Final Determination
and Permit Conditions

North Broward County Resource Recovery Facility

Broward County, Florida

PSD-FL-112

Prevention of Significant Deterioration

(40 CFR 52.21)

June 26, 1987

CONTENTS

I. INTRODUCTION

Pursuant to Section 403.505, Florida Statutes, North Broward Resource Recovery Project, Inc. (County), applied to the Florida Department of Environmental Regulation (DER) in February 1986 for certification of a steam electric generating, solid waste energy recovery facility at 2700 Hilton Road in unicorporated Broward County, Florida. After a thorough review by DER, including public hearings, the Florida Power Plant Siting Board issued a site certification to the County. At the time of its application to DER, the County also filed a separate application for the project with the United States Environmental Protection Agency (EPA) under Part C, Subpart 1, of the Clean Air Act.

In the summer of 1985, EPA became aware that the Florida Electrical Power Plant Siting Act (PPSA), under which the site certification was issued, restricts the authority of the State of Florida to implement any regulation (i.e., PSD Regulations) pertaining to power plants other than those in the Act. Consequently, EPA determined that the Florida PSD regulations were superseded by the PPSA, and that the PPSA could not legally be approved by EPA as part of the State Implementation Plan (SIP) since it did not comply with EPA PSD regulations both procedurally and substantively. Thus, EPA concluded that the proposed North Broward County Resource Recovery Facility (RRF) could not be issued a valid PSD permit by FDER. Nor could the PPSA certification substitute for a valid PSD permit. EPA subsequently remanded PSD authority for sources subject to the PPSA while delegating responsibility for the technical and administrative portions of the PSD review to the FDER. The following final determination and permit constitute EPA's final action as well as the culmination of those activities delegated to the FDER by EPA.

The applicant plans to construct a 2200 tons per day (TPD) solid waste-to-energy facility to be located at 2700 Hilton Road in unincorporated Broward County, Florida. Municipal solid waste (MSW) will be combusted to produce steam for power generation. The present plans are to construct four 550 TPD MSW incinerators. An ultimate maximum capacity of 3300 TPD is anticipated in the future which will require the addition of a fifth and sixth incinerator. The County will need to submit an application to construct the fifth and sixth units at a future date. The applicant requests that each unit be permitted at 110% of its rated capacity. At 110% capacity, each of the four energy recovery units will have an approximate heat input of 226.9 million Btu per hour based on a heat content of 4500 Btu/lb for MSW. Each incinerator will be allowed to operate 8760 hours per year. The yearly tonnage of the various air pollutants emitted were calculated on this basis.

II. RULE APPLICABILITY

The proposed site of the North Broward County RRF is located within a nonattainment area for ozone. This designation requires that all proposed new sources which would emit greater than 100 tons per year (TPY) of volatile organic compound (VOC) be subject to nonattainment review. As the proposed incineration facility is projected to emit less than 100 TPY of VOC, the proposed source is not subject to a nonattainment review.

The source is subject to the regulations for PSD of air quality under 40 CFR 52.21 regarding the assessment of source emissions in attainment or unclassified areas. Since this source is within the category of stationary sources listed under the PSD regulations which specifies the threshold of emissions for PSD applicability as 100 TPY or greater of any regulated pollutant, the source must provide a Best Available Control Technology (BACT) determination, an ambient air quality analysis, a source impact analysis and an additional impact analysis (soils, vegetation, visibility) for each pollutant emitted in significant amounts. These include: particulate matter (PM), sulfur dioxide (SO_2), carbon monoxide (CO), nitrogen oxides (NO_x), lead (Pb), mercury (Hg), fluorides (as hydrogen fluoride, HF), and sulfuric acid mist. In addition to the above, a Class I area impact analysis is required because the source is to be located within 100 kilometers of the Everglades National Park.

New Source Performance Standards (NSPS) for incinerators under 40 CFR 60, subpart E, and Standards of Performance for Industrial-Commercial-Institutional Steam Generating under 40 CFR 60, subpart Db, apply to each unit within the proposed facility. These NSPS set emission standards for a broad category of sources and limit the maximum amounts of PM and NO_x which may be emitted from any facility subject to these regulations.

III. PSD APPLICABILITY DETERMINATION

Title 40 Code of Federal Regulations, Section 52.21 requires that each pollutant subject to PSD review must be controlled by BACT. Nine pollutants are subject to BACT. The BACT emission limits proposed are summarized as follows:

Pollutant	BACT EMISSION LIMITS
Particulate Matter	0.015 gr/dscf, corrected to 12% CO_2
Sulfur Dioxide	0.140 lbs/mmBtu or 65% removal (not to exceed 0.310 lb/mmBtu)
Nitrogen Oxides	0.560 lb/mmBtu
Carbon Monoxide	0.090 lb/mmBtu
Lead	0.00056 lb/mmBtu
Mercury	7.50×10^{-4} lb/mmBtu
Beryllium	9.30×10^{-7} lb/mmBtu
Fluorides	0.0040 lb/mmBtu
Sulfuric Acid Mist	90% removal (not to exceed 4.70×10^{-3} lb/mmBtu)

These emission limitations are based on the determination that BACT is control of acid gas emissions and a high degree of particulate emissions reduction.

Based upon these air pollutant emission limits, the calculated total annual tonnage of regulated air pollutants emitted from the units to the atmosphere is listed as follows:

Pollutant		Maximum Annual Emissions (tons/year)	PSD Significant Emissions Rate (tons/year)
Particulate	(PM)	128	25
Sulfur Dioxide	(SO_2)	1233	40
Nitrogen Dioxide	(NO)	2227	40
Carbon Monoxide	(CO)	358	100
Lead	(Pb)	2.23	0.6
Mercury	(Hg)	2.98	0.1
Beryllium	(Be)	0.0037	0.0004
Fluorides	(F)	15.91	3
Sulfuric Acid Mist	(H_2SO_4)	18.7	7

IV. BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

A. Particulate Matter

New Source performance standards for incinerators limit particulate emissions from these units to 0.08 grains per dry standard cubic foot (gr/dscf) based on a 12% flue gas concentration of carbon dioxide. NSPS for industrial-commercial-institutional steam generating units limit particulate emissions from these units to 0.10 lb/mmBtu or approximately 0.05 gr/dscf. However, BACT clearinghouse reports incinerators emission limits to be from 0.01 to 0.03 gr/dscf.

In making the BACT determination, an emissions limit was selected to ensure that hazardous yet unregulated pollutants are controlled in accordance with the North County, California, incinerator PSD remand. The control of dioxins, furans, other condensible organics, and heavy metals is hypothesized to occur due to their condensation and adsorption on particulate matter. As the collective surface area of fine particulate matter is greater than that of larger particles per mass unit and fine particulate matter consists of a significant portion of the total particulate matter, control equipment should be selected which ensures a high degree of control for fine particulates. EPA has agreed that the use of an electrostatic precipitator (ESP) can provide this high degree of control and the limit which was determined to be BACT is 0.015 gr/dscf. This results in an approximate increase in ESP annualized costs of $178,200 per year over the originally proposed emission limit of 0.02 gr/dscf, or an overall cost of $348 per ton of particulate removed. However, the applicant may install either an ESP or baghouse to meet this limitation.

Energy impacts are considered to be insignificantly affected by the increase in removal efficiency, and environmental benefit due to decreased emissions of unregulated hazardous pollutants is not assessable at this time.

B. Sulfur Dioxide

The emissions of sulfur dioxide from municipal solid waste incinerators depend on three factors. These factors are: the sulfur content of the waste, the conversion of organic and inorganic sulfur compounds to sulfur dioxide, and the retention of the sulfur dioxide in the ash. This final determination assumes that all combined sulfur is converted and none is retained in the ash.

The applicant has reported the sulfur content of the waste to be 0.19 wt% maximum and 0.12 wt% average. This results in SO_2 emission rates of 7.6 to 4.8 lb/ton of MSW fired, or, at 4500 Btu/lb, 0.840 to 0.530 lb/mmBtu, respectively. Taking into account the selection of acid gas control devices (explained under acid gas BACT), the resultant emissions of sulfur dioxide

should be reduced by at least 65%. The emissions limit stipulated as BACT in the permit is 0.140 lb/mmBtu or a 65% reduction of sulfur dioxide emissions, not to exceed 0.310 lb/mmBtu. This limit was based on the emissions limits at other facilities and the variability of fuel sulfur content. Economic and environmental considerations are included under the acid gas BACT section.

C.   Acid Gases

Acid gases consist primarily of sulfuric acid mist, hydrogen fluoride, and the unregulated pollutant hydrogen chloride. BACT for acid gas control was selected based on the North County, Caliornia, remand which allows the consideration of unregulated pollutants in the assessment of BACT for regulated pollutants. The selection of 90% acid gas control includes the reduction of hydrogen chloride emissions in the economic analysis and the apparent reduction of condensible unregulated organic emissions (i.e., dioxins, furans) and heavy metals, due to the gas cooling effects of the acid gas control system proposed, in the environmental benefit analysis.

Sulfuric acid mist is generated as a result of the oxidation of sulfur dioxide to sulfur trioxide in the flue gas. Combination of sulfur trioxide and water results in the formation of sulfuric acid mists. The uncontrolled emissions of this pollutant are estimated to be as high as 187 TPY. BACT of 90% control of these emissions results in an emissions reduction of 168 TPY.

Hydrogen fluoride is created through the combustion of waste materials containing fluorine. Although the reported emissions of hydrogen fluoride vary greatly at existing facilities, the emissions have been reported to be as high as 0.02 lb/mmBtu. However, the applicant predicts an uncontrolled emission rate of 0.04 lb/mmBtu or 159 TPY at this facility. A 90% control efficiency for this pollutant results in the control of 143 TPY based on the agreed emission rate of 0.004 lb/mmBtu and is considered BACT.

The formation of hydrogen chloride emissions is due primarily to the combustion of plastics containing chlorine. It is assumed that the plastic content of municipal solid waste is 4.2 wt%, of which 11.2 wt% is PVC resin in plastics. Using the weight percent of chlorine in PVC (45.3 wt%), the expected uncontrolled emissions from this facility are 0.47 lb/mmBtu or 1869 tons per year. Acid gas control will provide control of 90% of these emissions of hydrogen chloride or 1682 TPY.

In assessing the economic impacts, 224 TPY of sulfur dioxide, 168 TPY of sulfuric acid mist, 143 TPY of hydrogen fluoride, and 1682 TPY of hydrogen chloride were used in determining the cost effectiveness of acid gas control. EPA studies have estimated that the cost of acid gas control for this facility to be approximately $3,213,200 in annualized costs. This results in a cost of $1449 per ton of total pollutants (listed above) and is considered reasonable.

The environmental benefits due to application of acid gas control are the reduction of the flue gas temperature for the condensation of dioxins, furans, pyrenes, biphenyls, and mercury which may then be removed by a high efficiency particulate control device. Even though the formation of the toxic organic compounds may be primarily due to the design and operation of the combustion device, studies show that the use of acid gas control and high efficiency particulate removal equipment is capable of achieving a 99+% reduction of the compounds formed. No acceptable levels of exposure to these compounds have been established by EPA and EPA is therefore obligated to ensure the public a minimal exposure to them.

D.   Nitrogen Oxides

During combustion of municipal solid waste, NO_x is formed in high temperature zones in and around the furnace flame by the oxidation of atmospheric nitrogen and nitrogen in the waste. The two primary variables that affect the formation of NO_x are the combustion temperatures and the concentration of oxygen. Techniques such as the method of fuel firing, correct distribution of combustion air between overfire and underfire air, exhaust gas recirculation, and decreased heat release rates have been used to reduce NO_x emission. A few add-on control techniques such as catalytic reduction with ammonia and thermal de-NO_x are still experimental and not considered to be demonstrated technology for the proposed project. State-of-the-art control of the combustion variables will be used to limit NO_x emissions at 0.54 lb/mmBtu. This level of control is judged to represent BACT.

NSPS for industrial-commercial-institutional steam generating units regulates nitrogen oxide emissions for this facility if auxiliary fuels exceed 10% of the fuel input. Permit limits have been stipulated to ensure that auxiliary fuel input at each of the units will be less than 10%.

E.   Carbon Monoxide

Incomplete combustion causes the emissions of solid carbon particles (e.g., smoke or soot) unburned and/or partially oxidized hydrocarbons and carbon monoxide, as well as resulting in the loss of heat energy. The applicant proposes that good equipment design and operation are BACT for carbon monoxide. Based on technical information relating good combustion practices and BACT determinations from other states, a limit of 0.090 lb/mmBtu is judged to represent BACT for carbon monoxide emissions.

F.   Lead

With respect to lead emissions, two conditions are needed to achieve high removal efficiencies of metallic compounds emitted at refuse burning facilities: (1) operation of particulate matter control equipment at temperatures below 500°F, and (2) consistently efficient removal of sub-micron fly ash particles. The maximum temperature of the incinerator com-bustion gases at the inlet to the particulate control device is estimated to be below 300°F. At this temperature the particulate control equipment would be capable of removing the lead emissions from the flue gas stream.

The emission limit judged to be reasonable for lead is based on test results at similar facilities and the degree of emission control that will be provided by the control equipment which has been determined to be BACT for this facility. In accordance with data contained in the California Air Resources Board (CARB) report on resource recovery facilities, the highest uncontrolled lead emission rate from refuse-fired incinerators tested is 0.037 lbs/mmBtu. Based on a heating value of 4500 Btu per pound of refuse and the control efficiency reported for lead emissions using the required BACT (scrubber and particulate control of 0.015 gr/dscf, corrected to 12% CO_2), an emission limitation of 0.00056 lb/mmBtu is judged to be BACT.

G.   Mercury

BACT is determined to be or 7.50×10^{-4} lb/mmBtu. This level of mercury emissions is judged to be reasonable based on test data from similar facilities and the degree of control that will be provided by the acid gas and particulate control equipment.

H.   Beryllium

The uncontrolled emission of beryllium, according to the California report, when firing MSW is estimated to be 6.2×10^{-6} lb/mmBtu. Uncontrolled beryllium emissions would be approximately 11 grams per 24 hours or 0.01 TPY. The operating temperature of the particulate matter emission control device will be below 300°F. Operation at this temperature will promote adsorption/ condensation of beryllium oxides, present in the flue gas stream, onto avail-able fly ash particulates for subsequent removal by the particulate control device. The annual beryllium emissions are estimated to be 0.004 TPY. This amount of beryllium emitted is considered to have a negligible impact on the environment. The emission limit of 9.3×10^{-7} lb/mmBtu is judged to be BACT.

V.   AIR QUALITY ANALYSIS

The air quality impact of the proposed facility has been analyzed. Atmospheric dispersion modeling has been completed and used in conjunction with an analysis of existing air quality data to determine maximum ground-level ambient concentrations of the criteria pollutants subject to BACT. Based on these analyses, EPA has reasonable assurance that the proposed solid waste recovery facility in South Broward County, subject to the BACT emission limitations, will not cause or contribute to a violation of any PSD increment or ambient air quality standard.

A.   Modeling Methodology

The EPA-approved Industrial Source Complex Short-Term (ISCST) dispersion model was used in the air quality impact analysis. This model determines ground-level concentrations of gaseous and solid pollutants emitted into the atmosphere by point, area, and volume sources. The model incorporates elements for plume rise, transport by the wind, gaussian dispersion, and pollutant removal mechanisms such as deposition or transformation. The ISCST model also allows for the separation of sources, building wake downwash, and various other input and output features. Both screening and refined analyses were completed using this model, the source parameters in Table V-1 and emission rates in Table V-2.

Table V-1

North Broward County Resource Recovery
Facility Source Parameters

Source (1)	UTM – E (km)	UTM – N (km)	Stack Height (M)	Exit Temp. (K)	Exit Velocity (M/S)	Stack Diameter (M)
Unit 1	583.6	2907.6	61.0	380	18.2 (2)	1.5
Unit 2	583.6	2907.6	61.0	380	18.2 (2)	1.5
Unit 3	583.6	2907.6	61.0	380	18.2 (2)	1.5
Unit 4	583.6	2907.6	61.0	380	18.2 (2)	1.5

(1) Four 605 TPD incinerators, each with a flue to a common stack. For modeling purposes the common stack was given a stack diameter of 3.0 m and an exit velocity of 18.2 m/s.

(2) Estimated by using a flow rate of 68,260 ACFM for each unit and calculated using given diameters.

Table V-2
North Broward County Resource Recovery Facility
Maximum Emission Rates[a]

Pollutant	(lb/ton)	(lb/MMBTU)	(PPM)	(lb/hr)	(ton/yr)
PM	0.29	0.032	---	29.2[b]	102
SO_2	2.8	0.31	124-60[c]	281	896[c]
NO_x	5.04	0.56	350[d]	508	1618
CO	0.81	0.090	e	262.5	260
VOC	0.12	0.013[f]	---	11.8	37.6
Pb	0.005	0.00056	---	0.51	2.23
F⁻	0.036	0.004	---	3.63	11.6
H_2SO_4 Mist[g]	0.042	0.0047	---	4.27	13.5
Be	8.4×10^{-6}	9.3×10^{-7}	---	0.00084	0.0027
Hg	0.00675	7.5×10^{-4}	---	0.68	2.2
As	2.8×10^{-4}	0.000031	---	0.028	0.090

a. Based on facility capacity of 907.6 MMBTU/hr firing 2420 TPD of MSW, which is 110 percent of nameplate capcity. Maximum emissions in lb/hr calculated based on maximum ppm level if applicable. Maximum tons per year based on 80 percent annual availability factor of nameplate capacity and maximum lb/hr emission rate except for NO_x and CO; these are based on maximum lb/MMBTU or lb/ton level.

b. Based on 0.015 gr/dscf corrected to 12% CO_2.

c. A maximum 3-hour rolling average corrected to 12% CO_2. A removal efticiency of 65% required. Actual tons per year will be between 890 and 431 depending on actual sulfur in MSW.

d. A maximum 3-hour rolling average corrected to 12% CO_2.

e. 400 ppm maximum 1-hour rolling average ppm and maximum 4-day rolling average of 88 ppm; corrected to 12% CO_2, dry.

f. Covered under nonattainment provisions for O_3 and not applicable for PSD review.

g. Operating practice to reduce SO_2 (see c).

Five years of sequential hourly meteorological data were used in the modeling analyses. Both the surface and the upper air data used were National Weather Service data collected at Miami, Florida, during the period 1970-1974. Since five years of data were used, the highest, second-high, short-term predicted concentrations are compared with the appropriate short-term ambient standard or PSD increment. The highest predicted concentration were used for comparison with long-term standards (annual).

The initial set of screening model runs determined the highest, second-high concentrations, over a polar coordinate receptor grid with 36 radials, 10 degrees apart, and 10 downwind distances from 0.3 km to 4.3 km. Concentrations are predicted for the initial capacity of the facility. Additional refined modeling was completed for those days having the highest, second high concentrations using a refined receptor grid of several radials, two degrees apart and at seven distances, 100 meters apart, centered on the location of the previously determined highest, second-high value. In all of these runs, only the proposed RRF was modeled.

All of the modeling was completed using the SO_2 emission rate of the proposed facility. The impacts of the other emitted pollutants were determined by ratioing the emission rates to the SO_2 emission rate and multiplying by the SO_2 impact. Total ambient air quality impacts were based on the modeled impacts plus the monitored "background" concentrations.

The impact of the proposed facility on the Everglades National Park Class I area was also evaluated. Modeling was completed placing receptors along the edge of the Class I area using five years of meteorological data. The 17 receptor locations were spaced two kilometers apart along the northeast boundary of the park.

B.   Analysis of Existing Air Quality

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review. In general, one year of quality assured data using EPA reference, or the equivalent monitor, must be submitted. Sometimes less than one year of data, but not less than four months, may be accepted when EPA approval is given. An exemption to the monitoring requirement can be obtained if the maximum air quality impact, as determined through air quality modeling, is less than a pollutant-specific de minimus concentration. In addition, if current monitoring data already exist and these data are representative of the proposed source area, then these data may be used at the discretion of the reviewing authority.

The predicted maximum air quality impacts of the proposed facility for those pollutants subject to PSD review are given in Table V-3. The monitoring de minimus level for each pollutant is also listed. Sulfuric acid mist and arsenic are not listed because there is no de minimus level for either of these pollutants. All pollutants have maximum predicted impacts below their respective de minimus values. Therfore, specific preconstruction monitoring is not required for any pollutant.

Table V-4 lists the measured ambient concentrations of all pollutants being currently monitored within 10 kilometers of the proposed facility. These values are used to estimate current background levels.

Table V-3

North Broward County Resource Recovery Facility
Maximum Air Quality Impacts
Compared to the De Minimis Ambient Levels

Pollutant and Averaging Time	Predicted Impact (ug/m^3)	De Minimus Ambient Impact Level (ug/m^3)
SO_2 (24-hour)	4.4	13
PM (24-hour)	0.46	10
NO_2 (Annual)	1.1	14
CO (8-hour)*	11.1	575
Pb (24-hour)	0.01	0.1 (quarterly)
F^- (24-hour)	0.06	0.25
Be (24-hour)	0.00001	0.0005
Hg (24-hour)	0.011	0.025

* Based on an assumed maximum of 400 ppm, 8-hour average.

Table V-4

North Broward County Resource Recovery
Facility Nearest Monitoring Station to
or Within 10 km of the RRF

Site	Location with Respect to the Proposed Facility Direction (degrees)	Distance (km)	Pollutant	Concentration 1984 Annual (ug/m^3)	24-hour (ug/m^3)	8-hour (ug/m^3)	1-hour (ug/m^3)
3700003	85	6.2	PM	36	63		
			Pb	0.2			
			(quarterly)				
3700002	14	6.1	PM	48	120		
2270001 (G01)	199	13.5	PM	38	76		
			NO$_2$	33			
			SO$_2$	3	6		
			CO			5	7
2270001 (G09)	199	13.5	PM	38	76		
			NO$_2$	34			
			SO$_2$	6	12		
0420003	267	12.4	O$_3$				202
3700004	170	7.5	CO			5	7
2560002	232	6.5	PM	29	59		
			Pb	0.1			
			(quarterly)				

C.   PSD Increment Analysis

The proposed Broward County RRF is to be located in a Class II area.
This area is designated as an attainment area for both SO_2 and PM. A
PSD increment analysis is therefore required to show compliance with the
Class II increments.

The PSD increments represent the amount that new sources in the area may
increase ambient ground-level concentrations of SO_2 and PM. At no time,
however, can the increased loading of these pollutants cause or contribute to
a violation of the ambient air quality standards.

All SO_2 and PM emission increases from sources constructed or modified
after the baseline date (December 1977) will consume PSD increment. In
addition, all SO_2 and PM emission increases associated with construction or
modification of major sources which occurred after January 6, 1975, will
consume increment. The proposed Broward County RRF is the only significant
source in the area which will consume PSD increment for either SO_2 or PM.

Atmospheric dispersion modeling, as previously described, was performed
to quantify the amount of PSD increment consumed. The results of this modeling
are summarized in Table V-5. The results indicate that the concentration
increases are within the allowable amounts.

A Class I area increment analysis is required because of the proposed
facility is located within 100 kilometers (57 km) of the Everglades National
Park, a designated Class I area. Although the distance to the Class I area
is greater than 50 kilometers (the distance to which the models are generally
considered valid), the applicant used the model to estimate the impact on
this area. The results indicate a less than significant impact.

D.   AAQS Analysis

Given existing air quality in the area of the proposed facility, emissions
from the new facility are not expected to cause or contribute to a violation
of an AAQS. Table V-6 shows the results of the AAQS analysis.

The results showed that, with the exception of SO_2 and lead, the maximum
impacts of the other criteria pollutants were less than the significant impact
levels defined in 40 CFR 52.21. As such, no further modeling analysis was
completed for PM, NO_x, and CO. For SO_2, additional modeling was performed
which included the interaction of surrounding sources of SO_2. For lead, there
is no significant impact level defined in the regulation. However, no further
modeling of lead was completed because the predominate sources of ambient lead
in the area are mobile sources.

Table V-5

North Broward County Resource Recovery Facility
Comparison of New Source Impacts with PSD Increments

Pollutant and Averaging Time	PSD Class II Analysis			PSD Class I Analysis		
	PSD Class II Increment (ug/m^3)	Predicted Increased Concentration (ug/m^3)	Percent Increment Consumed	PSD Class I Increment (ug/m^3)	Predicted Increased Concentration (ug/m^3)	Percent Increment Consumed
SO_2*						
3-hour	512	17.6	3	25	2	8
24-hour	91	4.4	5	5	0.3	6
Annual	20	<1	<5	2	<<1	<<1
PM						
24-hour	37	<1	<3	10	<1	<1
Annual	19	<<1	<<5	5	<<1	<<1

*Based on a maximum emission of 281 lb/hr; actual emissions would likely be much lower based on 65% SO_2 removal efficiency.

Table V-6

North Broward County Resource Recovery Facility
Comparison of Total Impact with the AAQS

Pollutant and Averaging Time	Maximum Impact Project (ug/m^3)	Maximum Impact (1) All Sources (ug/m^3)	Existing Background (2) (ug/m^3)	Maximum Total Impact (ug/m^3)	Florida AAQS (ug/m^3)
SO_2					
3-hour	18	332	27 (3)	359	1300
24-hour	4	92	12	104	260
Annual	<1 (4)	–	6	–	60
PM					
24-hour	<1 (4)	–	120	–	150
Annual	<<1 (4)	–	48	–	60
NO_2					
Annual	1 (4)	–	34	–	100
CO					
1-hour	39 (4)	–	7,000	–	40,000
8-hour	10 (4)	–	5,000	–	10,000
Pb					
3-months	<0.1	–	0.2	–	1.5

(1) Maximum impact includes the FPL Port Everglades and Fort Lauderdale power plants and minor sources within 10 km of proposed facility.

(2) Existing background is estimated using the highest monitored concentrations in the area near the proposed facility.

(3) The 3-hour background is estimated by multiplying the 24-hour background by 2.25.

(4) Less than significant, no further analysis completed. For CO, analysis based on 400 ppm, 8-hour average.

The total impact on ambient air is obtained by adding a "background" concentration to the maximum modeled concentration. This "background" concentration takes into account all sources of the particular pollutant in question that were not explicitly modeled. A conservative estimate of these "background" concentrations was made by using the highest monitored concentration for each pollutant as listed in Table V-4. This is a conservative estimate because sources used in the modeling may have contributed to the monitored value.

Based on this analysis, EPA has resonable assurance that no AAQS will be exceeded as a result of the operation of the proposed new resource recovery facility.

VI. ADDITIONAL IMPACTS ANALYSIS

A. Impacts on Soils and Vegetation

The maximum ground-level concentrations predicted to occur as a result of emissions from the proposed project in conjunction with all other sources, including background concentrations, will be at or below all applicable AAQS including the secondary standards designed to protect public welfare-related values. As such, these pollutants are not expected to have a harmful impact on soils and vegetation.

A summary of the types and quantities of soils and vegetation in and around the proposed RRF site area and in the Everglades National Park can be found in the Site Certification Application. The applicant has also compared predicted maximum impacts with known adverse impact levels for both criteria and noncriteria pollutants. No adverse impacts are expected.

B. Impact on Visibility

A level I visibility screening analysis was performed to determine if any impact may occur in the Class I area. The analysis showed that there was no potential for an adverse impact on visibility in this area.

C. Growth-Related Air Quality Impacts

The proposed facility is not expected to significantly change employment, population, housing, or commercial/industrial development in the area to the extent that a significant air quality impact will result.

D. GEP Stack Height Determination

Good Engineering Practice (GEP) Stack height is defined as the greater of: (1) 65 meters or (2) the maximum nearby building height plus 1.5 times the building height or width, whichever is less. For the proposed project, a single common stack, housing the individual flues for each incinerator, will be 61.0 meters high. This is below the allowed GEP stack height of 65 meters.

E. Noncriteria Pollutants

The proposed facility emits in significant amounts (as defined in the PSD regulations): fluorides, sulfuric acid mist, beryllium, mercury, and arsenic. All of these pollutants are regulated, but there is no ambient air quality standards or PSD increments set for any of them. For three of these pollutants--fluorides, beryllium, and mercury--a de minimus ambient impact level has been defined. Exceedance of these levels, usually determined by dispersion modeling, is used to determine if ambient monitoring is necessary. The results of this modeling for these pollutants is listed in Table V-3. For each of these three pollutants, the predicted impact is less than their respective de minimus impact level.

F.   Unregulated Pollutants

Two additional pollutants are often brought up in the context of resource recovery facilities. These are hydrogen chloride (HCl) and dioxins (2, 3, 7, 8-TCDD). Neither is currently regulated within the PSD regulations. Hydrogen chloride is regulated nationally for other type sources but not specifically for resource recovery facilities. Some states do regulate both of these substances. Both of these substances may become regulated either nationally or by the State in the future. The recommended control equipment necessary for the facility to meet the BACT emissions limitations for the regulated pollutants will also control HCl and dioxins.

VII. FINAL PERMIT

PART I. - Specific Conditions

1. Emission Limitations

    a. Stack emissions from each unit shall not exceed the following:

Particulate: 0.0150 gr/dscf dry volume corrected to 12% CO_2.

Sulfur Dioxide: (1) 0.140 lb/mmBtu heat input and 60 ppm (3-hr rolling average, dry volume, corrected to 12% CO_2); or

    (2) 65% reduction of uncontrolled SO_2 emissions.* In no case shall the SO_2 emissions exceed 0.310 lb/mmBtu heat input and 124 ppm (3-hr rolling average, dry volume, corrected to 12% CO_2).

The 124 ppm limit above shall be modified to reflect a new emission limit (in ppm) from the control device at 65% control efficiency. Within 18 months of start-up of operation, the County shall submit compliance tests that will be used to determine the new SO_2 emission limit (in ppm). The limit will be determined by observed average emission rate (u) from the submitted compliance tests and will be statistically analyzed using the one tailed student T test ($t_{.05} = (\bar{x} - u) \, n^{0.5}/s$) at the 95% confidence level to derive a mean emission rate ($\bar{x}$), where s is the standard deviation of observed values n. The final operating SO_2 emission limit (in ppm) shall be this mean emission rate ($\bar{x}$). This value shall be restricted to no more than 124 ppm or less than 60 ppm (3-hr rolling average, dry volume, corrected to 12% CO_2).

Nitrogen Oxides: .560 lb/mmBtu heat input and 350 ppm (3-hr rolling average, dry volume, corrected to 12% CO_2).

Carbon Monoxide: .090 lb/mmBtu heat input; 400 ppm (1-hr rolling average, dry volume, corrected to 12% CO_2); and 88 ppm (4-day rolling average, dry volume, corrected to 12% CO_2).

Lead: .00056 lb/mmBtu

Fluorides: .0040 lb/mmBtu

Beryllium: 9.30×10^{-7} lb/mmBtu

Mercury: 7.50×10^{-4} lb/mmBtu

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* Uncontrolled SO_2 emissions will be measured at the inlet to the acid gas control device.

Visible Emissions: Opacity of stack emissions shall not be greater than 15% opacity. Excess opacity resulting from startup or shut-down shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess opacity shall be minimized but in no case exceed two hours in any 24-hour period unless specifically authorized by EPA for longer duration.

The units are subject to 40 CFR Part 60, Subpart E and Subpart Db, New Source Performance Standards (NSPS), except that where requirements in this permit are more restrictive, the requirements in this permit shall apply.

There shall be no greater than 10% opacity for emissions from the refuse bunker and the ash handling and loadout. The potential for dust genera-tion by ash handling activities will be mitigated by quenching the ash prior to loading in ash transport trucks. Additionally, all portions of the proposed facility, including the ash handling facility, which have the potential for fugitive emissions will be enclosed. Also, those areas which have to be open for operational purposes, (e.g., tipping floor of the refuse bunker while trucks are entering and leaving) will be under negative air pressure.

b. Only distillate fuel oil or natural gas shall be used in startup burners. The annual capacity factor for use of natural gas and oil, as determined by 40 CFR 60.43b(d), shall be less than 10%. If the annual capacity factor of natural gas is greater than 10%, then the facility shall be subject to §60.44b.

c. (1) None of the four individual municipal solid waste incinerators shall be charged in excess of 226.9 mmBtu/hr and 605 tons per day MSW (110% rated capacity) nor produce in excess of 129,500 lbs/hr of steam (3-hr rolling average).

(2) The temperature of the flue gas exiting the final combustion chamber of the incinerator shall not be less than 1800°F.

d. Compliance Tests

(1) a. Annual compliance tests for particulate matter, lead, SO_2, nitrogen oxides, CO, fluorides, mercury, and beryllium shall be conducted in accordance with 40 CFR 60.8 (a), (b), (d), (e), and (f).

b. Compliance with the opacity standard for the incinerator stack emissions in condition 1.a. of this part shall be determined in accordance with 40 CFR 60.11 (b) and (e).

c. Compliance with the emission limitation for 65% control of total sulfur dioxide emissions shall be determined by using the test methods in condition 1.d.(2) and sampling for SO_2 emissions before and after the acid gas control device. Continuous emissions data shall also be used to demonstrate compliance with the SO_2 concentration limits in condition 1.a. above.

(2) The following test methods and procedures for 40 CFR Parts 60 and 61 shall be used for compliance testing:

a. Method 1 for selection of sample site and sample traverses.

b. Method 2 for determining stack gas flow rate when converting concentrations to or from mass emission limits.

c. Method 3 for gas analysis for calculation of percent O_2 and CO_2.

d. Method 4 for determining stack gas moisture content to convert the flow rate from actual standard cubic feet to dry standard cubic feet for use in converting concentrations in dry gases to or from mass emission limits.

e. Method 5 for concentration of particulate matter and associated moisture content. One sample shall constitute one test run.

f. Method 9 for visible determination of the opacity of emissions.

g. Method 6 for concentration of SO_2. Two samples, taken at approximately 30 minute intervals, shall contitute one test run.

h. Method 7 for concentration of nitrogen oxides. Four samples, taken at approximately 15 minute intervals, shall constitute one test run.

i. Method 10 for determination of CO concentrations. One sample constitutes one test run.

j. Method 12 for determination of lead concentration and associated moisture content. One sample constitutes one test run.

k. Method 13B for determination of fluoride concentrations and associated moisture content. One sample shall constitute one test run.

l. Method 101A for determination of mercury emission rate and associated moisture content. One sample shall constitute one test run.

m. Method 104 for determination of beryllium emission rate and associated moisture content. One sample shall constitute one test run.

2. Compliance with emission limitations specified in lb/mmBtu in conditions
1.a. and 1.c. of this part shall be determined by calculating an "F" factor
in dscf/mmBtu corrected to 12% CO_2 using the boilers' efficiency (as determined
by the calorimeter method contained in Attachment A during acceptance testing)
and the measured steam production. Data obtained from test methods required
in condition 1.d. of this part for compliance testing shall be used for the
calculation of the "F" factor required by this condition.

3. Devices shall be installed to continuously monitor and record steam production,
the final combustion chamber temperature, and flue gases temperature at the
exit of the acid gas removal equipment. These devices shall be adequately
maintained and operating during all periods of operation.

4. The height of each boiler exhaust stack shall not be less than 61.0 meters
above ground level at the base of the stack.

5. Each incinerator boiler shall have a metal name plate affixed in a conspicuous
place on the shell showing manufacturer, model number, type waste, rated
capacity, and certification number.

6. The permittee must submit to EPA and DER, within fifteen (15) days
after it becomes available to the County, copies of technical data
pertaining to the incinerator boiler design, acid gas control equip-
ment design, particulate control equipment design, and the fuel mix
that will be used to evaluate compliance of the facility with the
preceeding emission limitations.

7. Fuel

The Resource Recovery Facility shall utilize refuse such as garbage and
trash (as defined in Chapter 17-7, FAC) but not grease, scum, grit
screenings or sewage sludge.

8. Air Pollution Control Equipment

The permittee shall install, continuously operate, and maintain the following
air pollution controls to minimize emissions. Controls listed shall be fully
operational upon startup of the proposed equipment.

   a. Each boiler shall be equipped with a particulate emission control device
   for the control of particulates.

   b. Each boiler shall be equipped with an acid gas control device designed
   to remove at least 90% of the acid gases.

   c. The temperature of flue gases exiting the acid gas control equipment
   shall not exceed 300°F.

9. Continuous Emission Monitoring

   a. Prior to the date of startup and thereafter, the County shall install, maintain, and operate the following continuous monitoring systems for each boiler exhaust stack:

      (1) Continuous emission monitoring (CEM) systems to measure stack gas opacity and SO_2, NO_x, CO, CO_2, and O_2 concentrations for each unit. Continuous monitors for SO_2 shall be installed after the acid gas control device for each unit. The systems shall meet the EPA monitoring performance specifications of 40 CFR 60.13 and 40 CFR 60, Appendix B, during initial compliance testing and annually thereafter. Additionally, CEM's shall meet the quality control requirements of 40 CFR 60, Appendix F (Attachment B).

      (2) CEM data recorded during periods of startup, shutdown, and malfunction shall be reported but excluded from compliance averaging periods for CO, NO_x, and opacity.

      (3) a. CEM data recorded during periods of startup and shutdown shall be excluded from compliance averaging periods for SO_2.

          b. CEM data recorded during periods of acid gas control device malfunctions shall be excluded from compliance averaging periods for SO_2 provided that the preceeding thirty day period which ends on the last day of the malfunction period meets an average SO_2 emission limit equal to the SO_2 limit specified in condition l.a. CEM data must be available for 90% of the operating time for this exemption to apply. A malfunction as used in this permit means any sudden and unavoidable failure of air pollution control equipment or process equipment or of a process to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

      (4) The temperatures of the final combustion chamber of the furnace and flue gases exiting the acid gas control device shall be continuously monitored.

   b. An excess emissions report shall be submitted to EPA for every calendar quarter. The report shall include the following:

      (1) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factors used, and the date and time of commencement and completion of each period of excess emissions (60.7(c)(1)).

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the furnace/boiler system. The nature and cause of any malfunction (if known) and the corrective action taken or preventive measures adopted shall also be reported (60.7(c)(2)).

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks, and the nature of the system repairs or adjustments (60.7(c)(3)).

(4) When no excess emissions have occurred or the continuous monitoring system has not been inoperative, repaired, or adjusted, such information shall be stated in the report (60.7(c)(4)).

(5) County shall maintain a file of all measurements, including continuous monitoring systems performance evaluations; all continuous monitoring systems or monitoring device calibrartion checks; adjustments and maintenance performed on these systems or devices; and all other information required by this permit recorded in a permanent form suitable for inspection (60.7(d)).

(6) Excess emissions shall be defined as any applicable period during which the average emissions of CO, NO_x, and/or SO_2, as measured by the continuous monitoring system, exceeds the CO, NO_x, and/or SO_2 maximum emission limit (in ppm) set for each pollutant in condition 1.a. above.

c. Excess emissions indicated by the CEM systems shall be considered violations of the applicable opacity limit or operating emission limits (in ppm) for the purposes of this permit provided the data represents accurate emission levels and the CEM's do not exceed the calibration drift (as specified in the respective performance specification tests) on the day when initial and subsequent compliance is determined. The burden of proof to demonstrate that the data does not reflect accurate emission readings shall be the responsibility of the permittee.

10. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during start-up or shutdown shall be prohibited.

11. Reporting

a. A copy of the results of the compliance tests shall be submitted within forty-five days of testing to the DER Bureau of Air Quality Management, the DER Southeast Florida District Office, Broward County, and EPA Region IV.

b. Continuous emissions monitoring data shall be reported to the DER Southeast District Office and EPA Region IV on a quarterly basis in accordance with Section 17-2.710, FAC, and 40 CFR 60.7.

c. Addresses for submitting reports are:

EPA Region IV

    Chief, Air Compliance Branch
    U.S. Environmental Protection Agency
    345 Courtland Street, N.E.
    Atlanta, Georgia 30365

Florida Department of Environmental Regulation (DER)

    Deputy Chief, Compliance and Ambient Monitoring
    Bureau of Air Quality Management
    Florida Department of Environmental
      Regulation (DER)
    Twin Towers Office Building
    2600 Blair Stone Road
    Tallahassee, Florida 32301

Southeast District Office of DER

    District Manager
    Department of Environmental Regulation
    3301 Gun Club Road
    P.O. Box 3858
    West Palm Beach, Florida 33402

Broward County

    Broward County Environmental Quality
      Control Board
    500 Southwest 14th Court
    Ft. Lauderdale, Florida 33315

PART II. - General Conditions

1. The permittee shall comply with the notification and record-keeping require-
    ments codified at 40 CFR Part 60.7. In addition, the permittee shall pro-
    vide EPA with 30 days notice prior to conducting any compliance testing
    required under condition 1.a.

2. The permittee shall retain records of all information resulting from
    monitoring activities and information indicating operation parameters
    as specified in the specific conditions of this permit for a minimum
    of two (2) years from the date of recording.

3. If, for any reason, the permittee does not comply with or will not be
    able to comply with the emission limitations specified in this permit,
    the permittee shall provide EPA with the following information in writing
    within five (5) days of such condition:

    (a) description of noncomplying emission(s),
    (b) cause of noncompliance,
    (c) anticipated time the noncompliance is expected to continue or, if
         corrected, the duration of the period of noncompliance,
    (d) steps taken by the permittee to reduce and eliminate the noncomplying
         emission.

    Failure to provide the above information when appropriate shall constitute
    a violation of the terms and conditions of this permit. Submittal of the
    aforementioned information does not constitute a waiver of the emission
    limitations contained within this permit.

4. Any proposed change in the information contained in the final determina-
    tion regarding facility emissions or changes in the quantity or quality of
    materials processed that would result in new or increased emissions or ambient
    air quality impact must be reported to EPA. If appropriate, modifications to
    the permit may then be made by EPA to reflect any necessary changes in the
    permit conditions. In no case are any new or increased emissions allowed
    that will cause violation of the emission limitations specified herein. Any
    contruction or operation of the source in material variance with the final
    determination shall be considered a violation of this permit.

5. In the event of any change in control of ownership of the source described in
    the permit, the permittee shall notify the succeeding owner of the existence
    of this permit and EPA of the change in control of ownership within 30 days.

6. The permittee shall allow representatives of the state and local environ-
    mental control agency or representatives of the EPA, upon presentation of
    credentials:

(a) to enter upon the permittee's premises, or other premises under the control of the permittee, where an air pollutant source is located or in which any records are required to be kept under the terms and conditions of this permit;

(b) to have access to and copy at reasonable times any records required to be kept under the terms and conditions of this permit, or the Clean Air Act;

(c) to inspect at reasonable times any monitoring equipment or monitoring method required in this permit;

(d) to sample at reasonable times any emissions of pollutants; and

(e) to perform at reasonable times an operation and maintenance inspection of the permitted source.

7. The conditions of this permit are severable, and if any provision of this permit or the application of any provisions of this permit to any circumstances is held invalid, the application of such provision to other circumstances and the remainder of this permit shall not be affected.

VIII. PUBLIC COMMENTS/NOTICE

Comments were received by the Florida DER from eleven commentors in regard to the construction of the North Broward Resource Recovery Facility. All commentors urged that the facility not be permitted to construct without acid gas control and stringent particulate emissions limits. As this facility has been required to comply with the EPA BACT determination which includes acid gas control and stringent particulate emissions, the concerns of these commentors have been addressed in the Final Determination and Permit for the North Broward County Resource Recovery Facility.

FORT LAUDERDALE NEWS/SUN-SENTINEL

Published Daily
Fort Lauderdale, Broward County, Florida
Boca Raton, Palm Beach County, Florida

STATE OF FLORIDA
COUNTY OF BROWARD/PALM BEACH

Before the undersigned authority personally appeared ___Nancy Goldberg___

_____ who on oath says that he is _____

Classified Supervisor ___ of the Fort Lauderdale News/Sun-Sentinel, Daily

newspapers published in Broward/Palm Beach County, Florida that the attached

copy of advertisement, being a ___**Notice of Certification Hearing**___

in the matter of ___**operate an electrical power plant**___

_____

_____ in the _____ Court,

was published in said newspaper in the issues of _____
Sept. 13, 1986

_____

Affiant further says that the said Fort Lauderdale News/Sun-Sentinel are newspapers published in said Broward/Palm Beach County, Florida, and that the said newspapers have heretofore been continuously published in said Broward/Palm Beach County, Florida, each day, and have been entered as second class matter at the post office in Fort Lauderdale, in said Broward County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant says that he has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in said newspapers.

Sworn to and subscribed before me

this .... **15th** ...... day of...... **September**

A.D. 19........ **86**

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(SEAL)
Notary Public, State of Florida Notary Public

My Commission Expires Nov. 1, 1988

RDALE NEWS/SUN-SENTINEL

Published Daily

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Palm Beach County, Florida

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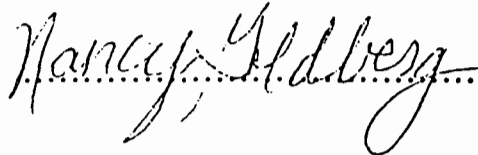
a ___Notice of Certification Hearing___

___an electrical power plant___

_____ in the _____ Court,

per in the issues of _____

Fort Lauderdale News/Sun-Sentinel are newspapers published in
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ublication of the attached copy of advertisement; and affiant says
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Nancy Goldberg

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NOTICE OF CERTIFIC
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1. Application number PA 86-22 for certification to authorize construction and operation of an electrical power plant near Pompano Beach, Florida, is now pending before the Department of Environmental Regulation, pursuant to the Florida Electrical Power Plant Siting Act, Part II, Chapter 403, F.S.

2. The proposed 25 acre resource recovery site is located in unicorporated Broward County near the southwest quadrant of the intersection of Powerline Road and N.W. 48th Street (Hilton Road). The facility site is directly east of the Florida Turnpike adjoining an existing sanitary landfill. The proposed plant will consist initially of a 55.5 MW unit Solid Waste Burning Resource Recovery Facility. The power plant will ultimantly be expanded to 83.25 MW. A short transmission line will connect to an existing FP & L substation to the south of the facility.

3. The Department of Environmental Regulation has evaluated the application for the proposed power plant. Certification of the plant would allow its construction and operation. The application, DER report, BACT and PSD determinations are available for public inspection at the addresses listed below:

**STATE OF FLORIDA
DEPARTMENT OF
ENVIRONMENTAL REGULATION**
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32301

**STATE OF FLORIDA
DEPARTMENT OF
ENVIRONMENTAL REGULATION**
South Florida District Office
3301 Gun Club Road
West Palm Beach, Florida 33402

**BROWARD COUNTY RESOURCE
RECOVERY OFFICE**
Room 521
115 South Andrews Avenue
Fort Lauderdale, Florida 33301

**SOUTH FLORIDA WATER
MANAGEMENT DISTRICT**
3301 Gun Club Road
West Palm Beach, Florida 33402

**POMPANO BEACH
CITY LIBRARY**
1213 E. Atlantic Boulevard
Pompano Beach, Florida 33060

4. Pursuant t
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NOTICE OF CERTIFICATION HEARING ON AN AI AND OPERATE AN ELECTRICAL POWER PLANT (NEAR POMPANO BEACH, F

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MANAGEMENT DISTRICT
3301 Gun Club Road
West Palm Beach, Florida 33402

POMPANO BEACH
CITY LIBRARY
1213 E. Atlantic Boulevard
Pompano Beach, Florida 33060

4. Pursuant to Section 403.508, Florida Statutes, the certification hearing will be held by the Division of Administrative Hearings on October 14, 1986, at 10:00 a.m., in the Coral Room, Palm-Aire Resort and Conference Center, 2501 Palm-Aire Drive North, Pompano Beach, Florida, in order to take written or oral testimony on the effects of the proposed electrical power plant or any other matter appropriate to the consideration of the site. Need for the facility has been predetermined by the Public Service Commission at a separate hearing. Written comments may be sent to the Hearing Officer on or before October 3, 1986.

5. Pursuant to 403.508(4), F.S.: "(a) Parties to the proceeding shall include: the applicant; the Public Service Commission; the Division of State Planning; the water management district as defined in Chapter 373, in whose jurisdiction the proposed electrical power plant is to be located; and the Department. (b) Upon the filing with the Department of a notice of intent to be a party at least 15 days prior to the date set for the land use hearing, the following shall also be parties to the proceeding:

1. Any county or municipality in whose jurisdiction the proposed electrical power plant is to be located.

2. Any state agency not listed in paragraph (a) as to matters within it jurisdiction.

3. Any domestic non-profit corporation or association formed in whole or in part to promote conservation or natural beauty; to protect the environment, personal health, or other biological values; to preserve historical sites; to promote consumer interest; to represent labor, commercial or industrial groups; or to promote orderly development of the area in which the proposed electrical power plant is to be located.

(c) Notwithstanding paragraph (4) (d), failure of an agency described in subparagraphs (4) (b) 1 and (4) (b) 2 to file a notice of intent to be a party within the time provided herein shall constitute a waiver of the right of the agency to participate as a party in the proceeding.

(d) Other parties may include any person, including those persons enumerated in paragraph (4) (b) who failed to timely file a notice of intent to be a party, whose substantial interests are affected and being determined by the proceeding and who timely file a motion to intervene pursuant to Chapter 120, F.S., and applicable rules. Intervention pursuant to this paragraph may be granted at the discretion of the disignated hearing officer and upon such conditions as he may prescribe any time prior to 15 days before the comencement of the certification hearing.

6. When appropriate, any person may be given an opportuntly to present oral or written communications to the designated hearing officer. If the designated hearing officer proposes to consider such communication, then all parties shall be given an opportunity to cross-examine or challenge or rebut such communications.

7. Notices or petitions made prior to the hearing should be made in writing to:

Mr. William J. Kendrick
Division of Administrative
Hearings
Oakland Office Building
2009 Apalachee Parkway
Tallahasee, Florida 32301

⌐ HEARING ON AN APPLICATION TC CONSTRUCT
⌐AL POWER PLANT ON A SITE TO BE LOCATED
⌐ POMPANO BEACH, FLORIDA

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Mr. William J. Kendrick
Division of Administrative Hearings
Oakland Office Building
2009 Apalachee Parkway
Tallahasee, Florida 32301

8. Those wishing to intervene in these proceedings must be represented by an attorney or other person who can be determined to be qualified to appear in administrative hearings pursuant to chapter 120, F.S., or Chapter 17-1.21, FAC.
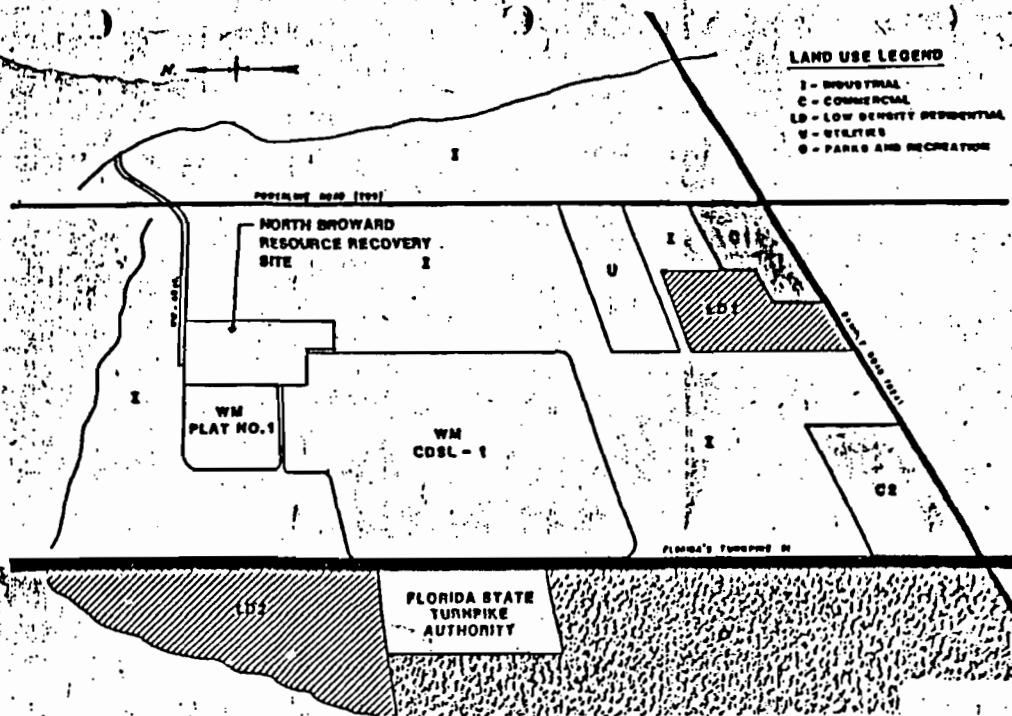
9. This Public Notice is also provided in compliance with the Federal Coastal Zone Management Act, as specified in 15 CFR Part 930, subpart D. Public comments on the applicant's federal consistency certification should be directed to the Federal Consistency Coordinator, Division of Environmental Permitting, Department of Environmental Regulation.

10. On February 26, 1986, Broward county applied to the DER to construct the aforementioned resource recovery plant. The application is also subject to U.S. Environmental Protection Agency (EPA) regulations for Prevention of Significant Deterioration of air quality (PSD), codified at 40 CFR 52.21. These regulations require that, before construction on a source of air pollution subject to PSD may begin, a permit must be obtained from EPA. Such permit can only be issued if the new construction has been determined by EPA to comply with the requirements of the PSD regulations, which are described in 40 CFR 52.21. These requirements include a restriction on incremental increases in air quality due to the new source and application of best available control technology (BACT).

The DER has been granted a delegation by EPA to carry out the PSD review of this source, except for the final signature of the federal PSD permit. Acting under that delegation, the DER has prepared a draft permit which is included in the DER's staff analysis report. The DER has made a preliminary determination that the proposed construction will comply with all applicable PSD regulations. The degree of Class II increment consumption that will result from the construction is:

Pollutant	Annual Average	24-hr. Average	3-hr. Average
Particulate	4%	3%	
Sulfur Dioxide	5%	10%	7%

The source is located approximately 78 kilometers from the nearest Class I area.

LAND USE LEGEND
I = INDUSTRIAL
C = COMMERCIAL
LD = LOW DENSITY RESIDENTIAL
U = UTILITIES
R = PARKS AND RECREATION

NORTH BROWARD RESOURCE RECOVERY SITE

WM PLAT NO.1

WM CDSL - 1

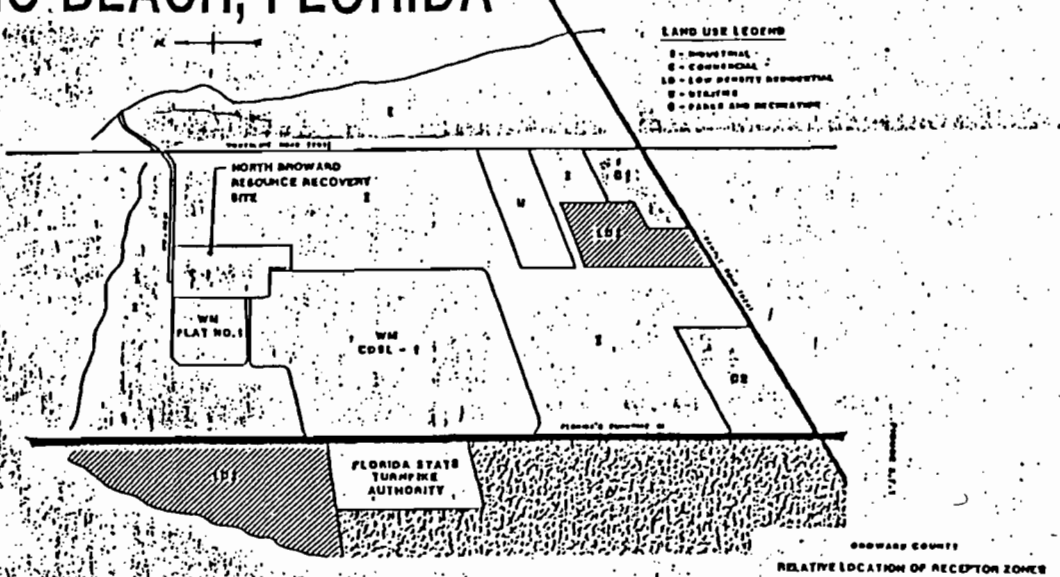FLORIDA STATE TURNPIKE AUTHORITY

NOTICE OF CERTIFICATION HEARING ON AN APPLICATION TO CONSTRUCT AND OPERATE AN ELECTRICAL POWER PLANT ON A SITE TO BE LOCATED NEAR POMPANO BEACH, FLORIDA

LAND USE LEGEND

RELATIVE LOCATION OF RECEPTOR ZONES

1. Application number PA 86-22 for certification to authorize construction and operation of an electrical power plant near Pompano Beach, Florida, is now pending before the Department of Environmental Regulation, pursuant to Florida Electrical Power Plant Siting Act, Part II, Chapter 403, F.S.

2. The proposed 25 acre resource recovery site is located in unincorporated Broward County near the southwest quadrant of the intersection of Powerline Road and N.W. 48th Street (Hilton Road). The facility site is directly east of the Florida Turnpike adjoining an existing sanitary landfill. The proposed plant will consist initially of a 55.5 MW unit Solid Waste Burning Resource Recovery Facility. The power plant will ultimately be expanded to 83.25 MW. A short transmission line will connect to an existing FP&L substation to the south of the facility.

3. The Department of Environmental Regulation has evaluated the application for the proposed power plant. Certification of the plant would allow its construction and operation. The application, DER report, BACT and PSD determinations are available for public inspection at the addresses listed below:

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32301

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION
South Florida District Office
3301 Gun Club Road
West Palm Beach, Florida 33402

BROWARD COUNTY RESOURCE RECOVERY OFFICE
Room 521
115 South Andrews Avenue
Fort Lauderdale, Florida 33301

SOUTH FLORIDA WATER MANAGEMENT DISTRICT
3301 Gun Club Road
West Palm Beach, Florida 33402

POMPANO BEACH CITY LIBRARY
1213 E. Atlantic Boulevard
Pompano Beach, Florida 33060

4. Pursuant to Section 403.508, Florida Statutes, the certification hearing will be held by the Division of Administrative Hearings on October 14, 1986, at 10:00 a.m., in the Coral Room, Palm Aire Resort and Conference Center, 2501 Palm-Aire Drive North, Pompano Beach, Florida, in order to take written or oral testimony on the effects of the proposed consideration of the site. Need for the facility has been predetermined by the Public Service Commission at a separate hearing. Written comments may be sent to the Hearing Officer on or before October 3, 1986.

5. Pursuant to 403.508(4), F.S.: "(a) Parties to the proceeding shall include: the applicant; the Public Service Commission; the Division of State Planning; the water management district as defined in Chapter 373, in whose jurisdiction the proposed electrical power plant is to be located; and the Department. (b) Upon the filing with the Department of a notice of intent to be a party at least 15 days prior to the date set for the land use hearing, the following shall also be parties to the proceeding:

2. Any state agency not listed in paragraph (a) as to matters within its jurisdiction.

3. Any domestic non-profit corporation or association formed in whole or in part to promote conservation or natural beauty; to protect the environment, personal health, or other biological values; to preserve historical sites; to promote consumer interests; to represent labor, commercial or industrial groups; or to promote orderly development of the area in which the proposed electrical power plant is to be located.

(c) Notwithstanding paragraph (4)(d), failure to an agency described in subparagraphs (4)(d), failure of an agency described in subparagraphs (4)(b)1 and (4)(b)2 to file a notice of intent to be a party within the time provided herein shall constitute a waiver of the right of the agency to participate as a party in the proceeding.

(d) Other parties may include any person, including those persons enumerated in paragraph (4)(b) who failed to timely file a notice of intent to be a party, whose substantial interests are affected and being determined by the proceeding and who timely file a motion to intervene pursuant to Chapter 120 F.S., and applicable rules. Intervention pursuant to this paragraph may be granted at the discretion of the designated hearing officer and upon such conditions as he may prescribe any time prior to 15 days before the commencement of the certification hearing.

6. When appropriate, any person may be given an opportunity to present oral or written communications to the designated hearing officer. If the designated hearing officer proposes to consider such communication, then all parties shall be given an opportunity to cross-examine or challenge or rebut such communications.

7. Notices or petitions made prior to the hearing should be made in writing to:

Mr. William J. Kendrick
Division of Administrative Hearings
Oakland Office Building
2009 Apalachee Parkway
Tallahassee, Florida 32301

8. Those wishing to intervene in these proceedings must be represented by an attorney or other person who can be determined to be qualified to appear in administrative hearings pursuant to Chapter 120, F.S. or Chapter 17-1.21, FAC.

9. This Public Notice is also provided in compliance with the federal Coastal Zone Management Act, as specified in 15 CFR Part 930, Subpart D. Public comments on the applicant's federal consistency certification should be directed to the Federal Consistency Coordinator, Division of Environmental Permitting, Department of Environmental Regulation.

10. On February 26, 1986, Broward County applied to the DER to construct the aforementioned resource recovery plant. The application is also subject to U.S. Environmental Protection Agency (EPA) regulations for Prevention of Significant Deterioration of air quality (PSD), codified at 40 CFR 52.21. These regulations require that, before construction on a source of air pollution subject to PSD may begin, a permit must be obtained from EPA. Such permit can only be issued if the new construction has been determined by EPA to comply with the requirements of the PSD regulations, which are described in 40 CFR 52.21. These requirements include a restriction on incremental increases in air quality due to the new source and application of best available control technology (BACT).

The DER has been granted a delegation by EPA to carry out the PSD review of this source, except for the final signature of the federal PSD permit. Acting under that delegation, the DER has prepared a draft permit which is included in the DER's staff analysis report. The DER has made a preliminary determination that the proposed construction will comply with all applicable PSD regulations. The degree of Class II increment consumption that will result from the construction is

Pollutant	Annual Average	24-Hr Average	3-Hr Average
Particulate	4%	3%	
Sulfur Dioxide	5%	10%	7%

The source is located approximately 78 kilometers from the nearest Class I area.

PLACE: Sheraton Orlando International Airport Inn, 3835 Beeline Expressway, Orlando, Florida.
PURPOSE: To receive public comment on the latest draft of the G-I rule.
A copy of the agenda may be obtained by writing to the Department of Environmental Regulation, Bureau of Ground Water Protection, Twin Towers Office Building, 2600 Blair Stone Road. Tallahassee, Florida 32399-2400, Attn: Donnie McClaugherty.

The Florida Department of Environmental Regulation announces the public hearing described below to which the public is invited.
DATE AND TIME: October 14, 1986, 9:30 a.m.
PLACE: Coral Room, Palm-Aire Resort and Conference Center, 2501 Palm Aire Drive North, Pompano Beach, Florida
PURPOSE: To conduct a certification hearing relative to the environmental impacts and other concerns relating to Broward County's proposed site for a 55.5 megawatt solid waste energy recovery facility power plant as required by the Florida Electrical Power Plant Siting Act, Section 403.508, Florida Statutes. Mr. William J. Kendrick, Hearing Officer, will conduct the hearing.
Anyone wishing to become a party to the hearing should contact Mr. Kendrick at the Division of Administrative Hearings. The Oakland Building, 2009 Apalachee Parkway, Tallahassee, Florida.

The Florida Board of Architecture announces the next official Board Meeting to which all interested persons are invited.
DATE AND TIME: Friday, October 3, 1986, 10:00 A.M.
PLACE: Sundial Beach and Tennis Resort, 1246 Middle Gulf Drive, Sanibel Island, Florida 33957
PURPOSE: Official Board Business
If any person decides to appeal any decision made by the Board with respect to any matter considered at this meeting or hearing, he/she will need a record of the proceedings, and for such purpose, he/she will need to ensure that a verbatim record of the proceedings is made which records include the testimony and evidence upon which the appeal is to be based.
For information, contact the Florida Board of Architecture, 130 North Monroe Street, Tallahassee, Florida 32301.

The Florida Board of Architecture announces the next official Workshop to which all interested persons are invited.
DATE AND TIME: Saturday, October 4, 1986, 9:00 A.M.
PLACE: Sundial Beach and Tennis Resort, 1246 Middle Gulf Drive, Sanibel Island, Florida 33957
PURPOSE: Sunset Review
If any person decides to appeal any decision made by the Board with respect to any matter considered at this meeting or hearing, he/she will need a record of the proceedings, and for such purpose, he/she will need to ensure that a verbatim record of the proceedings is made which records include the testimony and evidence upon which the appeal is to be based.

For information, contact the Florida Board of Architecture. 130 North Monroe Street, Tallahassee, Florida 32301.

The Florida Board of Cosmetology announces a meeting open to the public and all persons are invited to attend.*
DATE AND TIME: September 29, 1986; 9:00 A.M.
PLACE: Executive Suite, 522 Scotty's Lane, Tallahassee, FL 32303
PURPOSE: Regular Board Business and Disciplinary Matters.
*A copy of the agenda may be obtained by writing: Florida Board of Cosmetology, 130 N. Monroe St., Suite 35, Tallahassee, FL 32301
**If a person decides to appeal any decision made by the Board with respect to any matter considered at this meeting or hearing, he will need a record of the proceedings, and for such purpose he may need to ensure that a verbatim record of the proceedings is made, which record includes the testimony and evidence upon which the appeal is to be based.

The Advisory Council of Respiratory Care, Board of Medical Examiners, announces a public meeting to which all persons are invited.
DATE AND TIME: Wednesday, October 1, 1986, beginning at 8:00 a.m.
PLACE: Orlando International Airport, Airside B, Conference Room, Orlando, Florida
PURPOSE: To conduct general business of the Advisory Council on Respiratory Care.
A copy of the agenda may be obtained by writing to Mrs. Marcelle Flanagan, Executive Director, Advisory Council on Respiratory Care, 130 North Monroe Street, Tallahassee, Florida 32301.
Please note that if a person decides to appeal any decision made by the Council with respect to any matter considered at the above cited meeting or hearing, he/she will need a record of the proceedings, and for such purpose may need to insure that a verbatim record of the proceeding is made, which record includes the testimony and evidence upon which the appeal is based.

The Disciplinary Guidelines Committee, Florida Board of Medical Examiners announces a public meeting to which all persons are invited.
DATE AND TIME: Thursday, October 2, 1986, beginning at 9:00 a.m., or soon thereafter
PLACE: Tampa Marriott Airport Hotel, Tampa International Airport, Tampa, Florida
PURPOSE: To conduct general business of the Florida Board of Medical Examiners, Disciplinary Guidelines Committee
A copy of the agenda may be obtained by writing to Mrs. Dorothy J. Faircloth, Executive Director, 130 North Monroe Street, Tallahassee, Florida 32301.
Please note that if a person decides to appeal a decision made by the Board with respect to any matter considered at the

APPENDICES

ATTACHMENT A

AN EXAMINATION OF PROPOSED ACCEPTANCE TESTING METHODS

K. E. GRIGGS
Department of the Army
U.S. Army Construction Engineering Research Laboratory
Champaign, Illinois

ABSTRACT

This paper describes test procedures proposed to be used to determine the acceptance or operational performance of solid waste incinerators with heat recovery. The throughput capacity of the heat recovery incinerator, volume and mass reduction, environmental emissions, and overall thermal efficiency are used as performance indicators.

To develop the performance test, the manufacturers of heat recovery incinerators (HRI's) were contacted to obtain literature describing their products. The literature was reviewed to determine the characteristics that manufacturers use to describe their HRI's, and to learn general operating procedures and conditions. The Power Test Codes of the American Society of Mechanical Engineers (ASME) were reviewed to see whether they could be used for testing HRI's. In addition, the proposals presented at the last three National Waste Processing Conferences were also reviewed. Four efficiency test procedures—the input–output, heat-loss, modified heat-loss, and calorimeter methods—were identified from this information, along with an alternate concept of separate combustion efficiency and thermal energy recovery testing. Recommendations are made as to what should be considered as the "standard" for acceptance testing, based upon a user's perspective.

INTRODUCTION

The Resource Conservation and Recovery Act of 1976 recommended the use of recovered-material derived fuels to the maximum extent practical in Federally owned fossil fuel fired energy systems. To fulfill the intent of this Act and to take advantage of possible energy cost savings, the Army has undertaken the task of installing heat recovery incinerators (HRI's) at various installations throughout the continental United States. To provide planning guidance for such HRI installations, the U.S. Army Construction Engineering Research Laboratory (USA–CERL) has developed several publications [1–3]. Currently, HRI's are operational at Fort Eustis, Virginia, Fort Leonard Wood, Missouri, Fort Rucker, Alabama, and Redstone Arsenal, Alabama. By 1990, it is expected that waste may be burned at over 15 Army installations.

Unlike other large-scale equipment, such as coal- or oil-fired boilers, no standard performance test is currently available to assess field performance or to use as an acceptance test specifically for HRI plants. Within the Army, Directorates of Engineering and Housing (DEH's) and District Engineers need standard performance test procedures to trouble-shoot HRI systems and to ensure that new HRI's meet waste throughput and efficiency specifications before the systems are accepted and turned over to the DEH for operation.

Manufacturers of HRI's were contacted to obtain literature describing their incinerators. The literature was reviewed to determine the characteristics that manufacturers use to describe their products, and to learn general operating procedures and conditions. The American Society of Mechanical Engineers (ASME) Power Test Codes (PTC 4.1 and PTC 33) were reviewed to see whether they could be used for testing HRI's. The Naval Civil Engineering Laboratory procedures in HRI testing were reviewed for applicable testing information. It was determined that the basis, or core, of the acceptance test should be the repeated ability to demonstrate that the unit will operate at the specified thermal efficiency while simultaneously achieving the rated throughput capacity, weight and volume reduction, steam (or other thermal) output, and environmental emissions. While thermal efficiency (the ability to release the theoretical heat energy available in a useful form) can not be the sole criteria for acceptance, it is the best single indicator of the correctness of design and quality of manufacture.

The Army's requirement is for an acceptance test developed for HRI's in the range of 20–100 TPD (18–91 tpd) of solid waste. Tests for compliance with clean air requirements are defined by local, State, and Federal agencies. It is intended that new HRI's meet stipulated capacity, volume and weight reduction and efficiency guarantees while operating in compliance with clean air requirements. Therefore, the test procedures must be conducted concurrently with environmental testing, assuring compliance with air emission standards during normal operation.

Unfortunately, no matter how rigorous an acceptance test is, the performance standards that the HRI is required to meet must be clearly and completely defined in the project specifications. The test itself will not prevent or correct problems that previous HRI projects have encountered. However, the test procedures described in this paper will reveal the existence of these problems.

ELEMENTS OF A GOOD ACCEPTANCE TEST

The question of an appropriate and accurate HRI acceptance test is a matter that has been discussed in technical papers at the three ASME National Waste Processing Conferences in 1980, 1982, and 1984 [4–7]. The acceptance testing of an HRI is a very complex issue due to both the variability of the quality (heat content versus moisture and noncombustibles) of the refuse and the variety of technologies used to burn it, some of which are still developing. The simplest acceptance test would be to see if the HRI could produce the rated amount of steam when firing the rated amount of refuse and supplementary fuel (if required). Unfortunately, this does not take into consideration possible variations in the heat content (Btu/lb) of the waste which may allow a poorly operating unit to still make its rated steam output (high Btu waste) or may prohibit a well operating unit from making its rated steam output (low Btu waste) at the rated mass firing rate. There seems to be a general consensus by most investigators, in this area, that thermal efficiency is the best indicator of quality of performance, since it takes into consideration the heat content of the waste stream.

However, none of the investigators that have reported at the conferences referenced above, has directly addressed the problem of how much the thermal efficiency of the various HRI technologies may change due to "off design" operation as a result of burning waste of a quality other than that specified. The main controversy seems to be the method (and the degree of effort) that should be the standard in determining that thermal efficiency. Much of this controversy is prompted by the difficulty in determining the Higher Heating Value (HHV) of the waste. The various proposals that were made, have had the implied aim of minimizing the effect of this uncertainty. Very little effort has been made to develop automated equipment for more economic and accurate determination of the waste HHV. The National Bureau of Standards (NBS) has developed a calorimeter for "large", kilogram size RDF pellets. However, the methods for making this determination are still very labor intensive and involve the collection and processing of large amounts of waste in order to achieve a reasonable accuracy.

In addition to the above, it must not be forgotten that thermal efficiency can not be the sole criterion for acceptance, although it may be the central part or core of testing. The plant must also have the capability of processing the design amount of waste, produce acceptable environmental emissions, discharge ash that exhibits the desired volume and mass reductions, and do all of this reliably. The plant must be able to do all of these things, including demonstrating an acceptable thermal efficiency, at the same time. USA-CERL is currently recommending that acceptance testing consist of three 24 hr runs conducted within 5 days in order to demonstrate reliability. With the exception of thermal efficiency testing, all of the above criteria have very specific and well defined methods of being measured.

THERMAL EFFICIENCY TESTING PROCEDURES

The efficiency testing procedures described in this paper can serve two purposes. First, they may be used as the basis of an acceptance test to establish whether a specific system has complied with the capacity, volume and mass reduction, and efficiency criteria in the specification under which it was purchased. Second, these tests can be used as a periodic performance evaluation indicating when abnormally high inefficiencies are occurring. In this instance, the test is conducted regularly and the information is compared with that from previous tests. Reduced thermal efficiency may also indirectly indicate the possibility of environmental emission problems. This comparison may be made because of the common procedure and data base.

To accomplish these tasks, four thermal efficiency testing procedures have been identified, along with an alternate concept of separate combustion efficiency and thermal energy recovery testing. The primary procedures are the input–output, the heat-loss, the modified heat-loss, and the calorimeter methods. Figure 1 provides a very simplified illustration of most of the factors that must be considered in utilizing these methods. They are discussed in detail in the previously referenced papers [4–7] and are described by the following equations:

Input–output method:

Thermal efficiency (%)

$$= \frac{\text{Useful Heat Output}}{\text{Heat Input}} \times 100 \quad (1)$$

Heat-loss method:

Thermal efficiency (%)

$$= \left(1 - \frac{\text{Losses}}{\text{Heat Input}}\right) \times 100 \quad (2)$$

Modified heat-loss method:

Thermal efficiency (%)

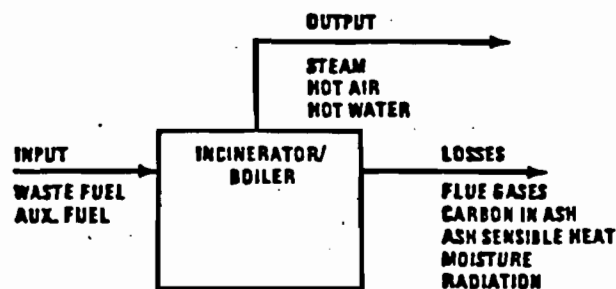$$= \left(1 - \frac{\text{Major Losses}}{\text{Heat Input}}\right) \times 100 \quad (3)$$

FIG. 1 ENERGY FLOW

Calorimeter method:

Thermal efficiency (%)

$$= \left(\frac{\text{Useful Heat Output}}{\text{Useful Heat Output + Losses}}\right) \times 100 \quad (4)$$

INPUT-OUTPUT

As the name input–output implies, only the energy inputs and the useful energy outputs are measured. The main disadvantage with this method is the accurate determination of the heat content of the waste. This normally involves the collection of large amounts of waste and making the determination based upon many laboratory analyses, sorting the waste into its components, or making a visual estimation. This method of efficiency determination is essentially based upon the very definition of thermal efficiency. However, it will only indicate that a problem exists and does nothing to define the problem.

The main advantage of the input–output method is that it is the simplest of the four. Much of the required instrumentation should already exist as a part of the system's normal operating controls. Moreover, there is a requirement for less data and laboratory analysis than with the other methods; except for the modified heat loss method, which is also the least accurate. The only method that has the potential for more accuracy than the input–output method is the calorimeter method, which is also very complex.

HEAT LOSS

The heat-loss method, which is also sometimes (erroneously) referred to as the heat-balance method, is less accurate than the input–output method. This

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method involves the measurement of heat losses from the system, such as sensible and latent heat in the flue gas, sensible heat in the ash, combustible material in the ash, radiation and convection from the incinerator and boiler surfaces, latent heat from evaporation of ash quench water, and heat contained in boiler blow-down. This method varies from the calorimeter and input–output methods in that the useful energy output is not measured, but the total heat input is measured and some smaller heat losses may be partially estimated. The accuracy of this method is variable, based upon the number of the losses estimated and the accuracy of that estimation. In addition, this method is also affected by the accuracy of the determination of the heat content of the waste, as noted above; and the accuracy of the determination of the moisture in the flue gas, which will have a large impact upon the gas latent heat losses. The results of a heat-loss determination will never agree (in practice) with the results of the input–output method (based upon coal fired boiler experience), although the difference may be as little as 2%.

While the heat-loss method is more difficult and potentially less accurate than the input–output method, its advantage is that it does provide more useful information. For example, if an incinerator system is not operating efficiently, this method should show where the excessive losses are (e.g., unburned carbon in the residue, high exit gas temperature, etc.). Hence, this method is most valuable in identifying operating and maintenance problems, and preferred by many engineers for all types of fossil fuel fired facilities.

SHORT FORM (MODIFIED) HEAT LOSS

The least accurate method is the modified or "short form" of the heat-loss determination. This method was proposed by Hecklinger and Grillo in 1982 [5] and based upon earlier recommendations by Stabenow in 1980 [4]. Although it is the least accurate, it is also extremely simple and quick. It is based upon the assumption that the major heat loss in the system is up the stack and normally involves taking only O_2 and temperature measurements on the stack gases in addition to measuring the fuel firing rate. This is a good assumption for oil/gas fired boilers and is reasonable for most of the larger coal fired boilers where efficient combustion of the fuel is very certain and the amount of moisture in these gases is low and well defined. With the thermal efficiency calculation depending so heavily on so few measurements, the highly variable and generally larger amounts of moisture in the stack gases

from an HRI can have a large impact on the results, as noted above in the discussion of the heat loss method. Additionally, incomplete combustion of the waste can result in losses as significant as the stack losses as demonstrated by some of the operating instances at Fort Knox and Fort Eustis where labels and other paper goods were readable after going through the incinerator. This can be compensated for by measuring the ash production rate and the carbon content of the ash. Unfortunately, that would make this method almost as complex, but still less accurate than the input–output method. However, this method could be used for day-to-day comparative indications of changes in thermal efficiency that may require more detailed investigation. It could also be used to monitor the results of changes associated with the operating crew and/or maintenance procedures.

CALORIMETER

The most rigorous method (which is used in Europe) is to use the HRI as a continuous calorimeter. The calorimeter method is much more complex than any of the other methods. It involves doing a complete mass and energy balance around the HRI, with the only unknown being the heat content of the waste stream. This involves a very large number of measurements (some of which can be quite tedious, such as heat loss to ash quench water including evaporation) and much more instrumentation than normally found on all but the largest HRI's. Essentially, all of the losses associated with the heat-loss method, and the energy output measurements associated with the input–output method, must be actually made, and not estimated. If these measurements are made carefully with accurate instrumentation, this method would produce the most accurate results, and avoid the problem of determining the heat content of the waste. However, the measurement of the total moisture of the flue gas is still a major problem at this time, since the traditional EPA Method 5 only involves grab samples. The amount of this moisture can be quite significant if internal sprays are used to cool the combustion zone, the waste is very wet, and/or a quench, ash cooling system is used that is not isolated from the combustion zone. In addition, the potential improvement in accuracy over the input–output method is not significant (0.73% [7]) based upon the size range and lack of sophistication of typical Army HRI plants.

Due to the complexity involved, the not yet totally resolved question of measuring the moisture in the flue gas, and a relatively small increase in accuracy, this

method is not considered appropriate for the size and type of HRI plants the Army would typically build. Starved air technology (the most common type of plant), specifically, is not sufficiently developed to warrant this level of accuracy, and additional instrumentation would have to be supplied (at a significant additional cost), especially for the testing. However, this method would be appropriate to very large (greater than 75 TPD/unit) excess air/water wall plants that also might include electrical cogeneration, and would most likely already have all of the instrumentation necessary, and represent both a state of the art and a magnitude of investment that *would* warrant this level of accuracy and effort. This type of plant would be typical of what the Army would be involved with on a joint basis with a local municipality.

AN ALTERNATE CONCEPT

The basis of this alternate concept is to consider that an HRI facility has two basic purposes: thermal reduction of the waste and energy recovery. These two functions could be examined separately and tested independently of each other. This would involve testing the boiler (separate or integral) by delivering to it the rated amount of hot gases at the temperature specified, and measuring its thermal efficiency by conventional methods. These hot gases would be produced by conventional firing of gas or oil. The efficiency of the incinerator itself would be measured only by determining the amount of carbon in the ash as an indicator of completeness of combustion at the design firing rate. The functioning of the incinerator and the heat content of the waste would not be directly involved in the determination of the efficiency of producing useful thermal output. Unfortunately, incinerators are not normally supplied with start-up and auxiliary (secondary zone) burners of sufficient size to produce the boiler's rated steam output with out burning any waste. However, some manufacturers of modular starved air systems do offer an option of a burner installed in the heat recovery boiler, capable of full steam production, as a back-up, in the event the incinerator ceases to function and steam output must be maintained. In those cases, this separate testing concept could be applicable.

CONCLUSIONS AND RECOMMENDATIONS

This paper has documented the investigation of a standard performance test for Army HRI's. The proposed test methods are based on existing ASME boiler and incinerator test procedures. A summary comparison of them may be found in Table 1. Unfortunately, there has not yet been any field comparison of these methods, and they have only been examined on a theoretical basis. It is recommended that the input–output method be used by the Army as the basis for the thermal efficiency portion of acceptance testing. The heat-loss method should be used to isolate the areas of inefficiencies should losses be excessive. The modified heat-loss method could be used for routine monitoring of the system. It is also recommended that the Army encourage the use of the calorimeter method for commercial HRI installations of unit sizes larger than 75 TPD (generally beyond starved air size), since that method seems most appropriate for plants of that size and expected sophistication. The alternate concept of separate combustion efficiency and thermal recovery testing should be allowed as an alternative where appropriate.

The procedure recommended above has been field tested for applicability at the Redstone Arsenal, Alabama, HRI. Revisions were made to the test procedure details to maximize the use of field available equipment. In addition, contractor-supplied data from performance and emissions tests at the Fort Leonard Wood, Missouri, HRI have been reviewed to evaluate the results of the procedure.

This paper is a condensation of a technical report currently being prepared by the US Army Construction Engineering Research Laboratory. The final report will discuss in much greater detail, the above testing methods, data requirements, and the procedure for conducting an acceptance test with consideration of field experience. When published, this report will be available through NTIS.

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[1] Hathaway, S. A., and Dealy R. J. "Technical Evaluation of Army-Scale Waste-to-Energy Systems." Interim Report E-110/ADA042578. USA-CERL, July 1977.

[2] Hathaway, S. A. "Recovery of Energy from Solid Waste at Army Installations." Technical Manuscript E-118/ADA044514. USA-CERL, August 1977."

[3] Hathaway, S. A. "Application of the Package Controlled-Air, Heat Recovery Solid Waste Incinerator on Army Fixed Facilities and Installations." Technical Report E-151/ADA071539. USA-CERL, June 1979.

[4] Stabenow, G. "Predicting and Testing Incinerator-Boiler Efficiency...." In *Proceedings of the 9th National Waste Processing Conference.* New York: The American Society of Mechanical Engineers, 1980, 301-313.

[5] Hecklinger, R., and Grillo, L. "Thermal Performance Eval-

TABLE 1 COMPARISON OF METHODS

Method	Heat Input	Heat Output	Heat Losses	Complexity	Advantages	Disadvantages	Recommendation
Input-Output	Yes	Yes	No	Simple	Direct Indication	No Indication of Problem Area Waste Quality	Use for Small Units (<75 TPD)
Heat-Loss	Yes	No	Most	Moderate	Indicates Problems	Some Losses Estimated Waste Quality	Use as Diagnostic
Modified Heat-Loss (Short Form)	Yes	No	Some	Very Simple	Simplicity	Most Losses Estimated Waste Quality	Use only to Monitor Operation
Calorimeter Method	Aux. Fuel Waste Feed	Yes	All	Very Complex	Most Accurate Avoids Waste Quality	Complexity	Use for Large Units (>75 TPD)
Alternate Concept	Fossil Fuel Only	Optional	Optional	Moderate	Avoids Waste Quality	Special Provision for Aux. Burners	Allow for Special Cases

uation of MSW Fired Steam Generators...." In *Proceedings of the 10th National Waste Processing Conference.* New York: The American Society of Mechanical Engineers, 1982, 65–69.

[6] Beckman, Dragovich, and DeGeyter. "Calculating Efficiency of Muncipal Waste Mass Burning Energy Recovery Systems." In *Proceedings of the 11th National Waste Processing Conference.* New York: The American Society of Mechanical Engineers, 1984, 217–229.

[7] Fernandes, J. "Uncertainties and Probable Errors Involved in Various Methods of Testing Incinerator/Boiler." In *Proceedings of the 11th National Waste Processing Conference.* New York: The American Society of Mechanical Engineers, 1984, 230–240.

CALCULATING EFFICIENCY OF MUNICIPAL WASTE MASS BURNING ENERGY RECOVERY SYSTEMS

ARTHUR H. BECKMAN and MARK G. DRAGOVICH
Katy-Seghers, Incorporated
St. Louis, Missouri

FERDNAND DeGEYTER
Seghers Engineering, SA

ABSTRACT

One of the questions on mass burning of municipal waste has been how much heat can be recovered from the waste. The answer must always be conditioned on the heating value of the waste. The problem is to determine that value. Every sample of waste will have different moisture, ash and chemical composition, which will calculate to different heating values. The practice in the U.S. is to use the high heat value in calculating energy production, which further complicates the question. Our suggestion is to use the furnace as the calorimeter to determine the heating value of the waste.

This is accomplished by measuring all the known inputs: waste quantity; combustion air; feedwater and cooling water; and all the known outputs: steam; blowdown; ash; radiation and flue gas. Flue gas O_2, CO_2, H_2O and S are measured and used to calculate a waste Btu content. Efficiency is calculated by dividing the net heat in steam by the calculated heat input.

INTRODUCTION

One system of incineration has been proven by over 30 years of successful operation in Europe and, to a limited extent, in the U.S.: mass burning of unsorted waste on specially designed grate systems.

Specially designed waterwall boilers recover heat energy from the hot flue gases in the form of steam for district heating, process or electrical production. One of the questions on mass burning has been determining exactly how much heat can be recovered from the waste. The main problem is calculating the heating value of municipal waste. If 20 samples are taken, it is likely that 20 different heating values will result. Every sample of waste will have different moisture, ash and chemical composition, which will calculate to different heating values.

The practice in the U.S. is to use the high heat value in calculating energy production, which further complicates the question. Two samples of waste may have similar high heat values (Table 1) but different moisture content and the resultant energy production (steaming rate) will vary significantly.

The steaming rate varies with the Btu content of the waste in a linear relationship over a range of about 3800 to 5200 Btu/lb kcal/kg (2100-29,000) assuming all other factors are equal. Below 4300 and above 5200, the ratio changes as indicated below:

HHV	3000	4300	4500	5200	6000 Btu/lb
	(1667)	(2400)	(2500)	(2900)	(3333 kcal/kg)
LHV	2400		4270		5740
	(1333)			(1318)	(3200 kcal/kg)
Steam Rate	1.25	2.20	2.31	2.67	3.20

Approximately the same amount of heat is lost through radiation of the boiler so lower Btu fuel would have a lower net steaming rate. Steaming rate would likewise vary inversely with the flue gas temperature, all other factors being equal.

Flue Gas Exhaust Temperature:	400°F (205°C)	374°F (190°C)
Steaming Rate (Net lb/lbs):	2.22	2.31

Finally, steaming rate varies with the percent furnace loading. Normally, mass burning furnaces will be run at

90 to 105 percent of rated capacity. Below 66 percent furnace loading, the boiler efficiency falls off rapidly to the point where it is not economically feasible to operate a furnace for energy recovery below 60 percent capacity.

The question is always asked: "What will the manufacturer guarantee as a steaming rate;" The answer must always be conditioned on the composition and heating value of the waste. The problem then is to determine those values. Our suggestion is to use the furnace as the calorimeter to determine the heating value of the waste.

Most furnace/boiler systems are designed for a total heat throughput or a maximum furnace capacity for waste at some specific heating value (Btu/lb or kcal/kg). The throughput may increase to some design overload if the heating value decreases and vice versa, so the maximum total heat throughput is not exceeded (Fig. 1).

PERFORMANCE GUARANTEES

Mass burning waste incinerator plants must meet specific performance guarantees, which are only partly within the dictates of the furnace/boiler and mostly a function of the waste processed.

Common guarantees are:

(a) waste throughput, hourly, daily or yearly (should be based on some assumed heating value of the waste);

(b) energy production (usually expressed as a factor of waste input (lb steam/lb waste) and contingent on an assumed composition and heat value of the waste);

(c) maximum putrescibles and combustible material in residue (a better indication of furnace performance than total amount of residue, which is more a function of the waste);

(d) maximum particulate emissions and other environmental factors.

We are concerned here with (a) and (b) and suggest a method for helping the supplier and customer to agree on how to determine if a system meets its guarantees.

ADJUSTMENTS TO OBSERVED THROUGHPUT CAPACITY AND ENERGY RECOVERY RATES

It is recognized that the refuse delivered to a mass burning facility for acceptance test purposes may not have the same composition as the reference processible waste and that throughput capacity and energy recovery are dependent upon the refuse composition, particularly its moisture content and heating value.

For example, the processing of lower Btu content than that of the reference waste will allow higher throughput rates but result in lower energy yield and may, therefore, appear to demonstrate higher throughput but lower per ton energy yields than that which would have been obtained had the plant been tested with reference processi-

ble waste. Similarly, if the waste furnished for acceptance testing purposes has a higher Btu content than that of the reference waste, the demonstrated throughput capacity may be less than that which would have been obtained with reference processible waste but the per ton energy yield would be higher.

It is further recognized that it is difficult and economically unfeasible to obtain an accurate measurement of the heating value of the waste through sampling of the waste being processed during the acceptance test and impossible after it has been incinerated. It is therefore proposed that the combustion system be used as a calorimeter, following in general the principles for determining efficiency and capacity described in the ASME Power Test Code 4.1 for steam generating units (1964, reaffirmed 1979) and the ASME Performance Test Code 33 for large incinerators (1978). The abbreviated effciency test (PTC 33a-1980, Appendix to ASME PTC 33) may be used to determine efficiency by the heat balance method.

The concept is to measure all the known inputs: fuel (waste) in pounds, combustion air flow and temperature, feedwater temperature and flow, and cooling water (to ash extractor) flow and temperature; and to measure all the outputs: steam flow, temperature and pressure, blowdown flow and temperature, ash quantity, temperature and carbon contents, and skin temperature (to calculate radiation).

We also measure flue gas temperature and flow so we know everything going in and coming out.

The flue gas is further analyzed to measure oxygen, carbon dioxide, water and sulphur and these figures are used to back into a waste analysis. Btu content is calculated from this analysis and compared with output to figure furnace/boiler efficiency. Given this calculated efficiency and, assuming that the efficiency obtained during the test, after appropriate corrections, would be the same as that which would have been obtained using reference processible waste, the throughput capacity and energy outputs observed in the test will be adjusted to reflect the difference between the calculated heating value of the test fuel and the assumed heating value of the reference processible waste.

SPECIFIC TEST PROCEDURES

INCINERATOR CAPACITY TEST

The purpose of this test is to demonstrate the ability of the boiler plant to handle and burn the guaranteed throughput of specified solid waste while staying within the limits of the specified normal operating grate temperatures and while meeting the guaranteed degree of burnout. This test should also give an indication regarding the reliability of
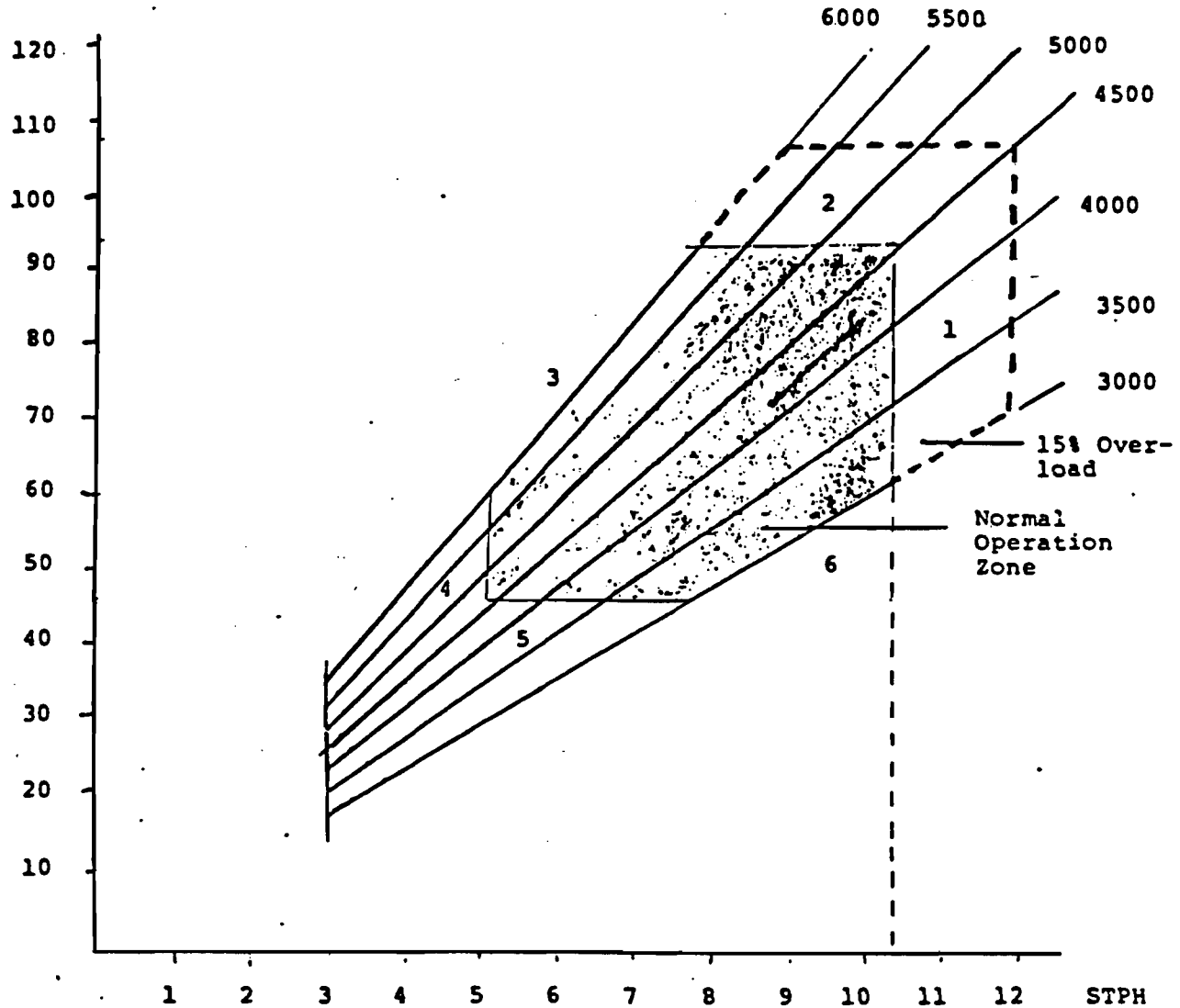
1 Maximum MSW throughput (10.41 STPH)
2 Maximum heat release rate (94 X 10^6 BTU/HR)
3 Maximum expected caloric value (6000 BTU/LB)
4 Minimum MSW through (50% Max)
5 Minimum heat release rate (50% Max)
6 Minimum expected caloric value (3000 BTU/LB)

FIG. 1 TYPICAL FURNACE OPERATION DIAGRAM

the equipment and, therefore, each line should be run at full load for at least 7 days, after stabilization, without interruption. In the event of a breakdown, the test should be repeated. All equipment should operate during the test at its normal mode and capacity, and the maintenance force and supplies should be those proposed to be available during normal operation of the plant — all to demonstrate the availability of the plant under normal operating conditions.

The facility should be operated for a 7 day period, at the maximum rated capacity and process at least six times (85 percent) the rated daily tons of processible waste.

During the 7 day test period, the total residue from the combustion process should be measured and sampled. The composition of the residue should be determined by hourly samples taken during the 72 hr period when the Facility is processing a total of three times the daily rated tons of processible waste.

The residue sampling should be submitted to the independent engineer for analysis by an independent laboratory prior to the conclusion of the acceptance tests. As a minimum, the residue should be analyzed for moisture content, combustible matter and putrescible matter in accordance with PTC 33.

The facility shall not have been deemed to have passed the throughput capacity test, even though the tonnage processed meets the capacity requirements stated above, if the percentage of combustible and putrescible matter in the total residue exceeds the guaranteed percentages of combustible and putrescible matter.

If the results are not as guaranteed, the Contractor and Customer will likely not be able to agree that the waste processed was identical to the "standard" waste used for contract purposes. Twenty samples will likely result in twenty different results. And, of course, there is no way to sample the waste after it has been incinerated, which would normally be when a controversy would arise. A reasonable alternative is what we are proposing.

The heat balance method of determining efficiency as described herein may be used to calculate the heat value of the waste fired during the test period. If the facility does not meet the throughput capacity test, the demonstrated throughput capacity will be adjusted by the inverse ratio of the heat value of the waste actually processed to the heat value of the reference waste usually assumed to be 4500 Btu/lb HHV.

If this adjustment results in a throughput capacity meeting the guarantee, the facility will have been deemed to have passed the throughput capacity test. If the heat value of the waste fired is determined to have been below 3800 Btu/lb HHV, the waste supplied shall be considered as not representative of processible waste and the test will then be repeated at the customer's expense.

ENERGY RECOVERY TEST

The energy recovery test will consist of a test of the steam raising rate and a test of the electric generation rate, if applicable. The test of the steam raising rate will establish whether the combustion process produces the guaranteed quantity of steam. The test of the electric generation rate will then determine whether the overall performance of the facility meets the guarantees as to energy recovery.

Steam Raising Rate

The purpose of this portion of the energy recovery test is to determine whether the facility meets the guaranteed steam raising rate, when processing solid waste, having the heating value of the reference solid waste, at a rate equal to the guaranteed daily throughput capacity under normal operating conditions as to boiler blowdown, exit gas temperatures and excess air ratio.

The test shall be conducted in accordance with the test codes referenced above, as modified herein, for the determination of heat outputs, credits and losses and the calculation of efficiency and fuel heating value by the heat balance method. For the purpose of determining the efficiency, steam output shall be measured at the superheater outlet and hot flue gases shall be measured at the inlet to the stack.

The test shall extend over an 8 hr test period. Pertinent test data shall be recorded at appropriate intervals, in accordance with the test code and shall include the following — all of which are relatively easy to measure with a high degree of accuracy:

- Processible waste feed rate (weight) and moisture
- Boiler outlet steam rate, temperature and pressure
- Feedwater rate and temperatures
- Desuperheater water rate, temperature and pressure (as applicable)
- Boiler drum pressure
- Flue gas rate and temperature at the stack inlet
- CO_2, O_2, SO_2 and H_2O in the flue gas at the stack inlet by various EPA methods
- Residue and fly ash quantities, temperature and unburned carbon and sulfur content
- Barometric pressure
- Combustion air flow and temperatures
- Ambient wet/dry bulb temperatures
- Residue quench water quantity and temperature
- Moisture in residue (after quench)
- In-house steam consumption
- Steam quality — percent moisture or PPM
- Boiler blowdown rate and temperature
- Furnace boiler skin temperature and area

Test measurements should be taken from installed plant instruments which have been previously calibrated
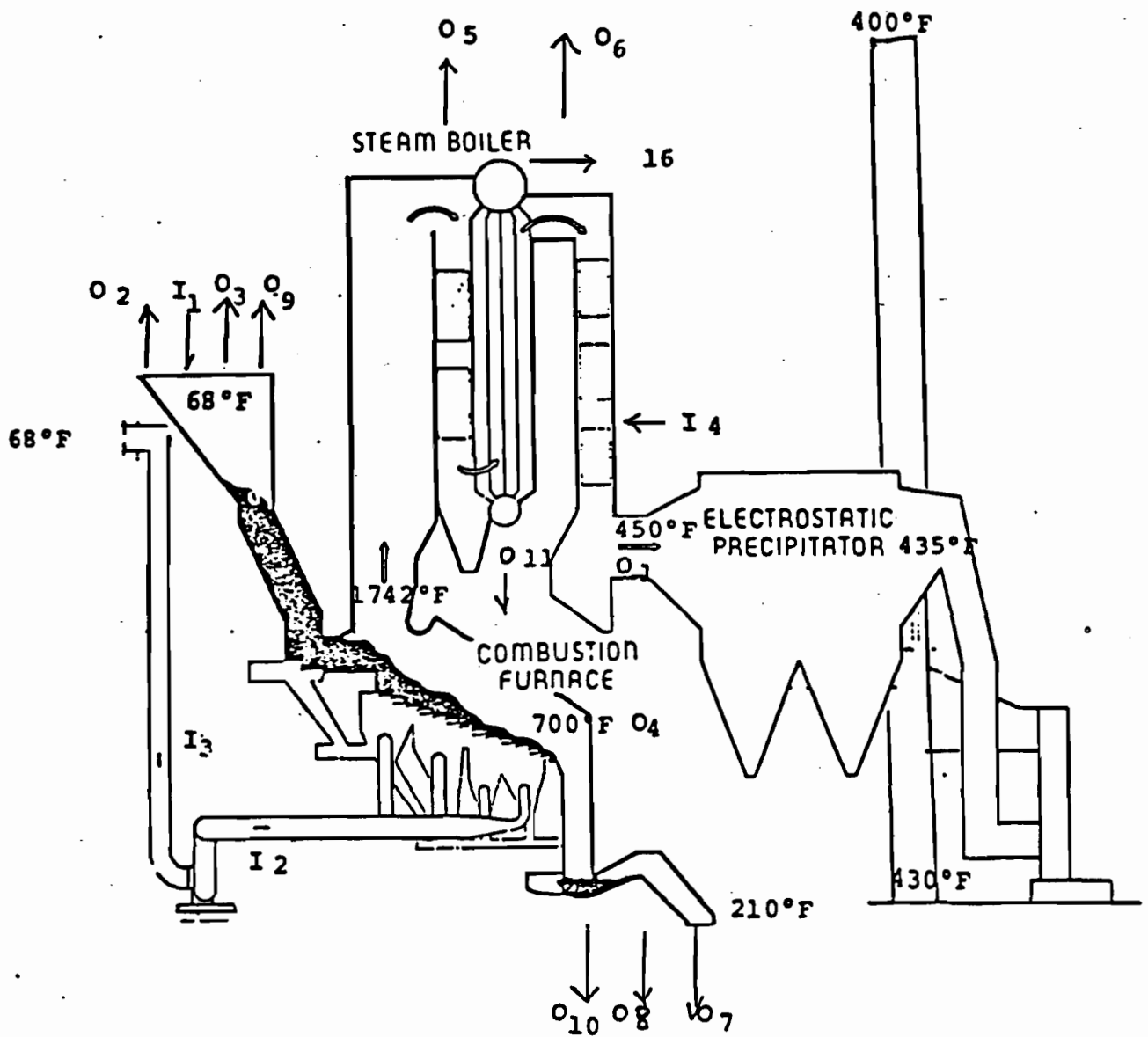
Efficiency = Net Heat in Steam X 100
             Net Avail. Heat Input

FIG. 2 ENERGY BALANCE FURNACE BOILER SYSTEM

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TABLE 1 STEAMING RATE

Assumed Waste Composition		% Moisture	
	20%	25%	
Carbon	26.6	22.7	
Hydrogen	3.4	4.3	
Sulphur	0.2	0.2	
Oxygen	25.4	22.6	
Nitrogen	0.2	0.2	
Moisture	20.0	25.0	
Ash	24.2	25.0	
High Heat Value	4502	4494 BTU/lb. (2500 KCAL/	
Gas Temperature	1742	1742° F. $(950^{\circ}$ C.) KG	
Excess Air	1.3882	1.2503	
O_2-Stoichiometric	0.6925	0.6870 lb./lb.	
Total Air	7.1445	6.6775 lb./lb.	
O_2	0.9614	0.8589 lb./lb.	
CO_2	0.9320	0.7875 lb./lb.	
H_2O	0.5273	0.6585 lb./lb.	
N_2	5.4925	5.1337 lb./lb.	
Flue Gas	7.9132	7.4386 lb./lb.	
Exhaust Temperature	374° F.	374° F. $(190^{\circ}$ C.)	
Steam Temperature	750° F.	750° F. $(400^{\circ}$ C.)	
Steam Pressure	600 psi	600 psi (41 ATA)	
Make-Up Water Temperature	250° F.	250° F. $(121^{\circ}$ C.)	
Steaming Rate, lb.steam/ lb.waste	2.31	2.22	

and agreed accurate by the independent engineer. Special portable instrumentation may also be used where required and agreed upon.

Utilizing the test data and measurements from the test, calculations will be made in accordance with the ASME test codes as modified herein, for the determination of boiler heat losses, heat outputs and heat credits (Fig. 2 and Table 2).

METHOD OF DETERMINING SOLID WASTE HIGH HEATING VALUE

With the information accurately obtained during the performance test, the high heating value of the solid waste can be calculated. In order to simplify the method of calculation and the test procedure, the ultimate analysis of the waste will be assumed to consist of only the major components:

• Carbon — Carbon content of the waste is calculated from the percentage of carbon dioxide in the flue gas and the percentage of carbon in the residue.

• Sulfur — Sulfur content of the waste is calculated from the percentage of sulfur dioxide in the flue gas and the percentage of sulfur in the ash.

• Hydrogen — Hydrogen is determined from the amount of moisture in the flue gas taking into account the moisture in the waste, combustion air and ash quench vapor.

• Nitrogen — Nitrogen is an assumed value agreed upon before the test. The nitrogen content of the refuse is very small and will have very little effect on the high heating value of the waste.

• Moisture — Moisture content is determined from samples taken during the performance tests.

• Ash — Ash content is determined from the total residue produced during the test less the moisture, sulfur and carbon contained in the ash.

TABLE 2 REFUSE-FIRED BOILER ENERGY BALANCE

Item	Heat Loss	BTU/LB$_R$	BTUX10^6/DAY
01.	Heat loss due to dry gas. Dry flue gas LB/LB$_R$ x specific heat x (exit gas temp. - ambient air temp.) 6.791 LB/LB$_R$ x .254 Btu/Lb.$^\circ$F. (400°F-70°F.).	569.2	170.8
02.	Heat loss due to moisture in fuel = (Enthalpy of vapor at 1.0 PSIA @ exit gas temp. - enthalpy of liquid @ ambient air temp.) x moisture in the fuel LB/LB$_R$ (.2119 LB/LB$_R$ x (1240 Btu/LB-48 Btu/LB).	252.6	75.8
03.	Heat loss due to H_2O from comb. of H_2 = 9 x hydrogen in fuel LB/LBL (Enthalpy of vapor - enthalpy of liquid) 9 x .0338 x (1240-48).	362.6	108.8
04.	Heat loss due to combustibles in residue Carbon in residue x 14.500 Btu/LB .0136 x 14.500 Btu/LB.	197.2	59.2
05.	Heat loss due to radiation (ABMA Chart).	45.0	13.5
06.	Unaccounted for losses.	55.0	16.5
07.	Heat loss in residue. Dry residue including unburned carbon x (specific heat of residue) x (residue temp. leaving furnace - residue temp. after quench) .2730 LB/LB$_R$ x .25 Btu/LB$^\circ$F. x (700°F-210°F.).	33.4	.10.0
08.	Heat loss due to moisture in residue. Moisture content of residue x (temp. @ residue leaving quench - temp. of water entering quench) 15/100 (.2730 LB/LB$_R$)(210°F.-70°F.) x 1 Btu/LB$^\circ$F.	5.7	1.7
09.	Heat loss due to moisture in air. Total dry air required based on fuel rate x moisture in air x specific heat of air x exit gas temp.-inlet air temp.)(0.5583 LB/ LB$_R$ x .013 LB$_{water}$/LB$_{air}$x 0.429 BTU/LB$^\circ$F. (400°F-70°F).	12.1	3.6
010.	Heat loss due to quench vapor. (Heat loss in dry residue ÷ latent heat of vapor @ atmospheric pressure) x (enthalpy of vapor entering boiler-enthalpy of vapor entering furnace. (33.44 Btu/LB ÷ 970.4 Btu/LB) x (1240 Btu/LB-970.4 Btu/LB).	9.3	2.8

TABLE 2 REFUSE-FIRED BOILER ENERGY BALANCE (CONT'D.)

Item	Heat Loss	BTU/LB_R	$BTUX10^6/DAY$
011.	Heat loss due to blowdown. Estimated steam production x specific heat of steam @ 150 PSIG sat. x blowdown rate. 2.8 LB/LB_R x 1196 Btu/LBS x 3%	106.5	32
		1648.6	494.6

Heat Input

Item		BTU/LB_R	$BTUX10^6/DAY$
I1.	Fuel heat input. HHV of refuse.	4500	1350
I2.	Dry air heat input. Total dry air required based on fuel rate x specific heat of air x (ambient air temp. − 32°F.) 6.5583 LB/LB_R x .24 Btu/LB°F. x (70°F.−32°F.).	59.81	17.9
I3	Heat input due to moisture in air. Moisture in air x specific heat of water vapor (ambient air temp. − 32°F.). 6.5583 LB/LB_R x .013 LB_w/LB_{air} x .489 Btu/LB° F. (70°F. − 32°F.).	1.6	.5
I4.	Enthalpy of feedwater entering boiler (Feedwater temp.−32°F.) x specific heat of water x lbs. of water/lb. of refuse. (250°F.−32°F.) x 1 Btu/LB°F x 2.884 LB_w/LB_R	628.7	188.6
		5190.1	1557.0

Steam Production

Item		BTU/LB_R	$BTUX10^6/DAY$
S1.	Heat absorbed in steam. (Items I1 + I2 + I3 +I4)−(Items 1 + 2 + 3 + 4 + 5 + 6 + 7 + 8 + 9 + 10 + 11) (4500 + 59.81 + 1.6 + 628.7) − (569.2 + 252.6 + 362.6 + 197.2 + 45.0 + 55.0 + 33.4 + 5.7 + 12.1 + 9.3 + 106.5). 5190.11 − 1648.6.	3541.5	1062.4

		LB_S/LB_R	
	Steaming Rate. Item S1. ÷ enthalpy of lbs. Steam @ 150 PSIG 465° F. 3529.4 ÷ 1254.	2.82	

TABLE 3 SAMPLE FUEL HEATING VALUE DETERMINATION

DATA FROM PERFORMANCE TEST

Flue Gas

CO_2	— 11.19% by wt.
H_2O	— 8.90% " "
O_2	— 11.55% " "
SO_2	— 0.20% " "
Flow	— 155,675 lbs./hr.
Temp.	— 400° F.

Ash

Weight	— 5,515 lbs./hr.
C	— 5.0% by wt.
S	— .1% " "
Temp.	— 210° F.
Mois.	— 15% by wt.

Combustion Air

Flow	— 140,067 lbs.
Temp.	— 70° F.

Refuse

Weight	— 20,200 lbs.
Moisture	— 27,74% by wt.

Ash Cooling Water

Temp.	— 70° F.
Flow	— 957 lbs./hr.

TABLE 3 SAMPLE FUEL HEATING VALUE DETERMINATION (CONTINUED)

DETERMINATION OF ULTIMATE ANALYSIS OF REFUSE

Item		Lbs./Lb. Refuse
1	Carbon Content	

$$\frac{\% \ CO_2 \ \text{Flue Gas X Lb./Hr. Flue Gas X Lb.}_C/CO_2}{\text{Lbs. Refuse}}$$

$$+ \ \frac{\% \ C_{Ash} \ X \ Lb._{Ash \ Dry}}{\text{Lbs. Refuse}}$$

$$\frac{.1179 \ X \ 155,675 \ X \ .2732}{20,200} + \frac{.08 \ X \ 4687}{20,200} \qquad .2472$$

2 Hydrogen Content

H_2O from H_2 Comb. $=$ $H_2O_{Flue \ Gas}$ $\sim$

H_2O_{Refuse} $-$ $H_2O_{Ash \ Vapor}$ $-$ $H_2O_{Comb.Air}$

$$H_2O_{Flue \ Gas} = \frac{\% \ H_2O_{FG} \ X \ Lb._{FG}}{Lbs._{Refuse}}$$

$$= \frac{.0890 \ X \ 155.675}{20,200} = .6859$$

$$H_2O_{Comb.Air.} = \frac{Lb._{Comb.Air} \ X \ Lb._{H_2O}/Lb._{Ash}}{Lb._{Refuse}}$$

$$= \frac{140,067 \ X \ .013}{20,200} = .090$$

$$H_2O_{Ash \ Vap.} = \frac{\text{Cooling Water Flow}}{Lb._{Refuse}} - \frac{\% \ \text{Mois.in Ash X Lb.}_{Ash}}{Lb._{Refuse}}$$

$$= \frac{957}{20,200} - \frac{.15 \ X \ 5155}{20,200} = .007$$

$$H_2O_{Refuse} = Lb._{H_2O}/Lb._{Refuse}$$
$$= .2774$$

TABLE 3 SAMPLE FUEL HEATING VALUE DETERMINATION (CONTINUED)

DETERMINATION OF ULTIMATE ANALYSIS OF REFUSE CONT'D.

Item		Lbs./Lb. Refuse

2 H_2O from H_2 Comb. = .6859 − .090 − .007 − .2774
   = .3115

Convert to Lb. H per Lb.$_{Refuse}$

$H = Lb._{H_2O} \times Lb._H/Lb._{H_2O}$

   = .3115 X .1188   .03484

3   Sulfur Content

$$\frac{\% SO_2 \times Lb._{FG} \times Lb._S/Lb._{SO_2}}{Lb._{Refuse}} + \frac{\% S_{Ash} \times Lb._{Ash}}{Lb._{Refuse}}$$

$$\frac{.002 \times 155,675 \times .5}{20,200} + \frac{.0024 \times 4682}{20,200}$$ .0011

4   Moisture Content   .2774

5   Nitrogen Content (Est. Value)   .0060

6   Ash Content

$= Residue - H_2O_{Refuse} - C_{Ash} - S_{Ash}$
$= \frac{5515}{20,200} - \frac{.15 \times 5515}{20,200} - \frac{.05 \times 5515}{20,200} -$
$\frac{.001 \times 5515}{20,200}$ .21817

7   Oxygen Content

1.00 − (Items) + 2 + 3 + 4 + 5 + 6) =

1.00 − (.2472 + .03483 + .0011 + .2774 +
     .0060 + .2183)   =   .21529

                                      1.000

TABLE 3 SAMPLE FUEL HEATING VALUE DETERMINATION (CONTINUED)

DETERMINATION OF HIGH HEATING VALUE

OF SOLID WASTE BY BOJE FORMULA

		Weight Fraction	Btu/Lb.	HHV
1	C	.2472	14,976	3702
2	H	.03484	49,374	1720
3	S	.0011	4,500	5
4	Moisture	.2774	-	
5	N	.0060	2,700	16
6	Ash	.21817	-	-
7	O	.21529	- 4,644	- 1000

4443 Btu/Lb.

- Oxygen — Oxygen content is taken as the remaining component of the refuse after all values have been calculated.

Neglecting the other minor components in the waste will result in a relatively small error in the high heating value calculation.

After the calculated analysis of the solid waste is determined, the heating value can be calculated using the BOJE formula.

This method of determination of heating values makes a number of assumptions and the results are contingent upon good testing methods.

The results reflect an accurate representation of the solid waste during the test period without the elaborate sampling and testing methods needed to do an accurate and representative chemical analysis of this waste.

SUMMARY

Calculating efficiency of municipal waste mass burning energy recovery systems by measuring the output of the system and basically using the furnace as a calorimeter seems to be reasonable and more accurate than trying to determine the precise composition of refuse by sorting and analysis.

All measurements are practical, timely and appropriate to the fuel actually used. Calculations are mathematically accurate and scientifically correct. This method actually answers more questions and leaves less to chance than any previously suggested procedure. More improvements will likely be found, but this seems to be a good place to start.

ACKNOWLEDGMENTS

REFERENCES

[1] *Steam/It's Generation and Use*, The Babcock & Wilcox Company, 1978.

[2] *Handbook of Solid Waste Management*, David Gordon Wilson, 1977.

[3] *Steam Generating Units – Power Test Codes*, ASME PTC 4.1, 1964.

[4] *Industrial Guide for Air Pollution Control*, EPA Handbook.

[5] *Predicting & Testing Incinerator-Boiler Efficiency. A Proposed Short Form Method in Line with the ASME Test Code PTC-33*, Georg Stabenow, 1980.

[6] *Large Incinerators*, ASME, PTC 33-1978.

Key Words: Calorific value • Efficiency • Energy • Furnace • Performance • Steam • Testing

Promulgation of Quality Assurance Requirements for Gaseous Continuous Emission Monitoring Systems Used for NSPS Compliance Determination

On June 4, 1987 quality assurance final rules were promulgated (40 CFR 60, Appendix F, Procedure 1) for gaseous continuous emission monitoring systems (CEMS) used for new source performance standards compliance determinations. These quality assurance requirements must be implemented by December 4, 1987 for the following source categories:

Subpart D_a (40 CFR 60): Electric Utility Steam Generating Units (constructed after 9-18-78). Both SO_2 and NO_x CEMS must implement the quality assurance requirements.

Subpart D_b (40 CFR 60): Industrial-Commercial-Institutional Steam Generating Units (constructed after 6-19-84). Both SO_2 and NO_x CEMS must implement the quality assurance requirements.

The quality assurance requirements include the following:

1. A quarterly performance audit to measure the CEMS accuracy and make sure the system is operating properly.

2. Criteria that defines when the CEMS is out of control and corrective action must be taken.

3. Criteria for invalidating CEMS measurement data.

4. A QC program must be developed that includes step-by-step written procedures for six activities described in Section 3 of the final rules.

Enclosed is a copy of the June 4 Federal Register containing the final rules. Also enclosed are the following three guidance documents which you may find useful in implementing the final rules:

Section 3.0.4. This is the revised EPA Traceability Protocol No. 1 for cylinder gases. Section 5.1.2 of the final rules requires that gases used for Cylinder Gas Audits (CGA) must be prepared according to this Section 3.0.4.

Section 3.0.7. This provides example calculations for the Relative Accuracy Test Audit (RATA), Relative Accuracy Audit (RAA) and the CGA.

Section 3.0.10. This provides guidance on the six activities that need written procedures as part of the QC program described in Section 3 of the final rules.

Sections 3.0.4, 3.0.7 and 3.0.10 will be published as part of the Quality Assurance Handbook for Air Pollution Measurement Systems. Volume III - Stationary Source Specific Methods (EPA-600/4-77-027b). These sections are included here to provide guidance in advance in order to meet the December 4, 1987 implementation date for the final rule.

After the final rules are implemented, the Quality Assurance Division of the Environmental Monitoring Systems Laboratory (EMSL) at RTP, NC plans an "Annual Report on CEMS Accuracy and Problems" based on the Data Assessment Reports (DAR) submitted quarterly by the source owners/operators.

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[AD-FRL-3021-7]

Standards of Performance for New Stationary Sources; Quality Assurance Requirements for Gaseous Continuous Emission Monitoring Systems Used for Compliance Determination

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Addition of Appendix F, Procedure 1—Quality Assurance Requirements for Gaseous Continuous Emission Monitoring Systems (CEMS's) Used for Compliance Determination was proposed in the Federal Register on March 14, 1984 (49 FR 9676). This action promulgates the addition of Appendix F, Procedure 1, that will be applicable for evaluating effectiveness of quality control (QC) and quality assurance (QA) procedures and the quality of data produced by any CEMS used to demonstrate compliance with 40 CFR Part 60 emission regulations on a continuous basis. Procedure 1 applies to steam generating units subject to 4 CFR Part 60, Subpart Da. The intended effect of this regulation is to require sources that are required to use CEMS's for continuous compliance determination to evaluate CEMS data quality and report results of quarterly accuracy determinations and calibration drift (CD) tests with the required emission reports. Procedure 1 defines the test procedures and criteria for acceptable data quality.

EFFECTIVE DATE: June 4, 1987.

Under section 307(b)(1) of the Clean Air Act, judicial review of these additions to 40 CFR Part 60 is available *only* by the filing of a petition for review in the U.S. Courts of Appeals for the District of Columbia Circuit within 60 days of today's publication of this rule. Under section 307(b)(2) of the Clean Air Act, the requirements that are the subject of today's notice may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

ADDRESSES: *Summary of Comments and Responses.* The summary of comments and responses for the proposed addition of Appendix F, Procedure 1, may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777. Please refer to "Appendix F—Quality Assurance Procedures, Procedure 1—Quality Assurance Requirements for Gaseous Continuous Emission Monitoring Systems Used for Compliance Determination (Proposed March 14, 1984, 49 FR 09676)—Summary of Comments and Responses, EPA-450/3-87-009." The document contains (1) a summary of the changes made to Procedure 1 since proposal and (2) a summary of all the public comments made on the proposed addition and the Agency's response to the comments.

Quality Assurance Guidelines: A document entitled "Calculation and Interpretation of Accuracy for Continuous Emission Monitoring Systems" is available from the U.S. EPA, Office of Research and Development Publications, 26 West St. Clair Street, Cincinnati, Ohio 45268. It is Section 3.0.7 of the Quality Assurance Handbook for Air Pollution Measurement Systems, Volume III, Stationary Source Specific Methods, EPA-600/4-77-0276. The

purpose of this document is to provide operators and reviewers of CEMS's with guidelines for evaluating results of CEMS relative accuracy tests and audits.

Docket. A docket, number A-80-29, containing information considered by the Agency in the development of the additions is available for public inspection between 8:00 a.m. and 4:00 p.m. Monday through Friday, at EPA's Central Docket Section (LE-131), West Tower Lobby, Gallery 1, 401 M Street, S.W., Washington, D.C. 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Darryl J. von Lehmden, Quality Assurance Division, Environmental Monitoring Systems Laboratory (MD-77), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone (919) 541-2415; or Peter R. Westlin, Emission Standards and Engineering Division, (MD-19), U.S. EPA, Research Triangle Park, North Carolina 27711, telephone number (919) 541-2237.

SUPPLEMENTARY INFORMATION:

I. Public Participation

The addition of Appendix F, Procedure 1, was proposed in the Federal Register on March 14, 1984 (49 FR 9676). Public comments were solicited at the time of proposal. To provide interested persons the opportunity for oral presentation of data, views, or arguments concerning the proposed procedures, a public hearing was scheduled for April 9, 1984, beginning at 9:00 a.m. However, the hearing was not held because no one requested to speak. The public comment period was from March 14, 1984, to May 14, 1984, and was later extended to July 13, 1984 (49 FR 24151).

Thirty-nine comment letters concerning the issues relative to the proposed procedures were received. The comments have been carefully considered; and, where determined to be appropriate by the Agency, changes have been made in the proposed addition.

II. Significant Comments and Changes to the Proposed Appendix F, Procedure 1

Comments on the proposed addition of Appendix F, Procedure 1, were received from industry, Federal agencies, State air pollution control agencies, trade associations, and equipment manufacturers. A detailed discussion of these comments and responses can be found in the document described in the **ADDRESSES** section of the preamble. The summary of

comments and responses are summarized in this preamble. Most of the comment letters contained multiple comments. The comments have been divided into categories cited below.

Applicability

Several commenters were concerned that Procedure 1 would become applicable to Subpart D sources which in turn would have to undertake significant changes to CEM's installed under less stringent regulations. The commenters suggested that the applicability of appendix F be limited to CEMS's installed after the promulgation of the regulation. The Agency has determined that QA procedures are necessary when CEMS's are used for compliance determinations. Revisions to Subpart D were proposed on October 21, 1983 (48 FR 48960), and the proposal contained continuous compliance provisions. However, the burden of any CEMS changes required because of the application of Procedure 1 will be evaluated when and if revisions to Subpart D are promulgated.

Two commenters stated that 6 months would be insufficient time to incorporate the data reduction procedures, write the QC procedures, and hire and train additional personnel needed to comply with the requirements in Procedure 1. The Agency revised Procedure 1 as proposed to eliminate the precision determination that would have required considerable revision of existing computer operated systems. It is the opinion of the Agency that, without the precision determination provisions, 6 months is sufficient time to prepare to comply with Procedure 1. The proposed revisions to Subpart D included a provision to allow affected sources 1 full year to develop CEMS's before having to comply with the revised regulations.

Several commenters expressed concerns about the applicability of continuous compliance regulations and the use of CEMS's for compliance determinations. The determination that a CEMS is an appropriate compliance tool for new source performance standards was not within the scope of the procedure 1 proposal. Such a determination was made with respect to Subpart Da in that rulemaking and is a subject of the pending Subpart D rulemaking. Procedure 1 provides a basis for evaluating CEMS data that are used for compliance determinations.

Quality Control Requirements

Three commenters suggested that the criteria list in the QC section be expanded to include several site-specific factors. The Agency believes that the list in Procedure 1 is as complete as

reasonably possible in a general regulation. The CEMS operator is encouraged to develop a quality control list specifically suited to the situation.

One commenter stated that the rewriting of the QC procedures following successive audit failures will not improve the performance of a poorly designed CEMS. The Agency recognizes that the design and application of a CEMS are important factors in the successful operation of the CEMS. Replacement of an inadequate CEMS may be the only appropriate action available after continued poor operation and is an action that should be considered in developing the QC plan.

Assessment of Data Precision

Many commenters stated that assignment of cylinder gas or gas cell concentration values using CEMS responses should not be allowed. The commenters suggested using reference methods for this determination. The Agency notes that the cylinder gas or gas cells are used in this case to measure CEMS response drift. For this purpose, it is not necessary to know the input values with absolute accuracy, but only that the value is stable.

Many commenters noted that present regulations require daily zero and span CD check and adjustment and that additional precision determinations were unnecessary. Reporting requirements for these precision assessments were burdensome, as well. The Agency agrees that the precision calculation and reporting are unnecessary for QA and has removed the precision section from Procedure 1. The CD determination procedure has been expanded to include the zero (or low-level) value as well as the upper-level value.

Zero and Upper-Level Calibration Drift

Three commenters stated that it would be appropriate to declare a CEMS to be out-of-control when drift exceeded twice the Appendix B specifications on any day, rather than only after 5 successive days. The Agency's experience is that application of this lower limit over an extended period of time may lead to excessive adjustment frequency and CEMS instability. A single drift measurement in excess of the lower limit could be a result of a statistical aberration, a dirty window which could be easily cleaned, or a nearly empty gas cylinder, none of which would be cause for declaring the CEMS out-of-control.

Many commenters stated that the requirement to conduct a relative accuracy audit (RAA) following an out-

of-control caused by excessive drift period is excessive. The Agency agrees with this comment and revised the proposal to include the determination of the end of the out-of-control period that is a result of excessive drift by demonstrating that the CEMS is operating within drift specifications.

Several commenters noted that this section and other sections of Procedure 1 required that source operators use alternate methods of obtaining emissions data when the CEMS is out-of-control. This requirement in Procedure 1 could lead to significant expenditures for alternate monitoring. The Agency has clarified the language from the proposal to note that Procedure 1 defines the criteria which determine when a CEMS is out-of-control. Under such conditions, the CEMS data are not valid for meeting the minimum data availability requirements found in continuous compliance regulations. The applicable regulations specify the minimum data availability requirements and these requirements, not Appendix F, dictate the necessity for alternate emission monitoring when the CEMS is out-of-control. The alternate monitoring method may be another CEMS which would also be subject to the requirements in Appendix F, Procedure 1.

Three commenters suggested the use of historical data for CEMS out-of-control periods as a valid alternative method. The Agency agrees that historical diluent emission data could be considered a valid alternative method, but that review of the alternative procedure and data by the Agency would be necessary before approval for specific or general use. Description of the procedure is included in 40 CFR 60.13(i).

One commenter provided a review of CEMS CD data (collected by EPA during a CEMS demonstration project) that indicated substantial invalidation of data because of excessive drift. The Agency reviewed the commenter's analyses and determined that the commenter erred in establishing the appropriate CD limits and in determining the number of out-of-control periods. The drift limit established by the commenter was about one-half of that defined in Procedure 1. This significant difference in CD on drift limits produced a significantly larger number of apparent drift limit violations than would be determined following the criteria in Procedure 1.

In addition, the commenter divided relatively long periods of poor CEMS performance into several periods of out-of-control operation. If the criteria in Procedure 1 had been followed, these

individual periods of out-of-control performance would have been consolidated into relatively few out-of-control periods that would have ended only when corrective action was completed. The Agency has determined the long term CEMS operation can continue uninterrupted or with only few interruptions attributable to drift criteria violations.

Assessment of Data Accuracy

Many commenters expressed the opinion that quarterly assessment of data accuracy is too frequent. Suggestions for alternative schedules ranged from annual to only once at the time of CEMS installation. The commenters provided no information supporting a reduction in audit frequency. While the Agency agrees that CEMS design, application, and maintenance are critical to proper operation and high data quality, the Agency is convinced that the only measure of QC effectiveness is a periodic accuracy audit. The Agency's experience indicates that a quarterly audit frequency is appropriate; this is based on the results of studies of long term performance of CEM's performed by the EPA Office of Research and Development (technical paper describing the work is in the docket).

Procedure 1 has been revised from the proposal to reduce the burden of accuracy auditing within the scope of quarterly audit periods. The relative accuracy test audit (RATA) is performed as defined in the applicable performance specification in Appendix B and is required only once per year. Either of two other audit procedures is allowed for the other three audit periods each year; these procedures are the cylinder gas audit (CGA) and the RAA based on a three-run, manual method test.

Five commenters urged the use of calibration gas cells as acceptable audit materials. The Agency has no independent procedure for determining accurately the appropriate CEMS response a gas cell should produce. Without an independent certification of gas cells or an appropriate application procedure, the Agency has determined that gas cell audit material is unacceptable for accuracy auditing.

Several commenters proposed alternative audit procedures including fuel sampling and analysis, process rate measurements, and inclusion of new test method procedures (e.g., Methods 6A and 6B). The Agency has no data to support the use of fuel sampling and analysis procedures as a basis for CEMS accuracy auditing on any reasonable time scale (e.g., hourly or daily). The

imprecision associated with fuel data for these short test periods is much greater than the acceptable drift limits specified for CEMS. Process rate measurements are also inappropriate as accuracy audit bases because of the source-specific nature of such procedures. The Agency provides means for reviewing and approving acceptable alternative procedures applicable to specific sources.

The Agency agrees that promulgated methods, such as Methods 3A, 6A, 6B, 6C, and 7E should be allowed as accuracy audit methods and has revised the appropriate paragraphs in the General Provisions accordingly.

Two commenters questioned the need to specify that all audits be completed in the first 2 months of any quarter. The Agency agrees and has changed the requirement in Procedure 1 to allow the audit to occur any time during a quarter, but there must be a minimum of 60 days between two quarterly audits.

Two commenters recommended three-point calibration checks in lieu of the two-point audit specified in Procedure 1 as a more appropriate audit procedure. The Agency disagrees that a three-point, repeated, calibration error test is a more appropriate audit. The calibration error test provides information about the linearity of the CEMS response throughout the range of the instrument response. The CGA in Procedure 1 tests the CEMS for the accuracy of responses to two audit gases with concentrations representing and bracketing the expected level of emissions at the level of the emission standard. This is a procedure that more appropriately represents an independent audit.

Several commenters proposed to allow manual method analysis of cylinder gas concentrations for the CGA. The Agency has determined that independent analysis of audits is necessary and has established a policy of traceability to National Bureau of Standards standard gaseous reference materials (SGRM's) or manufacturers' certified reference materials (CRM's) for this purpose.

Two commenters stated that use of the CGA and prohibition of the use of gas cells for auditing favors some CEMS technology over other types of systems. This, the commenters argued, discourages research and development of new equipment. The Agency believes the CGA is a technically acceptable, demonstrated, independent auditing procedure for CEM's. As noted earlier, the gas cell is not acceptable at this time as an audit material. Approval of a demonstrated alternative procedure, such as the CGA, is not favoritism nor

should it discourage development of other audit procedures or CEMS instrumentation.

Three commenters requested clarification or the definition of when an out-of-control period begins and ends. There are two tests that may result in out-of-control periods: the CD check and the accuracy audit. An out-of-control period resulting from excessive CEMS drift begins when the fifth consecutive excessive drift determination (or first drift determination in excess of four times the drift specification) occurs. The out-of-control period ends when corrective action is completed and the CEMS is demonstrated to operate within acceptable drift specifications again (i.e., at the end of the day when the CD measurements are within specifications).

The CEMS is determined to be out-of-control as a result of excessive inaccuracy from the time the accuracy audit sampling is completed. This does not include the time for sample analysis and data reduction. The out-of-control period ends when the CEMS completes the audit sampling successfully; again, time for sample analysis and data reduction is not included. This approach emphasizes the importance of expediting sample analysis and data reduction.

Two commenters questioned the requirement to conduct accuracy audits periodically when the source is operated seasonally or otherwise intermittently. The cost of possible forced-operation of a source in order to conduct an accuracy audit would be significant. Procedure 1 as promulgated requires only an annual RATA while quarterly audits may be completed using CGA or RAA. The Agency believes it is not burdensome to require a RATA and at least 50 percent load operation once per year. The Agency also believes it is critical to maintain operation of a CEMS regardless of operation of the source if that CEMS is to provide compliance data when the source is operating at compliance levels. The operator of a source that operates seasonally can request a revised schedule for auditing from the Agency that would include the RATA.

EPA Performance Audit Program

One commenter questioned the ability of the Agency to supply the EPA methods performance audit samples required for every RATA. The Agency has made the necessary plans with suppliers to have a sufficient supply of audit samples available not only for the RATA's but also for other compliance testing required using EPA methods.

Calculation of Data Accuracy

One commenter questioned the use of the confidence interval in calculating relative accuracy (RA) with fewer than nine data sets. While it is correct statistically to include the confidence interval with any number of data sets, the potential size of the confidence interval can overshadow the mean or average value when the number of data sets is reduced to as few as three. For this reason, the RAA quarterly audit alternative using only three runs will be determined based on the average values only. The RATA is conducted annually and will include the sum of the nine run average and the confidence interval in calculating RA.

Reporting Requirements

Five commenters stated that the promulgation of Appendix F, Procedure 1, would significantly increase recordkeeping and reporting requirements for affected facilities. They questioned whether the increase in labor and associated costs would yield a commensurate improvement in data quality. The Agency has eliminated a great deal of the data reduction and reporting requirements from the Procedure 1 proposal with the deletion of the precision determinations. The Agency believes it is not burdensome to require a source to supply audit results, drift assessments, and information about out-of-control periods with other compliance reports. Procedure 1 will not significantly increase the reporting requirements for sources using CEMS's for compliance monitoring.

One commenter proposed that Procedure 1 include a provision that would not preclude control agencies from taking into account QA results when reviewing CEMS data, but prohibit sources from doing so. The Agency's response is that it is technically incorrect to adjust CEMS data using RAA results. This applies to both the source owner/operator reporting the data and the control agency reviewing the results. Source operators must comply with reporting and recordkeeping requirements as they are written.

The bases for not allowing adjustment of CEMS results are the imprecision and error associated with both the CEMS and the audit method results. These measurement factors are the reason for allowing a range of audit results (e.g., 20 percent for the RATA) that indicates acceptable CEMS performance. In addition, the audits represent only a brief period of CEMS and process operation while compliance data represent relatively long periods of

operation. There is no technical basis for adjusting CEMS results using QA data. Quality assurance results should be considered only in assuring that the CEMS performance is within specifications.

Costs of Implementation

Five commenters recalculated the estimated labor-years required to implement Procedure 1 at Subpart Da sources and found the number to be 124 person-years instead of the 80 person-years mentioned in the proposed preamble. The Agency determined the labor needed to meet the Procedure 1 requirements in the industry recognizing that not all Subpart Da sources would be operating the entire evaluation period (5 years). The commenters' figures represent the worst case view, but the Agency's 80 person-year value is also a conservative figure that more closely represents the expected costs.

Many commenters noted that the level of effort included in the proposal substantially underestimates the expected costs, because the proposal has labor estimates based on an evaluation of a unit having only one SO_2 and one NO_x monitor. Subpart Da sources are required to monitor SO_2 control efficiency which dicates that uncontrolled SO_2 emissions and diluent gases also be monitored. The Agency underestimated the costs of implementing Procedure 1 at a Subpart Da source by a factor of two, according to the commenters.

The Agency agrees that the cost estimates in the proposal were derived for only an outlet CEMS. However, adding the costs incurred by including an inlet CEMS will not necessarily double the costs of applying Procedure 1. Many QA tasks can be consolidated and duplication avoided so that total costs should be considerably less than twice the conservative costs mentioned in the proposal.

There are a number of other changes incorporated into Procedure 1 since proposal that will decrease estimated costs of implementation. The precision assessment and reporting have been eliminated. The RATA has been changed to once annually instead of semiannually, and the CGA and abbreviated RAA are allowed the other three quarters. The Agency has estimated effort for implementing Procedure 1 based on the promulgation version and determined these costs to be between 326 and 704 labor hours per year for a Subpart Da facility depending on the type of audit used, CGA or RAA. This cost is consistent with the estimate described in the proposal and does not

significantly change the estimated effects on the industry.

The Agency believes that the benefits from providing useable, valid, compliance emission data apply to both the source operator and the regulatory agency. The expenses for implementing Procedure 1 are worthwhile for the increased confidence in demonstrating compliance and in instituting enforcement action. Source operators further benefit through the availability of continuous, valid information on the operation of the control system and can use such data to optimize operation.

Miscellaneous

One commenter suggested that the Agency should focus on the research and development of CEMS technology in developing less burdensome QA requirements. The Agency believes CEMS technology is sufficiently developed to apply it to continuous compliance determinations. Numerous, successful, long-term, CEMS demonstrations have been reported by both the Agency and by industrial users. There is no substantive reason for delaying the implementation of Procedure 1.

III. Docket

The docket is an organized and complete file of the information considered by EPA in the development of this rulemaking. The docket is a dynamic file, since material is added throughout the rulemaking development. The docketing system is intended to allow members of the public and industries involved to identify and locate documents readily so they can intelligently and effectively participate in the rulemaking process. Along with the statement of basis and purposes of the proposed and promulgated rule and EPA responses to significant comments, the contents of the docket will serve as the record in case of judicial review [section 307(d)(7)(a)].

IV. Miscellaneous

Under Executive Order 12291, EPA must judge whether a regulation is "major" and, therefore, subject to the requirement of a regulatory impact analysis. This regulation is not major because it will not have an annual effect on the economy of $100 million or more; it will not result in a major increase in costs or prices: and there will be no significant adverse effects on competition, employment, investment, productivity, innovation, or on the ability of U.S.-based entrprises to compete with foreign-based enterprises in domestic or export markets.

The Regulatory Flexibility Act of 1980 requires identification of potentially adverse impacts of Federal regulations upon small business entities. The Act specifically requires the completion of a Regulatory Flexibility Analysis in those instances where small business impacts are possible. Because this regulation affects only one source category, large utility boilers, and does not affect small business entities, no Regulatory Flexibility Analysis has been conducted.

Pursuant to the provisions of 5 U.S.C. 605(b), I hereby certify that the proposed rule will not have a significant economic impact on any small entities.

This regulation was submitted to the Office of Management and Budget (OMB) for review as required by Executive Order 12291. Any written comments from OMB and any written EPA responses are available in the docket.

Dated: May 27, 1987.

Lee M. Thomas,

Administrator.

List of Subjects in 40 CFR Part 60

Air pollution control, sulfur dioxide.

PART 60—[AMENDED]

40 CFR Part 60 is amended as follows:

1. The authority for testing, monitoring, and reporting in Part 60 continues to read.

Authority: Secs. 101, 111, 114, 116, 301 of the Clean Air Act, as amended 42 U.S.C. 7401, 7411, 7414, 7416, 7601.

2. Section 60.13 is amended by revising paragraph (a) to read as follows:

§ 60.13   Monitoring requirements.

(a) For the purposes of this section, all continuous monitoring systems required under applicable subparts shall be subject to the provisions of this section upon promulgation of peformance specifications for continuous monitoring systems under Appendix B to this part and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, Appendix F to this part, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987.

*   *   *   *   *

3. Section 60.45 is amended by revising paragraph (c)(1) to read as follows:

§ 60.45   Emission and fuel monitoring.

*   *   *   *   *

(c) *   *   *

(1) Methods 3 or 3A, 6, 6A, 6B or 6C, and 7, 7A, 7C, 7D or 7E, as applicable, shall be used for conducting relative accuracy evaluations of sulfur dioxide and nitrogen oxides continuous emission monitoring systems. Methods 3A, 6C, and 7E shall be used only at the sole discretion of the source owner or operator.

*   *   *   *   *

4. Section 60.47a is amended by revising paragraphs (h), (h)(1), (h)(2), and (i)(1) to read as follows:

§ 60.47a   Emission monitoring.

*   *   *   *   *

(h) Methods used to supplement continuous emission monitoring system data to meet the minimum data requirements in § 60.47a(f) will be used as specified below or as otherwise approved by the Administrator.

(1) Methods 3 or 3A, 6 or 6C and 7, 7A, 7C, 7D or 7E as applicable, are used. Method 6A or 6B may be used whenever Methods 6 and 3 data are required to determine the SO₂ emission rate in ng/J. Methods 3A, 6C, and 7E are used only at the sole discretion of the source owner or operator. The sampling location(s) are the same as those specified for the continuous emission monitoring system.

(2) For Method 6 or 6A, the minimum sampling is 20 minutes and the minimum sampling volume is 0.02 dsm³ (0.71 dscf) for each sample. Samples are collected at approximately 60-minute intervals. Each sample represents a 1-hour average. Method 6B shall be operated for 24 hours per sample, and the minimum sample volume is 0.02 dsm³ (0.71 dscf) for each sample. Each Method 6b sample represents 24 1-hour averages.

*   *   *   *   *

(i) *   *   *

(1) Methods 3 or 3A, 6, 6A, 6B or 6C, and 7, 7A, 7C, 7D or 7E, as applicable, are used for conducting relative accuracy evaluations of sulfur dioxide and nitrogen oxides continuous emission monitoring systems. Methods 3A, 6C, and 7E are used only at the sole discretion of the source owner or operator.

*   *   *   *   *

5. By adding Appendix F, Procedure 1, to read as follows:

Appendix F—Quality Assurance Procedures

Procedure 1. Quality Assurance Requirements for Gas Continuous Emission Monitoring Systems Used for Compliance Determination

1. Applicability and Principle

1.1   Applicability. Procedure 1 is used to evaluate the effectiveness of quality control (QC) and quality assurance (QA) procedures

and the quality of data produced by any continuous emission monitoring system (CEMS) that is used for determining compliance with the emission standards on a continuous basis as specified in the applicable regulation. The CEMS may include pollutant (e.g., SO_2 and NO_x) and diluent (e.g., O_2 or CO_2) monitors.

This procedure specifies the minimum QA requirements necessary for the control and assessment of the quality of CEMS data submitted to the Environmental Protection Agency (EPA). Source owners and operators responsible for one or more CEMS's used for compliance monitoring must meet these minimum requirements and are encouraged to develop and implement a more extensive QA program or to continue such programs where they already exist.

Data collected as a result of QA and QC measures required in this procedure are to be submitted to the Agency. These data are to be used by both the Agency and the CEMS operator in assessing the effectiveness of the CEMS QC and QA procedures in the maintenance of acceptable CEMS operation and valid emission data.

Appendix F, Procedure 1 is applicable December 4, 1987. The first CEMS accuracy assessment shall be a relative accuracy test audit (RATA) (see section 5) and shall be completed by March 4, 1988 or the date of the initial performance test required by the applicable regulation, whichever is later.

1.2 Principle. The QA procedures consist of two distinct and equally important functions. One function is the assessment of the quality of the CEMS data by estimating accuracy. The other function is the control and improvement of the quality of the CEMS data by implementing QC policies and corrective actions. These two functions form a control loop: When the assessment function indicates that the data quality is inadequate, the control effort must be increased until the data quality is acceptable. In order to provide uniformity in the assessment and reporting of data quality, this procedure explicitly specifies the assessment methods for response drift and accuracy. The methods are based on procedures included in the applicable performance specifications (PS's) in Appendix B of 40 CFR Part 60. Procedure 1 also requires the analysis of the EPA audit samples concurrent with certain reference method (RM) analyses as specified in the applicable RM's.

Because the control and corrective action function encompasses a variety of policies, specifications, standards, and corrective measures, this procedure treats QC requirements in general terms to allow each source owner or operator to develop a QC system that is most effective and efficient for the circumstances.

2. Definitions

2.1 Continuous Emission Monitoring System. The total equipment required for the determination of a gas concentration or emission rate.

2.2 Diluent Gas. A major gaseous constituent in a gaseous pollutant mixture. For combustion sources, CO_2 and O_2 are the major gaseous constituents of interest.

2.3 Span Value. The upper limit of a gas concentration measurement range that is

specified for affected source categories in the applicable subpart of the regulation.

2.4 Zero, Low-Level, and High-Level Values. The CEMS response values related to the source specific span value. Determination of zero, low-level, and high-level values is defined in the appropriate PS in Appendix B of this part.

2.5 Calibration Drift (CD). The difference in the CEMS output reading from a reference value after a period of operation during which no unscheduled maintenance, repair or adjustment took place. The reference value may be supplied by a cylinder gas, gas cell, or optical filter and need not be certified.

2.6 Relative Accuracy (RA). The absolute mean difference between the gas concentration or emission rate determined by the CEMS and the value determined by the RM's plus the 2.5 percent error confidence coefficient of a series of tests divided by the mean of the RM tests or the applicable emission limit.

3. QC Requirements

Each source owner or operator must develop and implement a QC program. As a minimum, each QC program must include written procedures which should describe in detail, complete, step-by-step procedures and operations for each of the following activities:

1. Calibration of CEMS.
2. CD determination and adjustment of CEMS.
3. Preventive maintenance of CEMS (including spare parts inventory).
4. Data recording, calculations, and reporting.
5. Accuracy audit procedures including sampling and analysis methods.
6. Program of corrective action for malfunctioning CEMS.

As described in Section 5.2, whenever excessive inaccuracies occur for two consecutive quarters, the source owner or operator must revise the current written procedures or modify or replace the CEMS to correct the deficiency causing the excessive inaccuracies.

These written procedures must be kept on record and available for inspection by the enforcement agency.

4. CD Assessment

4.1 CD Requirement. As described in 40 CFR Part 60.13(d), source owners and operators of CEMS must check, record, and quantify the CD at two concentration values at least once daily (approximately 24 hours) in accordance with the method prescribed by the manufacturer. The CEMS calibration must, as minimum, be adjusted whenever the daily zero (or low-level) CD or the daily high-level CD exceeds two times the limits of the applicable PS's in Appendix B of this regulation.

4.2 Recording Requirement for Automatic CD Adjusting Monitors. Monitors that automatically adjust the data to the corrected calibration values (e.g., microprocessor control) must be programmed to record the unadjusted concentration measured in the CD prior to resetting the calibration, if performed, or record the amount of adjustment.

4.3 Criteria for Excessive CD. If either the zero (or low-level) or high-level CD result

exceeds twice the applicable drift specification in Appendix B for five consecutive, daily periods, the CEMS is out-of-control. If either the zero (or low-level) or high-level CD result exceeds four times the applicable drift specification in Appendix B during any CD check, the CEMS is out-of-control. If the CEMS is out-of-control, take necessary corrective action. Following corrective action, repeat the CD checks.

4.3.1 Out-Of-Control Period Definition. The beginning of the out-of-control period is the time corresponding to the completion of the fifth, consecutive, daily CD check with a CD in excess of two times the allowable limit, or the time corresponding to the completion of the daily CD check preceding the daily CD check that results in a CD in excess of four times the allowable limit. The end of the out-of-control period is the time corresponding to the completion of the CD check following corrective action that results in the CD's at both the zero (or low-level) and high-level measurement points being within the corresponding allowable CD limit (i.e., either two times or four times the allowable limit in Appendix B).

4.3.2 CEMS Data Status During Out-of-Control Period. During the period the CEMS is out-of-control, the CEMS data may not be used in calculating emission compliance nor be counted towards meeting minimum data availability as required and described in the applicable subpart [e.g., § 60.47a(f)].

4.4 Data Recording and Reporting. As required in § 60.7(d) of this regulation (40 CFR Part 60), all measurements from the CEMS must be retained on file by the source owner for at least 2 years. However, emission data obtained on each successive day while the CEMS is out-of-control may not be included as part of the minimum daily data requirement of the applicable subpart (e.g., § 60.47a(f)] nor be used in the calculation of reported emissions for that period.

5. Data Accuracy Assessment

5.1 Auditing Requirements. Each CEMS must be audited at least once each calendar quarter. Successive quarterly audits shall occur no closer than 2 months. The audits shall be conducted as follows:

5.1.1 Relative Accuracy Test Audit (RATA). The RATA must be conducted at least once every four calendar quarters. Conduct the RATA as described for the RA test procedure in the applicable PS in Appendix B (e.g., PS 2 for SO_2 and NO_x). In addition, analyze the appropriate performance audit samples received from EPA as described in the applicable sampling methods (e.g., Methods 6 and 7).

5.1.2 Cylinder Gas Audit (CGA). If applicable, a CGA may be conducted in three of four calendar quarters, but in no more than three quarters in succession.

To conduct a CGA: (1) Challenge the CEMS (both pollutant and diluent portions of the CEMS, if applicable) with an audit gas of known concentration at two points within the following ranges:

Please note that section 5.2 - Criteria for Excessive Inaccuracy has not
been published correctly and should be as follows:

5.2 Criteria for Excessive Inaccuracy. If the RA, using
the RATA, exceeds 20 percent or 10 percent of the applicable   -
standard, whichever is greater, the CEMS is out-of-control.
For SO_2 emission standards between 100 and 86 ng/J (0.30 and
0.20 lb/million BTU), use 15 percent of the applicable standard;
below 86 ng/J (0.20 lb/million BTU), use 20 perent of the
applicable standard. If the inaccuracy exceeds $\pm$ 15 percent
using the CGA or the RAA or, for the RAA, 7.5 percent of the
applicable standard, whichever is greater, the CEMS is out-of-
control. If the CEMs is out-of-control, then corrective action
must be taken and following the corrective action the source
owner or operator must audit the CEMs accuracy with a RATA,
CGA or RAA. RATA must always be used following an out-of-control
period resulting from a RATA. The CEMS audit following corrective   °
action does not require the analysis of EPA performance audit
samples. If accuracy audit results show the CEMS to be out-of-
control the CEMS operator shall report both the audit showing the
CEMS to be out-of-control and the result of the audit following
corrective action showing the CEMS to be operating within   .
specifications.

Audit point	Audit range		
	Pollutant monitors	Diluent monitors for—	
		CO₂	O₂
1	20 to 30% of span value.	5 to 8% by volume.	4 to 8% by volume.
2	50 to 60% of span value.	10 to 14% by volume.	8 to 12% by volume.

Challenge the CEMS three times at each audit point, and use the average of the three responses in determining accuracy.

Use of separate audit gas cylinder for audit points 1 and 2. Do not dilute gas from audit cylinder when challenging the CEMS.

The monitor should be challenged at each audit point for a sufficient period of time to assure adsorption-desorption of the CEMS sample transport surfaces has stabilized.

(2) Operate each monitor in its normal sampling mode, i.e., pass the audit gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling, and as much of the sampling probe as is practical. At a minimum, the audit gas should be introduced at the connection between the probe and the sample line.

(3) Use audit gases that have been certified by comparision to National Bureau of Standards (NBS) gaseous Standard Reference Materials (SRM's) or NBS/EPA approved gas manufacturer's Certified Reference Materials (CRM's) (See Citation 1) following EPA Traceability Protocol No. 1 (See Citation 2). As an alternative to Protocol No. 1 audit gases, CRM's may be used directly as audit gases. A list of gas manufacturers that have prepared approved CRM's is available from EPA at the address shown in Citation 1. Procedures for preparation of CRM's are described in Citation 1. Procedures for preparation of EPA Traceability Protocol 1 materials are described in Citation 2.

The difference between the actual concentration of the audit gas and the concentration indicated by the monitor is used to assess the accuracy of the CEMS.

5.1.3 Relative Accuracy Audit (RAA). The RAA may be conducted three of four calendar quarters, but in no more than three quarters in succession. To conduct a RAA, follow the procedure described in the applicable PS in Appendix B for the relative accuracy test, except that only three sets of measurement data are required. Analyses of EPA performance audit samples are also required.

The relative difference between the mean of the RM values and the mean of the CEMS responses will be used to assess the accuracy of the CEMS.

5.1.4 Other Alternative Audits. Other alternative audit procedures may be used as approved by the Administrator for three of four calendar quarters. One RATA is required at least once every four calendar quarters.

5.2 Criteria for Excessive Inaccuracy. If the RA, using the RATA, exceeds 20 percent or 10 percent of the applicable standard, whichever is greater, the CEMS is out-of-control. For SO₂ emission standards between 130 and 86 ng/J (0.30 and 0.20 lb/million Btu), use 15 percent of the applicable standard; below 86 ng/J (0.20 ng/J) (0.20 lb/million Btu),

use 20 percent of emission standard. If the inaccuracy exceeds ±15 percent using the CGA or the RAA, or, for the RAA, 7.5 percent of the applicable standard, whichever is greater, the CEMS is out-of-control. If the CEMS is out-of-control, corrective action, the source owner or operator must audit the CEMS accuracy with a RATA, CGA, or RATA must always be used following an out-of-control period resulting from a RATA. The audit following corrective action does not require analysis of EPA performance audit samples. If accuracy audit results show the CEMS to be out-of-control, the CEMS operator shall report both the audit showing the dems to be out-of-control and the results of the audit following corrective action showing the CEMS to be operating within specifications.

5.2.1 Out-Of-Control Period Definition. The beginning of the out-of-control period is the time corresponding to the completion of the sampling for the RATA, RAA, or CGA. The end of the out-of-control period is the time corresponding to the completion of the sampling of the subsequent successful audit.

5.2.2 CEMS Data Status During Out-Of-Control Period. During the period the monitor is out-of-control, the CEMS data may not be used in calculating emission compliance nor be counted towards meeting minimum data availability as required and described in the applicable subpart [e.g., § 60.47a(f)].

5.3 Criteria for Acceptable QC Procedure. Repeated excessive inaccuracies (i.e., out-of-control conditions resulting from the quarterly audits) indicates the QC procedures are inadequate or that the CEMS is incapable of providing quality data. Therefore, whenever excessive inaccuracies occur for two consecutive quarters, the source owner or operator must revise the QC procedures (see Section 3) or modify or replace the CEMS.

6. *Calculations for CEMS Data Accuracy*

6.1 RATA RA Calculation. Follow the equations described in Section 8 of Appendix B, PS 2 to calculate the RA for the RATA. The RATA must be calculated in units of the applicable emission standard (e.g., ng/J).

6.2 RAA Accuracy Calculation. Use Equation 1–1 to calculate the accuracy for the RAA. The RAA must be calculated in units of the applicable emission standard (e.g., ng/J).

6.3 CGA Accuracy Calculation. Use Equation 1–1 to calculate the accuracy for the CGA, which is calculated in units of the appropriate concentration (e.g., ppm SO₂ or percent O₂). Each component of the CEMS must meet the acceptable accuracy requirement.

$$A = \frac{C_m - C_a}{C_a} \times 100 \qquad \text{Eq. 1–1}$$

where:

A = Accuracy of the CEMS, percent.
C_m = Average CEMS response during audit in units of applicable standard or appropriate concentration.
C_a = Average audit value (CGA certified value or three-run average for RAA) in units of applicable standard or appropriate concentration.

6.4 Example Accuracy Calculations. Example calculations for the RATA, RAA, and CGA are available in Citation 3.

7. *Reporting Requirements*

At the reporting interval specified in the applicable regulation, report for each CEMS the accuracy results from Section 6 and the CD assessment results from Section 4. Report the drift and accuracy information as a Data Assessment Report (DAR), and include one copy of this DAR for each quarterly audit with the report of emissions required under the applicable subparts of this part.

As a minimum, the DAR must contain the following information:

1. Source owner or operator name and address.

2. Identification and location of monitors in the CEMS.

3. Manufacturer and model number of each monitor in the CEMS.

4. Assessment of CEMS data accuracy and date of assessment as determined by a RATA, RAA, or CGA described in Section 5 including the RA for the RATA, the A for the RAA or CGA, the RM results, the cylinder gases certified values, the CEMS responses, and the calculations results as defined in Section 6. If the accuracy audit results show the CEMS to be out-of-control, the CEMS operator shall report both the audit results showing the CEMS to be out-of-control and the results of the audit following corrective action showing the CEMS to be operating within specifications.

5. Results from EPA performance audit samples described in Section 5 and the applicable RM's.

6. Summary of all corrective actions taken when CEMS was determined out-of-control, as described in Sections 4 and 5.

An example of a DAR format is shown in Figure 1.

8. *Bibliography*

1. "A Procedure for Establishing Traceability of Gas Mixtures to Certain National Bureau of Standards Standard Reference Materials." Joint publication by NBS and EPA-600/7-81-010. Available from the U.S. Environmental Protection Agency. Quality Assurance Division (MD-77). Research Triangle Park, North Carolina 27711.

2. "Traceability Protocol for Establishing True Concentrations of Gases Used for Calibration and Audits of Continuous Source Emission Monitors (Protocol Number 1)" June 1978. Section 3.0.4 of the Quality Assurance Handbook for Air Pollution Measurement Systems. Volume III. Stationary Source Specific Methods. EPA-600/4-77-027b. August 1977. U.S. Environmental Protection Agency. Office of Research and Development Publications. 26 West St. Clair Street. Cincinnati, Ohio 45268.

3. Calculation and Interpretation of Accuracy for Continuous Emission Monitoring Systems (CEMS). Section 3.0.7 of the Quality Assurance Handbook for Air Pollution Measurement Systems. Volume III. Stationary Source Specific Methods. EPA-600/4-77-027b. August 1977. U.S. Environmental Protection Agency. Office of

Research and Development Publications. 26 West St. Clair Street, Cincinnati, Ohio 45288.

Figure 1. Example Format for Data Assessment Report

Period ending date ————————
Year ——————————————
Company name ———————————
Plant name ————————————
Source unit no. ———————————
CEMS manufacturer ————————
Model no. ————————————
CEMS serial no. ————————
CEMS type (e.g., in situ)——————
CEMS sampling location (e.g., control device outlet)——————————————
CEMS span values as per the applicable regulation. SO2 ———— ppm, O2 ————
percent, NOx ———— ppm, CO2 ————
percent

L. Accuracy assessment results (Complete A, B, or C below for each CEMS or for each pollutant and diluent analyzer, as applicable.) If the quarterly audit results show the CEMS to be out-of-control, report the results of both the quarterly audit and the audit following corrective action showing the CEMS to be operating properly.

A. Relative accuracy test audit (RATA) for
———— (e.g., SO2 in ng/J).
  1. Date of audit ————
  2. Reference methods (RM's) used ————
(e.g., Methods 3 and 6).
  3. Average RM value ———— (e.g., ng/J, mg/dsm³, or percent volume).
  4. Average CEMS value ————
  5. Absolute value of mean difference [d]
————
  6. Confidence coefficient [CC] ————
  7. Percent relative accuracy (RA) ————
percent.
  8. EPA performance audit results:
  a. Audit lot number (1) ———— (2)
————
  b. Audit sample number (1) ———— (2)
————
  c. Results (mg/dsm³) (1) ———— (2)
————
  d. Actual value (mg/dsm³)· (1) ———— (2)
————
  e. Relative error· (1) ———— (2) ————
B. Cylinder gas audit (CGA) for ————
(e.g., SO2 in ppm).

	Audit point 1	Audit point 2
1. Date of audit	————	
2. Cylinder ID number.	————	
3. Date of certification.	————	
4. Type of certification.	————	(e.g., EPA Protocol 1 or CRM).
5. Certified audit value.	————	(e.g., ppm).
6. CEMS response value.	————	(e.g., ppm).
7. Accuracy	————	percent.

C. Relative accuracy audit (RAA) for
———— (e.g., SO2 in ng/J).
  1. Date of audit ————

  2. Reference methods (RM's) used ————
(e.g., Methods 3 and 6).
  3. Average RM value ———— (e.g., ng/J).
  4. Average CEMS value ————
  5. Accuracy ———— percent.
  6. EPA performance audit results:
  a. Audit lot number (1) ———— (2)
————
  b. Audit sample number (1) ———— (2)
————
  c. Results (mg/dsm³) (1) ———— (2)
————
  d. Actual value (mg/dsm³) ·(1) ———— (2)
  e. Relative error· (1) ———— (2) ————
D. Corrective action for excessive inaccuracy.
  1. Out-of-control periods.
  a. Date(s) ————
  b. Number of days ————
  2. Corrective action taken ————

  3. Results of audit following corrective action. (Use format of A, B, or C above, as applicable.)
II. Calibration drift assessment.
A. Out-of-control periods.
  1. Date(s) ————
  2. Number of days ————
B. Corrective action taken————

**3.0.4. PROCEDURE FOR NBS-TRACEABLE CERTIFICATION OF COMPRESSED
GAS WORKING STANDARDS USED FOR CALIBRATION AND
AUDIT OF CONTINUOUS SOURCE EMISSION MONITORS
(Revised Traceability Protocol No. 1)**

CONTENTS

4.0 GENERAL INFORMATION

4.0.1 Purpose and Scope of the Procedure

Section 3.0.4 describes a procedure for assaying the concentration of gaseous pollutant concentration standards and certifying that the assay concentrations are traceable to an authoritative reference concentration standard. This procedure is recommended for certifying the local working concentration standards required by the pollutant monitoring regulations of 40 CFR Part 60[1,2] for the calibration and audit of continuous source emission monitors. The procedure covers certification of compressed gas (cylinder) standards for CO, CO_2, NO, NO_2, and SO_2 (Procedure G1).

4.0.2 Reference Standards

Part 60 of the monitoring regulations[1,2] require that working standards used for calibration and audit of continuous source emission monitors be traceable to either a National Bureau of Standards (NBS) gaseous Standard Reference Material (SRM) or a NBS/EPA-approved Certified Reference Material (CRM)[3]. Accordingly, the reference standard used for assaying and certifying a working standard for these purposes must be an SRM, a CRM, or a suitable intermediate standard (see the next paragraph). SRM cylinder gas standards available from NBS are listed in Table 7.2 at the end of subsection 4.0. A current list of CRM cylinder gases and CRM vendors is available from the Quality Assurance Division (MD-77), Environmental Monitoring Systems Laboratory, U. S. EPA, Research Triangle Park, NC 27711.

The EPA regulations define a "traceable" standard as one which "...has been compared and certified, either directly or via not more than one intermediate standard, to a primary standard such as a...NBS [gaseous] SRM or...CRM"[4,5]. Certification of a working standard directly to an SRM or CRM primary standard is, of course, preferred and recommended because of the lower error. However, an intermediate reference standard is permitted, if necessary. In particular, a Gas Manufacturer's Intermediate Standard (see subsection 4.0.2.1) that has been referenced directly to an SRM or a CRM according to Procedure G1 is an acceptable intermediate standard and could be used as the reference standard on that basis. However, purchasers of com-

mercial gas standards referenced to an intermediate standard such as a GMIS should be aware that, according to the above definition, such a standard would have to be used directly for calibration or audit. Since a second intermediate standard is not permitted, such a standard could not be used as a reference standard to certify other standards.

4.0.2.1 Gas Manufacturer's Intermediate Standard (GMIS). A GMIS is a compressed (cylinder) gas standard that has been assayed with direct reference to an SRM or CRM and certified according to Procedure G1, and also meets the following requirements:

1. A candidate GMIS must be assayed a minimum of three (3) times, uniformly spaced over a three (3) month period.

2. Each of the three (or more) assays must be within 1.0 percent of the mean of the three (or more) assays.

3. The difference between the last assay and the first assay must not exceed 1.5 percent of the mean of the three (or more) assays.

4. The GMIS must be recertified every three months, and the reassay must be within 1.5 percent of the previous certified assay. The recertified concentration of the GMIS is the mean of the previous certified concentration and the reassay concentration.

4.0.2.2 Recertification of Reference Standards. Recertification requirements for SRMs and CRMs are specified by NBS and NBS/EPA, respectively. See 4.0.2.1 for GMIS recertification requirements.

4.0.3 Using the Procedure

The assay/certification procedure described here is carefully designed to minimize both systematic and random errors in the assay process. Therefore, the procedure should be carried out as closely as possible to the way it is described. Similarly, the assay apparatus has been specifically designed to minimize errors and should be configured as closely as possible to the design specified. Good laboratory practice should be observed in the selection of inert materials (e.g. Teflon, stainless steel, or glass, if possible) and clean, non-contaminating components for use in portions of the apparatus in contact with the candidate or reference gas concentrations.

4.0.4 Certification Documentation

Each assay/certification must be documented in a written certification report signed by the analyst and containing at least the following information:

1. Identification number (cylinder number).

2. Certified concentration of the standard, in ppm or mole percent.

3. Balance gas in the standard mixture.

4. Cylinder pressure at certification.

5. Date of the assay/certification.

6. Certification expiration date (see 4.0.6.3).

7. Identification of the reference standard used: SRM number, cylinder number, and concentration for an SRM; cylinder number and concentration for a CRM or GMIS.

8. Statement that the assay/certification was performed according to this Section 3.0.4.

9. Identification of the laboratory where the standard was certified and the analyst who performed the certification.

10. Identification of the gas analyzer used for the certification, including the make, model, serial number, the measurement principle, and the date of the last multipoint calibration.

11. All analyzer readings used during the assay/certification and the calculations used to obtain the reported certified value.

12. Chronological record of all certifications for the standard.

Certification concentrations should be reported to 3 significant digits. Certification documentation should be maintained for at least 3 years.

4.0.5 Certification Label

A label or tag bearing the information described in items 1 through 9 of subsection 4.0.4 must be attached to each certified gas cylinder.

4.0.6 Assay/Certification of Compressed Gas (Cylinder) Standards

4.0.6.1 Aging of newly-prepared gas standards. Freshly prepared gas standard concentrations and newly filled gas cylinders must be aged before being assayed and certified. SO_2 concentrations contained in steel cylinders must be aged at least 15 days; other standards must be aged at least 4 days.

4.0.6.2 Stability test for reactive gas standards. Reactive gas standards, including nitric oxide (NO), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), and carbon monoxide (CO), that have not been previously certified must be tested for stability as follows: Reassay the concentration at least 7 days after the first assay and compare the two assays. If the second assay differs from the first assay by 1.5% or less, the cylinder may be considered stable, and the mean of the two assays should be reported as the certified concentration. Otherwise, age the cylinder for a week or more and repeat the test, using the second and third assays as if they were the first and second assays. Cylinders that are not stable may not be sold and/or used for calibration or audit purposes.

4.0.6.3 Recertification of compressed gas standards. Compressed gas standards must be recertified according to this Section 3.0.4 within the time limits specified in Table 7.1[3,6,7]. The reassay concentration must be within 5% of the previous certified concentration. If not, the cylinder must be retested for stability (subsection 4.0.6.2). The certified concentration of a recertified standard should be reported as the mean of all assays, unless a clear trend or substantial change suggests that previous assays are no longer valid.

Table 7.1 Recertification limits for compressed gas standards.

Pollutant	Balance gas	Concentration range	Maximum months until recertification for cylinder material:	
			Al or SS	other
Carbon monoxide	N_2 or air	≥ 5 ppm	18	6
Nitric oxide	N_2	≥ 10 ppm	18	6
Sulfur dioxide	N_2	≥ 10 ppm	18	6
Nitrogen dioxide	N_2 or air	≥ 10 ppm	6	6
Carbon dioxide	N_2 or air	≥ 300 ppm	18	18
Oxygen	N_2	≥ 2 percent	18	18
Sulfur dioxide and carbon dioxide	N_2	≥ 200 ppm SO_2, ≥ 10 percent CO_2	18	6
Propane	N_2 or air	≥ 5 ppm	18	6
Others not specifically listed			6	6

4.0.6.4 Minimum cylinder pressure. No compressed gas cylinder standard should be used when its gas pressure is below 700 kPa (100 psi), as indicated by the cylinder pressure gauge.

4.0.6.5 Assay/certification of multi-component compressed gas standards. Procedure G1 may be used to assay and certify individual components of multi-component gas standards, provided that none of the components other than the component being assayed cause a detectable response on the analyzer.

4.0.7 Analyzer Calibration

4.0.7.1 Basic analyzer calibration requirements. The assay procedure described in this Section 3.0.4 employs a direct ratio referencing technique that inherently corrects for minor analyzer calibration variations (drift) and DOES NOT depend on the absolute accuracy of the analyzer calibration.   What is required of the analyzer is as follows: 1) it must have a linear response to the pollutant of interest (see subsection 4.0.7.5), 2) it must have good resolution and low noise, 3) its response calibration must be reasonably stable during the assay/certification process, and 4) all assay concentration measurements must fall within the calibrated response range of the analyzer.

4.0.7.2 Analyzer multipoint calibration.   The gas analyzer used for the assay/ certification must have had a multipoint calibration within 3 months of its use when used with this procedure. This calibration is not used to quantitatively interpret analyzer readings during the assay/certification of the candidate gas because a more accurate, direct ratio comparison of the candidate concentration to the reference standard concentration is used. However, this multipoint calibration is necessary to establish the calibrated range of the analyzer and its response linearity.
     The multipoint calibration should consist of analyzer responses to at least 5 concentrations, including zero, approximately evenly spaced over the concentration range. Analyzer response units may be volts, millivolts, percent of scale, or other measurable analyzer response units.   The upper range limit of the calibrated range is determined by the highest calibration point used. If the analyzer has a choice of concentration ranges, the optimum range for the procedure should be selected and calibrated.   Plot the calibration points and compute the linear regression slope and intercept.   See subsection 4.0.7.5 for linearity requirements and the use of a mathematical transformation, if needed. The intercept should be less than 1 percent of the upper concentration range limit, and the correlation coefficient (r) should be at least 0.999.

4.0.7.3 Zero and span check and adjustment.   On each day that the analyzer will be used for assay/certification, its response calibration must be checked with a zero and at least one span concentration near the upper concentration range limit. If necessary, the zero and span controls of the analyzer should be adjusted so that the analyzer's response (i.e. calibration slope) is within about ±5 percent of the response indicated by the most recent multipoint calibration. If a zero or span adjustment is made, allow the analyzer to stabilize for at least an hour or more before beginning the assay procedure, since some analyzers drift for a period of time following zero or span adjustment. If the analyzer is not in continuous operation, turn it on and allow it to stabilize for at least 12 hours before the zero and span check.

4.0.7.4 Pollutant standard for multipoint calibration and zero and span adjustment. The pollutant standard or standards used for multipoint calibration or zero and span checks or adjustments must be obtained from a compressed gas standard certified traceable to an NBS SRM or a NBS/EPA CRM according to Procedure G1 of this Section 3.0.4. This standard need not be the same as the reference standard used in the assay/certification. The zero gas must meet the requirements in subsection 4.0.8.

4.0.7.5 <u>Linearity of analyzer response</u>. The direct ratio assay technique used in Procedure G1 requires that the analyzer have a linear response to concentration. Linearity is determined by comparing the quantitative difference between a smoothly-drawn calibration curve based on all calibration points and a straight line drawn between zero and an upper reference point (see Figure 1). This difference is measured in concentration units, parallel to the concentration axis, from a point on the calibration curve to the corresponding point for the same response on the straight line.

For the general linearity requirement, the straight line is drawn between zero and the highest calibration point (Figure 1a). Linearity is then acceptable when no point on the smooth calibration curve deviates from the straight line by more than 1.5 percent of the value of the highest calibration concentration. An alternative linearity requirement is defined on the basis of the actual reference and candidate concentrations to be used for the assay. In this case, the reference and candidate concentrations are plotted on the calibration curve, and the straight line is drawn from zero to the reference concentration and extrapolated, if necessary, beyond the candidate concentration (Figure 1b). The deviation of the smooth calibration curve from the straight line at the candidate concentration point then must not exceed 0.8 percent of the value of the reference concentration. This latter specification may allow the use of an analyzer having greater nonlinearity when the reference and candidate concentrations are nearly the same.

For analyzers having an inherently non-linear response, the response can usually be linearized with a simple mathematical transformation of the response values, such as $R' =$ square root(R) or $R' = \log(R)$, where R' is the transformed response value and R is the actual analyzer response value. Using the transformed response values, the multipoint calibration should meet one of the above linearity requirements as well as the requirements for intercept and correlation coefficient given in subsection 4.0.7.2.

4.0.8 Zero Gas

Zero gas used for dilution of any candidate or reference standard should be clean, dry, zero-grade air or nitrogen containing a concentration of the pollutant of interest equivalent to less than 0.5 percent of the analyzer's upper range limit concentration. The zero gas also should contain no contaminant that causes a detectable response on the analyzer or that suppresses or enhances the analyzer's response to the pollutant. The oxygen content of zero air should be the same as that of ambient air.

4.0.9 Accuracy Assessment of Commercially Available Standards

Periodically, the USEPA will assess the accuracy of commercially available compressed gas standards that have been assayed and certified according to this Section 3.0.4. Accuracy will be assessed by EPA audit analysis of representative actual commercial standards obtained via an anonymous agent. The accuracy audit results, identifying the actual gas manufacturers or vendors, will be published as public information.
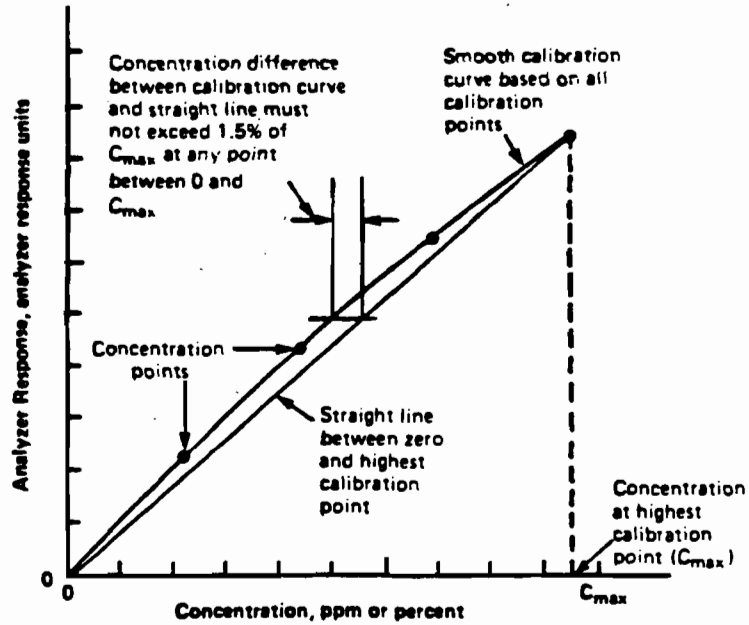
a) General linearity requirement
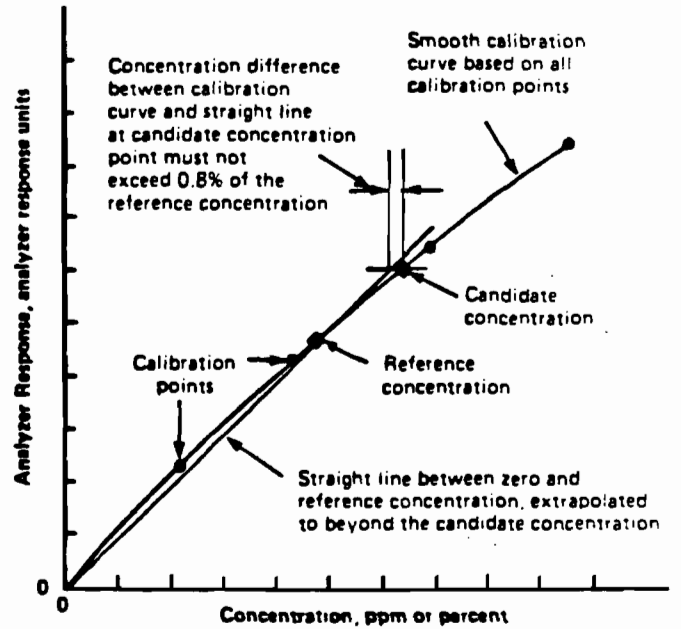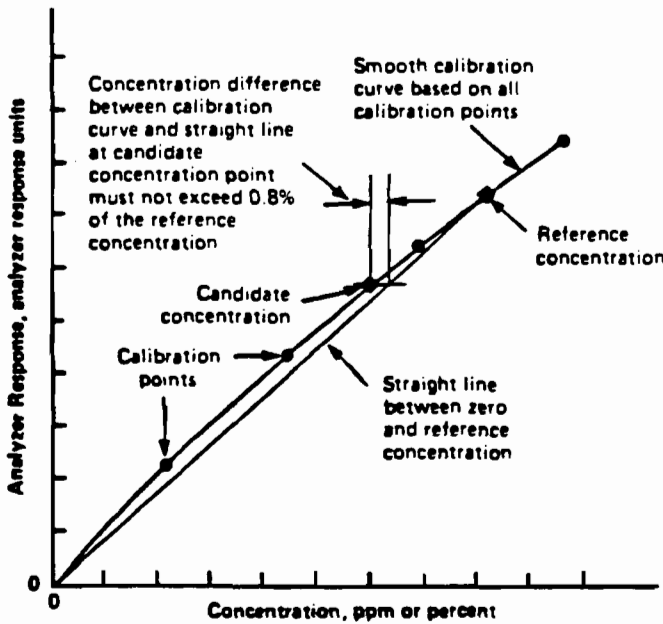
b) Alternative linearity requirement

Figure 1. Illustration of linearity requirements.

Table 7.2.   NBS SRM reference gases.

SRM number	Type	Nominal concentration		SRM number	Type	Nominal concentration	
2627	NO/N_2	5	ppm	1693	SO_2/N_2	50	ppm
2628	NO/N_2	10	ppm	1694	SO_2/N_2	100	ppm
2629	NO/N_2	20	ppm	1661a	SO_2/N_2	500	ppm
1683b	NO/N_2	50	ppm	1662a	SO_2/N_2	1000	ppm
1684b	NO/N_2	100	ppm	1663a	SO_2/N_2	1500	ppm
1685b	NO/N_2	250	ppm	1664a	SO_2/N_2	2500	ppm
1686b	NO/N_2	500	ppm	1696	SO_2/N_2	3500	ppm
1687b	NO/N_2	1000	ppm				
2630	NO/N_2	1500	ppm	1670	CO_2/Air	330	ppm
2631	NO/N_2	3000	ppm	1671	CO_2/Air	340	ppm
				1672	CO_2/Air	350	ppm
2653	NO_2/Air	250	ppm				
2654	NO_2/Air	500	ppm	2632	CO_2/N_2	300	ppm
2655	NO_2/Air	1000	ppm	2633	CO_2/N_2	400	ppm
2656	NO_2/Air	2500	ppm	2634	CO_2/N_2	800	ppm
				2619a	CO_2/N_2	0.5	percent
2612a	CO/Air	10	ppm	2620a	CO_2/N_2	1.0	percent
2613a	CO/Air	20	ppm	2621a	CO_2/N_2	1.5	percent
2614a	CO/Air	45	ppm	2622a	CO_2/N_2	2.0	percent
				2623a	CO_2/N_2	2.5	percent
1677c	CO/N_2	10	ppm	2624a	CO_2/N_2	3.0	percent
2635	CO/N_2	25	ppm	2625a	CO_2/N_2	3.5	percent
1678c	CO/N_2	50	ppm	2626a	CO_2/N_2	4.0	percent
1679c	CO/N_2	100	ppm	1674b	CO_2/N_2	7.0	percent
2636	CO/N_2	250	ppm	1675b	CO_2/N_2	14.0	percent
1680c	CO/N_2	500	ppm				
1681c	CO/N_2	1000	ppm	1665b	C_3H_8/Air	3	ppm
2637	CO/N_2	2500	ppm	1666b	C_3H_8/Air	10	ppm
2638	CO/N_2	5000	ppm	1667b	C_3H_8/Air	50	ppm
2639	CO/N_2	1	percent	1668b	C_3H_8/Air	100	ppm
2640	CO/N_2	2	percent	1669b	C_3H_8/Air	500	ppm
2641	CO/N_2	4	percent				
2642	CO/N_2	8	percent	2643	C_3H_8/N_2	100	ppm
				2644	C_3H_8/N_2	250	ppm
2657	O_2/N_2	2	percent	2645	C_3H_8/N_2	500	ppm
2658	O_2/N_2	10	percent	2646	C_3H_8/N_2	1000	ppm
2659	O_2/N_2	21	percent	2647	C_3H_8/N_2	2500	ppm
				2648	C_3H_8/N_2	5000	ppm
				2649	C_3H_8/N_2	1	percent
				2650	C_3H_8/N_2	2	percent

NBS-SRM cylinders contain approximately 870 liters of gas at STP.

For availability, contact: Office of Standard Reference Materials
Chemistry Building, Room B311
NBS, Gaithersburg, Maryland 20899
(301) 975-6776.   (FTS 879-6776)

4.1 PROCEDURE G1: ASSAY AND CERTIFICATION OF A COMPRESSED GAS STANDARD WITHOUT DILUTION

4.1.1 Applicability

This procedure may be used to assay the concentration of a candidate compressed gas (cylinder) pollutant standard, based on the concentration of a compressed gas (cylinder) reference standard of the same pollutant compound, and certify that the assayed concentration thus established for the candidate standard is traceable to the reference standard. The procedure employs a pollutant gas analyzer to compare the candidate and reference gas concentrations by direct measurement--without dilution of either gas--to minimize assay error.

4.1.2 Limitations

1. The concentration of the candidate gas standard must be between 0.3 and 1.3 times the concentration of the reference gas standard.

2. The analyzer must have a calibrated range capable of directly measuring both the candidate and the reference gas concentrations.

3. The analyzer's response (or transformed response) must be linear with respect to concentration.

4. The balance gas in both the candidate and reference standards must be identical, unless it can be shown that the analyzer is insensitive to any difference in the balance gases.

5. A source of clean, dry zero gas is required.

4.1.3 Assay Apparatus

Figure G1 illustrates the relatively simple assay apparatus. The configuration is designed to allow convenient routing of the zero gas and undiluted samples of the reference gas and candidate gases, in turn, to the analyzer for measurement, as selected by three-way valves V1 and V2. Pressure regulators and needle valves (V3 and V4) control the individual gas flows. The pollutant concentrations are delivered to the analyzer via a vented tee, which discharges excess flow and insures that the assay concentrations sampled by the analyzer are always at a fixed (atmospheric) pressure. A small, uncalibrated rotameter monitors the vent flow to verify that the total gas flow rate exceeds the sample flow rate demand of the analyzer so that no room air is admitted through the vent. Valves V1 and V2 could be replaced by a single four-way valve (with 3 inputs and 1 output) or by manually moving the output connection to each of the gases as needed. See also subsection 4.0.3.

4.1.4 Analyzer

See subsection 4.0.7.1. The pollutant gas analyzer must have a linear response function and a calibrated range capable of measuring the full concentration of both the candidate and the reference gas standards directly, without dilution. It must
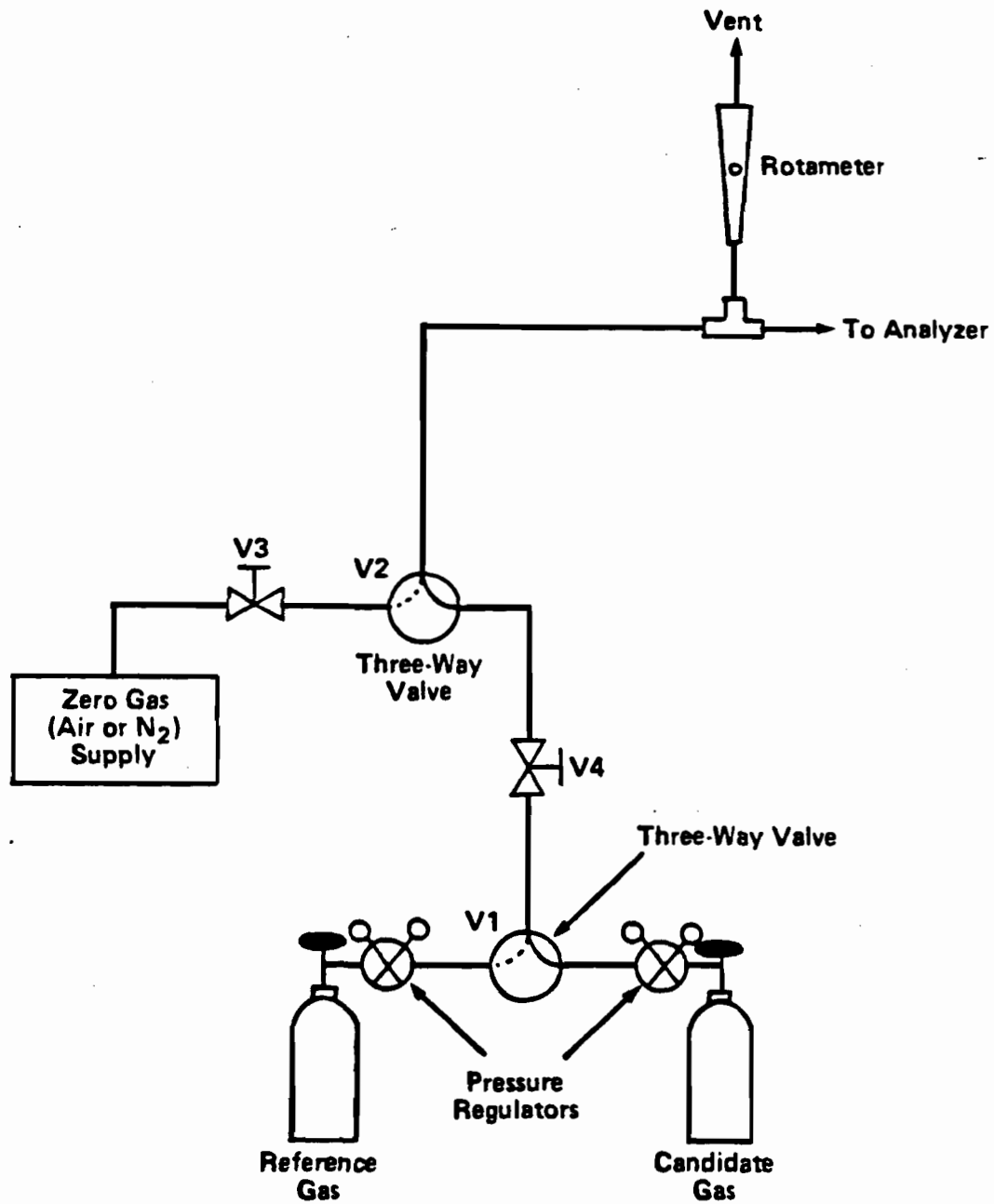
Figure G1.   Suggested assay apparatus for Procedure G1.

have good resolution (readability), good precision, a stable response, and low output signal noise. In addition, the analyzer must have good specificity for the pollutant of interest so that it has no detectable response to any contaminant that may be contained in either the candidate or reference gas. If the candidate and reference gases contain dissimilar balance gases (air versus nitrogen or different proportions of oxygen in the balance air, for example), the analyzer must be proven to be insensitive to the two different balance gases. This may be accomplished by showing no difference in analyzer response when measuring pollutant concentrations diluted with identical flow rates of the two balance gases.

The analyzer should be connected to a suitable, precision chart recorder or other data acquisition device to facilitate graphical observation and documentation of the analyzer responses obtained during the assay.

4.1.5 Analyzer Calibration

4.1.5.1 Multipoint calibration. See subsections 4.0.7.2 and 4.0.7.4.

4.1.5.2 Calibration range. The calibrated range of the analyzer must include both the candidate and reference gas concentrations, such that the higher concentration does not exceed 97 percent of the upper range limit, and the lower concentration is not below 25 percent of the upper range limit (assuming a lower range limit of zero). Within these limits, select a calibrated analyzer range that will produce the highest analyzer responses.

4.1.5.3 Linearity. The direct ratio assay technique used in this procedure requires that the analyzer have a linear response to concentration (see subsection 4.0.7.5). High-concentration-range analyzers of the type that are required for this procedure may not be inherently linear, but they usually have a predictable, non-linear response characteristic that can be mathematically transformed to produce a sufficiently linear response characteristic suitable for use in this procedure. Any such response transformation should be verified by using it for the multipoint calibration. Caution should be exercised in using a transformed response curve because physical zero or span adjustments to the analyzer may produce unexpected effects on the transformed characteristic.

4.1.5.4 Zero and span adjustment. See subsections 4.0.7.3 and 4.0.7.4. Prior to carrying out the assay/certification procedure, check the calibration of the analyzer and, if necessary, adjust the analyzer's zero and span controls to reestablish the response characteristic determined at the most recent multipoint calibration. Allow the analyzer to stabilize for an hour or more after any zero or span adjustment. If there is any doubt that a transformed response characteristic is still linear following a zero or span adjustment, verify linearity with a multipoint calibration (subsection 4.0.7.2) using at least 3 known pollutant concentrations, including zero.

4.1.6 Assay Gases

4.1.6.1 Candidate gas standard. See subsections 4.0.6 and 4.1.2.

4.1.6.2 Reference gas standard. See subsections 4.0.2, 4.1.2, and 4.0.6.4. Select a reference standard such that the concentration of the candidate gas is not

more than 30 percent above nor less than 70 percent below the concentration of the standard.

4.1.6.3 <u>Zero gas.</u> See subsection 4.0.8. *The zero gas should match the balance gas used in the cylinder concentrations.*

4.1.7 Assay Procedure

1. Verify that the assay apparatus is properly configured, as described in subsection 4.1.3 and shown in Figure G1.

2. Verify that the linearity of the analyzer has been checked within the last 3 months (see subsections 4.0.7.2, 4.0.7.5, and 4.1.4), that the zero and span are adjusted correctly (subsection 4.0.7.3), that the candidate and reference gas concentrations are within 25 and 97 percent of the upper range limit of the calibrated measurement range of the analyzer, and that the analyzer is operating stably.

3. Adjust the flow rates of the three gases (reference, candidate, and zero) to approximately the same value that will provide enough flow for the analyzer and sufficient excess to assure that no ambient air will be drawn into the vent.

4. Conduct a triad of measurements with the analyzer. Each triad consists of a measurement of the zero gas concentration, a measurement of the reference gas concentration, and a measurement of the candidate gas concentration. Use valves V1 and V2 to select each of the three concentrations for measurement. For each measurement, allow ample time for the analyzer to achieve a stable response reading. Record the stable analyzer response for each measurement, using the same response units (volt, millivolts, percent of scale, etc.) used for the multipoint calibration and any transformation of the response readings necessary for linearity. Do not translate the response readings to concentration values via the calibration curve (see the footnote following Equation G1). Do not make any zero, span, or other physical adjustments to the analyzer during the triad of measurements.

5. Conduct at least 2 additional measurement triads, similar to step 4 above. However, for these subsequent triads, change the order of the three measurements (e.g. measure reference gas, zero gas, candidate gas for the second triad and zero gas, candidate gas, reference gas for the third triad, etc.).

6. If any one or more of the measurements of a triad is invalid or abnormal for any reason, discard all three measurements of the triad and repeat the triad.

7. For each triad of measurements, calculate the assay concentration of the candidate gas as follows:

$$C_c = C_r \frac{R_c - R_z}{R_r - R_z} \qquad \text{Equation G1}$$

where: C_c = Assay concentration of the candidate gas standard, ppm or percent;

C_r = Concentration of the reference gas standard, ppm or percent;

R_c = Stable response reading of the analyzer for the candidate gas, analyzer response units;[*]

R_z = Stable response reading of the analyzer for the zero gas, analyzer response units;[*]

R_r = Stable response reading of the analyzer for the reference gas, analyzer response units.[*]

[*]Analyzer response units are the units used to express the direct response readings of the analyzer, such as volts, millivolts, percent of scale, etc. DO NOT convert these direct response readings to concentration units with the multipoint calibration curve or otherwise adjust these readings except for transformation necessary to achieve response linearity.

8. Calculate the mean of the 3 (or more) valid assays. Calculate the percent difference of each assay from the mean. If any one of the assay values differs from the mean by more than 1.5%, discard that assay value and conduct another triad of measurements to obtain another assay value. When at least 3 assay values all agree within 1.5% of their mean, report the mean value as the certified concentration of the candidate gas standard. For newly-prepared reactive standards, a reassay at least 7 days later is required to check the stability of the standard; see subsection 4.0.6.2.

4.1.8 Stability Test for Newly-Prepared Standards

See subsections 4.0.6.1 and 4.0.6.2.

4.1.9 Certification Documentation

See subsections 4.0.4 and 4.0.5.

4.1.10 Recertification Requirements

See subsections 4.0.6.3 and 4.0.6.4.

4.2 References.

1. Code of Federal Regulations, Title 40, Part 60, "Standards of Performance for New Stationary Sources," Appendix A, Method 20 (1982).

2. Standards of Performance for New Stationary Sources; Quality Assurance Requirements for Gaseous Continuous Emission Monitoring Systems Used for Compliance Determination, promulgated in the Federal Register, June 4, 1987, pp. 21003-21010.

3. "A Procedure for Establishing Traceability of Gas Mixtures to Certain National Bureau of Standards Standard Reference Materials. EPA-600/7-81-010. Joint publication by NBS and EPA, May 1981. Available from the U.S. Environmental Protection Agency, Environmental Monitoring Systems Laboratory (MD-77), Research Triangle Park, NC 27711.

4. Code of Federal Regulations, Title 40, Part 50, "National Ambient Air Quality Measurement Methodology".

5. Code of Federal Regulations, Title 40, Part 58, "Ambient Air Quality Surveillance," Appendixes A and B.

6. Shores, R. C. and F. Smith, "Stability Evaluation of Sulfur Dioxide, Nitric Oxide, and Carbon Monoxide Gases in Cylinders. NTIS No. PB 85-122646. Available from the National Technical Information Service, 5285 Port Royal Road, Springfield, VA 22161.

7. Method 6A and 6B, "Determination of Sulfur Dioxide, Moisture, and Carbon Dioxide Emissions from Fossil Fuel Combustion Sources," Quality Assurance Handbook for Air Pollution Measurement Systems, Volume III, Section 3.13.8, July 1986. Available from the U.S. Environmental Protection Agency, Center for Environmental Research Information, Cincinnati, OH 45268.

8. "List of Designated Reference and Equivalent Methods." Current edition available from the U.S. Environmental Protection Agency, Environmental Monitoring Systems Laboratory, Quality Assurance Division (MD-77), Research Triangle Park, NC 27711.

7.0 CALCULATION AND INTERPRETATION OF ACCURACY FOR CONTINUOUS EMISSION MONITORING SYSTEM (CEMS)

This section contains a discussion on the accuracy calculations required in Appendix F[1] and their interpretation. The goals of Appendix F, Procedure 1, are to (1) assess CEMS accuracy, (2) indicate when a CEMS is out-of-control and correction is required, and (3) specify criteria for unacceptable CEMS data. The quarterly accuracy assessments required in Appendix F provide a mechanism for identifying and correcting CEMS's that are out-of-control. This results in an increase in acceptable CEMS data. Increasing acceptable CEMS data strengthens decisions made with regard to compliance.

The following subsections discuss the meaning, interpretation, calculation, and reporting of accuracy data.

7.1 Meaning of Accuracy

Accuracy is the measure of the closeness of a measurement to its "true value." Although the true value is not known, it can be approximated by the use of an appropriate standard of reference, for example, an NBS-SRM (National Bureau of Standards - Standard Reference Materials), a primary standard. Secondary standards are also used as an approximation to "truth," although errors may be introduced in this process.

The preferred measure of accuracy depends on the situation. If the magnitude of the difference tends to be dependent on the true value, T, then the percentage difference is preferable. If it is desired to follow or observe the pattern of the differences over time, then the signed difference or signed percentage difference is preferable.

In the context of accuracy data based on Appendix F, three types of audits for CEMS accuracy assessment are specified: Relative Accuracy Test Audits (RATA), Relative Accuracy Audits (RAA), and Cylinder Gas Audits (CGA). The procedure for the RATA and the RAA are the same as for the Relative Accuracy Test described in the applicable EPA performance specification (e.g., Performance Specification 2 for SO_2 and NO_x, and Performance Specification 3 for O_2 and CO_2), with the exception that the RAA requires three rather than nine sets of measurements, and the accuracy is based on the average of the three sets of data. In addition, EPA performance audit samples must be analyzed concurrently with the RATA samples to demonstrate and document the proficiency and accuracy of the analytical system. The same person must conduct the RATA and the EPA audit sample analysis. Thus, the RATA approximates "truth" by the reference method test results, which are in turn checked for analytical accuracy by EPA audit sample analyses. The EPA audit sample analysis must agree

within 5 percent of the audit concentration on each of two SO_2 audit samples or within 10 percent of the audit concentration on each of two NO_x audit samples.

In Appendix F, each CEMS must be audited at least once each calendar quarter. Successive audits shall occur no closer than two months apart. The audits must be conducted as follows:

1. The RATA must be conducted at least once every four calendar quarters. The RATA is conducted as described in the Performance Specifications in Appendix B (e.g., Performance Specification 2 for SO_2 and NO_x). In addition, the appropriate performance audit samples received from EPA are analyzed as described in the applicable Reference Methods (e.g., Methods 6 for SO_2 and 7 for NO_x).

2. If applicable, a CGA may be conducted in three of the four calendar quarters. A CGA is conducted by challenging the CEMS's (both pollutant and diluent monitors, if applicable) with an audit gas of known concentration at two points within the following ranges:

Audit point	Audit range		
	Pollutant monitors	Diluent monitors for--	
		CO_2	O_2
1	20 to 30% of span value	5 to 8% by volume	4 to 6% by volume
2	50 to 60% of span value	10 to 14% by volume	8 to 12% by volume

A separate audit gas cylinder must be used for audit points 1 and 2. No dilution of the gas from the audit cylinder is allowed when challenging the CEMS. Challenge the CEMS three times at each point, and use the average of the three responses in determining accuracy. The monitor should be challenged at each point for a sufficient period of time to assure absorption-desorption of the CEMS sample transport surfaces has stabilized. Each monitor is audited in its normal sampling mode, i.e., pass the audit gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling and as much of the sampling probe as is practical. At a minimum, the audit gas should be introduced at the connection between the probe and the sample line. Audit gases must be certified

by comparison with gaseous NBS-SRM or NBS/EPA approved CRM (Certified Reference Material) following EPA Traceability Protocol No. 1. Procedures for preparation of CRM's are described in Reference 2. Procedures for preparation of EPA Traceability Protocol No. 1 gases are described in Reference 3. The difference between the actual concentration of the audit gas and the concentration indicated by the monitor is used to assess the accuracy of the CEMS.

3. The RAA may be conducted three of the four calendar quarters. To conduct a RAA, follow the procedures described in the applicable Performance Specification in Appendix B for the Relative Accuracy Test, except that only three sets of measurement data are required. Analysis of EPA performance audit samples is required for the RAA. The relative difference between the mean of the reference method values and the mean of the CEMS values (in terms of the standard) are used to assess the accuracy of the CEMS.

The performance of RATA's, RAA's, and CGA's provides an independent check of the CEMS accuracy. These independent audits serve to document that the CEMS is providing quality data. Examples of audit calculations are given in the subsection that follows.

In summary, an accuracy assessment is a measure of the deviation of a measurement obtained under standard operational procedures from a known reference measurement. There is no reason to expect that accuracy will remain constant over each quarter because of changes in calibration gases, analysts, and environment.

7.2 Example Calculations and Interpretation for Accuracy

7.2.1 Relative Accuracy Test Audit Calculations - Example data from a RATA on a SO_2/O_2 CEMS are shown in Table 7.1.

The SO_2 and O_2 CEMS data shown in Table 7.1 were corrected to a dry basis using Equation 7-1:

$$CEMS_{ppm, dry} = \frac{CEMS_{ppm, wet}}{1 - B_{ws}} \qquad \text{Equation 7-1}$$

where

B_{ws} = moisture fraction of the CEMS gas sampled.

TABLE 7.1   RELATIVE ACCURACY TEST AUDIT DATA FOR SO_2 AND O_2 CEMS

Run number	SO_2 RM_d, ppm	SO_2 $CEMS_d$, ppm	O_2 RM_d, %	O_2 $CEMS_d$, %	SO_2 RM_d, ng/J	SO_2 $CEMS_d$, ng/J	SO_2 Diff, ng/J
1	500	475	3.0	3.1	422.4	403.5	18.9
2	505	480	3.0	3.1	426.6	407.7	18.9
3	510	480	3.0	3.0	430.8	405.4	25.4
4	510	480	2.9	2.9	428.4	403.2	25.2
5	500	480	2.9	3.0	420.0	405.4	14.6
6	500	500	3.0	3.1	422.4	424.7	-2.3
7	510	510	3.0	3.1	430.8	433.3	-2.5
8	505	505	2.9	3.0	424.2	426.6	-2.4
9	510	520	2.9	3.0	428.4	439.3	-10.9
Avg	---	---	---	---	426.0	413.1	9.43

RM_d = reference method data, dry basis.

$CEMS_d$ = monitor data, dry basis.

The SO_2 and O_2 CEMS and RATA data in Table 7.1 were converted to the units of the applicable standard using Equation 7-2:

$$E = CF \frac{20.9}{20.9 - \text{percent } O_2}$$ Equation 7-2

where

E = pollutant emission, ng/J (lb/million Btu),

C = pollutant concentration, ng/dsm^3 (lb/dscf),

F = factor representing a ratio of the volume of dry flue gas generated to the calorific value of the fuel, dsm^3/J (dscf/million Btu), and

Percent O_2 = oxygen content by volume (expressed as percent), dry basis.

Note: For the calculations shown in Table 7.1, ppm of SO_2 was converted to ng/J using a conversion factor of 2.66×10^6 ng/scm/ppm and an F factor of 2.72×10^{-7} dsm^3/J.

For complete explanation of the equations and calculations, see 40 CFR; Part 60; Appendix A; Method 19; 5. Calculation of Particulate, Sulfur Dioxide, and Nitrogen Oxides Emission Rates.

After the data are converted to the units of the standard, the Relative Accuracy (RA) is calculated by using the equations in Section 8 of Performance Specification 2. For convenience in illustrating the calculation, these equations (7-3 through 7-8) are also shown here.

The average difference, $\bar{d}$, is calculated for the SO_2 monitor using Equation 7-3:

$$\bar{d} = \frac{1}{n} \sum_{i=1}^{n} (X_i - Y_i) = \frac{1}{n} \sum_{i=1}^{n} d_i \qquad \text{Equation 7-3}$$

$$= \frac{1}{9} (84.9) = 9.43 \text{ ng/J}$$

where

n = number of data points,

X_i = concentration from reference method (RM_d in Table 7.1), ng/J,

Y_i = concentration from the CEMS ($CEMS_d$ in Table 7.1), ng/J,

d_i = signed difference between individual pairs, X_i and Y_i, ng/J, and

Σd_i = algebraic sum of the individual differences, d_i, ng/J.

The standard deviation S_d is calculated using Equation 7-4:

$$S_d = \sqrt{\frac{1}{n-1}\left[\sum_{i=1}^{n} d_i^2 - \frac{1}{n}\left(\sum_{i=1}^{n} d_i\right)^2\right]} \qquad \text{Equation 7-4}$$
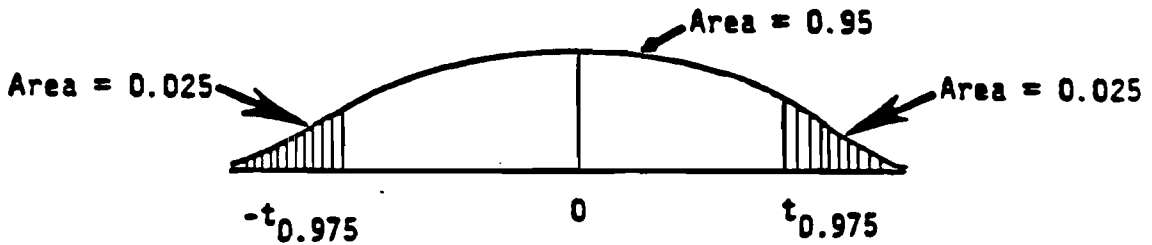
$$= \sqrt{\left[\frac{1}{8} \; 2344 - \frac{1}{9} \; (84.9)^2\right]} = 13.9 \; ng/J.$$

The 2.5 percent error confidence coefficient, CC, is calculated using Equation 7-5:

$$CC = t_{0.975}\frac{S_d}{\sqrt{n}}$$
  Equation 7-5

$$= 2.306 \; \frac{13.9}{\sqrt{9}} = 10.68 \; ng/J.$$

where $t_{0.975}$ = t-values in Table 7.2 for n = 9.

TABLE 7.2.   VALUES OF t FOR 95 PERCENT PROBABILITY[a]

n^a	$t_{0.975}$	n^a	$t_{0.975}$	n^a	$t_{0.975}$
2	12.706	7	2.447	12	2.201
3	4.303	8	2.365	13	2.179
4	3.182	9	2.306	14	2.160
5	2.776	10	2.262	15	2.145
6	2.571	11	2.228	16	2.131

[a]The values in this table are already corrected for n-1 degrees of freedom. Use n equal to the number of individual values.

The RA for the RATA is calculated using Equation 7-6:

$$RA = \frac{|\bar{d}| + |CC|}{\overline{RM}} \times 100 \qquad \text{Equation 7-6}$$

$$= \frac{|9.43| + |10.68|}{426} \times 100 = 4.72\%$$

where

RA = relative accuracy, %,

$|\bar{d}|$ = absolute value of the mean differences from Equation 7-3, ng/J,

|CC| = absolute value of the confidence coefficient from Equation 7-5, ng/J, and

$\overline{RM}$ = average reference method value or applicable standard, ng/J.

7.2.2 **Relative Accuracy Audit Calculations** - Example data from an RAA on an SO_2/O_2 CEMS are shown in Table 7.3.

TABLE 7.3 RELATIVE ACCURACY AUDIT DATA FOR SO_2 AND O_2 CEMS

Run number	SO_2 RM_d, ppm	SO_2 $CEMS_d$, ppm	O_2 RM_d, %	O_2 $CEMS_d$, %	SO_2 RM_d, ng/J	SO_2 $CEMS_d$, ng/J
1	500	475	3.0	3.1	422.4	403.5
2	505	480	3.0	3.1	426.6	407.7
3	510	480	3.0	3.0	430.8	405.4
Avg	---	---	---	---	426.6	405.5

RM_d = reference method data, dry basis.

$CEMS_d$ = monitor data, dry basis.

The SO_2 and O_2 CEMS data shown in Table 7.3 were corrected to a dry basis using Equation 7-1. The SO_2 and O_2 CEMS and RAA data were converted to the units of the applicable standard using Equation 7-2.

The accuracy (A) for the RAA is calculated using Equation 7-7.

$$A = \frac{C_m - C_a}{C_a} \times 100 \qquad\qquad \text{Equation 7-7}$$

$$= \frac{405.5 - 426.6}{426.6} \times 100 = -4.95\%$$

where

A = accuracy of the CEMS, %,

C_m = average CEMS response during audit in units of applicable standard, and

C_a = average audit value of the three reference method runs in units of the applicable standard.

7.2.3 Cylinder Gas Audit Calculations - Example data from a CGA on an SO_2/O_2 CEMS are shown in Table 7.4.

TABLE 7.4 CYLINDER GAS AUDIT DATA FOR SO_2 AND O_2 CEMS

Audit number	Reading No.	SO_2	SO_2	A	O_2	O_2	A
		CGA_d, ppm	$CEMS_d$, ppm	Diff, %	CGA_d, %	$CEMS_d$, %	Diff, %
1	1	212	218		5.0	5.2	
	2	212	219		5.0	5.3	
	3	208	225		5.1	5.2	
	Avg	210.7	220.7	4.75	5.03	5.23	3.98
2	1	398	409		9.1	8.9	
	2	399	416		9.1	8.9	
	3	403	414		8.9	8.9	
	Avg	400.0	413	3.25	9.03	8.90	-1.44

CGA_d = cylinder gas audit value, dry basis.

$CEMS_d$ = average of the three monitor values, dry basis.

The SO_2 and O_2 CEMS data shown in Table 7.4 were corrected to a dry basis using Equation 7-1. The accuracy (A) for the GCA is calculated using Equation 7-8.

$$A = \frac{C_m - C_a}{C_a} \times 100 \qquad \text{Equation 7-8}$$

$$= \frac{220.7 - 210.7}{210.7} \times 100 = 4.75\%$$

where

A = accuracy of the CEMS component, %,

C_m = CEMS component mean response for three values during audit with CGA in units of the appropriate concentration, and

C_a = audit value of the cylinder gas in units of appropriate concentration.

7.3 Reporting Requirements

At the reporting interval specified in the applicable regulation, a report of each CEMS accuracy audit must be submitted in the form of a Data Accuracy Report (DAR). One copy of the DAR must be included for each quarterly audit along with the report of emissions required under the applicable regulation. As a minimum, the DAR must contain the following information:

1.   Source owner or operator name and address.

2.   Identification and location of monitors in the CEMS.

3.   Manufacturer and model number of each monitor in the CEMS.

4.   Assessment of CEMS data accuracy and date of assessment as determined by a RATA, RAA, or CGA, including the RA for the RATA, the A for the RAA or CGA, the reference method results, certified values for the cylinder gases, the CEMS responses, and the CEMS accuracy calculation results. If the accuracy audit results show the CEMS to be out-of-control, the CEMS operator shall report both the audit results showing the CEMS to be out-of-control and the results of the audit following corrective action showing the CEMS to be operating within specifications.

5.   Results from the EPA performance audit samples.

6.   Summary of all corrective actions taken when the monitor was determined out-of-control.

An example of a DAR form is shown in Figure 7.1.

Period ending date _____ Year _____

Company name _____

Plant name _____ Source unit no. _____

CEMS manufacturer _____ Model no. _____

CEMS serial no. _____ CEMS type (e.g., in situ) _____

CEMS sampling location (e.g., control device outlet) _____

CEMS span values as per the applicable regulation, SO_2 ppm _____

O_2 _____ percent, NO_x _____ ppm, CO_2 _____ percent

I. Accuracy assessment results (Complete A, B, or C below for each CEMS or for each pollutant and diluent analyzer, as applicable.) If the quarterly audit results show the CEMS to be out-of-control, report the results of both the quarterly audit and the audit following the corrective action showing the CEMS to be operating properly.

  A. Relative accuracy test audit (RATA) for _____ (e.g., SO_2 in ng/J).

     1. Date of Audit _____

     2. Reference methods (RM's) used _____ (e.g., Methods 3 and 6).

     3. Average RM value _____ (e.g., ng/J, mg/dsm^3, or percent volume).

     4. Average CEMS value _____.

     5. Absolute value of the mean difference $|\bar{d}|$ _____.

     6. Confidence coefficient $|CC|$ _____.

     7. Percent relative accuracy (RA) _____ percent.

     8. EPA performance audit results:

        a. Audit lot number   (1)_____ (2)_____
        b. Audit sample number   (1)_____ (2)_____
        c. Results (mg/dsm^3)   (1)_____ (2)_____
        d. Actual value (mg/dsm^3)* (1)_____ (2)_____
        e. Relative error*   (1)_____ (2)_____

*To be completed by the Agency.

Figure 7.1 Example format for data assessment report (DAR).

B. Cylinder gas audit (CGA) for _____ (e.g., SO_2 in ppm).

   1. Date of audit _____ .

		Audit point 1	Audit point 2	
2.	Cylinder ID number	_____	_____	
3.	Date of certification	_____	_____	
4.	Type of certification	_____	_____	(e.g., EPA Protocol 1 or CRM).
5.	Certified audit value	_____	_____	(e.g., ppm).
6.	CEMS response value	_____	_____	(e.g., ppm).
7.	Accuracy	_____	_____	percent.

C. Relative accuracy audit (RAA) for _____ (e.g., SO_2 in ng/J).

   1. Date of audit _____ .

   2. Reference methods (RM's) used _____ (e.g., Methods 3 and 6).

   3. Average RM value _____ (e.g., ng/J).

   4. Average CEMS value _____ .

   5. Accuracy _____ percent.

   6. EPA performance audit results:

      a. Audit lot number   (1)_____ (2)_____
      b. Audit sample number (1)_____ (2)_____
      c. Results (mg/dsm^3)* (1)_____ (2)_____
      d. Actual value (mg/dsm^3)* (1)_____ (2)_____
      e. Relative error* (1)_____ (2)_____

---

*To be completed by the Agency.

Figure 7.1 (continued)

D. Corrective action for excessive inaccuracy.

    1. Out-of-control periods.

        a. Date(s) _____ .

        b. Number of days _____ .

    2. Corrective action taken _____

        _____

        _____

        _____ .

    3. Results of audit following corrective action. (Use format of
        A, B, or C above, as applicable.

II. Calibration drift assessment.

    A. Out-of-control periods.

        1. Date(s) _____ .

        2. Number of days _____ .

    B. Corrective action taken _____

        _____

        _____

        _____ .

Figure 7.1 (continued)

7.4 References

1. Standards of Performance for New Stationary Sources: 40 CFR 60, Appendix F - Quality Assurance Procedures, Procedure 1 - Quality Assurance Requirements for Gaseous Continuous Emission Monitoring Systems Used for Compliance Determination.

2. A Procedure for Establishing Traceability of Gas Mixtures to Certain National Bureau of Standards Standard Reference Materials. Joint publication by NBS and EPA, EPA-600/7-81-010. Available from the U. S. Environmental Protection Agency, Quality Assurance Division (MD-77), Research Triangle Park, North Carolina 27711.

3. Traceability Protocol for Establishing True Concentrations of Gases Used for Calibration and Audits of Continuous Source Emission Monitors (Protocol Number 1). June 1978, Section 3.0.4 of the Quality Assurance Handbook for Air Pollution Measurement Systems, Volume III, Stationary Source Specific Methods. EPA-600/4-77-027b. August 1977. U. S. Environmental Protection Agency, Office of Research and Development Publications, 26 West St. Clair Street, Cincinnati, Ohio 45268.

10.0 GUIDELINE FOR DEVELOPING QUALITY CONTROL PROCEDURES FOR GASEOUS CONTINUOUS EMISSION MONITORING SYSTEMS

10.1 Introduction.

This guideline describes the minimum content for a quality control plan to satisfy the requirements of Section 3 of Appendix F, Procedure 1 to 40 CFR Part 60. Source owners or operators may wish to add other items to assure the generation and reporting of valid data from their continuous emission monitoring systems (CEMS's).

Appendix F, Procedure 1 requires written procedures for each of the following activities:

1. Calibration of the CEMS.

2. Calibration drift determination and adjustment of the CEMS.

3. Preventive maintenance of the CEMS (including maintaining a spare parts inventory).

4. Data recording, calculations, and reporting for emissions and QA data.

5. Accuracy audit procedures including sampling and analysis methods.

6. Program of corrective action for the malfunctioning CEMS.

Figure 1 is a flow chart showing the requirements in Appendix F, Procedure 1 for quality assurance and in Part 60.13 for monitoring requirements. This flow chart is included to show how these requirements for CEMS's interact.

10.2 Calibration of the CEMS

Calibration refers to the adjustment of the CEMS response relative to specified standards such as gas cells or calibration gases, or relative to independent effluent measurements. Appendix F, Procedure 1 requires that sources have written procedures for CEMS calibration. Sources may develop their own written procedures; alternatively, they may specify applicable sections of the instrument manual as their written procedures.

There are no currently promulgated regulations that require either specific calibration frequencies or specific criteria for initiating calibration procedures. Sources may therefore choose their own frequency or criteria for calibration based on operating experience or manufacturer's recommendations.
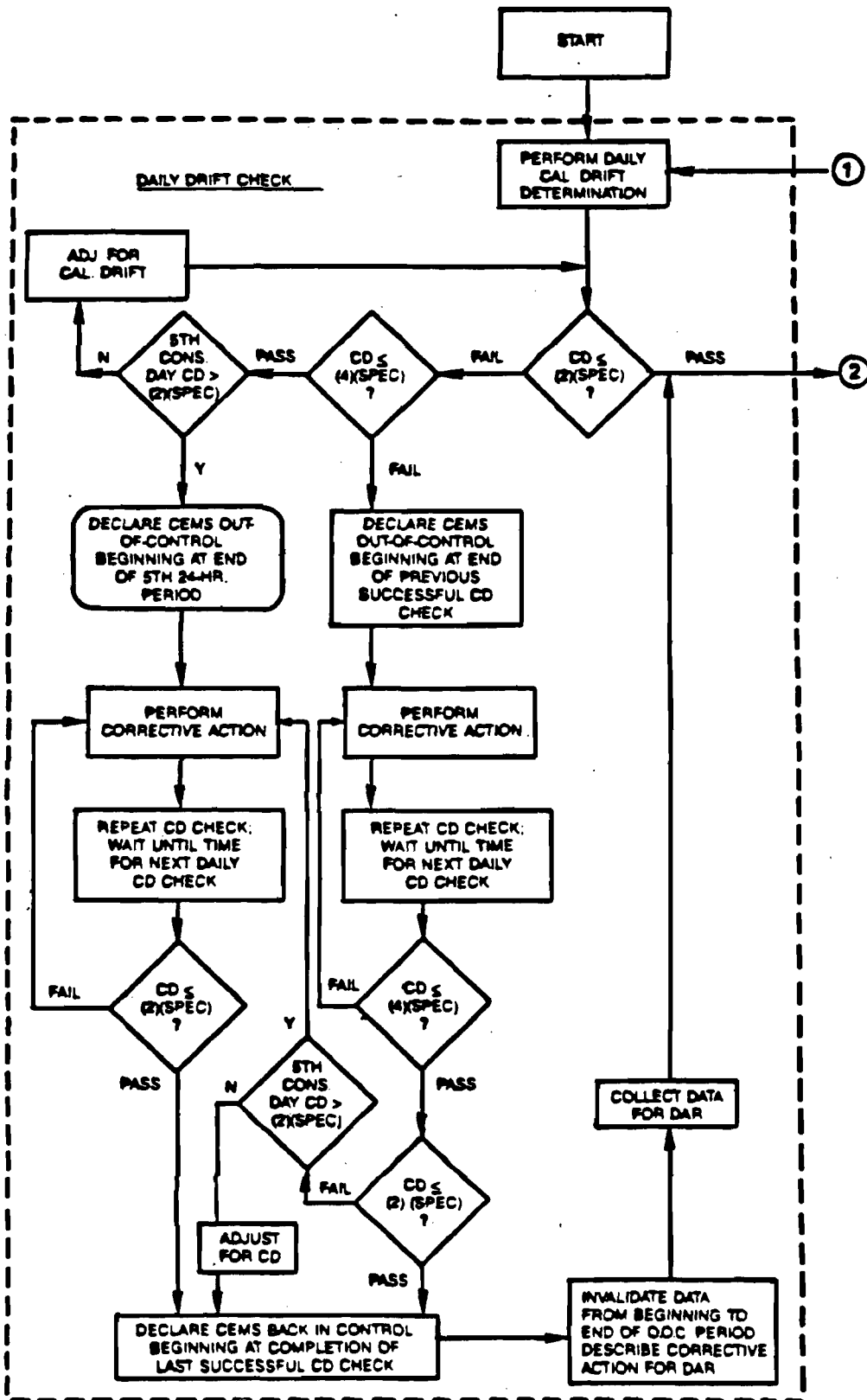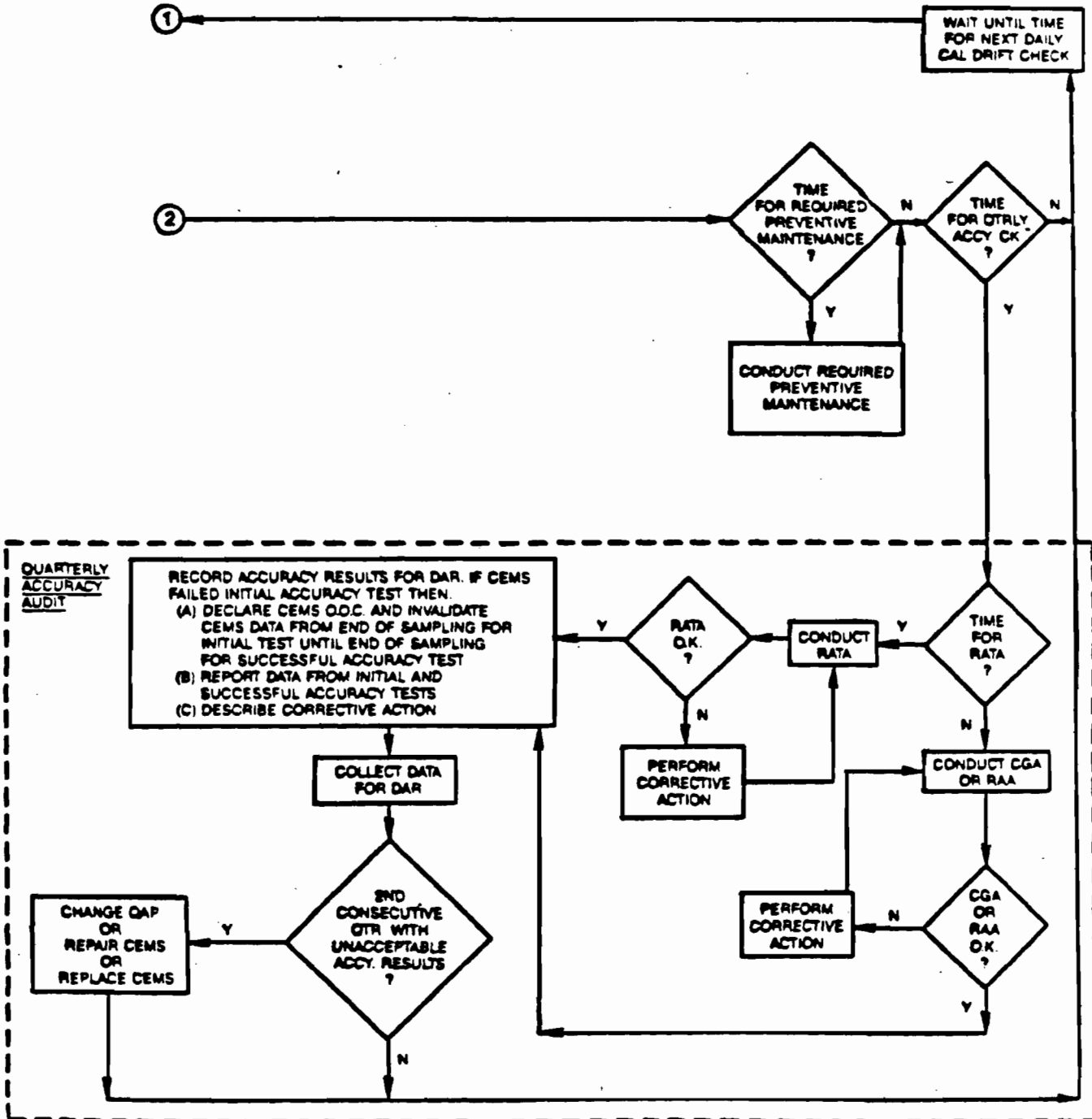
Figure 1. Flow Chart for Required QC Procedures.

Figure 1. (continued)

For calibrations based on external gas cells, sufficient time should be allowed for the cell and/or analyzer cabinet to reach normal operating temperature; accordingly, it is recommended that procedures be incorporated into the QC program that ensure sufficient time for the monitor response to stabilize before it is compared to the cell's named value. Some in-situ analyzers partially or totally disable temperature compensation circuitry during cell-type calibrations. In these cases, it is recommended that additional procedures addressing the calibration of this circuitry be incorporated into the QC program.

For analyzers calibrated using calibration gases as the reference, the written procedures should specify (1) at what point in the sampling system the calibration gases are to be introduced and (2) either the specific gas flow rate to be used or how the flow rate is determined. Although current continuous emission monitoring (CEM) regulations do not require establishing the traceability of calibration gases to higher standards, it is strongly recommended that procedures be established and included within the QC program for verifying the concentrations of calibration gases. One acceptable procedure is EPA's traceability protocol 1 (Reference 1).

In cases where a portable CEMS is to be used as the reference for adjusting the installed CEMS, written procedures should specify calibration and operating procedures for the portable CEMS, including the portable CEMS sampling location.

The written calibration procedures for the installed CEMS may be incorporated into one or more of the following sections of a QC program:

1. A Stand-Alone "Calibration" Section of the QC Program. In this case, the frequency of calibration or the criteria for initiating calibration activities should be clearly specified.

2. Preventive Maintenance. Within the section delineating the preventive maintenance procedures, calibration may be specified as a routine maintenance activity to be performed at regular, specified intervals. Alternatively, calibration may be specified on an as-needed basis with stated criteria for the implementation of calibration activities.

3. Corrective Action. Calibration procedures may be included within the section delineating corrective action activities to be performed at the discretion of CEMS repair personnel in response to an out-of-control CEMS.

Regardless of how the calibration procedures are incorporated into the QC program, it is recommended that the individual or

group responsible for CEMS calibration be identified within the written QC plan.

10.3 Calibration Drift and Adjustment of the CEMS

Calibration drift (CD) refers to the difference between the CEMS output reading and a reference value after a period of operation during which no unscheduled maintenance, repair, or adjustment took place. Daily zero (or low level) and span drift checks are required by 40 CFR 60.13; these checks are to be used to fulfill the calibration drift check requirement of Appendix F, Procedure 1. Appendix F, Procedure 1 requires written procedures that specify how the zero (or low level) and span calibration drift determinations are to be performed. These procedures must be consistent with the monitor vendor's prescribed method for checking CD.

Table 10.1 presents CD criteria and the corresponding required source responses. Sources may choose to establish more stringent criteria for adjustment of CEMS for zero (or low level) and/or span calibration drift. It is recommended that the CD criteria selected for adjustment of the CEMS be incorporated into the written instructions for the calibration drift check procedures, so that the need for adjustment based on calibration drift may be determined immediately.

Corrections for excessive drift may consist of any adjustments or activities that the operator or technician deems necessary to correct for the observed drift. These activities typically consist of routine checks and adjustments of calibration gas flow rates and pressures, verification of proper sample cell temperatures, verification of the status of monitor specific auxiliary monitoring parameters, and adjustment of zero and/or span potentiometers. Written procedures should be available for performing these routine activities and should include criteria for determining that adjustments have been successful.

10.4 Preventive Maintenance of the CEMS

Preventive maintenance is comprised of activities designed to detect and prevent the development of monitoring problems. These activities typically include both routine maintenance procedures and maintenance, repairs, or adjustments performed on an as-needed basis. An example of as-needed preventive maintenance would be the repairing of the protective covering of an extractive sample line following damage resulting from an accident during the construction activities. If the sample line itself were not damaged, the repair would be considered preventive maintenance and would not consititute corrective action for a malfunctioning CEMS. The importance of this type of

TABLE 10.1. CEMS CALIBRATION DRIFT CRITERIA

Parameter	Criterion*	Action Required
Zero (or low) level calibration drift	CD > 2 x (Spec)**	Adjust CEMS for calibration drift
	CD > 2 x (Spec) for 5 consecutive 24-hour periods	CEMS out-of-control period begins at end of 5th day the CD exceeds 2 x (Spec); perform corrective action and repeat CD check
	CD > 4 x (Spec)	CEMS out-of-control period begins at the time corresponding to the completion of the last acceptable CD check preceding the CD check which exceeds 4 x (Spec); perform corrective action and repeat the CD check
Span calibration drift	CD > 2 x (Spec)**	Adjust CEMS for calibration drift
	CD > 2 x (Spec) for 5 consecutive 24-hour periods	CEMS out-of-control period begins at end of 5th day the CD exceeds 2 x (Spec); perform corrective action and repeat CD check
	CD > 4 x (Spec)	CEMS out-of-control period begins at the time corresponding to the completion of the last successful CD check preceding the CD check that exceeds 4 x (Spec); perform corrective action and repeat the CD check

*Spec refers to the applicable performance specification in Appendix B.

**This is the minimum criterion for adjustment of the CEMS. More stringent criteria, which may be preferred by many sources, are also acceptable.

maintenance is recognized; however, it is neither practical nor necessary to develop written procedures for such needed activities.

Written procedures must be available for routine maintenance activities. These procedures should specify what procedures are to be conducted and the frequency with which the various activities are to be performed. The QC program should specify the individual or office responsible for ensuring that the preventive maintenance procedures are conducted at the appropriate frequencies and the individual or group who will perform the actual routine maintenance procedures.

The applicable regulations do not specify the minimum level of routine preventive maintenance. It is suggested that, at a minimum, the initial procedures should incorporate the vendor's recommendations regarding preventive maintenance activities and frequencies. These procedures may later be adjusted to reflect actual operating experience with individual CEMS installations.

A list of spare parts for the CEMS must be included in the written QC plan. At a minimum, those spare parts recommended by the monitor vendor should be available. The QC program should specify the individual or office who is responsible for maintaining the listed spare parts inventory.

10.5 Data Records, Calculations, and Reporting for the CEMS

The QA/QC program must address recordkeeping, calculations, and reporting of emissions and quality assurance data. The requirements for these activities are contained in the subparts of 40 CFR 60 that specify the use of CEM. A Data Assessment Report (DAR) must be provided with emissions reports required by the applicable subpart of 40 CFR 60. The DAR must contain, at a minimum:

1. The name and address of the source owner or operator.

2. Identification and location of each monitor in the CEMS.

3. The manufacturer and model number of each monitor in the CEMS.

4. Quarterly accuracy results, including dates, CEMS responses, and either reference method results or certified gas values; if either a RATA or a RAA was performed, the results from the EPA performance audit sample analysis must also be included.

5. A summary of corrective actions taken when the monitor was determined to be out-of-control.

For emissions data, a list or diagram should be provided indicating the offices or individuals responsible for (1) retrieving the data from the CEMS, (2) calculating emissions rates from the CEMS data, (3) compiling emissions reports, and (4) reviewing and/or approving emissions reports. Formulas and example calculations should be provided for emission rate calculations. Similar information should be provided for emissions data from alternative monitoring methods that may be necessary during CEMS out-of-control periods.

A list or diagram should also be provided indicating the offices or individuals responsible for (1) collecting quality assurance (QA) data, (2) performing applicable calculations of QA/QC results, (3) recording the QA/QC results in appropriate logs (as applicable), (4) preparing the DAR, and (5) approving and/or reviewing the DAR. Formulas and example calculations should be provided for all required QA data calculations.

10.6 Accuracy Audit Procedures Including Sampling and Analysis Methods

Appendix F, Procedure 1 requires that each CEMS be audited at least once each calendar quarter. Three audit techniques are acceptable:

1. Relative accuracy test audits (RATA's);

2. Cylinder Gas Audits (CGA's); and

3. Relative accuracy audits (RAA's).

In addition, other alternative audit procedures may be used as approved by the Administrator.

If the CEMS does not demonstrate acceptable accuracy during the quarterly audit, then corrective actions must be initiated, and the CEMS must be declared out-of-control from the time corresponding to the completion of the sampling for the unsuccessful audit until the completion of the sampling for a successful follow-up audit. If the CEMS demonstrates unacceptable accuracy for two consecutive quarters, then the QA program must be revised, or the CEMS must be modified or replaced.

Table 10.2 presents the specific requirements and the corresponding CEMS performance criteria for each of the three acceptable audit techniques.

The QC program must include written sampling and analysis procedures to be used during the required quarterly accuracy audits. At a minimum, these procedures must describe the methods to be used to conduct a RATA. Applicable sections of Appendix A (Reference Methods) and Appendix B (Performance Specifications)

TABLE 10.2. REQUIREMENTS AND CRITERIA FOR
APPENDIX F, PROCEDURE 1 AUDIT TECHNIQUES

Technique	Requirements	Performance Criteria
RATA	Conduct as per applicable performance specification (PS) in Appendix B (e.g., PS 2 for SO_2 and NO_x) Analyze appropriate performance audit samples from EPA	RA must not exceed 20% or 10% of applicable standard, whichever is greater For SO_2 standards from 0.20 to 0.30 lb/10^6 Btu, RA must not exceed 15% of the standard For SO_2 standards below 0.20 lb/10^6 Btu, RA must not exceed 20% of the standard
RAA	Conduct as per applicable PS in Appendix B except only 3 runs are required Use relative difference between the mean reference method values and the mean of the CEMS responses to assess the accuracy of the CEMS data	Inaccuracy must not exceed ± 15% or 7.5% of the applicable standard, whichever is greater
CGA	Challenge both pollutant and diluent channels (if applicable) of CEMS three times at the two points specified in Procedure 1 Use gases that have been certified by comparison to NBS SRM's or NBS/EPA approved gas manufacturer's CRM's Operate analyzer in normal sampling mode Use average difference between actual gas value and concentration indicated by CEMS to access accuracy	Inaccuracy must not exceed ± 15%

may be cited where possible to describe audit procedures. The written procedures should specify individuals or groups responsible for audit program oversight, sampling, analysis, and accuracy assessment calculations. If the source chooses to conduct RAA's and/or CGA's during quarters when RATA's are not required, the QC plan should include written procedures for these audit techniques. Again, applicable sections of Appendix - A, Appendix B, and/or instrument operation manuals may be cited where possible.

Sources may choose to have an outside contractor perform some or all of the accuracy audit activities. Since contractor selection may be subject to competitive bidding, the QC program need not specify a particular contractor. However, the specific activities for which the contractor will be responsible should be listed.

10.7 Program of Corrective Action for the Malfunctioning CEMS

Appendix F, Procedure 1 specifies that corrective action must be performed when a CEMS is out-of-control. Appropriate corrective action will depend on the nature of the CEMS malfunction. At a minimum, written procedures must be available, to be applied as necessary, for instrument start-up and trouble shooting. Appropriate sections of instrument operation and/or repair manuals may be referenced to fulfill this requirement. Where possible, it is recommended that additional quality assessment procedures be provided to verify proper operation of the CEMS following repair or adjustment.

A list should be provided to indicate what alternative methods are to be used for monitoring emissions during CEMS out-of-control periods in order to fulfill the minimum data availability requirements of the applicable subpart. Written procedures should be available for operation of these alternative methods.

A list or chart should be provided to indicate the offices or individuals (1) to be contacted when a CEMS out-of-control period occurs, (2) to approve the corrective action (if applicable), and (3) to be responsible for determining when alternative monitoring procedures are to be employed. Criteria should be provided for determining when the CEMS is out-of-control. As a minimum, these must include the Appendix F, Procedure 1 criteria for excessive drift and excessive inaccuracy.

10.8 References

1. Traceability Protocol for Establishing True Concentrations of Gases Used for Calibration and Audits of Continuous Source Emission Monitors (Protocol Number 1). June 1978, Section 3.0.4 of the Quality Assurance Handbook for Air

Pollution Measurement Systems, Volume III, Stationary Source Specific Methods. EPA-600/4-77-027b. August 1977. U. S. Environmental Protection Agency, Office of Research and Development Publications, 26 West St. Clair Street, Cincinnati, Ohio 45268.