per hour for the new fuel burning unit(s);

H_{et} is the total design heat input in million B.T.U.'s per hour of the existing and new similar units;

R_{et} is the total allowable emission rate in pounds per hour corresponding to H_{et}; and

H_e is the total design heat input in million B.T.U.'s per hour for the new fuel burning unit(s).

4.2. Addition of sulfur oxides to combustion unit exist gas stream. No person shall cause, suffer, allow, or permit the addition of sulfur oxides to a combustion unit exit gas stream for the purpose of improving control equipment efficiency. Such action shall constitute a violation of this regulation.

4.3. The provisions of Sub-Section 4.2 of this section shall not apply to combustion units in existence ~~operation~~ on ~~the effective date of this regulation,~~ September 1, 1974, or to any other unit that may be approved by the Director.

4.4. The Director may establish an alternative emission standard to that set forth in Sub-section 4.1 of this section upon demonstration by the owner or operator of a fuel burning unit that any such alternative emission standard will assure the attainment and maintenance of National Ambient Air Quality Standards for particulate matter, satisfy all other requirements of law and be no greater than the product of 0.10 and the actual heat input for such unit in million British Thermal Units (B.T.U.'s) per hour.

4.5. During periods of start-up and shut-down of a fuel burning unit, the emission requirements of Sub-section 4.1 shall not apply.

§45-2-5. Control of fugitive particulate matter.

5.1. No person shall cause, suffer, allow, or permit any source of fugitive particulate matter to operate that is not equipped with a fugitive particulate matter control system. This system shall be operated and maintained in such a manner as to minimize the emission of fugitive particulate matter. Sources of fugitive particulate matter associated with fuel burning units shall include, but not be limited to, the following:

(a) Stockpiling of ash or fuel either in the open or in enclosures such as silos;

(b) Transport of ash in vehicles or on conveying systems, to include spillage, tracking, or blowing of particulate matter from or by such vehicles or equipment; and

(c) Ash or fuel systems and ash disposal areas.

§45-2-6. Registration.

6.1. ~~Within thirty (30) days after the effective date of this regulation~~ Aall persons owning and/or operating ~~existing~~ fuel burning units in existence on September 1, 1974 not previously registered shall have registered such units with the Director ~~Commission~~. The information required for registration shall be determined and provided in the manner specified by the Director. Registration forms should be requested from the Director by the owner and/or operator of fuel burning unit(s) subject to the provisions of this section.

6.2. The owner and/or operator of fuel burning units that were ~~are~~ under construction or on which construction was ~~is~~ initiated as of October 1, 1974 not previously registered ~~within thirty (30) days after the effective date of this regulation~~ shall have registered such fuel burning units with the Director. ~~within this thirty (30) day period.~~

§45-2-7. Permits

7.1 After September 1, 1974 ~~the effective date of this regulation~~, no person shall construct or modify any fuel burning unit without first obtaining a permit for such construction or modification. Applications for permits shall be made upon forms available from the Director and ~~shall be filed not less than ninety (90) days prior to the construction or modification. These forms~~ shall include such information as in the judgment of the Director will enable him or her to determine whether such source(s) will be so designed as to operate in conformance with the provisions of this regulation and other applicable regulations, the Code of West Virginia, and will not cause or contribute to the violation of Ambient ~~Secondary~~ Air Quality Standards. ~~Within ninety (90) days of the receipt of an application the Director shall issue or deny such permit in accordance with the provisions of Section Two of Chapter Sixteen, Article Twenty, Paragraph 11b of the Code of West Virginia, as amended.~~

§45-2-8. Reports and testing.

8.1. At such reasonable times as the Director may designate, the owner or operator of any fuel burning unit(s) may be required to conduct or have conducted tests to determine the compliance of such unit(s) with the emission limitations of Section 4. Such tests shall be conducted in accordance with EPA Method 5B for facilities with wet FGD systems or EPA Methods 5 or 17 for facilities without wet FGD systems, or such other test method as may be approved by the Director. The Director, or his duly authorized representative, may at his option witness or conduct such tests. Should the Director exercise his option to conduct such tests, the operator will provide all the necessary sampling connections and sampling ports to be located in such manner as the

Director may require, power for test equipment, and the required safety equipment such as scaffolding, railings, and ladders to comply with generally accepted good safety practices.

~~Within a reasonable tolerance, the individual samples for such emission tests shall be extracted isokinetically, with the probe and filter media maintained at, or about, stack temperatures. Individual measurements shall be made at each of the various extraction points throughout the sampling plane in a manner that yields a composite sample and a distribution of measurements which are representative of the total stack gas flow and pollutant concentrations during the test.~~

~~The primary particulate sample collector shall be a pre-conditioned, fiberglass mat filter, certified as being at least ninety-nine (99) percent efficient in collecting 0.3 micron DOP (Dioctyl Phthalate) smoke, or a filter of equivalent properties and efficiency. The filter used shall be pre-weighed to at least one-tenth (0.1) of a milligram.~~

~~The total sample weight shall include both the particulate collected by the filter and the particulate obtained by appropriate cleaning of all devices preceding this filter in the sampling train. The total sample weight shall be determined to the nearest one-tenth (0.1) of a milligram.~~

Sufficient information on temperatures, velocities, pressures, weights and dimensional values shall be reported to the Director, with such necessary commentary as he may require to allow an accurate evaluation of the reported test results and the conditions under which they were obtained.

8.2. The Director, or his duly authorized representative, may conduct such other tests as he may deem necessary to evaluate air pollution emissions other than those noted in Sub-Section 4.1.

8.3. The operators of fuel burning units shall submit data on operating schedules and the quality of fuel used in such units. Such data shall be reported in the manner the Director may specify, and will include, but not necessarily be limited to, information such as the number of start-ups and shut-downs, the quantity of fuel burned, and the ash, sulfur, moisture, volatile matter, and B.T.U. content.

8.4 Within a reasonable time after ~~prior to~~ the start-up or shut-down of a fuel burning unit(s), the owner and/or operator of such unit(s) shall notify the Director of the ~~proposed~~ start-up or shut-down. ~~If such prior notification is not practicable (e.g., if emergency conditions require prompt action, or if the requirement for the start-up and the start-up itself must necessarily occur, in time, outside the Commission's normal working hours) notification should be made within a reasonable time thereafter.~~ This requirement will be deemed to have been satisfied with respect to any unit for which approved continuous opacity monitoring data, including start-up and shut-down dates, are submitted to the Director no less frequently than on a calendar quarter basis.

8.5. The Director ~~Commission~~ may publish, and from time to time revise, detailed test procedures and reporting instructions implementing the provisions of this section.

~~§45-2-9. Compliance programs and schedules.~~

~~9.1. In the event that a fuel burning unit(s) in existence prior to the adoption of this regulation does not meet the emission limitations, an acceptable program to fully comply with the regulation shall be developed and offered to the Commission by the person responsible for the plant. This program shall be submitted upon the request of, and within such time as shall be fixed by, the Commission. Once this program has been approved by the Commission, the owner and/or operator of such installation shall not be in violation of this regulation so long as the approved or amended program is observed. Compliance programs, schedules, and variances that have previously been issued by the Commission under Series 2 (1972) shall remain in effect until the expiration date of that compliance program, schedule, or variance.~~

~~9.2. In the event that an owner or operator of such a fuel burning unit(s) fails to submit a program or an acceptable program and schedule, the Commission shall, by order, determine the compliance program and schedule.~~

§45-2-~~10~~9. Variance.

~~10.1.~~ Due to unavoidable malfunction of equipment, emissions exceeding those provided for in this regulation may be permitted by the Director for periods not to exceed ten (10) days upon specific application to the Director. Such application shall be made within twenty-four (24) hours of the malfunction. In cases of major equipment failure, additional time periods may be granted by the Director ~~Commission~~ provided a corrective program has been submitted by the owner or operator and approved by the Director ~~Commission~~.

~~10.2. For the purpose of preventing possible equipment damage during the start-up or shut-down of a fuel burning unit(s), emissions exceeding those provided for in this regulation may be permitted by the Director for periods not to exceed twenty-four (24) hours, upon specific application to the Director no less than twenty-four (24) hours prior to the start-up operation.~~

§45-2-10. Exemptions.

~~All fuel burning units having a heat input under ten (10) million B.T.U.'s per hour will be exempt from Sections 4 through 8 9. However, failure to attain acceptable air quality in parts of some urban areas may require the mandatory control of these sources at a later date.~~

~~TABLE 45-2A~~

~~(a) From March 15, 1972, until September 1, 1972, smoke which is as dark or darker than:~~

~~Areas of State~~	~~Installation Date of Fuel Burning Unit~~	~~Ringelmann Limitations On Fuel Burning Units~~
~~Kanawha Valley~~	~~Before April 4, 1966~~	~~2~~
~~Air Basin~~	~~After April 4, 1966~~	~~1~~
~~All Other~~	~~No Limitations~~	

~~(b) From September 1, 1972, until June 30, 1975, smoke which is as dark as or darker than:~~

~~Areas of State~~	~~Ringelmann Limitation on Fuel Burning Units~~
~~All~~	~~1~~

~~(c) After June 30, 1975, smoke which is darker than:~~

~~Areas of State~~	~~Ringelmann Limitations On Fuel Burning Units~~
~~All~~	~~0.5~~

~~TABLE 45-2B~~

~~Type of Fuel Burning Unit~~	~~Exemptions Allowed for No More than Two (2) Hours Per Start-up Operation Shall Not be as Dark or Darker in Shade or Appearance As:~~
~~Type 'a' and~~	~~No. 2 Ringelmann~~
~~Type 'b'~~	
~~Type 'c'~~	~~(1) For forty-five (45) minutes No. 3 Ringelmann~~
	~~(2) For the remaining seventy-five (75) minutes No. 2 Ringelmann~~

45CSR2

TO PREVENT AND CONTROL PARTICULATE AIR POLLUTION FROM COMBUSTION OF FUEL IN INDIRECT HEAT EXCHANGERS

RESPONSE TO COMMENTS

At the public hearing on proposed revisions to 45CSR2 conducted on November 29, 1994, oral comments were received from six people in attendance. Written comments/information were submitted on behalf of the West Virginia Manufacturers Association and several of its individual members that had filed the original petition for regulatory changes. The petition and its supporting documentation was made a part of the formal rule-making record. Three of the six oral commenters spoke in opposition to the proposed rule revisions including former Air Pollution Control Commission Director Carl G. Beard. Mr. David White provided oral and written comments. A letter opposing the proposed rule changes was also submitted by the Ohio Valley Environmental Coalition.

The DEP (OAQ) staff has summarized those comments provided to the proposed rule revisions and has provided responses as follows. It should also be noted that OAQ staff completed an extensive review of agency files for those facilities operating coal-fired boilers that are subject to 45CSR2 during the period immediately following the November 29, 1994, public hearing. This review was conducted to obtain an overall view of the level of compliance or non-compliance with the existing opacity standards of 45CSR2 over an extended period of time reflected in office files for those facilities primarily affected by the current rule. One year of data from continuous opacity monitoring at several Title IV Phase I utility plants were also analyzed to determine the extent of non-compliance with current opacity standards.

1. Response to Oral Comments by former APCC Director Carl Beard

Carl Beard questioned the necessity for any of the proposed changes to 45CSR2 but was particularly concerned by the proposed doubling of the opacity standards and proposed revision allowing the DEP Director to approve a relaxation of the mass emission standards for a specific boiler to a level up to 0.10 pounds of particulate per million Btu's of heat input without rule-making. Mr. Beard, as the former Director of the APCC during the period in which 45CSR2 was originally enacted, emphasized that 45CSR2 was largely responsible for the dramatic clean up of the severe ambient particulate problems in West Virginia particularly in the Kanawha Valley.

Mr. Beard provided some history concerning the development and implementation of the existing version of 45CSR2 and provided comments to the effect that the proposed rule changes would result in higher emissions of respirable particulate matter possibly contaminated with sulphates. He also noted that West Virginia has the worst meteorological conditions in the eastern United States with respect to dispersion of air pollution with frequent air stagnation periods and temperature inversions leading to poor ventilation. Mr. Beard criticized the emphasis on conformance with generic EPA emission standards such as the federal NSPS.

RESPONSE: The OAQ staff takes no exceptions to Mr. Beard's comments overall and recognizes that the current version of 45CSR2 was developed as the key emission control element in West Virginia's early 1970's plan to abate serious ambient particulate matter air quality problems in the Kanawha Valley and other industrialized areas of the state.

OAQ recognizes that an actual degradation of the performance of existing boilers and particulate control equipment as a result of the enactment of less restrictive opacity standards could adversely affect air quality since opacity is believed to be a good indicator of small particle density in industrial boiler discharges. Although the effect of the proposed opacity standard relaxation to 20 percent in 45CSR2 cannot be quantified, potential adverse impacts upon air quality including visibility may result from the poorer operation of boilers effected by relaxation of visible emission standards. Accordingly, DEP has modified the proposed visible emissions revisions to retain the existing opacity standard but has provided a mechanism for the DEP Director to approve plant or boiler-specific exceptions to the opacity standard up to a level of 20 percent (six-minute average) based upon certain demonstrations by the plant or boiler owner/operator. Having reconsidered this matter and the basis for establishing 45CSR2, DEP believes that it is extremely important to maintain, to the extent possible, the integrity of the current particulate matter emissions control program. West Virginia has attained and maintained compliance with the National Ambient Air Quality Standards for particulate matter in all areas of West Virginia except small areas in the immediate vicinity of the large steel manufacturing plants in Weirton and Follansbee and strongly desires to maintain this achievement. A review of agency records and one year of continuous opacity monitoring data collected by five West Virginia utilities has indicated that most facilities regulated under 45CSR2 have complied with the 10 percent opacity standard a very high percentage of the time or when inspected and performance tested. Continuous opacity monitoring (COM) data, however, indicate that compliance with the 10 percent opacity standard is not demonstrated 100 percent of the time at any facility and that an enforcement policy specific to COM should be considered by the DEP.

In recognition of some of the long-term issues raised concerning boiler compliance during facility start-ups, shut-downs, and malfunctions, other proposed revisions to 45CSR2 have been retained or modified as further explained.

2. Comments by David White and Responses

David White spoke in opposition to the proposed rule revisions. His primary points are characterized with responses as follows:

(a) COMMENT: The visible emission standards of 45CSR2 are a separate and independent standard from the weight emission standards.

RESPONSE: OAQ fully agrees with this point although this is one area where the agency and USEPA somewhat differ with respect to the importance of opacity standards as a compliance measure for boilers.

(b) COMMENT: The opacity standard relaxation will result in higher emissions of small, light-scattering, and respirable particulate matter.

RESPONSE: With respect to potential emission changes, this comment is correct, however, the affected companies argue that the effect of the proposed rule changes will only maintain the actual status quo and at the same time relieve them of enforcement liability for some allegedly unavoidable exceedances of the opacity standards that have been occurring for many years. Due to agency concerns for potential air quality deterioration, the agency has redrafted the revisions to largely retain the 10 percent opacity standard as explained previously.

(c) COMMENT: The opacity standard should not be relaxed because existing health-based National Ambient Air Quality Standards are already compromised or are violated.

RESPONSE: As previously stated, ambient air quality measurements for particulate matter at all monitoring sites in West Virginia except those in Weirton have shown attainment with the National Ambient Air Quality Standards for many years. Ambient particulate matter concentrations in the Weirton and Follansbee areas exceeding the national standards are believed to result not only from the operation of boilers (subject to 45CSR2) in the area but from the very large and concentrated steel producing operations at Weirton and Follansbee, West Virginia, and Steubenville, Ohio. Plans to further reduce particulate emissions in Follansbee and Steubenville have already been formulated and largely implemented, and DEP should conclude extensive particulate matter studies in Weirton during 1995 to determine the nature and extent of necessary further regulatory requirements in that area. The largest boilers operated by Weirton Steel Corporation in Weirton and subject to 45CSR2 are coal-fired high-pressure units using wet scrubbers for particulate matter emissions control. Use of an opacity standard as a means of controlling particulate matter emissions from a scrubber system is much more limiting and ineffective than such application to a more typical unit with a dry collector such as an electrostatic precipitator. Notwithstanding these considerations, the proposed revisions to 45CSR2 have been modified to retain the 10 percent opacity standard unless a case-by-case review by the Director justifies a relaxation. Such a relaxation would not be applicable or permissible to a unit affecting a particulate non-attainment area under the terms of the modified language.

(d) COMMENT: Small particulate emissions will often be better limited by an opacity standard than a mass emissions standard.

RESPONSE: OAQ agrees that a stringent opacity standard may be a much more effective regulatory limit for very small particulate matter on a continuous basis than a mass emission standard.

3. <u>Comments by Wendy Radcliff, Environmental Advocate, and Response</u>

Wendy Radcliff expressed concern about the proposed regulatory revisions noting the particular problems with air stagnation in West Virginia and high numbers of large coal-fired electric utility plants. She, like Mr. Beard, noted that generic national regulations may not have good application for West Virginia.

RESPONSE: See the prior responses to Carl Beard's comments.

4. <u>Written Comments from the Ohio Valley Environmental Coalition (OVEC) and Responses</u>

COMMENT: OVEC stated its opposition to the weakening of the current regulation and submitted a copy of a study report by Joel Shwartz and Douglas Dockery which showed a reportedly high correlation between particulate (TSP) air concentrations and mortality.

RESPONSE: These written comments and attached study were incorporated into the record and are considered as supportive of the DEP's reconsideration and modification of the proposed rule revisions.

5. <u>Comments from the West Virginia Manufacturers and Petitioners and Responses</u>

The agency provides the following response to the comments of the West Virginia Manufacturers Association along with the comments of several of its individual members. Responding section by section:

<u>Section 1.6.</u> - Several commenters stated that the proposed rules are more stringent than the federal regulations and gave some examples. The agency responds that there is no federal counterpart regulation to 45CSR2; however, even if there were, the State is justified in being more stringent (<u>See</u> "Determination of Stringency" filed with this rule).

<u>Section 2</u> - The agency agrees with the comments on this section. The rule has been so modified, along with several other corrections the agency has made.

<u>Section 3.1.</u> - Several comments supported the proposed language which changed the existing opacity standard from ten (10) percent to twenty (20) percent. (Several other commenters disagreed with the agency's proposed change -- see previous discussion above).

After careful consideration of all the comments, the agency has decided to retain the existing ten (10) percent standard as the presumptively applicable standard, but allow an alternative standard to be established on a case-by-case basis.

The agency finds there is justification from a human health standpoint to retain the State's current opacity standard and further finds it desirable to maintain the State's current high quality of ambient air for particulate matter, from both an environmental and an economic standpoint. There may, however, be some limited instances where a deviation from the ten (10) percent opacity is justifiable and necessary, thus the new language allowing an alternative standard to be established, upon a satisfactory demonstration to the Director.

Several other commenters requested an exception be added to Section 3.1. for wet flue-gas desulfurization equipment and for the instance when condensate forms in the stack. The agency disagrees with the need for such language, since EPA's Method 9 (being incorporated as an Appendix to the rule) addresses these situations with regard to determining compliance by stack observation. Language has been added to the rule to clarify that continuous opacity monitoring equipment will not be required on units which employ wet scrubbing systems.

<u>Section 3.2.</u> - Several commenters requested the agency to include language providing for an enforcement policy for those sources utilizing continuous opacity monitors. The agency will conduct a technical review to determine if such a policy is appropriate or necessary in light of the language allowing an alternate opacity standard and has modified the proposed rule to give the Director the discretionary authority to establish such a policy, as well as the authority to require the installation of continuous opacity monitoring systems.

<u>Section 3.3.</u> - Several commenters suggested change to this section, which relates to soot blowing operations. The agency disagrees with the suggestion that formal approval of an alternative standard for soot blowing is inappropriate. Considering that the rule will allow up to forty (40) percent opacity during such events, compared to the existing standard of twenty (20) percent opacity, the requirement for approval by the Director is justifiable. It should be noted that the soot blowing allowances could be established for each plant on a one-time basis.

The agency does agree, however, with the comments suggesting that the eight (8) minute period be replaced with a twelve (12) minute period per an eight (8) hour period.

<u>Section 4.1.(a).</u> - The agency agrees with the comments regarding the appropriate cross-reference to the Table in the Appendix.

<u>Section 4.2.</u> - The agency agrees with the comments suggesting that the "grandfather clause" in the existing regulation be retained.

<u>Section 4.4.</u> - Several commenters supported the proposed language allowing alternative weight emission standards to be established. Upon further consideration, however, the Director believes that the existing weight emission standards should be retained and that there should be no variances to this standard. This position is based upon a desire to maintain existing high air quality and a belief that relaxed weight emission standards are unnecessary from a technological and/or economic standpoint.

Section 8.4. - The agency agrees with the comment that the method of notification for start-ups and shut-downs should be specified and has provided such language.

The agency disagrees with the comment that the results of continuous opacity monitoring should be submitted on a quarterly basis, instead of a monthly basis. The agency believes monthly notification is necessary to allow the agency adequate oversight and control of start-up and shut-down events. Monthly fuel quality reports have been required for more than 20 years.

Section 9.1. - Several commenters stated that not only should a facility be exempted from opacity standards during start-ups, shut-downs, and malfunctions, but facilities should also be exempted from the weight emission standards during such events.

The agency disagrees with this comment. With respect to start-ups and shut-downs, the agency believes the opacity standard should not apply during such events, provided that start-up and shut-down operations by a source are not excessive. (See language in Section 9.1.). However, the agency does not believe that exemption from weight emission standards is necessary or appropriate during start-ups and shut-downs. The weight emission standards are calculated on a maximum allowable design basis, which means the standards should be achieved during start-up and shut-down events.

With respect to malfunctions, however, the agency believes that a malfunction, if demonstrated satisfactorily, may constitute an affirmative defense to an enforcement action brought for noncompliance with the weight emission standards of Section 4 of the rule. Language to this effect has been added to the rule in Section 9.5.

Section 9.3. - The agency agrees with the comment that a specific reference to Sections 3 and 4 should be contained in this section, and such change has been made.

Section 10 - See previous discussion under Section 9.1. In light of the new language in section 9.5, the variance provisions in the current rule are unnecessary.

Section 11 - Several commenters suggested that the existing exemption for boilers with a heat input under ten (10) million BTU's be changed to exempt boilers with a heat input under 250 million BTU's. The agency disagrees with this suggestion, since it would allow many large sources of particulate matter and visible emissions to operate without any standards and would render the State's SIP unapprovable by USEPA.

Appendix - 4.1.a. - The comment suggested that the agency reference the federal language instead of retaining the language from the existing rule. The agency believes it is necessary to retain the existing language since the original rule specified that particulate mass emissions from each individual stack would be characterized and defined "at or about" stack temperature. Allowing gas reheat at a scrubber outlet to 250°F better conforms to the original intent than allowing reheat to 320°F. Section 4.1. has been slightly amended to clarify that federal method 5B may be used as modified by 4.1.a.

Appendix - The other comments suggested that provisions be added to allow alternative testing methods approved by the Director. The agency does not believe such language is necessary since the current language in Section 6 of the Appendix provides for some minor exceptions to be made.

MISCELLANEOUS

The agency notes for the record that on January 26, 1995, it met with several of the persons who had provided comments during the public comment period on this rule. The purpose of the meeting was to further explore some of the issues and facts which had been previously raised during the public comment period; the purpose of the meeting was not to consider any new issues relating to 45CSR2.