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Opacity Control Guidelines for Oil-Fired Plants

Opacity Control Guidelines for Oil-Fired Plants

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REPORT SUMMARY

This document is designed to help utility engineers and plant supervisory personnel diagnose and mitigate stack opacity problems at oil-fired boilers. The diagnostic approaches and mitigation strategies discussed in the report target boiler operating and maintenance practices that contribute to high opacity.

Background
Opacity regulations and penalties for opacity exceedances are becoming increasingly stringent, particularly in metropolitan areas. More and more, opacity exceedances are subject to regulatory scrutiny and enforcement action. Even intermittent incidents of high opacity can have serious consequences that may include boiler de-rates and fines. Consequently, reducing plume opacity at oil-fired utility boilers is an issue of growing significance to plant operators. For many utility companies, avoiding opacity exceedances is a major concern in the operation, maintenance, and dispatching of oil-fired boilers.

Objective
To help utility engineers and plant supervisory personnel diagnose and mitigate stack opacity problems at oil-fired boilers.

Approach
The project team reviewed existing industry techniques and experiences relevant to diagnosing and mitigating opacity problems at oil-fired boilers. They identified the design, operating, and maintenance factors that affect opacity and detailed the available options for reducing opacity and particulate emissions.

Results
Stack opacity at oil-fired boilers can be the direct or indirect result of the design of boiler components, plant operating practices, or maintenance of critical hardware. Specific operating factors may be important contributors to opacity during steady boiler operation, transient boiler operations, or both. In general boilers that undergo daily load cycling are more prone to incidents of high opacity, but base-loaded units that experience minimal load cycling may also suffer continuous or intermittent opacity problems. Boiler operators are often unaware of the underlying cause and effect relationship between opacity and operating conditions. The design and maintenance of

combustion equipment also impacts the opacity characteristics of a boiler. Pertinent equipment includes the fuel supply system, the combustion air supply system, fuel atomization, burners, ignitors, burner management systems, and NO_x controls. Plant equipment design factors that can impact opacity include furnace geometry and sootblower design, ductwork, and boiler control systems. Fuel composition and physical properties also impact opacity.

This document contains troubleshooting guidelines that provide step-by-step procedures for diagnosing and correcting common types of opacity problems encountered during steady-state and transient boiler operation. Supplemental information is provided on the characteristics of stack opacity unique to oil-fired boilers, the sources of particulate matter emissions that cause opacity, and the operating and maintenance problems that impact opacity. Options for reducing opacity—when modifying O&M practices alone is not sufficient—are also summarized, including combustion hardware modifications and installation of particulate matter control devices.

EPRI Perspective

Continuing EPRI research seeks to optimize combustion in existing oil-fired boilers in order to improve the utilization and extend the lifespan of existing fuel-oil capacity. Recent EPRI publications related to oil-fired boilers include *Residual Fuel Oil User's Guidebook, Volume 2* (AP-5826);*REACH: Reduced Emissions and Advanced Combustion Hardware* (TR-105708); and *Retrofit* NO_x *Control Guidelines for Gas- And Oil-Fired Boilers Version 2.0* (TR-108181).

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Interest Categories
Air emission control
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Keywords
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ABSTRACT

This document is designed to help utility engineers and plant supervisory personnel diagnose and mitigate stack opacity problems at oil-fired boilers. The emphasis of the diagnostic approaches presented is to identify boiler operating and maintenance (O&M) practices that contribute to, or are the primary cause of, high opacity. Likewise, the mitigation strategies focus on modifying pertinent O&M practices to minimize opacity.

The document contains troubleshooting guidelines which provide step-by-step procedures for diagnosing and correcting common types of opacity problems encountered during steady-state and transient boiler operation. Supplemental information is provided on the characteristics of stack opacity unique to oil-fired boilers, the sources of particulate matter emissions that cause opacity, and the operating and maintenance practices that impact opacity. Options for reducing opacity—when modifying O&M practices alone is not sufficient—are also summarized, including combustion hardware modifications and installation of particulate matter control devices.

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1

INTRODUCTION

1.1 Background

Opacity regulations and penalties for opacity exceedances are becoming increasingly stringent, particularly in metropolitan areas. Consequently, reducing plume opacity at oil-fired utility boilers is becoming an issue of growing significance to plant operators. For many utility companies, avoiding opacity exceedances has become a major criteria in the operation, maintenance, and dispatching of oil-fired boilers.

The origins of stack opacity at oil-fired boilers are complex. To successfully address an opacity problem, a systematic approach to diagnosing the root cause(s) of opacity problems and determining the optimum solution(s) is often essential, and is the main purpose of this document.

1.1.1 Opacity Regulations and Driving Forces for Control

Opacity limits imposed at an oil-fired boiler may have originated from one or more underlying regulatory requirements, including local or state laws designed to protect ambient visibility, or federal standards imposed on new or modified facilities. Opacity limits are typically 20% to 40% for oil-fired boilers during normal operations, calculated on an instantaneous or time-averaged basis. Relaxed opacity limits (e.g., up to 60%) may be allowed for sootblowing or upset conditions, and exemptions may exist for plant startup, shutdown, and malfunctions.

Opacity exceedances are increasingly subject to regulatory scrutiny and enforcement action. Even intermittent incidents of high opacity can have serious consequences, including boiler de-rates and fines. Moreover, opacity that is in compliance with the regulated limits may be unacceptable from a public relations standpoint. Opacity problems are particularly acute in metropolitan areas, or near recreational or environmentally sensitive regions. In such cases, opacities that are well below the regulation may prompt a negative response from the public or regulatory authorities that is disproportionate to any actual increase in emissions or environmental threat. Nevertheless, these current situations have created less tolerance for opacity exceedances by power company management, and have increased the pressure on power plant operating and maintenance personnel to implement tighter controls on stack opacity.

In addition to regulatory pressures for opacity control, other factors have increased the need for reducing opacity. Increased cycling duties implemented on some boilers have created the need to reduce opacity when it has been a limiting factor in boiler capacity or turndown. Market pressures in the power generation sector to reduce costs have also forced boiler operators to minimize heat rates, placing a higher emphasis on opacity reduction in order to minimize boiler excess air and combustion efficiency. Finally, traditional means of controlling opacity (e.g., increase the excess air) may no longer be possible in light of contradicting requirements for NOx emissions control.

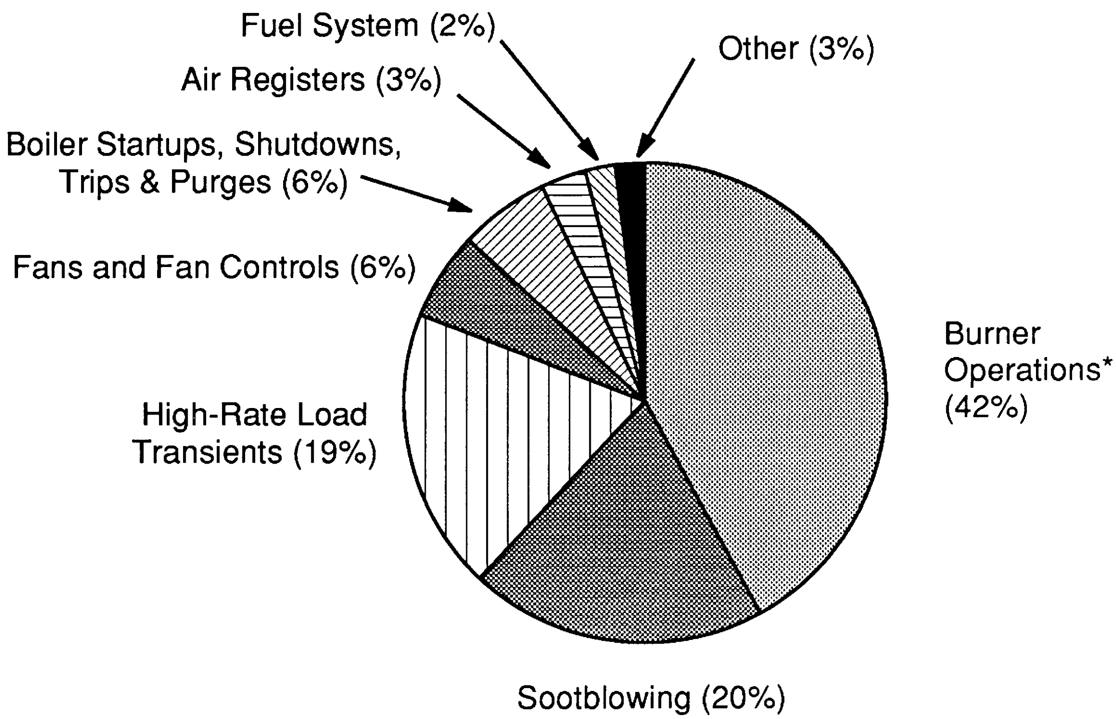
1.1.2 Types of Opacity Problems

As indicated above, the causes of opacity are complex, and a specific "opacity problem" may originate from one or more sources within the boiler. Moreover, one or more types of particulate matter emissions may be involved in an opacity problem. For purposes of diagnosis and remediation, opacity problems addressed in this document have been broken down into the following types (symptoms):

1. Black smoke during boiler startup
2. White dense smoke during boiler startup
3. Black smoke, intermittent during load increases or decreases
4. Black smoke during steady operation
5. White, faint smoke (SO_3 condensation)
6. Black smoke (opacity spikes) during burner light-offs
7. Black smoke (opacity spikes) during burner shutdown
8. Opacity problems during sootblowing
9. Black smoke when co-firing oil and gas
10. High opacity during load ramp-ups

1.1.3 Causes of Opacity Problems

Stack opacity at oil-fired boilers can be the direct or indirect result of the design of boiler components, plant operating practices, maintenance of critical hardware, or combinations of these. Figure 1-1 illustrates causes of opacity exceedances that were documented for a 360-MW boiler over a period of 18-months. The graph emphasizes the variety of sources that contribute to opacity problems at oil-fired boilers.



* Burner operations include problems placing burners in and out of service, poor oil atomization (improper oil temperature), and problems controlling burner air-fuel ratios.

Figure 1-1
Causes of opacity exceedances at a 360-MW oil-fired boiler.

Specific operating factors may be important contributors to opacity during steady boiler operation, transient boiler operations, or both. In general, boilers that undergo daily load cycling are more prone to incidents of high opacity, because of the greater number of operating modes that are experienced (e.g., burner light-offs, load changes, burner adjustments, etc.). However, base-loaded units or boilers that experience minimal load cycling may also be prone to continuous or intermittent opacity problems. Boiler operators are often unaware of the underlying cause and effect relationships between opacity and operating conditions and, consequently, opacity problems reoccur as the root causes remain.

The design and maintenance of combustion equipment directly impacts the opacity characteristics of a boiler. Pertinent equipment includes: the fuel supply system (e.g., oil heaters, pumps, fuel piping), combustion air supply system (e.g., windbox and dampers), fuel atomization, burners (air registers and flame stabilizers), ignitors, burner management system, and NOx controls (e.g., overfire air). Other plant equipment design factors which can impact opacity include: furnace geometry and the design of sootblowers, ductwork, and boiler control systems. Fuel composition and physical properties also impact opacity by affecting carbon particle formation during combustion, carbon burnout, ash deposition, and acidic emissions.

1.1.4 Problems Related to Opacity

High particulate matter (PM) mass emissions and stack fallout ("acid smut") problems may be related to problems of high stack opacity, but this is not always the case.

An increase in stack opacity often indicates an increase in the total particulate matter (PM) mass emissions. However, there is no direct correlation between opacity and PM. Depending on the cause of high opacity, PM emissions may decrease or remain unchanged with a reduction in opacity. It is now widely accepted that opacity cannot be used as a surrogate for PM for purposes of monitoring PM emissions compliance or as a reliable indicator of total PM emissions.

For a given boiler, there can be tradeoffs between opacity and PM, the exact nature of which is site specific. Raising excess oxygen to reduce carbonaceous PM emissions and total PM may increase the opacity due to sulfuric acid condensation. Conversely, reducing excess oxygen to control NOx emissions may reduce opacity from sulfuric acid condensation, but at the same time increase opacity due to a higher concentration of carbonaceous particulate matter emissions.

Particulate fallout problems in the vicinity of the plant are the result of large, acidic particles that are released from deposits on boiler heat transfer surfaces and ductwork, and large, unburned carbon particles. The emission of fallout particles from the stack may result in simultaneous increases in stack opacity (e.g., during sootblowing or load ramps). However, continuous or episodic emissions of these particles may not be evident as an increase in opacity, because of their relatively low concentration and ineffective light-scattering properties compared to smaller particles.

1.2 How to Use This Document

The subject matter of the subsequent five sections of the report are summarized in the following table.

Table 1-1
Report Contents — Sections 2 through 8

Report Section	Section Title/Description	Contents
2	Characteristics of Opacity	Reviews the characteristics of opacity, including: (1) the definition of opacity and basic properties related to visibility, and (2) size and composition of particulate matter that cause opacity.
3	Origins of Opacity	Discusses the origins of particulate matter and opacity, beginning with the properties of the fuel and progressing through the combustion process, the boiler, and to the stack. The role of fuel additives and back-end corrosion additives are also discussed.
4	Boiler Design Factors Which Affect Opacity	Identifies the design factors relevant to stack opacity and describes the ways that they impact opacity.
5	Boiler Operating Factors Which Affect Opacity	Identifies the operating factors relevant to stack opacity and describes the ways that they impact opacity.
6	Maintenance Factors Which Affect Opacity	Identifies the maintenance factors relevant to stack opacity and describes the ways that they impact opacity.
7	Options for Reducing Opacity and Particulate Matter Emissions	Reviews options for reducing opacity, including modified operating and maintenance practices, upgrading of combustion equipment and other boiler components, use of additives, changes in fuel specifications, and retrofit of particulate control devices.
8	Troubleshooting Opacity Problems	Troubleshooting guidelines for diagnosing opacity problems, including step-by-step procedures for each type of opacity problem listed above. A general discussion of problems related to high PM emissions and acidic fallout is also included.

For readers not familiar with the characteristics and origins of particulate matter emissions and opacity in oil-fired boilers, it is highly recommended that they review Sections 2 and 3. Understanding these basic aspects of particulate matter and opacity can be beneficial in the practical work of diagnosing and rectifying opacity problems.

Sections 4, 5, and 6 provide readers with a reference for design, operating, and maintenance factors affecting opacity, respectively. For each factor, the ways in which it may affect opacity within the power plant are discussed. However, Sections 4, 5, and 6 are primarily intended to be used in conjunction with Section 8 (troubleshooting guidelines), when additional information for diagnosing and correcting a specific opacity problem is required. For various types of opacity problems and causes, users of Section 8 are referred to specific subsections in Sections 4-6 for further insight.

Section 7 reviews the options for correcting opacity problems. It provides guidance for adopting revised operating and maintenance procedures, and reviews other options for reducing opacity including upgrading of combustion equipment, use of chemical additives, and installation of particulate control devices.

Section 8 provides a guideline for troubleshooting opacity problems and is the primary focus of this document. It will likely be the primary entry point for many users of this document. Readers with specific opacity problems, characterized by one or more specific symptoms, are provided with recommendations for making observations and conducting tests to help identify the root cause(s) of the opacity problem, and are provided guidance on the appropriate course of action to solve the problem.

A discussion of problems related to high PM mass emissions and acidic fallout ("acid smut"), including generalized diagnostic and remedial actions, is included at the end of Section 8.

1.3 Related EPRI Products and Reports

Other EPRI products related to oil-fired boilers which provide guidance and information that is complementary to this guideline are listed below. For additional information on these products, contact the EPRI Project Managers named on the cover of this document.

Topic	Product	Description	Status
Residual Oil End Use	*Residual Fuel Oil User's Guidebook, Volumes 1 and 2* (AP-5826)	Guideline document	Published 1988
	Development of Fuel Oil Management System Software, Phase 1: Tank Management Module (TR-100311)	Oil mixing and storage optimization software	Prototype software field tested in 1991
Residual Oil Analysis and Characterization	*Methods for Assessing the Stability and Compatibility of Residual Fuel Oils* (GS-6570)	Oil analysis and predictive methodology	Published 1989
	HOT FOIL Instrument for Measuring the Coking Index of Residual Oils (TR-101662)	Laboratory instrument and methodology	Commercial product
Burner Modification	*REACH: Reduced Emissions and Advanced Combustion Hardware* (TR-105708)	Combustion Upgrade Hardware	Commercial product
NOx Control Overview	*Retrofit NOx Control Guidelines for Gas- and Oil-Fired Boilers Version 2.0* (TR-108181)	Guideline document, electronic data base, and cost estimating software	Published 1997

2

CHARACTERISTICS OF OPACITY

2.1 Background

The term "opacity" is commonly used to describe the visibility of stack plumes from combustion sources. It is defined in general terms as the degree to which stack emissions reduce the transmission of light and obscure the view of an object in the background. Opacity is typically measured by instruments (transmissometers) which determine the attenuation of a light beam directed across the stack through the flue gas steam, i.e., in-stack measurement. These measurements yield real-time, continuous opacity data which can be related to stack plume visibility. Opacity can also be measured by direct visual observation of the plume by a qualified ("certified") observer in accordance with Environmental Protection Agency Reference Method 9 (Reference 2-1)

Opacity measured by an in-stack transmissometer (i.e., opacity monitor) may not correlate with plume visibility as perceived by stack observers. This is due to a variety of reasons. For example, water vapor and sulfuric acid contained in the flue gas can condense downstream of the opacity monitor and increase plume opacity. Further, external factors such as the viewing angle between the observer and the plume, location of the sun with respect to the observer and the plume, and background contrast of the sky can significantly impact the visual appearance of the stack plume (Reference 2-2). For certified observers, stringent procedures for viewing the stack plume are required to assure that consistent measurements are achieved.

For oil-fired utility boilers, the primary contributors to plume opacity are solid particles of ash and unburned carbon, and droplets of condensed sulfuric acid. Discoloration of the plume by gases such as nitrogen dioxide (NO_2) can also contribute to plume visibility, but this is rare at oil-fired boilers due to relatively low NO_2 emissions, particularly with the widespread implementation of NOx emissions controls.

2.2 Definition of Opacity

Opacity is defined as the percentage of incident light removed by a gas stream or plume due to scattering and absorption by suspended particles. Absorption of light by gaseous species is considered negligible for oil-fired boilers. In equation form, opacity (expressed as percent) is defined as:

$$\text{Opacity, \%} = (1 - I/Io) \cdot 100 \qquad (2\text{-}1)$$

where,

Io = intensity of incident light
I = intensity of light transmitted through the flue gas

The transmission of light through a volume containing a suspension of particles is described by the Bouguer (Lambert-Beer) law:

$$I/Io = \exp(-N \cdot L \cdot A \cdot Qext) \qquad (2\text{-}2)$$

where,

N = particle concentration
L = path length of light
A = average particle projected (cross sectional) area
$Qext$ = particle light extinction coefficient

Ensor and Pilat (References 2-3 and 2-4) have developed a procedure to estimate the particle concentration which will produce a given level of opacity for industrial sources. The procedure uses a transformation of equation 2-2:

$$W = (-K \cdot \rho/L) \cdot \mathrm{Ln}(1 - I/Io) \qquad (2\text{-}3)$$

where,

W = particle concentration, g/m^3
K = particle volume/extinction parameter, cm^3/m^2
ρ = particle density, g/cm^3
L = path length, m

The parameter K is the ratio of the specific particulate volume (cm^3/m^3) divided by the extinction coefficient (m^{-1}), and is primarily a function of the particle size distribution, refractive index, and to a lesser degree, the wavelength of light. By selecting the appropriate value of K from charts produced by Ensor and Pilat, it is possible to estimate the mass concentration and particle size which will produce a given opacity for different types of particles (aerosols). The parameter K is strongly influenced by particle diameter and geometric standard deviation as shown in Figure 2-1 for a "black" (light absorbing) aerosol with a log normal distribution. Such particles are good approximations for ash and carbonaceous particles emitted from oil-fired boilers.

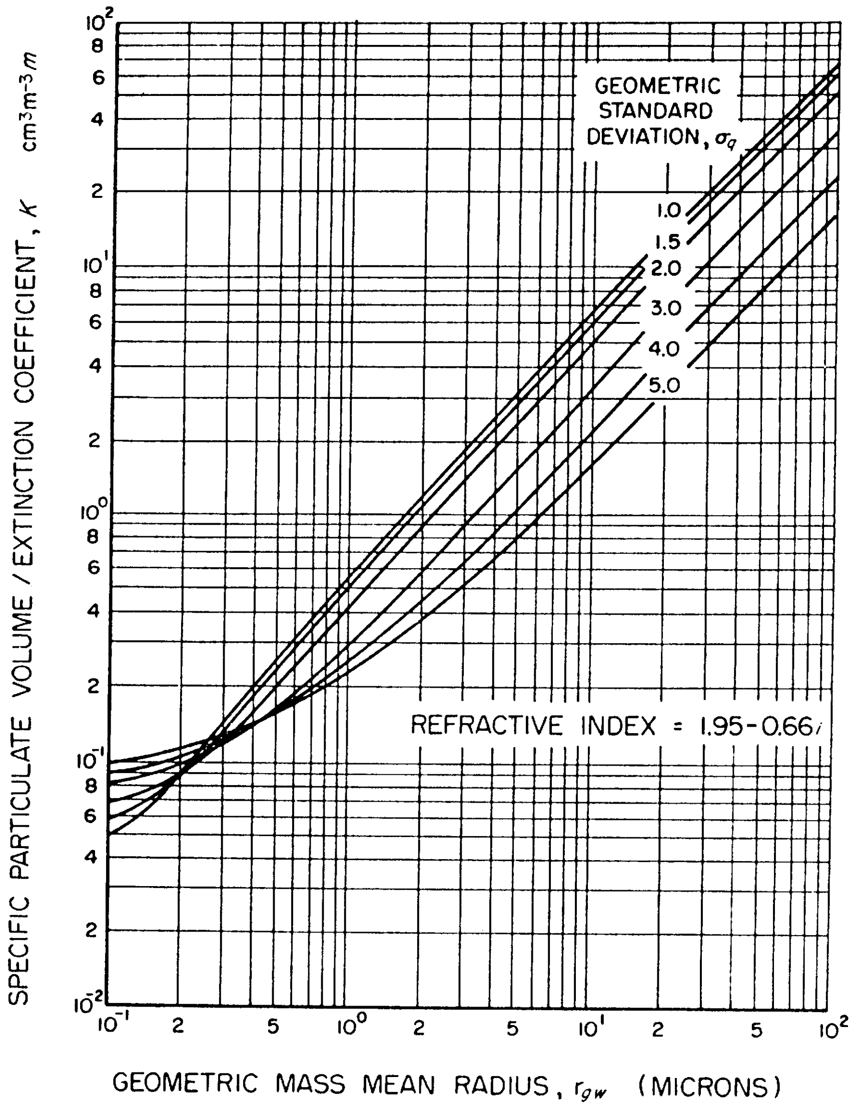
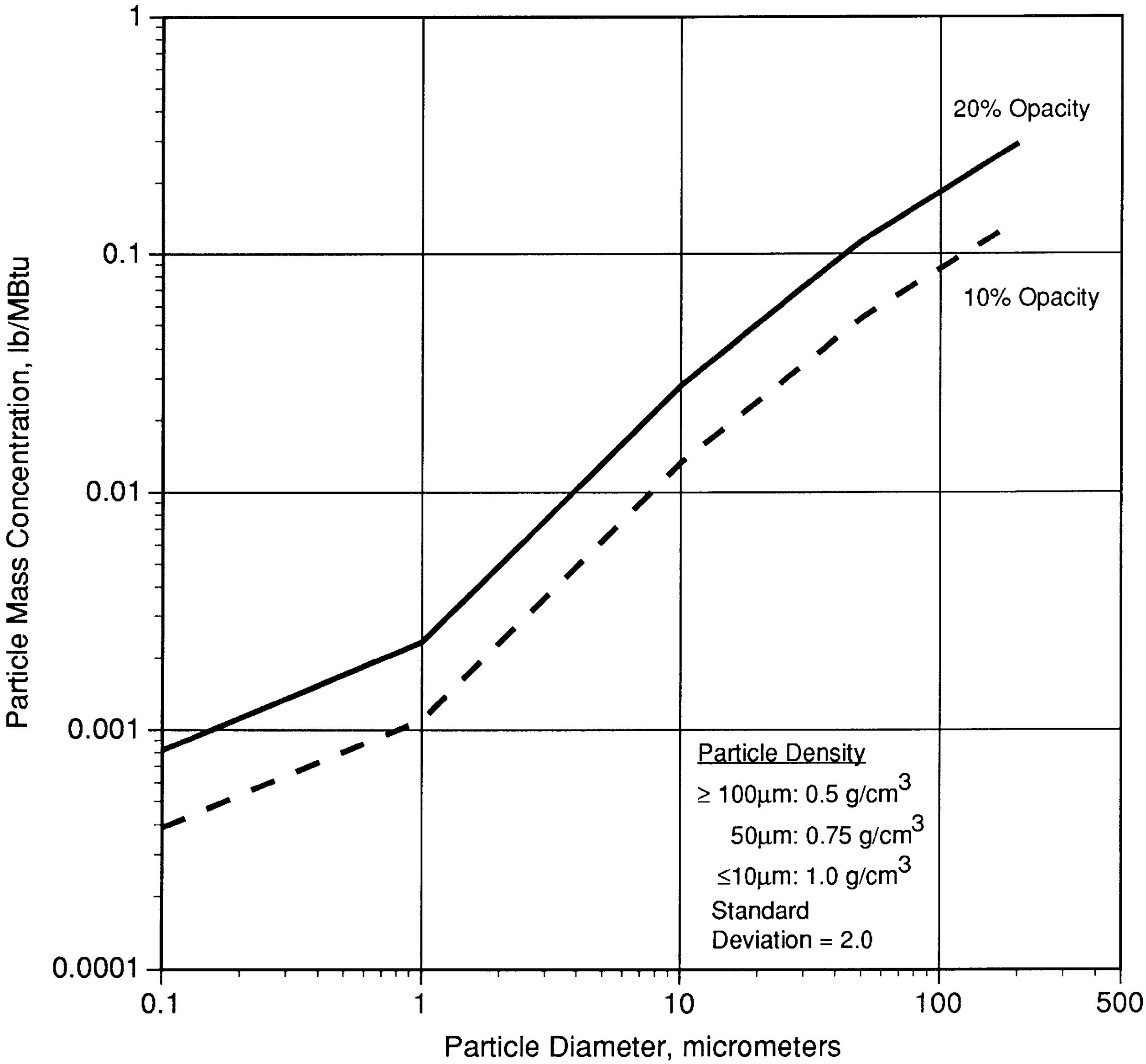


Figure 2-1
Relationship of parameter K (specific particulate volume/extinction coefficient) to particle size distribution parameters for a black (light absorbing) aerosol. Excerpted from Reference 2-4.

2.3 Relationships Between Opacity and Size of Particulate Matter

The relationships in Figure 2-1 can be used to estimate the influence of different concentrations of particulate matter size (i.e., diameter) on plume opacity. Combining this information with equation 2-3, it was possible estimate the mass concentration (W) of particles with different diameters which are required to produce 10% and 20% opacity for a stack with a diameter of 10 meters. In this regard, calculations were performed by the authors for a particle size distribution with a geometric deviation of 2.0, and for particles with diameters of 0.1, 1, 10, 50, 100, and 200 micrometers. The particle densities were assumed to be 0.5 g/m^3 for particles ≥100 micrometers (μm), 0.75 g/m^3 for 50μm particles, and 1.0 g/m^3 for particles ≤10 μm. For each particle diameter, the parameter K was obtained from Figure 2-1 (note that K is plotted as a function of particle radius in Figure 2-1). W was then calculated from Equation 2-3 by inputting K, particle diameter, opacity (10% or 20%), path length (10 meters), and particle density for the diameter ranges described above.

Results are shown in Figure 2-2, which plots particulate matter mass emissions (lb/MBtu) vs. particle diameter (micrometers) for 10% and 20% plume opacity. For both instances, the mass concentration of 1μm particles required for the specified opacity was approximately 2% of the concentration required for 50μm particles. This result was expected since it is well known that particles with diameters comparable to the wavelength of light (0.3-1.5μm) make a disproportionately high contribution to opacity.



Particle densities are based on data for carbon cenospheres from oil-fired boilers.

Figure 2-2
Particulate mass emissions required for 10% and 20% opacity vs. particle diameter.

Figure 2-2 also shows that large particles (i.e., 50-200μm) can be important contributors to opacity at moderate mass concentrations, and may account for high opacity (e.g., black smoke) observed during many boiler operating conditions. In this regard, the figure shows that 50μm particles can produce plumes of 10% and 20% opacity with particulate mass concentrations of 0.05 and 0.11 lb/MBtu, respectively. There are a number of operating conditions at oil-fired boilers where concentrations of 50μm particles may easily reach or exceed these levels, including poor oil atomization, low excess air, soot blowing, burner lightoff and shutdown, load ramps, etc.

The results described above are significant because they clarify a misconception that opacity excursions at oil-fired utility boilers are predominantly caused by fine particle emissions. This perception is due in part to the fact that the majority of opacity research has been conducted on coal-fired boilers. In this regard, emissions of particulate matter from coal-fired boilers are biased to smaller-sized particles (i.e., less than 10 µm) because these units are equipped with high-efficiency dust collectors that easily remove large particles. Thus, for coal units the primary source of opacity is particles less than 10µm diameter, except perhaps during brief periods when "puffs" of larger (and quite visible) particles are emitted due to rapping of collecting plates in electrostatic precipitators or cleaning bags in fabric filters. For oil-fired boilers, however, there is substantial evidence from field observations that large particles are a significant cause of opacity. In fact, with the exception of opacity caused by droplets of sulfuric acid mist, most of the opacity excursions at oil-fired boilers are likely caused by emissions of particles with diameters greater than 10µm.

2.4 Characteristics of Particulate Matter From Oil-Fired Boilers

The primary contributors to plume opacity at oil-fired boilers are solid particulate matter emissions (e.g., unburned carbon, sulfates, and ash) and droplets of sulfuric acid. The particles emitted from oil-fired boilers are typically distributed in a bimodal size distribution, which consists of a large particle mode greater than 1µm diameter, and a small particle mode less than 1µm in diameter. Figure 2-3 shows particle size distributions measured at an oil-fired utility boiler for three operating conditions: baseline, low excess air, and poor atomization quality (Reference 2-5).

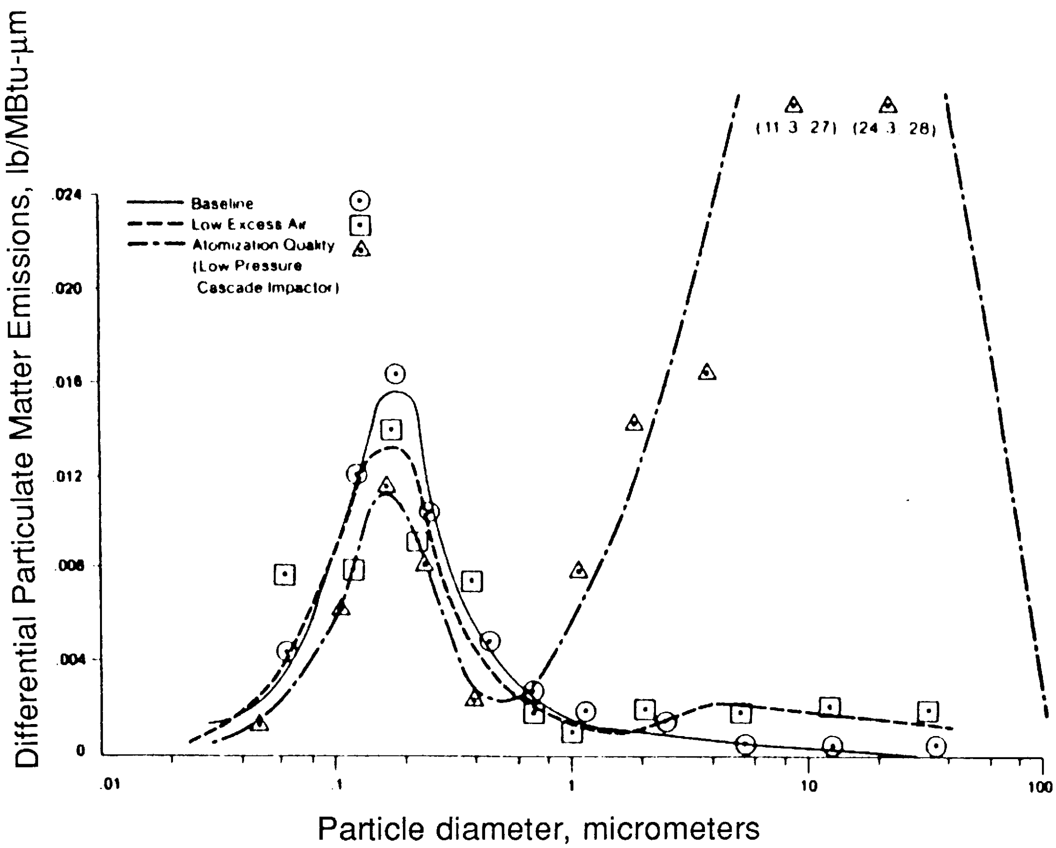


Figure 2-3
Particulate matter size distributions comparing normal (baseline) operation to low excess air and poor oil atomization conditions for a 360-MW tangential-fired boiler. The oil atomizers were steam atomized. Excerpted from Reference 2-5.

The figure shows that for baseline conditions, the majority of particulate matter mass was in a submicron mode with a peak in concentration near 0.2µm. For low excess air operation, the large-particle mode between 1 and 100µm increased in size. For the case of poor oil atomization the large particle mode increased significantly. It is interesting to note that the magnitude of the submicron mode was relatively unchanged for all the operating conditions.

Analysis of particulate matter from oil-fired boilers has shown that the large particles produced during steady-state boiler operation are composed primarily of carbonaceous by-products of incomplete combustion called cenospheres and burned-out remnants of cenospheres. During transient boiler operations (e.g., sootblowing and load ramps) other types of large particles are emitted which originate from deposits on the surfaces of the boiler, ducts, air heaters, and stack. As shown in Figure 2-3, the concentration of large particles is strongly influenced by boiler design and operating factors whereas the very small particles (<1µm) may to some degree be an unavoidable feature of oil combustion. Brief discussions of the types of particles present in oil-fired boilers are presented below. More detailed discussions of these topics are contained in subsequent sections as indicated.

2.4.1 Cenospheres

Cenospheres produced in oil combustion are the remnants of coke particles formed in a "two-step" process when individual drops of oil produced at the burner oil atomizer undergo combustion in the furnace. Each oil droplet produces a cenosphere. Cenospheres have a characteristically spherical, sponge-like appearance, are often hollow, and are typically in the 25 to 500 micron size range. The cenosphere formation process is described below under origins of stack opacity. Figure 2-4 show photographs of typical cenospheres collected from oil-fired boilers.

2.4.2 Fine Particles

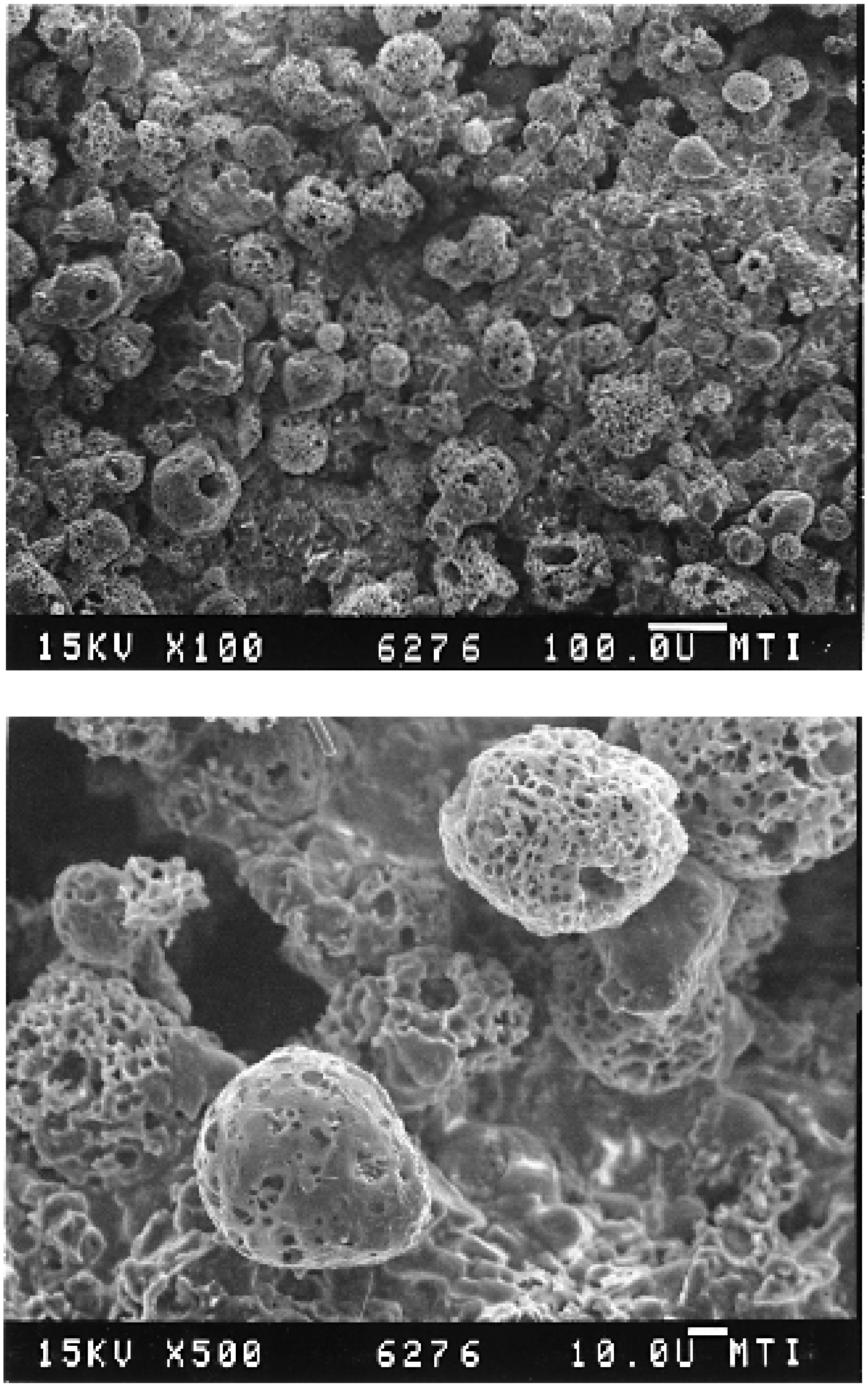
The small particles less than 1μm in diameter are believed to be the result of volatilization and subsequent condensation of inorganic material contained in the oil (e.g., oil ash). Therefore, the mass of particles produced by this mechanism is expected to be relatively constant regardless of the boiler operating conditions.

2.4.3 Sulfuric Acid

The sulfuric acid concentration in the flue gas is directly dependent upon the sulfur content of the fuel oil, the concentration of vanadium in the fuel oil, and the excess air level in the boiler. These factors influence the production of SO_3 during the combustion process by oxidation of SO_2. As the flue gas cools to the acid dew point in the boiler ductwork, condensation of SO_3 forms sulfuric acid, which remains in suspension as a fine aerosol or condenses on the surfaces of particles, ash deposits, and surfaces of the air heaters, ducts, and stack liner. Reactions of sulfur compounds with ash constituents produce sulfate particles which are frequently in the large-particle size range, e.g., ≥1μm.

2.4.4 Other Combustion-Derived Particles

Deposits of oil ash on the boiler heat transfer surfaces and low-velocity regions in the boiler are dislodged, particularly during sootblowing and load ramps, and may be entrained by the flue gas and emitted out the stack. Similarly, deposit accumulations on low-temperature ductwork and the stack liner may be periodically swept out the stack. Additional discussion regarding this source of particulate matter emissions is presented in Sections 3.2.4, 5.10, 6.7, and 6.9.



(A)

(B)

Figure 2-4
Scanning electron micrographs of a particulate matter sample collected at full load for a 300-MW oil-fired boiler. The top image is 100x magnification and the lower image is 500x magnification. Carbonaceous cenospheres range in size from 10μm to over 100μm diameter.

2.4.5 Additives

Chemical compounds injected into the boiler gas passages or blended with the oil are marketed commercially to improve combustion, control boiler deposits, and/or reduce corrosion. Use of additives can alter the composition and magnitude of particulate matter emissions and can also affect opacity, depending on the type of additive, dose rate, and injection location. Additional discussion regarding additives is presented in Sections 3.2.3, 3.2.5, 5.12, and 6.11.

2.5 References

1. Code of Federal Regulations, Protection of the Environment, 40 Part 60, "Visual Determination of the Opacity of Emissions From Stationary Sources."

2. Alexander Weir, Jr., "Cleaning the Opacity Issue," Environmental Science and Technology, Vol. 11, Number 6, June 1977.

3. D. S. Ensor and M. J. Pilat, "Calculation of Smoke Plume Opacity from Particulate Air Pollutant Properties," APCA Journal, Vol. 21, No. 8, August 1971.

4. Michael J. Pilat and David S. Ensor, "Plume Opacity and Particulate Mass Concentration," Atmospheric Environment Permagon Press 1970, Vol. 4, pages 163–173.

5. *Particulate Emission Characteristics of Oil-Fired Utility Boilers*. EPRI CS-1995, August 1981.

3

ORIGINS OF OPACITY

3.1 Background

The variety and complexity of particles that contribute to total particulate mass emissions and opacity from oil-fired boilers reflect the various processes which occur during refining of the fuel, combustion of the fuel, and after combustion as the combustion byproducts transit the boiler and exit the stack.

Particulate matter emissions from oil-fired boilers contain both inorganic and organic constituents. The inorganic fraction includes: (1) ash in the fuel oil which consists primarily of vanadium, aluminum, iron, silica, nickel, magnesium sodium, and calcium compounds; (2) sediments originating from oil tank storage facilities; (3) alkali sulfates; (4) salts (primarily sodium compounds) from contamination by sea water during transportation, or incomplete separation of crude oil from its associated salt brine during production; and (5) mineral matter (usually calcium, magnesium, or alumina compounds) in additives that are mixed with the fuel and injected into the boiler to improve carbon burnout, inhibit tube corrosion, control ash deposition, and reduce formation of sulfuric acid.

The organic component of the fly ash normally consists of: (1) coke residue resulting from incomplete burnout of oil droplets; (2) soot — a carbon residue formed by vapor phase condensation of reaction intermediates in the combustion process; and (3) acid smut — a combination of carbonaceous materials, sulfuric acid, and ash which has deposited on the cold-end surfaces of the air heater (or other heat transfer surfaces) and is re-entrained into the flue gas by soot blowing or load increases.

3.2 Sources of Particulate Matter Emissions

Figure 3-1 illustrates the most common sources of particulate matter emissions which contribute to opacity at oil-fired boilers. The most important of these sources are discussed below.

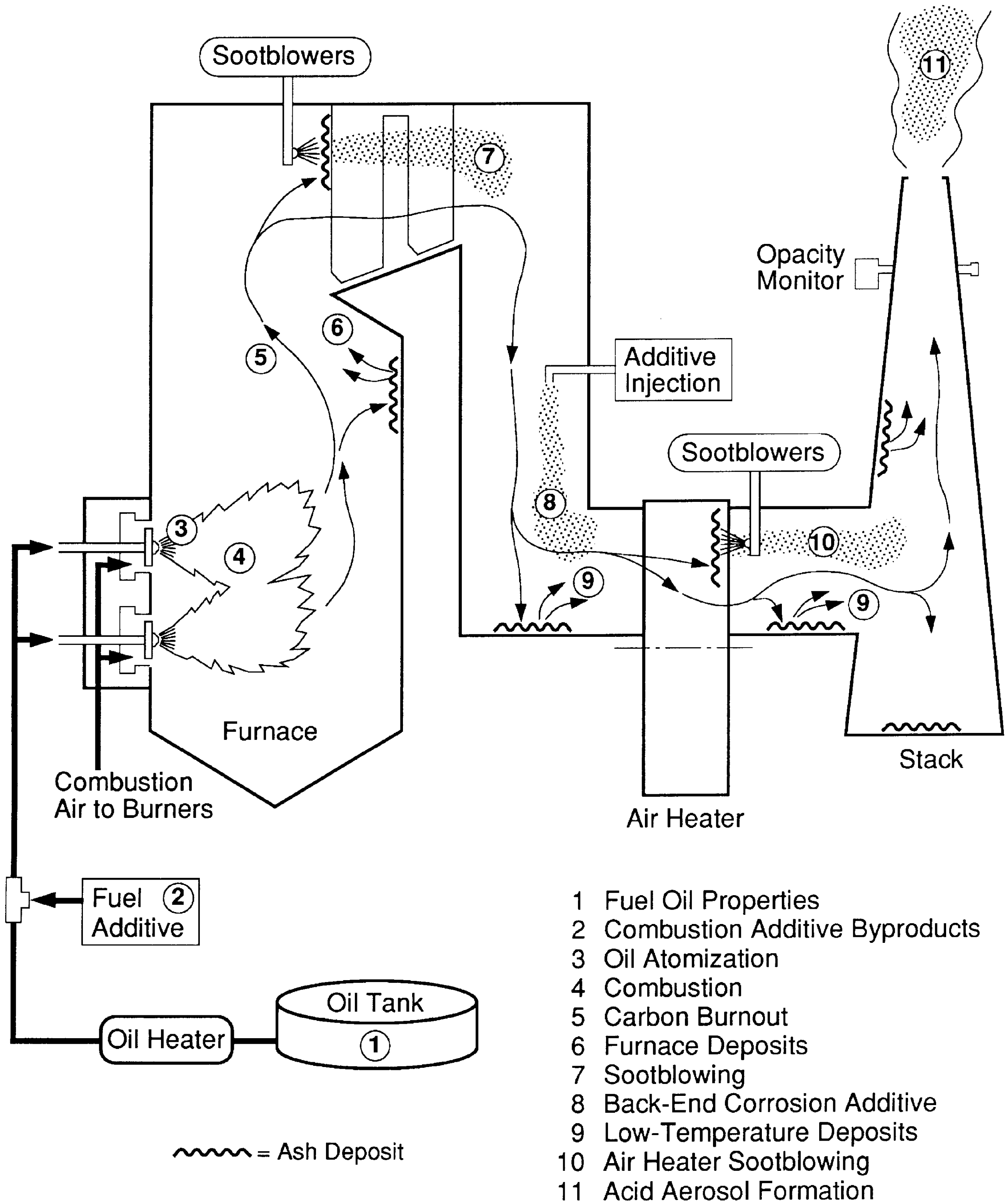


Figure 3-1
Sources of particulate matter emissions and opacity at oil-fired boilers.

3.2.1 Fuel properties (Item 1 in Figure 3-1)

A number of fuel oil properties are directly related to increased particulate matter emissions and opacity. The most important ones are described below.

3.2.1.1 Asphaltene Content, Coking Index, and Conradson Carbon.

Asphaltenes are long-chain, high molecular weight hydrocarbon compounds which can be a significant fraction of residual fuel oils. Their structure requires high temperatures and high atomization energy to burn completely. Oils with high asphaltene content have a greater propensity to produce carbonaceous particulate matter emissions and opacity. Asphaltene content varies from less than 1% for low-sulfur oils (<0.5%S) to as high as 18% for high-sulfur (4%S) oils. Asphaltene content is commonly used as a measure of coke formation tendency when the fuel is burned. However, attempts to correlate particulate matter emissions from oil-fired boilers with asphaltene content have met with limited success.

The Coking Index (CI) is a fundamental property of residual oil which defines the mass of nonvolatile or "fixed" carbon (i.e., coke cenospheres) formed during the initial stages of combustion (Reference 3-1). CI influences the size of the coke particles, and is a more precise indicator of coke formation potential than asphaltene or other conventional carbon indices such as Conradson Carbon. With all other factors being equal, fuel oils with a high CI can be expected to produce higher emissions of unburned carbon.

EPRI has developed a method and apparatus for measurement of CI for residual oils (Reference 3-2). Although not yet widely available for routine analysis of fuel oils, the method has proven to be a better indicator of coke forming tendency for residual oils than other techniques. In this regard, Conradson Carbon measurements have been shown to exhibit a linear relationship with CI, although Conradson Carbon overstates the coke-forming tendency of residual fuel oils (see Reference 3-2).

3.2.1.2 Sulfur Content.

Sulfur content is an indicator of corrosion potential for fuel oils. During combustion, sulfur is oxidized to sulfur oxides. The primary oxide is sulfur dioxide (SO_2), although a fraction of the SO_2 is oxidized to sulfur trioxide (SO_3). These oxides can react with water vapor and ash constituents to form corrosive acids and salts. Furthermore, vanadium in the oil (see below) can combine with sulfur oxides to form corrosive compounds. Higher concentrations of sulfur in the oil increase the acid content of the flue gas because of higher concentrations of SO_3. Higher acid content increases the potential for acid condensation plumes as discussed below. Also, increased cold-end deposits, low-temperature corrosion, and particulate matter mass emissions (e.g., sulfates) will result which may adversely impact opacity.

3.2.1.3 Ash Content.

Ash contained in the fuel oil is continually released into the flue gas during combustion. The majority of the ash remains in suspension and is emitted from the stack as particulate matter. The maximum ash content of residual fuel oils is typically 0.1% by weight which, if completely emitted from the boiler, would result in approximately 0.05 lb/MBtu of particulate matter emissions. Actual emissions are higher because from 10% to 90% of the particulate matter may be composed of organic material, principally unburned carbon and sulfates (see Sections 3.2.2 and 3.2.3, below). Consequently, particulate matter emissions from uncontrolled, oil-fired boilers can be as high as 0.5 lb/MBtu during steady boiler operation.

A small quantity of the particulate matter continuously accumulates on heat transfer and ductwork surfaces during operation. Deposits continue to build up until they are dislodged by load transients, sootblowing cycles, and natural "shedding." Relatively large concentrations of particulate matter are then released into the flue gas stream. If the boiler is not equipped with a particulate matter collection device, these episodes can cause very high opacity for brief time periods.

3.2.1.4 Vanadium Content.

The vanadium content in the oil is a concern for two reasons. First, vanadium compounds in deposits on tube surfaces can act as catalysts which promote the conversion of SO_2 to SO_3, thereby increasing the sulfuric acid content of the flue gases and the potential for increased opacity due to condensed droplets of sulfuric acid. Second, many vanadium compounds have low melting points which can increase ash deposits on furnace walls and on tubes in the convective sections. During subsequent sootblowing and load cycling, these deposits can be dislodged leading to increased particulate matter emissions and opacity.

3.2.1.5 Viscosity.

Oil viscosity affects the quality of oil atomization (e.g., the size of the oil droplets at the burner) which in turn affects the number and size of carbonaceous cenosphere particles produced during combustion. It has been shown that the larger the oil droplets, the larger the cenospheres that are produced in the combustion process and the longer the time required for them to burn out. The effects of viscosity on opacity and the relationships between viscosity and oil temperature are discussed in greater detail in Section 5.4.

3.2.2 Combustion and Oil Atomization (Items 3, 4, & 5 in Figure 3-1)

Carbonaceous particulate matter from oil-fired boilers results from a two-step combustion process. The first step is referred to a the “Coke Formation Step” which produces coke cenospheres. The second step is referred to as the “Coke Burnout Step.” The quantity of coke produced is primarily dependent upon the fuel properties, whereas coke burnout is dependent upon the physical characteristics of the coke and the combustion conditions in the boiler (Reference 3-1).

3.2.2.1 Coke Formation Step.

Carbon particles formed in the initial combustion zone of a flame are of two types: soot and coke. Soot is formed as a result of a gas phase chemical process. Although very rich in carbon, soot is typically a very small percentage of the total carbon in the oil and has a particle size not exceeding several microns. Soot burns out rapidly in utility boilers because of the large surface-to-volume ratio of the soot particles and the high temperatures and long residence times for combustion in utility boilers. Thus, soot is not an important contributor to particulate matter mass emissions and opacity.

In contrast to soot, coke cenospheres constitute the major component of carbonaceous particulate matter mass emissions at oil-fired, utility boilers. The cenospheres are principally carbon (sometimes greater than 80% by weight) and oil ash, and are substantially larger than soot particles. They range in size from ten to a few hundred micrometers in diameter and are typically hollow, nearly spherical, and have many holes through and pores within the particle structure. The size of the cenospheres depends on the Coking Index of the oil and the initial oil droplet diameter (which is determined by oil atomization as discussed in Section 3.2.2.3, below).

Coke cenospheres are formed in the initial combustion zones of a flame. For typical fuel oils each oil droplet produces a coke cenosphere. The fraction of coke cenospheres which do not burnout contributes directly to particulate matter mass emissions. If their concentration is high enough (refer to Section 2.3), coke cenospheres can also be a significant contributor to plume opacity.

3.2.2.2 Coke Burnout Step.

The degree of burnout of coke cenospheres in a boiler will depend on many factors including: (1) the initial coke particle size, (2) particle surface-to-volume ratio, and (3) particle time-temperature-oxidation profile as it passes through the boiler. Experimental observations have indicated that coke burnout undergoes a transition from outer surface burning (which dominates initially) to a condition where combustion within the internal pore and void structure of the cenosphere is dominant.

3.2.2.3 Oil Atomization.

The quality of oil atomization is generally defined by the characteristics of the oil droplet size distribution. The droplet size distribution produced by commercial oil atomizers covers a wide range of particle diameters, i.e., from 10 to 1,000 micrometers in diameter. The distribution of the oil spray is generally characterized by mean diameter. For combustion applications, the volume-surface mean diameter or Sauter Mean Diameter (SMD) is commonly used. The SMD is the diameter of a hypothetical droplet that has the same surface-to-volume ratio as that of the total spray distribution. Generally speaking, improving atomizing quality implies the generation of a droplet size distribution which has a smaller SMD. Since every oil droplet produces a coke cenosphere, the chances for completely burning the cenospheres in a given combustion system is enhanced by oil sprays with smaller SMD, since the coke particles are smaller and therefore burn out more quickly. Descriptions of different atomizer designs, and the effects of atomizer design and operating parameters on opacity are discussed in greater detail in Section 4.1.1.1.

3.2.3 Fuel Oil Additives (Item 2 in Figure 3-1)

Additives injected with fuel oil are generally intended to achieve one of two objectives, i.e., improved combustion or reduced deposition and corrosion. “Combustion-improving” additives promote the burnout of carbonaceous particulate matter. Although many benefits are claimed and some successes have been documented, results are not always predictable and the exact mechanisms by which the additives work are not well understood. Other types of oil additives are intended to react with vanadium compounds in the oil to mitigate the catalytic conversion of SO_2 to SO_3, and to produce high-melting point compounds which are non-corrosive and easily removed from tube surfaces by sootblowers or “ash shedding” during load cycling. The potential benefits of additives may be offset by adverse consequences elsewhere (refer to Sections 5.12 and 7.3)

3.2.4 Ash Accumulation and Migration (Items 6, 7, 9, & 10 in Figure 3-1)

Deposits of oil ash which collect on the boiler heat transfer surfaces are normally dislodged during sootblowing and load cycling. These materials generally consist of large particles which can be entrained by the flue gas and discharged out the stack. Similarly, deposit accumulations on low-temperature ductwork and the stack liner may be periodically swept out the stack. The quantity of material dislodged can be significant for short periods of time, and can produce opacity spikes of comparable magnitude as those during sootblowing, e.g., 20–80%.

Ash deposition in oil-fired boilers occurs on: (1) water walls in the furnace cavity near the burners; (2) superheater, reheater, and economizer tube surfaces; and (3) surfaces in air heaters and in low-velocity regions of the ducts and stack. Of the many constituents in oil ash, the most important from the standpoint of deposition are vanadium, sodium, and sulfur because they will determine the melting point, friability (ease of removal by sootblowers), and corrosion potential of the ash.

Because the ash content of fuel oil is low, oil-fired units are normally not equipped with large numbers of sootblowers. Further, oil-fired boilers generally do not have sootblowers to clean the furnace walls (except for combination oil- and coal-fired boilers). Superheater and reheater sections are more likely to be equipped with sootblowers, although they may be relatively few in number compared to a coal unit of the same size. Economizers frequently do not have soot blowers, whereas air heaters must have sootblowers because of the small gas flow passages which are prone to pluggage by ash. If "problem" oils are burned or operating conditions are encountered which significantly increase the rates of ash deposition, large quantities of material can be dislodged during subsequent load cycling and soot blowing periods. Such events will cause incidents of high opacity and large-particle fallout in the vicinity of the plant.

Sootblowing practices at oil-fired boilers can be tailored to minimize high opacity while at the same time maintaining clean heat transfer surfaces. To accomplish this objective, specific tests must be conducted to determine the best combination of sootblowing frequency (i.e., number of sootblows per day), duration (i.e., length of sootblow), and program (i.e., the sequence that heat transfer sections are cleaned).

3.2.5 Low-Temperature Corrosion and Additives (Item 8 in Figure 3-1)

Corrosion of low-temperature boiler heat transfer surfaces and passages (air heater, ductwork, and stack liner) is accelerated by acid condensation. However, corrosion products are not typically a significant contributor to opacity. Although corrosion products are entrained in the flue gas and discharged from the stack during sootblowing and load cycling, the majority of the material remains in the boiler until maintenance outages to water wash the heat transfer surfaces.

Efforts to control corrosion of air heater surfaces and low-temperature ductwork commonly involve the use of "back-end" alkali additives. These additives are typically magnesium based, and can be injected in powder or slurry form. Normally, the additives are continuously injected into the boiler ductwork between the economizer and air heater. The purpose is to uniformly deposit a thin layer of alkali additive on low-temperature metal surfaces susceptible to corrosion by sulfuric acid, e.g., air heater baskets and neighboring ductwork. The condensed acid will react with the alkali compounds and be neutralized, thereby protecting the metal surfaces from corrosion. However, continuous additive injection will increase baseline opacity and particulate matter emissions, depending on the injection rate of the additive. Moreover, additive reaction products (and unreacted additive) will be dislodged from the heat transfer surfaces during sootblowing and load cycling, also contributing to increased opacity.

3.2.6 Sulfuric Acid Condensation (Item 11 in Figure 3-1)

As described in Section 3.2.1.2, SO_3 is formed during the combustion process by gas-phase oxidation of SO_2. Conversion of SO_2 to SO_3 increases as the SO_2 and oxygen concentrations in the flue gas increase. Further, vanadium compounds in ash deposits on high-temperature tube surfaces (i.e., furnace and superheater) are effective catalysts for conversion of SO_2 to SO_3. Therefore, higher concentrations of sulfur and vanadium in the fuel oil will lead to greater concentrations of SO_3 in the flue gas. As a rule of thumb, the SO_3 concentration in the flue gas for boilers burning residual oil with sulfur contents ≥ 1.5 percent is 5 to 25 ppm, although concentrations as high as 100 ppm have been measured for very high-sulfur oils (i.e., 4% sulfur).

Sulfuric acid is formed by the rapid combination of SO_3 and water in the flue gas when the gas temperature cools to the acid dew point, which can occur in the ductwork downstream of the air heater, in the stack, or in the atmosphere downwind of the stack. The acid dew point is a function of the SO_3 concentration and water concentration in the flue gas. Figure 3-2 shows the relationship between the acid dew point temperature and the SO_3 concentration in the flue gas for oil firing (Reference 3-3). The water dew point of flue gas for oil-fired boilers is typically 120–130°F (49–55°C). As shown in Figure 3-2, the acid dew point is significantly higher than the water dew point, and can approach or exceed the gas temperature downstream of the air heater (typically 275–310°C) at SO_3 concentrations of approximately 10 ppmv in the flue gas. At the acid dew point, a submicron aerosol of sulfuric acid is produced (commonly referred to as acid mist). The submicron acid droplets are extremely effective at scattering light, thereby contributing significantly to plume opacity even in the absence of particulate matter.

As the flue gas cools during its passage through the ductwork, stack, and into the atmosphere the quantity of condensed acid particles will increase. This explains why opacity measured with a transmissometer in the stack of boilers burning high-sulfur fuels may frequently be less than 20 percent, whereas opacity in the stack plume can exceed the in-stack value due to condensation of gas phase SO_3 in the cooler atmosphere (this also explains why sulfuric acid plumes are frequently "detached" from the stack exit). If the atmosphere is stagnant or poorly mixed (e.g., with temperature inversion conditions), sulfuric acid plumes can be very persistent and can be observed for several miles from the stack exit.

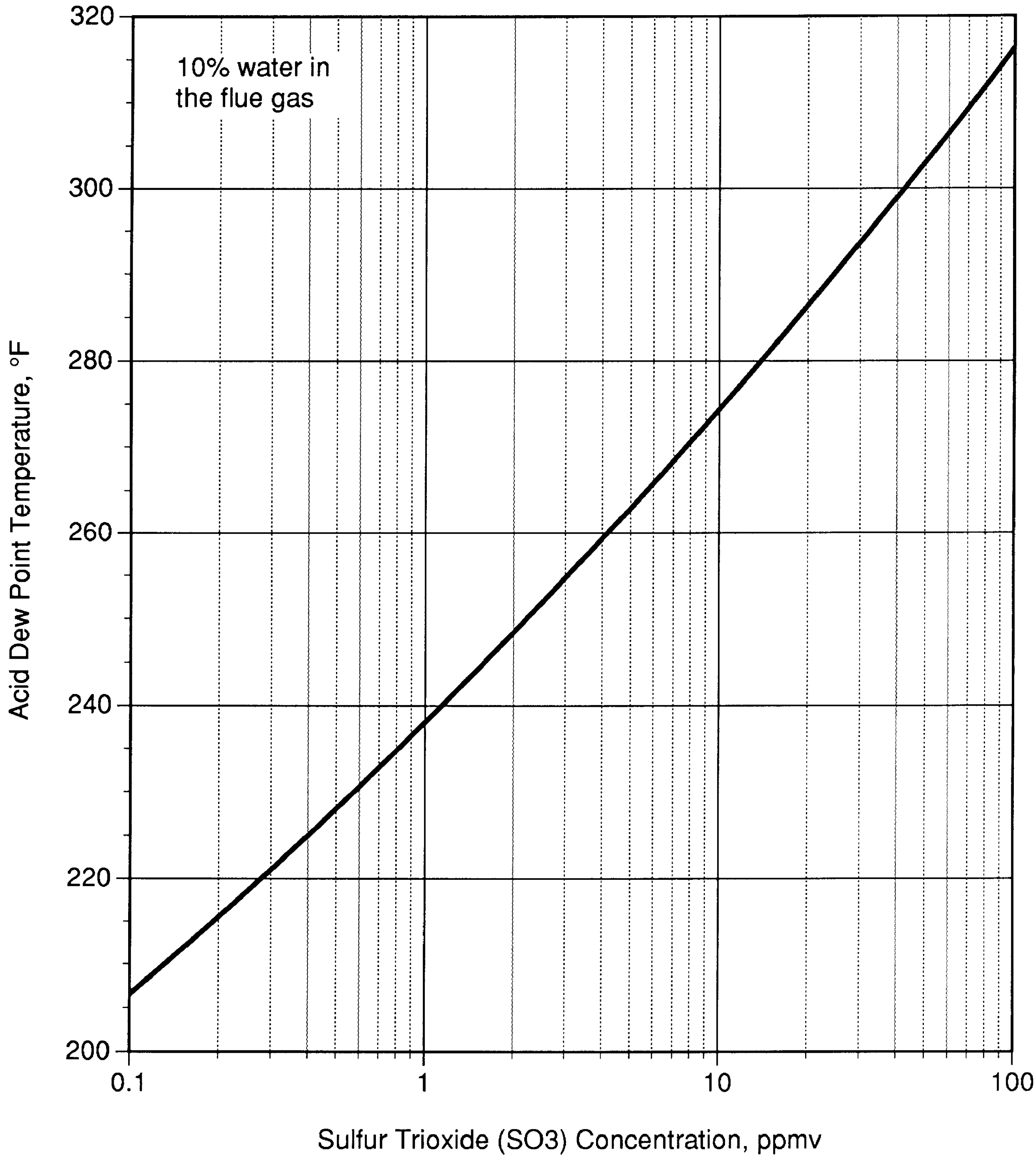


Figure 3-2
Acid dew point temperature vs. sulfur trioxide (SO_3) concentration for flue gas with 10% water by volume. Graph prepared from data in reference 3-3.

3.2.7 Other Factors

Other factors which can impact stack opacity include nitrogen dioxide (NO_2) emissions and condensation of water vapor in the atmosphere. NO_2 can produce a light brown coloration to the plume, which is generally most noticeable (if at all) well downstream of the stack as nitric oxide (NO) in the flue gas is oxidized to NO_2. As mentioned in Section 2.1, the relatively small concentrations of NO_2 at the stack exit for oil-fired boilers are typically not visible and do not contribute significantly to stack opacity. This is particularly true due to the widespread implementation of NOx emissions controls at oil-fired boilers.

Water condensation plumes are often misinterpreted as white smoke or acid condensation plumes. Water condensation plumes may occur naturally on oil-fired boilers as a result of condensation of water vapor from the combustion process, especially during very cold, humid weather conditions. Large boiler tube leaks may also produce a water condensation plume. Water vapor plumes are distinguished from sulfuric acid plumes because the former should dissipate a short distance from the stack exit. If a sulfuric acid plume is present, it will typically be visible after the water vapor plume has disappeared and have a bluish white-to-gray color.

3.3 References

1. *Coke Formation Index: A Measure of Particulate Formation in Oil Combustion.* EPRI GS-6714, February 1990.

2. *HOT FOIL™ Instrument for Measuring the Coking Index of Residual Oils.* EPRI TR-101662, March 1993.

3. Robert R. Pierce, "Estimating Acid Dewpoints in Stack Gases," Chemical Engineering, April 11, 1977.

4

DESIGN FACTORS AFFECTING OPACITY

Stack opacity at oil-fired boilers is influenced by the design of boiler components, plant operating practices, and the maintenance of critical hardware. In this section, the design factors that impact stack opacity are identified, and the ways in which they can contribute to an opacity problem are described. Sections 5 and 6 which follow describe how plant operating and maintenance practices, respectively, affect opacity. For specific opacity problems relating to all of these issues, step-by-step troubleshooting guidelines are presented in Section 8.

4.1 Design Factors

Design factors affecting stack opacity are categorized into the following three plant systems:

- Combustion System
- Boiler, Furnace, and Auxiliary Equipment
- Instrumentation and Control

Table 4-1 lists the design factors pertinent to stack opacity within each of these areas, and the associated hardware components that are of primary importance to opacity. Also listed in the table are the report sections where discussion of the hardware components can be located.

Each plant system and design factor are discussed in sequence. As evident in Table 4-1, individual hardware components can affect more than one design factor affecting opacity. In such cases, the effects of the particular hardware components are discussed in sequence under the related design factor.

Table 4-1
Design Factors Affecting Opacity

Plant System	Design Factor	Hardware Components Affecting Opacity	Section
Combustion System	Oil Atomization	Oil Temperature (Viscosity) Oil Atomizer Design and Type	4.1.1.1
	Air and Fuel Mixing	Flame Stabilizer Oil Atomizer Spray Plate Burner Air Register Overfire Air	4.1.1.2
	Ignitors	Oil Atomizer, Flame Stabilizer	4.1.1.3
Boiler, Furnace and Auxiliary Equipment	Combustion Residence Time	Furnace Geometry Burner Arrangement Flue Gas Recirculation Overfire Air	4.1.2.1
	Flame Shape and Impingement	Furnace Geometry Burner Arrangement Burner Design Oil Atomizer Flame Stabilizer	4.1.2.2
	Uniformity of Fuel-Air Ratio	Windbox Geometry Burner Air Register Fuel Delivery System Atomizing Steam Delivery System	4.1.2.3
Instrumentation and Controls	Air and Fuel Flows	Fuel Flow Meter Air Flow Meter	4.1.3.1
	Fuel-Air Ratio Control	Excess O_2 Monitor Air and Fuel Controllers	4.1.3.2
	Opacity Measurement	Opacity Monitor	4.1.3.3

4.1.1 Combustion System

The burner is the principal component for the combustion of fuel oil in a utility boiler. Two functions of the burner are critical to achieving good combustion, and they have a significant impact on the potential for opacity and smoking problems: (1) atomization of the oil and (2) mixing of fuel and air. In practice, oil atomization and air-fuel mixing are an integrated process that determines the characteristics of the burner flame. However, each is described separately below.

4.1.1.1 Oil Atomization.

For fuel oil to burn efficiently, it must be atomized into a spray of fine droplets. As discussed in Section 3.2, the droplets burn as they evaporate and mix with oxygen in the combustion air. The size distribution of the oil spray is commonly characterized by its Sauter Mean Diameter (SMD), the diameter of a hypothetical droplet having a surface to volume ratio equivalent to that of the entire spray (see Section 3.2.2).

Atomizers which produce smaller droplet diameters (i.e., smaller SMD) are generally preferable from an opacity standpoint, because of more rapid burning of the oil and less likelihood of unburned carbonaceous particulate matter emitted from the stack. Poor atomization, characterized by large SMD, can be the root cause of smoking problems and may contribute to other problems such as flame instability, high furnace excess O_2 requirements, and flame impingement.

The four basic types of atomizer designs commonly used in utility boilers are illustrated in Figure 4-1. They are distinguished by the physical mechanisms of the atomization process. Two steam-assisted atomizers, the Y-Jet atomizer and the Internal-Mix atomizer, rely on the impaction of high velocity streams of oil and steam within the atomizer to breakup the oil into fine droplets prior to leaving the atomizer through multiple exit holes or slots. Two mechanical atomizers, the Return-Flow or Spill-Return atomizer and the Direct Mechanical or Simplex atomizer, produce a swirling oil film around the periphery of a single exit orifice, which expands into a hollow cone as it exits the atomizer. Atomization occurs as the thin oil film of the spray cone breaks up into droplets external to the atomizer.

For each atomizer type, internal geometry and operating pressures impact the size and number of oil droplets in the oil spray. In general, higher oil supply pressures and atomizer flow rates produce smaller oil droplets.

Steam atomizers generally operate with atomizing steam pressure higher than the oil pressure as measured at the burner. The higher the differential pressure between the atomizing steam and the oil, and the higher the mass ratio of steam-to-oil, the smaller the oil droplets that are produced for a given oil flow rate. Some atomizers are designed to operate at their high end of capacity with steam pressure below the oil pressure (e.g., in a “Racer” mode). This generally produces poorer atomization at higher capacity compared to intermediate capacities when the steam pressure exceeds the oil pressure.

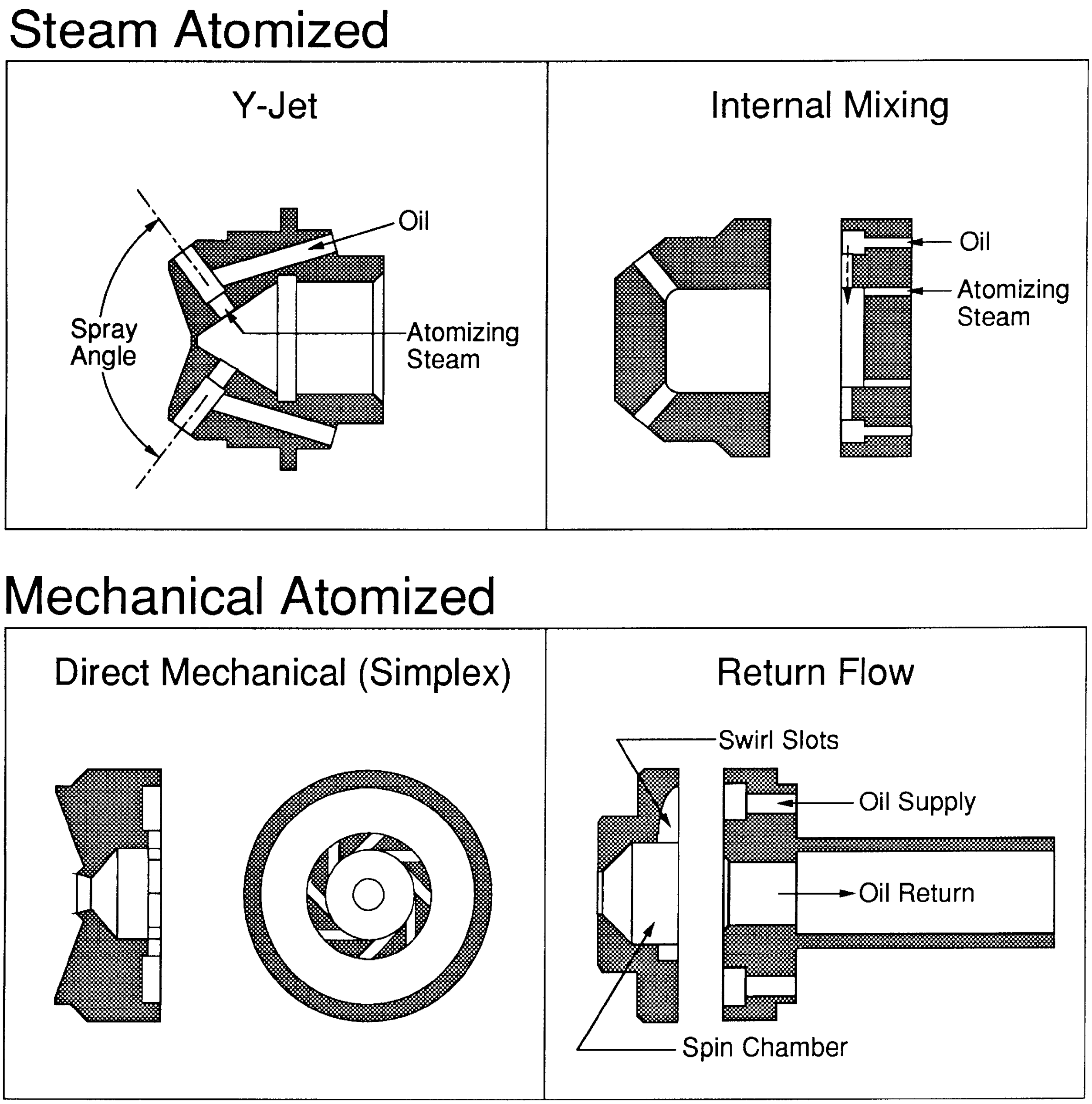
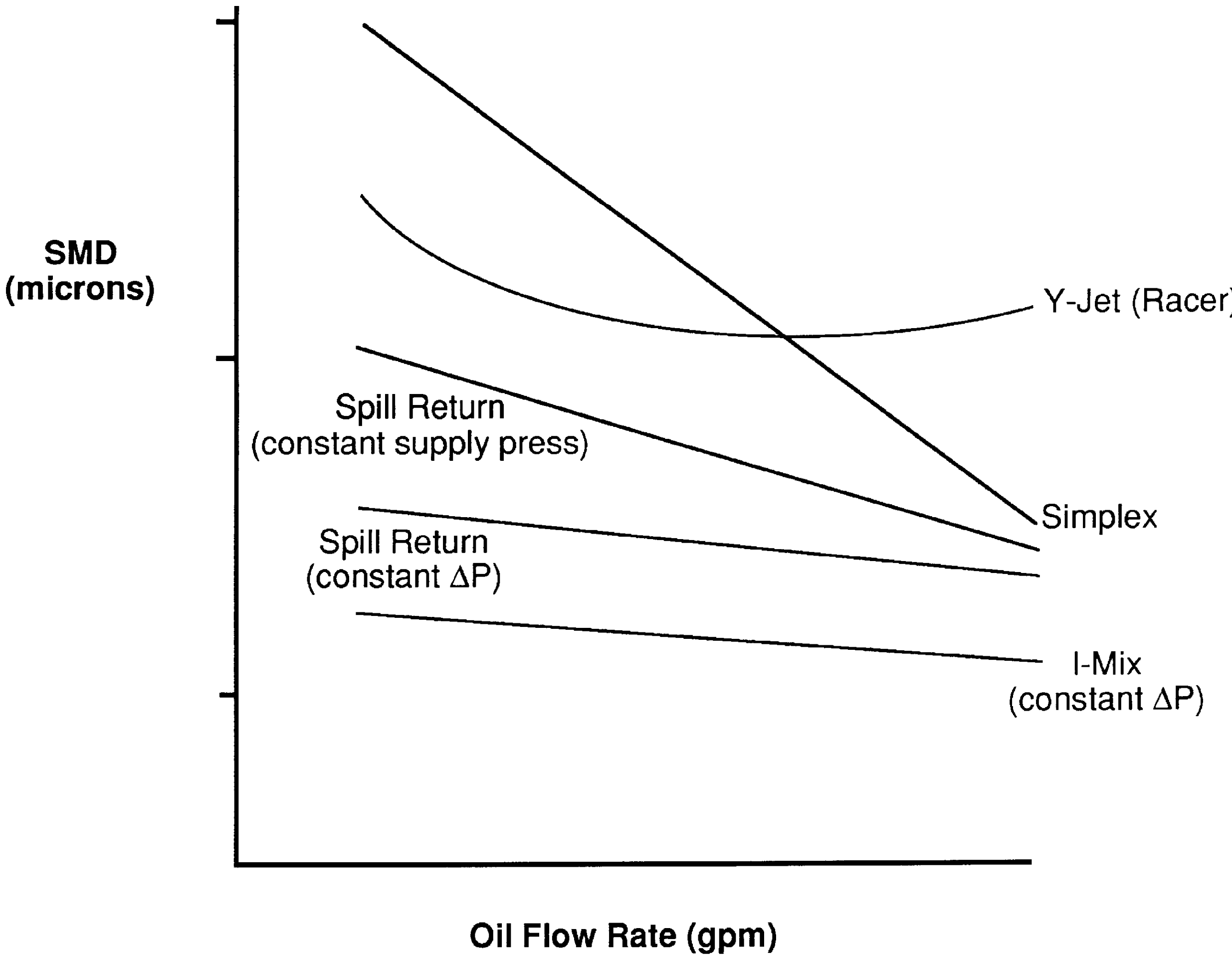


Figure 4-1
Types of atomizer designs. (Source: EPT)

Consequently, the operating mode of the atomizer as it changes with burner firing rate will impact oil droplet size. For a given atomizer type, differences in design among manufacturers and differences in atomizing steam and oil supply conditions from one boiler to another, result in a range of oil drop spray characteristics. With this in mind, oil spray quality expressed as SMD is compared in Figure 4-2 on a relative basis for various atomizer types.



SMD = Sauter Mean Diameter, which is the diameter of a hypothetical single droplet having the same surface-to-volume ratio of that averaged for all droplets in a spray.

Figure 4-2
Oil spray quality (SMD) versus atomizer type.

4.1.1.2 Air and Fuel Mixing.

The mixing of fuel oil droplets with the combustion air is a complex process, influenced by the inertial and geometrical properties of the oil spray and the aerodynamics of the burner air stream(s). The mixing process affects flame shape, flame intensity, and the oil droplet burning rate. Improper mixing can produce flames that are smoky and excessively long or too wide. Depending on the boiler, this can result in flame impingement problems, increased carbonaceous particulate emissions, and high opacity. Other problems directly or indirectly related to poor mixing include erratic flame detection, unreliable burner light-offs, flame instability, and overheating and deterioration of burner parts.

The primary burner components that affect air and fuel mixing are: (1) the oil atomizer spray plate, (2) the flame stabilizer, and (3) the burner air register.

Atomizer Spray Plate. The atomizer spray plate is the external part of the atomizer through which the oil exits into the furnace. The spray plate affects air-fuel mixing by determining the velocity, spray angle, and shape of the oil spray for a given oil flow rate. These factors along with droplet size determine penetration and distribution of the oil droplets with the combustion air. For mechanical atomizers, the diameter and contour of the discharge orifice are the relevant design parameters. For steam atomizers, the number of discharge holes, the diameter of the holes, the arrangement of holes on the spray plate, and the angle of the holes relative to the axis of the oil gun are important parameters. In general, the design criteria for these parameters are proprietary to each manufacturer and vary according to burner design, burner capacity, oil and atomizing steam supply conditions, and other site-specific factors. Accordingly, the design of the spray plate and its suitability for a given burner cannot be independently evaluated by a utility company.

Flame Stabilizer. Flame stabilization is achieved by creating a low velocity region near the burner discharge throat, in which the velocity is lower than the flame propagation speed. In this region, hot combustion products can recirculate and mix with the incoming air and fuel to promote faster volatilization and ignition of the oil drops.

An effective way to create flame stabilization on wall-fired and tangential-fired boilers is through the use of a vaned swirler. A typical swirler, shown in Figure 4-3, is attached to the end of the oil gun guide tube surrounding the oil atomizer. Air flowing through the swirler is given a rotational component by the vanes, setting up a spiral form of flow. Sufficiently high levels of swirl produce an internal recirculation zone (IRZ) downstream of the swirler in which hot combustion gases reverse direction and recirculate back towards the burner. The IRZ creates the low velocities and a continuous ignition source of hot gases at the base of the flame to provide flame stability.

The amount of swirl and size and location of the recirculation zone are impacted by the design of the swirler (e.g., blade angles, swirler diameter) and additional swirl, if any, provided by the design of the burner air register (see below). These burner design features establish the aerodynamic flow pattern which in conjunction with the oil atomizer spray determine to a large extent the characteristics of the flame and the combustion process. The relative axial locations of the swirler and the oil atomizer within the contour of the burner throat are prescribed by the burner manufacturer, and are also important in optimizing combustion conditions.

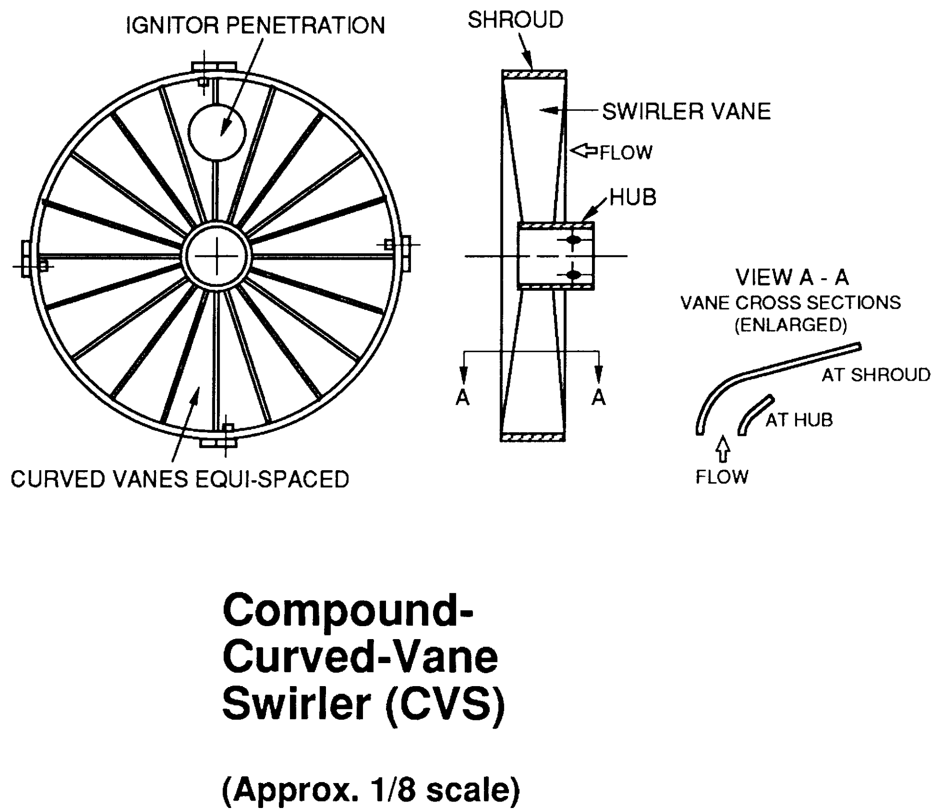


Figure 4-3
Compound-curved-vane swirler flame stabilizer. (Source: EPT)

Other types of flame stabilizers are in use and generally fall into the category of "bluff body." These devices commonly incorporate a conical shape with holes or slots to prevent overheating and carbon deposition. They essentially operate as a flow blockage, which creates a vortex in the wake of the bluff body. Hot gases which penetrate back toward the burner, and the relatively low flow velocity near the boundary of the bluff body, enable the flame to be stabilized. These devices are seldom offered in new burners and are gradually being replaced in existing burners by vaned swirler type flame stabilizers, which have shown superior performance in terms of smoke suppression, flame stability, low pressure drop, and combustion efficiency.

Burner Air Register. In this report the term "air register" includes the entire air frame of the burner from the air inlet to the discharge throat of the burner, including air shut-off dampers, spin vanes, and throat profile. Air registers provide a number of functions which impact the combustion process. The functions include:

- Provide pressure drop to aid in distributing combustion air uniformly within the windbox and among the burners.

- Shut off air to idle burners, thereby maintaining proper combustion air flow to active burners.
- Create flow patterns at the exit of the burner, which in combination with the flame stabilizer, establish the aerodynamic characteristic of the flame.
- Provide the means to bias combustion air among burners as required for balancing air-fuel ratio among burners.
- Vary burner air flow rates as may be required for light-off, purging, and normal operation.
- Bias or distribute the air within the burner to achieve desired air-fuel mixing or for reduced NOx emissions.

Air register designs for circular burners generally fall within three basic categories: axial (parallel) flow, single register swirl-type, and dual air zone. These are shown schematically in Figure 4-4. The axial-flow burner is the simplest design, typically equipped with a single slide-type damper that is the only air flow control adjustment. The dual air zone burner — which generally provides the greatest amount of air flow control — may be equipped with air spin devices in each air zone, a means of biasing air flow among each air zone, and in some cases total on-off flow control damper(s). The single register swirl-type design, common on older burners, generally uses a single set of adjustable air register louvers or vanes to control air flow and air spin. Air register designs and adjustability vary substantially among manufacturers and models, even within each of the three design categories above, and is often a major distinguishing feature of oil-fired burners offered by competing manufacturers.

On tangential-fired boilers, the functions of air registers listed above are performed by the corner windbox compartments. The air compartments are divided into fuel-air compartments, which deliver combustion air in close proximity to the oil gun and atomizer, and auxiliary-air compartments, which inject air between the fuel compartments. The proportioning of air among the fuel-air and auxiliary-air compartments is achieved by modulation of air flow dampers (generally performed automatically by the boiler controls). The air quantity and its distribution among the compartments (determined by damper positions and compartment dimensions), the design of the air nozzles located in the discharge of each compartment, and the flame stabilizer are the critical factors impacting burner aerodynamics and the combustion process.

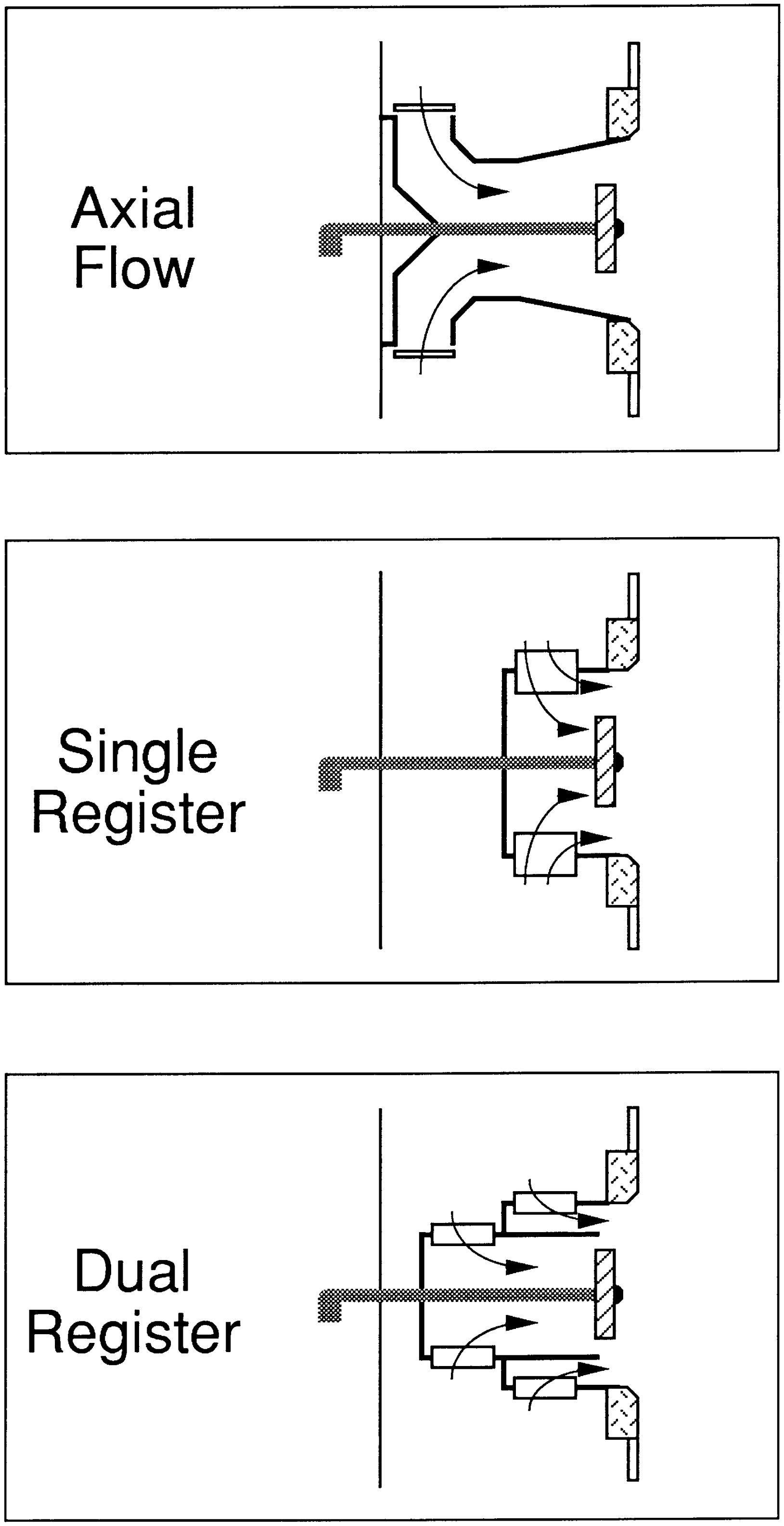


Figure 4-4
Types of burner air registers. (Source: EPT)

Overfire Air. Overfire air (OFA) ports divert a portion of the combustion air from the burners and inject it into the furnace above the burner zone. The quantity of air diverted to OFA ports typically varies from 10% to as high as 30%. The purpose is to reduce the air-fuel ratio at the burners for control of NOx emissions. Of critical importance in the design of overfire air ports is penetration and mixing of the combustion air with the bulk gases in the furnace. To achieve optimum mixing, OFA ports may be designed with independent control of air velocity, directional control of the air, and separate windboxes for the combustion air.

4.1.1.3 Ignitors.

No. 2 oil ignitors are frequently the source of significant opacity problems during boiler startups and burner light-offs. As with main burners, oil atomization and air/fuel mixing are critical design parameters, particularly since ignitors must operate under a wide variety of conditions, e.g., at very low load with large quantities of excess air, at any boiler load between minimum and full load, and with or without the associated main burner in operation, etc. For smoke-free performance, the atomizer must produce the proper droplet size (SMD) and distribution pattern for reliable ignition and complete carbon burnout (see Section 3.2.2). Also, the ignitor should be equipped with it own flame stabilizer which assures stable ignitor operation independent of the design of the main burner.

4.1.2 Boiler, Furnace, and Auxiliary Equipment

4.1.2.1 Combustion Residence Time.

The amount of time available within the furnace for burning the fuel is commonly referred to as furnace or combustion residence time. It is usually defined as an average time for combustion gases to travel from the burner zone to the exit of the radiant furnace cavity (i.e., entrance to the convective pass). It is assumed that little or no further combustion will occur once unburned fuel reaches the exit of the furnace cavity, due to rapid quenching (cooling) of the gases within the convective pass.

Longer residence times will generally promote more complete burnout of the fuel and, therefore, less carbonaceous particulate matter at the furnace exit that can contribute to stack opacity. Thus, boilers with longer residence time (e.g., boilers originally designed for coal firing) may be more accommodating to adverse combustion conditions that tend to increase opacity. Alternatively, boilers with relatively short combustion residence time may be more susceptible to smoking problems due to combustion system upsets or design deficiencies. Furnace geometry and the arrangement of burners in the furnace are the primary design factors that impact residence time. The use of flue gas recirculation and overfire air usually impact residence time to lesser degrees.

Furnace Geometry. The dimensions of the furnace have an obvious and direct affect on residence time. The depth, width, and height of the furnace above a particular furnace elevation determine the volume within which the fuel must burn before reaching the furnace exit. For a given furnace volume, the volumetric flow rate of gases determines the residence time. Since the volumetric flow rate increases with boiler firing rate, residence times decrease with increasing load.

A critical factor is the residence time from the upper burner elevation to the furnace outlet plane. This distance, often referred to as the "upper furnace residence time," corresponds to the shortest distance and time for fuel burnout. The specific procedure for calculating upper furnace residence time is a matter of preference and subject to various assumptions and interpretation. Generally, residence times less than 0.5 to 0.8 seconds for oil-fired boilers are considered short and may cause a higher tendency for smoking problems in which carbon burnout is a factor.

Furnace geometry also determines the distances from the burners to the furnace walls and, therefore, is an important factor affecting furnace wall flame impingement. This problem is discussed separately below.

Burner Arrangement. The locations of burners on the firing walls or corners of the furnace determine combustion residence time for each burner within a given furnace geometry. Intuitively, combustion problems on burners located nearest to the furnace exit may have a greater influence on opacity than problems in lower burner elevations. While this is true in some circumstances, it is important to realize that stratification of combustion gases within the furnace, particularly on wall-fired boilers, can result in opacity problems which originate from poor combustion at lower burner elevations.

Flue Gas Recirculation. The use of flue gas recirculation (FGR), either mixed with the windbox air or injected through furnace hopper ports, has the effect of reducing the combustion residence time, due to the increased mass flow through the boiler. While this in itself would be expected to decrease carbon burnout, experience has not usually borne this out. Other effects of FGR on combustion characteristics, including effects on flame stability and air-fuel mixing, are generally more important. In some instances, FGR to the windbox has improved combustion, as evidenced by the ability to operate with lower furnace excess O_2. In such cases the increased combustion intensity, due to higher burner throat velocities, may have offset any adverse impact of reduced combustion residence time on fuel burnout.

Overfire Air. As described previously, overfire air (OFA) ports divert a portion of the combustion air from the burners and inject it into the furnace above the burner zone. While this may impact somewhat the calculated combustion residence time for individual burners, of greater significance to stack opacity problems is the impact of OFA design on air-fuel ratio in the burner zone and the mixing of the overfire air with the furnace gases. The impact on air-fuel ratio is discussed later.

Mixing of the overfire air with furnace gases, and burnout of any fuel remaining at the elevation of the overfire air ports, must occur within the residence time available between the overfire air ports and the furnace exit. As with furnaces having limited upper furnace residence time, boilers operating with OFA and having relatively short residence time between the overfire air ports and the furnace exit may be more prone to problems with unburned carbon. Criteria for acceptable OFA residence time cannot be generalized. However, parameters under the control of boiler operators, including OFA port dampers and directional vanes, can be used to optimize the mixing of OFA within the constraints of existing furnace geometry and residence time.

4.1.2.2 Flame Shape and Impingement.

The design of the oil atomizer, flame stabilizer, air register, and burner throat contour are the primary burner design factors that determine the size and shape of the flame as a function of burner firing rate. For a given flame shape, the geometry of the furnace enclosure, the overall flow pattern of gases in the furnace, and the locations of the burners on the walls of the furnace enclosure, determine the potential for flame impingement on furnace walls and on leading convective surface.

From the standpoint of opacity control, flame impingement must be avoided since quenching of the combustion process or deposition of burning fuel by the impinging flame can generate carbonaceous particulate matter and soot that result in smoking. For the same reasons, flame impingement on burner throat refractory or other burner parts must also be avoided.

A general distinction should be made between flame impingement problems that are potentially serious from an opacity standpoint and flame impingement that may be visually detected but which does not likely contribute to opacity. In general, serious problems exist when there is continuous impingement of active flame, causing smoking at the wall, deposition of oil droplets, and/or buildup of carbon. Such conditions can also lead to accelerated wastage and premature failure of the boiler tubes. Alternatively, flame tips that intermittently reach the wall and do not have the above characteristics may be acceptable for long term operation. If in doubt whether a serious flame impingement situation exists and requires remediation, it is advisable to seek the opinion of a combustion specialist.

Furnace Geometry. In wall-fired boilers, the common types of furnace wall flame impingement are: (1) flames impinging on walls opposite the burner due to long flames (e.g., rear-wall impingement on front-wall-fired boilers); (2) flames impinging on the side walls due to wide or flaring flames; and (3) impingement on the firing walls due to flames that roll back or flare too wide. These three types of flame impingement are illustrated in Figure 4-5. In general, flame impingement problems are worse at higher boiler firing rates where flames tend to reach maximum size. Furnaces with relatively small cross-sectional areas, or those that are over-fired, are more prone to furnace impingement problems.

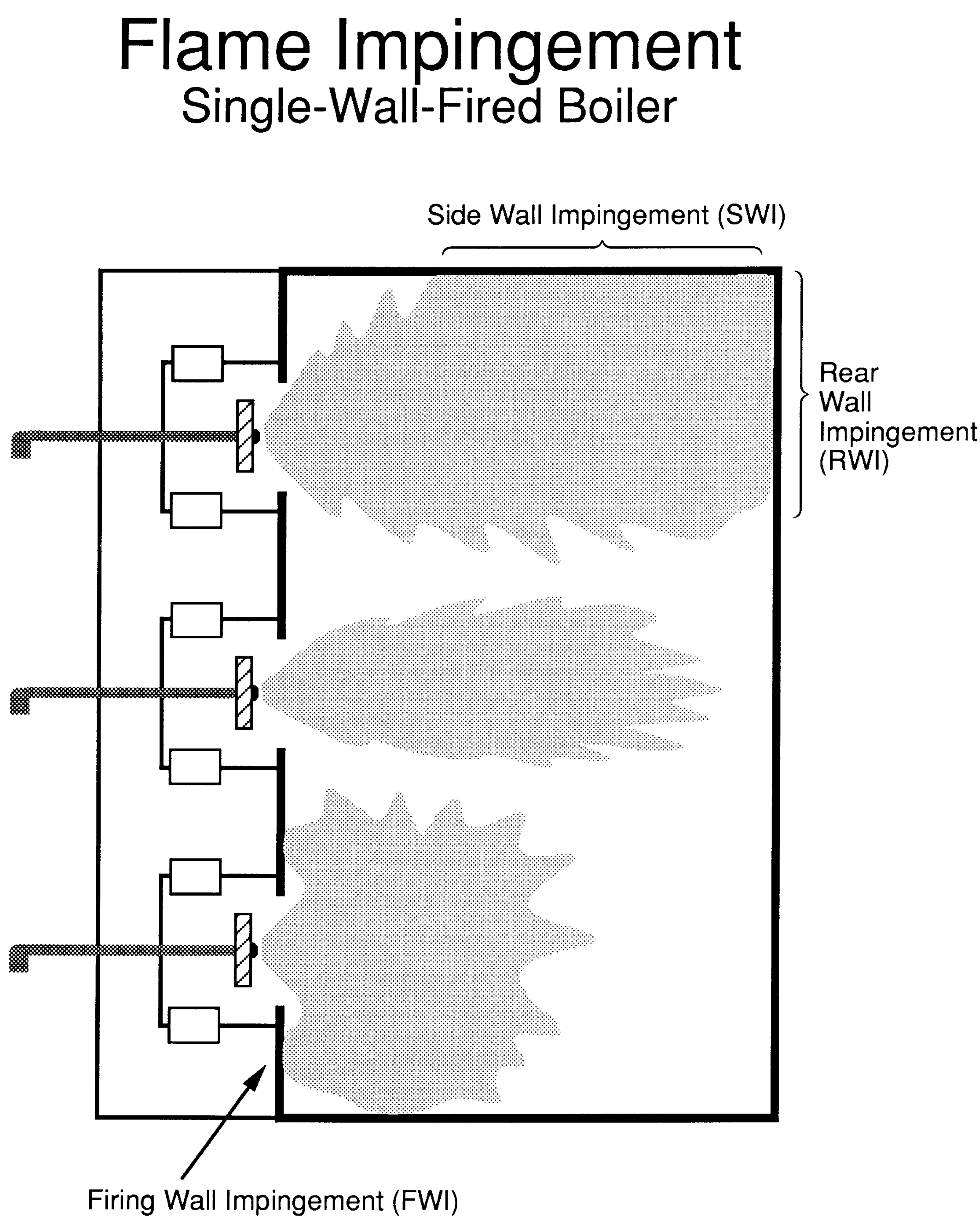


Figure 4-5
Flame impingement locations - wall-fired boilers. (Source: EPT)

For tangential-fired boilers, common types of flame impingement problems are side-wall impingement and opposite-side or rear-wall impingement as depicted in Figure 4-6. The potential for these problems depend mainly on the furnace cross-sectional dimensions (e.g., width-depth aspect ratio) and the factors that influence flame shape as discussed below.

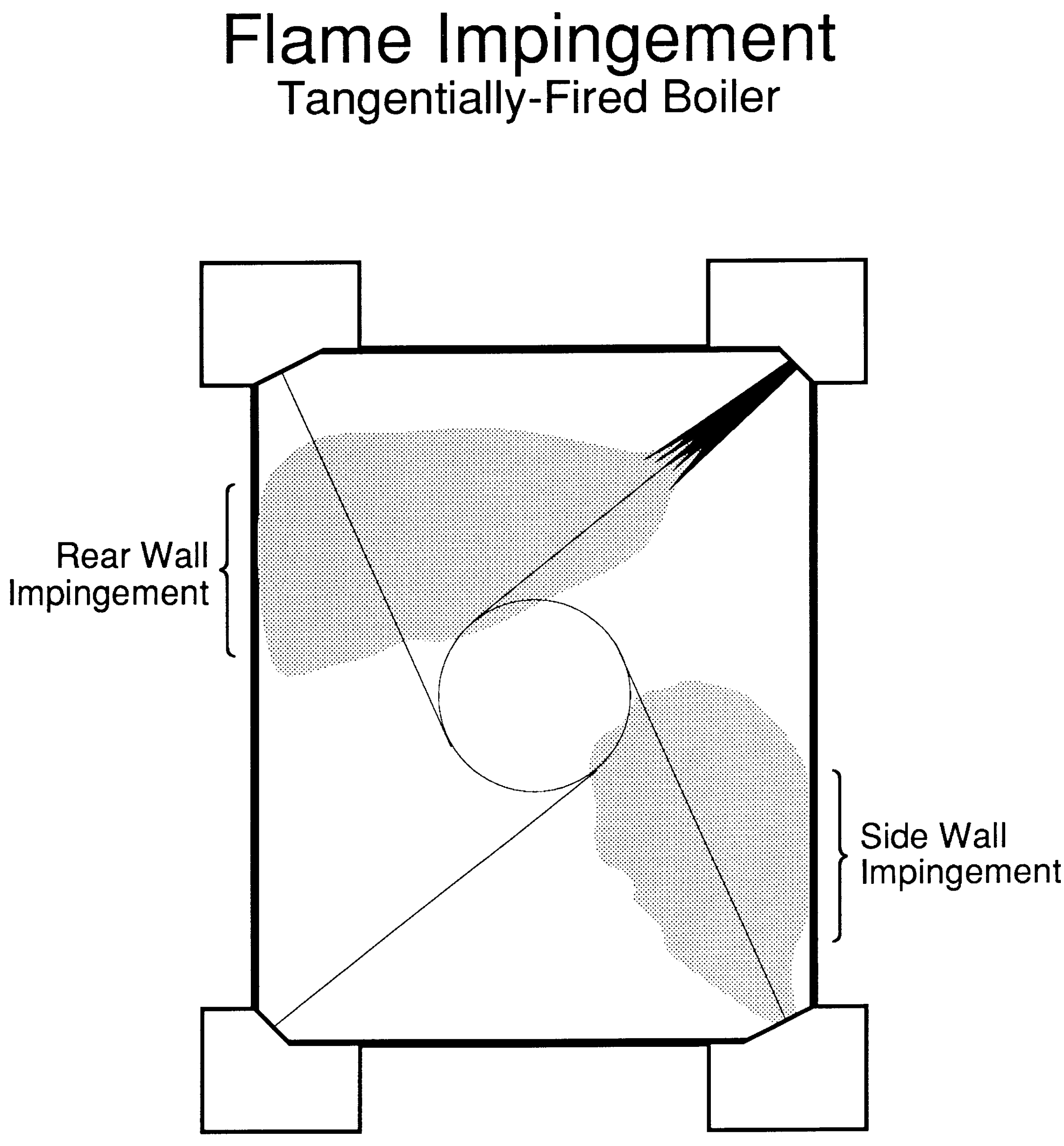


Figure 4-6
Flame impingement locations - tangential-fired boilers. (Source: EPT)

For both furnace types, impingement of flames on burner components can also occur due to recirculation of the flame back to the burner or impingement of the oil spray on the burner throat or surrounding surfaces. The former is likely to be the result of burner aerodynamics, as controlled by the flame stabilizer, air register, and burner throat geometry, while the latter is influenced by the oil atomizer, burner throat design, and axial positioning of the oil gun and flame stabilizer.

Flame impingement on the superheater tubes can occur when flames are too long or the upper furnance residence time is too short. Furnance geometry is implicated in the latter case, while excessive flame length may be related to burner design, operation, or maintenance.

Burner Arrangement. As illustrated in Figures 4-5 and 4-6, the arrangement of burners in wall-fired and tangential-fired boilers results in potential flame impingement problems unique to these two boiler types. Burner arrangements that tend to increase the potential for flame impingement can be summarized as follows:

1. Wall-fired boilers with burners located on a single wall. These single-wall-fired arrangements generally pose the greatest potential for opposite wall impingement, especially when combustion conditions result in long flames. For opposed-fired units with burners on two firing walls, flames rarely penetrate to the opposite wall because of the greater furnace depth and the impaction of opposed flames near the center of the furnace.

2. Burners located close to the side walls on wall-fired boilers. This increases the potential for side wall impingement from the “wing burners,” especially when flames are wide.

3. Tangential-fired boilers with furnace plane aspect ratios greater than one (i.e., width not equal to depth). Two of the flames will be aimed closer to the adjacent side wall than the other flames, increasing the likelihood for flame impingement on the wall (refer to Figure 4-6).

As indicated above, the top elevation of burners will have a higher likelihood of flame carryover into the superheater, all other factors being equal. This may or may not cause problems related to opacity, tube fouling, tube overheating, etc. — depending on the specific circumstances. Shortening the flames may minimize or eliminate the problem.

The primary factors affecting air and fuel mixing as discussed above in Section 4.1.1.2 are important in determining the shape of the flame. The relevant burner components are the overall burner design, the oil atomizer, and the flame stabilizer.

Burner Components and Impacts on Flame Shape. For wall-fired boilers, the overall type of burner design (refer to Figure 4-4) and the specific design features of the air register and throat contour determine the combustion air velocity at the burner throat, the turbulence of the air, and the swirl of the air (if spin vanes or louvers are present). For tangential-fired boilers, the size and geometry of the air compartments, and the design of the air nozzles perform analogous functions. Working in conjunction with the flame stabilizer and the oil atomizer, these components determine the shape of the flame. To the extent that adjustments can be made to individual burners to change the swirl and/or air distribution within the burner, the flame shape can be varied. For example, for wall-fired boilers with conventional louver-type air registers or independently-controlled spin vanes, pinching down on the air registers or increasing the angle of the spin vane will increase the swirl of the combustion air and produce shorter, wider flames. This approach may correct a rear-wall flame impingement problem. Tangential-fired boilers typically have less flexibility to adjust flame shape and may require changes in the design of the flame stabilizer or oil atomizer to correct a flame shape problem.

Oil Atomizer. As discussed previously, the design of the oil atomizer is a factor in the mixing of fuel and air, and likewise has an impact on flame shape. It is difficult to isolate the effect of atomizer design alone on flame shape, due to the synergistic effects of the atomizer, burner, and flame stabilizer on flame shape. However, the following generalizations can be made:

- Smaller oil droplet size distributions tend to reduce fuel burnout time, produce shorter flames, and reduce unburned carbon for a given level of excess O_2.
- Wider oil spray angles generally produce wider flames.
- Fewer and/or higher velocity atomizer exit holes tend to increase flame length.

Steam atomizers exhibit a nearly constant spray angle over their operating range, whereas mechanical atomizers commonly produce a widening of the oil spray at lower firing rates. Consequently, it is a common feature of burners equipped with mechanical atomizers to experience an increase in flame width at low loads.

Flame Stabilizer. Experience has confirmed that the design of the flame stabilizer has a major impact on flame shape by: (1) stabilizing the flame front and initiating combustion close to the burner, and (2) creating a recirculation zone at the base of the flame. As discussed for oil atomizers above, it is not always straightforward to isolate the effects of flame stabilizer design from other factors affecting flame shape. Moreover, it is increasingly recognized that the oil atomizer and flame stabilizer are an integral technology that must be optimized as a single assembly for optimum combustion.

4.1.2.3 Uniformity of Air-Fuel Ratio.

Ideally, the boiler combustion air and fuel supply systems are designed to supply air and fuel uniformly among the burners. Non-uniform distribution of one or both of these quantities will result in a range of air-fuel ratios at the burners. If these imbalances are large enough, they can adversely impact combustion and opacity.

In practice, the distribution of air and/or fuel among the burners is not perfectly uniform and variations in burner air-fuel ratios exist. On wall-fired boilers, a common approach to overcome such imbalances is by means of air register adjustments — that is, biasing the air registers on individual burners to achieve more uniform air-fuel ratios among the burners. On tangential-fired boilers, it is commonly assumed that minor variations in air-fuel ratio among individual burners are equalized by the mixing and burning that takes place in the central fireball.

If the imbalances in fuel and/or air distribution to the burners are too large to be overcome by these methods, design modifications of the fuel and/or air supply systems may be warranted.

Windbox Geometry. The geometry of the windbox, and to a lesser extent the geometry of the air ducts supplying the windbox, affect the distribution of combustion air to the burners. Internal obstructions, turns, non-symmetric air inlets, and windbox shape rarely produce a windbox that is an ideal plenum. Consequently, air flow rates to individual burners will vary.

Other factors that can impact windbox air flow distribution are non-uniform mixing of recirculated flue gas to the combustion air, non-symmetrical patterns of burners or overfire air ports that are out of service, forced draft (FD) fans that do not have balanced flows, and flue gas or tempering air proportioning dampers that are not set properly.

Air flow imbalances can be assessed by either physical or computational modeling. To a large extent, air flow imbalances caused by the windbox geometry can be overcome by biasing air registers at the individual burners. However, caution must be used with this approach because, depending upon the burner design, changing air register settings may also change combustion air swirl and flame shape.

Burner Air Register. For a well designed windbox performing close to the ideal plenum, the uniformity of combustion air flow among the burners depends primarily on the burner air register or air damper adjustments and secondarily on the uniformity from burner to burner of other flow devices incorporated into the burner register or air compartment that produce pressure drop. These devices may include spin vanes, gas fuel elements, ignitors, air nozzles, and flame stabilizers.

The ability to independently adjust or bias the air flow to each burner is the single most important design feature for purposes of air flow balancing. The preferable design is with the damper, sleeve, or other device used for controlling air flow uncoupled from any devices used for controlling air spin. In this way, the air flow can be varied without substantially impacting the shape of the flame.

Some burners are equipped with air flow measuring devices which may be useful in evaluating the uniformity of air flow among burners. These devices, which generally rely on a pressure drop across a section of the air register, are prone to error due to corrosion or leaks in the sensing lines that develop over time.

Fuel Delivery System. The design of the fuel piping system which delivers oil to the burner front can adversely impact air-fuel ratios among the burners if similar oil supply pressures and flows at the oil guns cannot be maintained. Such situations are common and can be due to a variety of design factors, including undersized oil piping, long pipe runs between burners, and multiple oil supply headers with inadequate pressure regulation. Calibrated oil pressure gages at each burner are the preferred means of confirming oil supply uniformity among burners.

Atomizing Steam Delivery System. For steam atomized oil burners, the distribution of atomizing steam to the burners can be equally important as fuel distribution. Low steam pressure to one or more burners will result in higher flows of oil and degraded oil atomization quality which may result in air-starved flames and smoky flames. Similar to the oil supply system, design deficiencies in the steam distribution system are not uncommon, and may result from undersized piping, long piping runs between burners, poor steam quality, inadequate steam line insulation, and inadequate pressure regulation among different burner supply headers or burner elevations. As above, calibrated steam pressure gages at each burner provide the best means of confirming steam supply uniformity among burners.

4.1.3 Instrumentation and Controls

The best designed combustion equipment and Burner Management System may still be prone to smoking and opacity problems if the boiler control systems are not capable of automatically maintaining proper air-fuel ratios at the burners during steady and transient boiler operations. In addition, accurate instrumentation for monitoring excess O_2 and opacity are essential to plant personnel for diagnosing and avoiding opacity incidents.

4.1.3.1 Air and Fuel Flows.

Reliable and accurate metering of fuel flow and air flow is essential for fuel air ratio control on a boiler that is expected to maintain high efficiency (e.g., low excess O_2) and avoid combustion-related opacity problems.

The accuracy and responsiveness of the fuel flow and air flow meters can be limiting factors in controlling air-fuel ratio during normal boiler operation. Their accuracy can vary substantially depending on their design, age, and maintenance history. Inspection of the meters and related controls by a combustion controls specialists is required to evaluate their performance, and is warranted if control system problems are implicated in opacity problems. Problems such as inability to maintain flow meter calibration and sluggish or erratic responses of control room flow indicators should be considered possible indications of serious air or fuel metering problems.

4.1.3.2 Air-Fuel Ratio Control.

A critical function of the combustion control system is to maintain a prescribed air-fuel ratio over the boiler load range. Air-fuel ratio controls vary in complexity from manual control of excess air to automated systems with active feedback from excess O_2 monitors for automatic excess air trim.

Excess O_2 Monitor. It is imperative to have accurate instrumentation to measure the furnace excess O_2, whether used for automated excess O_2 trim control or as a stand-alone system providing feedback to boiler operators. General design guidelines for O_2 monitoring include:

- A minimum of one O_2 sensor is required in each boiler exhaust duct. More may be required in large ducts or where stratification in O_2 is present. Three O_2 sensors per duct is preferred for large (>300 MW) boilers. The readings from individual sensors may be averaged to determine the overall furnace excess O_2. Comparison of readouts from individual sensors are useful for evaluating the uniformity of the combustion process in the furnace.

- The O_2 sensors should be located upstream of the air heater and, if possible, upstream of the flue gas recirculation (FGR) take-off duct. For windbox FGR systems, it is important to recognize that when the FGR fans are stopped with dampers closed, back flow of leakage air from the windbox can produce erroneously high O_2 readings, if the O_2 sensors are located downstream of the FGR duct.

- On balanced-draft units, air in-leakage through boiler casing leaks and expansion joints located between the burners and O_2 sensors will result in erroneously high O_2 readings. In such cases, the actual excess O_2 for combustion at the burners is less than indicated. This can cause problems for automated excess O_2 trim controls and for boiler operators when attempting to maintain prescribed furnace excess O_2 levels, unless steps are taken to compensate for the leakage. A high priority should be placed on repair of the boiler air leaks.

- O_2 monitors should be designed for easy calibration, since frequent calibration checks may be an essential part of an opacity reduction program.

Air and Fuel Controllers. For boilers required to meet stringent opacity limits, accurate and reliable air-fuel ratio control is a critical design requirement for the boiler control system. Generally, control systems with automatic excess O_2 trim for air flow control are preferred. Deficiencies in reliability or precision of the air-fuel control may be related to control system design, needed maintenance, or both. Evaluation by a controls specialist will be warranted, if plant instrumentation personnel are not successful in correcting problems.

The functioning of the control room controllers, local fuel valve and air fan actuators, valve and damper control mechanisms, and related instrumentation and control elements can all impact the precision of air and fuel control, and must be evaluated from a design and maintenance standpoint to rectify air-fuel control system problems.

4.1.3.3 Opacity Measurement.

The plant opacity monitor is typically the official indicator for opacity compliance at an oil-fired boiler, and is a primary diagnostic tool for characterizing and troubleshooting opacity problems. Obviously, the accuracy of the opacity monitor is an important element of an opacity reduction and control program.

The accepted opacity monitoring approach is via a transmissometer located in the exhaust duct or stack. Design and performance specifications for transmissometers, and procedures for installation, maintenance, testing, and calibration are well established, and are often specified in boiler operating permits by way of reference to standard EPA methodology. Older style smoke meters (e.g., bolometers) are generally not sensitive or accurate in comparison to modern transmissometers, and should not be relied upon for opacity compliance or diagnostic purposes.

Despite the standardization of opacity monitoring technology that has occurred over the past two decades, several design factors pertinent to implementing and maintaining an effective opacity control program should be emphasized:

- *Ease of calibration.* Opacity monitoring systems requiring manual calibration should be designed so that the calibration is easily accomplished by plant technicians.

- *Access for maintenance.* Difficulties in physically accessing the opacity monitor components should be minimized, so that poor access does not become a deterrent to maintenance.

- *Dedicated opacity monitor(s) per boiler.* Even though boilers with a common stack may be required to have a single stack opacity monitor, this hinders the diagnosis of opacity problems when multiple units are operating. The cost of installing separate opacity monitors for each boiler may be justifiable compared to the consequences of undiagnosed opacity problems.

In addition, on boilers that are prone to sulfuric acid condensations plumes, the opacity monitor will respond to the acid condensation, if it occurs at the location of the monitor. Under the right conditions, the acid condensation may occur at the opacity monitor intermittently as flue gas temperatures vary above and below the acid dew point. This can cause spikes in opacity or unexpected increases or decreases in opacity that may mistakenly be attributed to combustion system problems. Generally, opacity monitors located close to the stack exit are more susceptible to this condition, since the likelihood of acid condensation at that location is greater.

5

OPERATING FACTORS AFFECTING OPACITY

The primary boiler operating factors and relevant operating parameters that affect stack opacity are summarized in Table 5-1 and are discussed below. Table 5-1 also lists the report sections where discussion of the relevant parameters can be located. In some cases, the operating procedures may be specified in existing plant guidelines, while in other cases procedures may rely on the intuition or experience of operating personnel. In the latter case, the operating procedures may be subject to the discretion of individual boiler operators. In any event, it is important to understand the cause and effect relationships between the operating practices and opacity in order to maintain an effective opacity mitigation program.

Table 5-1
Operational Factors Affecting Opacity

Operating Factor	Relevant Parameters	Section
Fuel Specification	Fuel properties	5.1.1
	Fuel handling	5.1.2
Fuel Distribution to the Burners	Oil supply (and return) flow at the burners	5.2.1
	Atomizing steam flow at the burners	5.2.2
	Steam-to-oil differential pressure	5.2.3
Air Distribution to the Burners	Windbox-to-furnace ΔP	5.2.4
	Burner air register/damper positions	5.2.5
	Overfire air port adjustments	5.2.6
	Flue gas recirculation mixing	5.2.7
	Fan balance and crossover ducts	5.2.8
Excess Oxygen (O_2)	Excess O_2 versus load	5.3.1
	Excess O_2 bias	5.3.2

Table 5-1
(*Continued*)

Operating Factor	Relevant Parameters	Section
Oil Viscosity	Oil temperature	5.4.1
	Oil temperature control	5.4.2
	Automatic viscosity control	5.4.3
Oil Atomization and Spray Quality	Oil supply (and return) flow at the burners	5.5.1
	Atomizing steam flow at the burners	5.5.2
	Steam-to-oil differential pressure	5.5.3
Flue Gas Recirculation (FGR)	FGR flow rate (% FGR)	5.6.1
	FGR fan startup and idle conditions	5.6.2
Overfire Air (OFA)	OFA flow rate (% OFA)	5.7.1
	OFA port adjustments	5.7.2.
Burner Adjustments	Air register and spin vane adjustments	5.8.1
	Air compartment damper positions	5.8.2
	Oil gun/swirler assembly inserted position	5.8.3
Burners Out of Service	Air register positions on idle burners	5.9.1
	Burner firing pattern	5.9.2
Sootblowing	Sootblowing frequency	5.10.1
	Optimization of sootblowing cycles	5.10.2
Boiler Operating Mode	Boiler startup	5.11.1
	Burner light-offs and shutdowns	5.11.2
	Load changes	5.11.3
	Steady load	5.11.4
	Maximum load and turndown	5.11.5
	Sootblowing	5.11.6
	Boiler shutdown	5.11.7
	Co-firing gas and oil	5.11.8
Additives	Combustion additives	5.12
	Back-end additives	5.12

5.1 Fuel Specification

The physical and chemical properties of the fuel oil, as received or modified via on-site blending and storage procedures, can influence stack opacity directly (e.g., higher ash concentration increases particulate emissions) or indirectly by affecting the performance of the combustion system, sootblowing system, or other operations and equipment that affect opacity. Undersirable fuel properties can be avoided by changing the fuel purchase specification, but this is often not a viable alternative due to fuel availability, cost, or existing fuel supply contracts.

5.1.1 Fuel Properties.

The fuel oil physical and chemical properties that are of primary importance to stack opacity are discussed in Section 3. The preferred ranges of the critical properties for beneficial effects on opacity are summarized in Table 5-2.

5.1.2 Fuel Handling.

Fuel storage and blending practices can contribute to opacity problems by altering the properties of the fuel from the time that the fuel shipment is received at station. Specific problems include:

1. Stratification of oil in storage tanks, resulting in unpredictable shifts in oil properties (i.e., viscosity) that can result in deteriorated oil atomization and combustion.

2. Incompatibility of blended oils or long-term storage can produce sludge and formation of sediments that can adversely affect pumping, atomization, and burning properties of the oil.

In addition, improper recirculation and control of oil temperature in the storage tanks and oil lines can result in oil that is too cold or too hot reaching the burners, particularly during startup. Either condition may cause smoking problems. Oil that is too cold (high viscosity) can produce black smoke due to poor atomization. Oil that is too hot (low viscosity) can result in higher oil flows to a burner due to lower flow resistance in the oil gun and atomizer, causing smoke due to fuel-rich combustion.

Table 5-2
Fuel Oil Properties and Impacts on Opacity

Oil Property	Desirable Specification	Primary Impacts on Opacity
Vanadium	<50 ppm (by wt.)	Low vanadium results in: —Less catalytic conversion of SO_2 to SO_3, reducing SO_3 condensation plumes. —Fewer ash deposits in the boiler, reducing opacity spikes during sootblowing and load changes.
Sulfur	Minimum economically available	Lower sulfur results in: —Less SO_3 and reduced opacity due to SO_3 condensation. —Fewer emissions of acidic particulate matter during air heater sootblows and load changes. —Fewer ash deposits in the boiler. —Less corrosive ash deposits.
Asphaltene Content, Coking Index, and Conradson Carbon	≤5% (by wt.) for asphaltene content and Coking Index. ≤10% (by wt.) for Conradson arbon	Lower asphaltene, Coking Index, and Conradson Carbon reduce the mass of Carbonaceous particles (cenospheres) formed during combustion. This improves burnout of the fuel and reduces emissions of carbonaceous particulate matter that can contribute to smoking or opacity problems.
Ash	Minimum (typ. < 0.05% by wt.)	Reduced ash content results in less ash deposition in the boiler and lower emissions of ash particulate matter during sootblowing and steady operation. For boilers with specific ash deposition problems, the trace metals content of the ash may be important and warrant additional fuel specification for particular elements (e.g., sodium).
Nitrogen	Minimum (typ. < 0.3% by wt.)	Lower nitrogen produces less NOx and minimizes potential trade-offs between NOx emissions, PM emissions, and opacity. Such trade-offs may result in lower boiler operating margins to avoid opacity problems or more frequent opacity exceedances.
Viscosity	100–150 SSU within heating capacity of oil heaters. (Typical temperature range 200–250°F).	For boilers with marginal oil heater capacity, oil viscosity may be an important fuel specification. The oil heaters must be capable of heating the oil to the manufacturer’s recommended viscosity specification for proper combustion (typically 100 to 150 SSU). Low viscosity results in poor fuel oil atomization, which can cause or contribute to smoking problems.

5.2 Air and Fuel Distribution to the Burners

Operating factors that affect the total flow of air and fuel or the distribution of air and fuel among the burners are discussed below. The underlying issue with respect to opacity is the extent to which operating factors impact the air-fuel ratios at the burners, creating fuel-rich combustion conditions at one or more burners. Such conditions can create black smoke due to insufficient excess air for combustion, or cause other problems such as flame impingement and flame instability that lead to smoking. Opacity problems due to combustion that is excessively air-rich (white smoke) are usually encountered during boiler startup when few burners are in service, as discussed below under Boiler Operating Mode.

5.2.1 Oil Supply (and Return) Flow at the Burners

While total oil flow to the boiler is controlled by the oil demand of the boiler control system, the distribution of oil to individually controlled burners or groups of burners can be influenced by a variety of operating factors:

- Blockages or pluggage of oil supply (or return) lines or oil guns.
- Improper positioning of manual oil control valves or isolation valves that restrict flow to burners.
- Installation of the wrong oil atomizer in one or more oil guns.
- Improper installation of one or more oil atomizers that results in cross-over of oil supply and return flows, or cross-over of oil and atomizing steam flows within the atomizer.
- Cross-over of oil supply and return flows, or cross-over of oil and atomizing steam flows within the oil gun due to damaged oil gun barrels.
- Improperly set oil pressure regulators controlling oil supply pressure to individual burners or groups of burners.

The best approach for evaluating the distribution of oil flows among burners is by measuring the oil gun supply pressures with calibrated pressure gages permanently mounted close to each oil gun. For mechanical atomizers, measure the supply and return pressure. For steam-atomized burners, measure the oil and steam pressures. Use the atomizer manufacturer’s oil flow versus pressure curves to evaluate oil flow uniformity among burners. Flows should be within ±5% among burners when measured with all burners in service at high load. Alternatively, as a general rule, the oil pressures among burners should not vary by more than ±5%.

5.2.2 Atomizing Steam Flow at the Burners

For steam-atomized oil guns, maintaining a uniform distribution of atomizing steam flow among the burners is as important as maintaining uniform oil flows. As discussed above for oil flows, the best approach for evaluating steam flows is via calibrated pressure gages located at the oil guns. Steam pressures should not vary by more than ±5% among burners. Low or high steam pressures at one or more burners may indicate blockages in steam lines, malfunctioning or improperly adjusted steam control or isolation valves, improperly set steam pressure regulators, or atomizer or oil gun problems listed above.

Other problems that can impact steam flow are: (1) insufficient atomizing steam supply due to use of an under-sized steam source or supply line, (2) diversion of steam for other uses (e.g., sootblowers), and (3) poor quality (i.e., wet) steam that condenses in the steam lines.

Atomizer operating conditions that result in atomizing steam flows that are too high can also create opacity problems. Problems are generally more likely to occur at low burner firing rates (e.g., during boiler startups), where atomizer steam-to-oil ratios increase by design and where burner air velocities, temperatures, and combustion intensities are lowest. Excessively high atomizing steam flow may produce oil sprays that have too high momentum and penetrate beyond the aerodynamic flow field of the burner, resulting in unburned, finely-atomized, oil droplets that appear as white dense smoke at the stack. Additionally, excessively high atomizing steam-to-oil ratios that result in quenching of the combustion process, which can also cause white smoke. Such problems and their solutions are site-specific — remedies may include re-designing atomizers for higher turndown, reducing atomization steam-to-oil pressures at low firing rates, and optimizing burner air register positions at low loads.

5.2.3 Steam-to-Oil Differential Pressure

The differential pressure (ΔP) between the oil and atomizing steam, measured at the oil gun, is a critical operating parameter affecting oil and steam flow to the burner and the size of oil droplets in the oil spray.

For atomizers operating in a constant ΔP mode (e.g., steam-to-oil differential pressure constant over the entire load range), the ΔP should be set according to manufacturer's specifications for the specific atomizer design. This adjustment is made at the atomizing steam differential pressure controller or regulator, but the actual ΔP should be measured at the oil gun.

For steam atomizers operating in a constant steam supply pressure mode, the pressure should likewise be set to manufacturer's specifications, and it should be confirmed that a constant steam pressure is maintained over the turndown range of the burners.

5.2.4 Windbox-to-Furnace ΔP

The pressure drop between the windbox and the furnace, often referred to as "burner pressure drop," helps to distribute the windbox air flow more uniformly within the windbox. Typically, values may range from over 10-inches H_2O at maximum burner rating to below 1-inch H_2O at minimum firing conditions.

Per conventional wisdom, higher pressures are beneficial in balancing air flows among burners, while lower pressures may be detrimental to flow uniformity. However, depending on air register adjustments, individual burners can have substantially different air flows and air-side pressure drops, regardless of the total windbox-furnace ΔP measured.

For a given boiler firing rate and total boiler air flow, the windbox-furnace ΔP will be affected by the number of burners in service, the air register positions on the inservice and idle burners, the position of overfire air port dampers, and the quantity of windbox flue gas recirculation. To support good combustion conditions, as a general rule the windbox-furnace ΔP should be in the range of 3 to 5-inches H_2O at maximum burner rating, and should be kept above a minimum of 1-inch H_2O at the minimum burner firing conditions. Exceptions to this are made when high burner turndown is required and, accordingly, burner equipment design has been optimized for good atomization and high combustion efficiency.

5.2.5 Burner Air Register/Damper Positions

As discussed above under Design Factors affecting opacity, the adjustment of burner air registers or dampers influence flame shape, combustion intensity, and distribution of combustion air among burners. Poor combustion conditions on one or more burners, as evidenced by smoky flames or flames that are too narrow or too wide, may be the result of improper air register adjustment. The position of the air registers on these burners should be compared to other burners or to previously determined optimum settings for the particular boiler load and fuel.

As a general rule, it is desirable to have all burner registers set at approximately the same settings to help ensure that air flow is balanced among the burners. However, the air registers on individual burners may need to be optimized to prevent localized flame impingement problems or to adapt to localized non-uniformities in windbox air supply.

For circular burners with independent control of air spin and air flow control, adjustments of air registers to balance air flow among burners can be made without significantly affecting flame shape. When a single set of dampers controls both air flow and spin, care must be used so that other problems such as poor flame shape or flame impingement are not created while attempting to balance air flow among burners.

The effectiveness of air register adjustments to balance air flow or air-fuel ratio among burners can be evaluated on the basis of visual flame appearance, burner air flow measuring devices, and/or by evaluating the uniformity of excess O_2 at the furnace exit.

5.2.6 Overfire Air Port Adjustments

Opening the overfire air (OFA) ports results in less combustion air at the burners and lower windbox-furnace ΔP. Ideally, as the OFA ports are opened, the combustion air flows decrease uniformly among the burners. However, in practice the operation of the overfire air ports may impart non-uniform air flow among burners, depending on the air flow characteristics of the burner windbox, the quantity of OFA used, the uniformity of air flows among the OFA ports, and the design of the OFA air supply (e.g., separate air supply duct and windbox versus common burner/OFA windbox).

The impact of OFA on the distribution of air flow among burners can be evaluated on the basis of visual flame appearance and burner air flow measuring devices. Measurements of excess O_2 and NOx distribution at the furnace exit can also be used to evaluate the distribution of air-fuel ratio among the burners when using OFA, but the mixing of the overfire air into the combustion gasses can affect the O_2 distribution in unexpected ways and complicate the analysis. A combustion consulting company using specialized test equipment may be required to optimize OFA and evaluate impacts on combustion conditions at the burner.

5.2.7 Flue Gas Recirculation Mixing

Flue gas recirculation (FGR) to the burner windbox is used as a NOx control technique on many gas- and oil-fired boilers. The FGR is mixed into the combustion air upstream of the burner windbox by means of a FGR distribution or mixing device. If the mixing is not uniform and results in gradients in flue gas and O_2 concentration within the windbox, this will result in variations in total air or oxygen flow among the burners. Measurement of the O_2 concentration at various locations in the windbox will reveal whether such a condition exists.

Non-uniform distribution of FGR in the windbox and among the burners may or may not be a problem, depending on the severity of the O_2 concentration gradients and the sensitivity of burner combustion to changes in FGR rate.

It should be mentioned that variations in O_2 concentration may also indicate gradients in temperature within the windbox, since the temperature of the recirculated flue gas is higher than the combustion air supplied from the air heater. The temperature gradients can also impact the distribution of mass flow of air among the burners.

5.2.8 Fan Balance and Crossover Ducts

The function of the combustion air system — including the forced draft (FD) fans, air heaters, and interconnecting ductwork — is to uniformly pressurize the windbox such that air flow through individual burners is determined solely by the burner air registers and windbox-furnace ΔP. As indicated above, non-ideal conditions in windbox design can result in biasing of combustion air flow among regions of the windbox. Other operating conditions of the combustion air supply system can produce non-uniform air flow to and within the windbox. Depending on the particular design of the system, items may include:

- *FD fan flows not balanced.* Biasing the flow through one of the fans can result in more air flow to the windbox closest to that fan.
- *Cross-over duct dampers closed.* Cross-over ducts used to equalize air flow and pressure among separate air supply ducts should be opened to minimize the impacts of any imbalances in FD fan flows and air heater pressure drops.
- *Imbalances in air heater pressure drop.* Similar to imbalances in FD fans, different pressure drops between air heaters can lead to unequal pressurization of the windbox(es), unless the air ductwork design can equalize the flows prior to the windbox.
- *Tempering duct dampers set improperly.* On boilers with FGR or air tempering ducts leading to the furnace hopper or upper furnace cavity, improper adjustment of duct dampers may adversely impact air flow to the burners.

Partially plugged air heaters introduce draft pulsations as the plugged sections rotate into the FD discharge and economizer outlet ducts. In fact, it is not unusual to find that the time interval between significant draft or opacity swings is synchronized with the rotational speed of the air heater. If this is the case, the magnitude of these transients can actually be used to indicate local plugging, which might otherwise not be reflected by gas temperature changes. In almost all cases, it is operationally better to compensate for air heater induced draft swings with a higher average excess air, such that the low end of the air flow swing does not create an opacity incident, than to try to compensate for the short term reduction in air flow by modulating the fans.

5.3 Excess Oxygen (O_2)

The furnace excess oxygen provides a measure of the overall excess air supplied to the boiler for combustion. A common cause of high opacity and smoking problems on oil-fired boilers is insufficient excess air during steady state or transient boiler operations.

5.3.1 Excess O_2 Versus Load

The excess air is generally adjusted automatically as a function of load by the combustion control system. Regardless of the exact control scheme, it is necessary to maintain a sufficient margin of excess O_2 above the level at which smoking occurs (i.e., the "smoke point"). This provides an operating margin to maintain a clean stack as normal boiler transients occur on load dispatch, and as other operating conditions arise such as variations in fuel properties and minor upsets (e.g., burner trips) for which the boiler operators may not have advanced warning. In addition, a margin is required to account for normal imprecision in the combustion control system which produces unavoidable variations in boiler air-fuel ratio.

The excess O_2 versus load profile is determined empirically by testing the boiler over its operating load range. As changes in fuels, boiler duty cycle, and the conditions of controls and combustion equipment occur over time, an existing excess O_2 profile may not provide a sufficient margin to avoid smoking. In addition, changing boiler operating priorities or demands, such as increased emphasis on minimizing heat rate and requirements for lower NOx emissions, may require lower excess O_2 and less operating margin above the smoke point. Consequently, the excess O_2 set point as a function of load should be periodically re-evaluated in light of changing demands or operating conditions of the boiler. The final characteristics of the O_2 control function versus load may involve subjective tradeoffs between competing requirements.

5.3.2 Excess O_2 Bias

In addition to the O_2 margin that is provided by the calibration of the control system, manual or automatic biasing of the excess O_2 from the programmed O_2 versus load curve is usually available to boiler operators. Methods vary, but can include cumbersome, manual operation of FD fans (which may only be suitable for boilers operating at constant load), excess air bias controllers, and automated O_2 trim controllers based on feedback from the excess O_2 monitor. For boilers with stringent opacity controls and low-excess air requirements, the more sophisticated, automated system is usually desirable and upgrading of the controls to provide this function may be easily justified.

Raising the excess O_2 in response to the sudden onset of a smoking problem, and maintaining an elevated excess O_2 until cause of the smoking is identified and corrected, is usually the correct approach. In addition, it is often a standard practice to raise the excess O_2 during certain boiler operations that are known to cause high opacity, such as burner shutdowns and light-offs.

5.4 Oil Viscosity

Oil viscosity is an important and often overlooked operating factor that can have a major impact on oil atomization, combustion, and opacity. Burner equipment (particularly the oil atomizer) is designed to operate within a relatively narrow range of oil viscosity for optimum performance. Operating outside the recommended range, particularly with too high viscosity, can have adverse effects on opacity. Opacity problems from operating with viscosity that is too low (oil temperatures too high) are generally not encountered, because oil heating system capacity by design may limit the potential for overheating the oil, and low oil viscosity will probably improve combustion under most conditions.

Typical oil viscosity at the burners specified by manufacturers range between 100 and 150 Saybolt Universal Seconds (SSU). Operating with higher viscosity can lead to deteriorated combustion conditions by increasing the average oil droplet diameter in the oil atomizer spray. Higher viscosity will also increase pressure drop of the oil through the oil gun and atomizer, causing changes in oil supply pressures, return pressures, and atomizing steam flow.

5.4.1 Oil Temperature

For a given oil shipment, varying the oil temperature is the means of adjusting viscosity to the proper range. From an operating standpoint, it is necessary to know the viscosity of each shipment of oil received at the plant in order to determine the proper "burn temperature." If different shipments of oil are blended on-site, then it is recommended that viscosity analysis of the blended oil be obtained.

Laboratory analysis typically provides values of viscosity at two specific oil temperatures. The oil temperature required to achieve the required oil viscosity can then be obtained from standard viscosity-temperature charts similar to the chart shown in Figure 5-1. The correct temperature lies on a line connecting the two known viscosity points and corresponding to the desired oil viscosity value. If only one viscosity-temperature point for an oil is known, it can be assumed that the slope of the viscosity line for a particular oil parallels the slope of standard viscosity lines which are typically provided on the viscosity chart (refer to Figure 5-1).

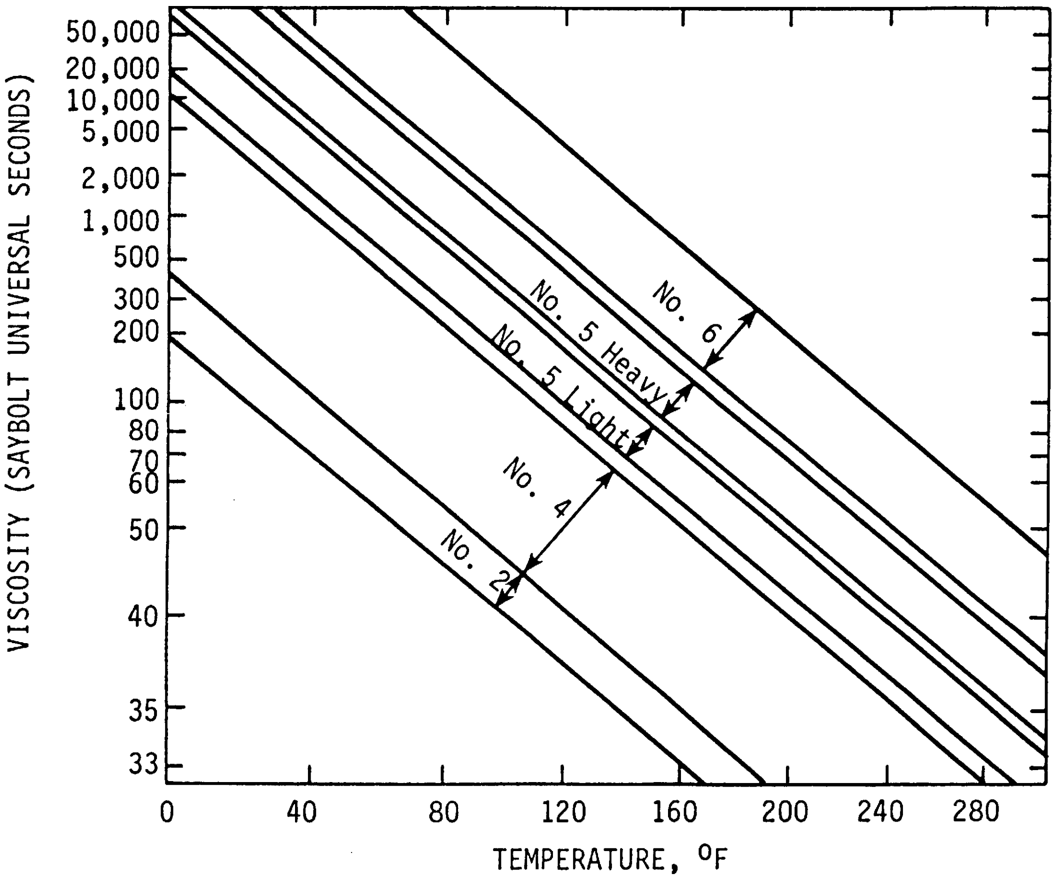


Figure 5-1
Oil viscosity versus temperature chart. (Reproduced from page 1–22 of Reference 5-1).

5.4.2 Oil Temperature Control

The ability to maintain the prescribed oil temperature (and viscosity) depends on the heating capacity of the oil heater(s), and the responsiveness and accuracy of the temperature controller. During rapid load ramp-ups, it is not uncommon for the oil temperature to lag as the oil heating system catches up with the increased oil flow.

A common problem encountered on many boilers is an undersized oil heater that limits the ability to achieve the proper oil temperature at high loads. To offset the potential adverse impact on combustion, changes in atomizer operating conditions (e.g., increased atomizing steam-to-oil ΔP) to restore good atomization may be required.

One note of caution related to oil temperature and automatic viscosity control: The oil temperature can decrease up to 10 to 20°F between the oil heaters and the burners, depending on the length of oil lines and condition of piping insulation. Operators should confirm that oil temperature set points maintain the proper temperature *at the burners* by measuring the temperature of the oil as close to the burners as possible.

5.4.3 Automatic Viscosity Control

In-line oil viscometers are recommended as a means of ensuring proper oil viscosity at the burners at all times. Control room read-outs of viscosity may be used by operators to make manual adjustments to oil temperature. Alternatively, automated viscosity control systems with oil temperature feed-back maintain an oil viscosity set point by automatically controlling heat input or bypass at the oil heater.

5.5 Oil Atomization and Spray Quality

The oil and atomizing steam supply conditions at the burners impact the spray quality of the oil atomizers as measured by the oil droplet size distribution of the oil spray. As discussed earlier, the size distribution of the oil spray is commonly characterized by its Sauter Mean Diameter (SMD). Atomizer operating conditions which produce smaller droplet diameters (i.e., smaller SMD) are preferable from an opacity standpoint, with rare exceptions. Poor atomization, characterized by a large SMD, can be the root cause of smoking problems and may contribute to other combustion-related problems.

5.5.1 Oil Supply (and Return) Flow at the Burners

Mechanical atomizers operating in a constant supply pressure, spill-return mode, exhibit the following operating characteristics with respect to spray quality:

1. SMD *decreases* as the oil flow through the atomizer *increases.*

2. SMD *decreases* as the oil supply pressure to the atomizer *increases*.

Accordingly, the SMD will generally decrease at higher burner firing rates.

These characteristics also apply for mechanical spill-return atomizers operating in a constant differential pressure mode (i.e., constant differential pressure between supply and return flow). Increasing the supply-return differential pressure will also decrease SMD.

Mechanical atomizers operating in a once-through or “simplex” mode (i.e., without an oil return flow from the atomizer) generally exhibit the same trends as listed above for the constant supply pressure atomizer.

It is not recommended that fundamental changes in the operating pressure conditions of an atomizer be made without assistance from the atomizer or burner supplier.

Another feature common to most conventional mechanical atomizer designs, with the possible exception of simplex atomizers, is that the angle of the oil spray cone produced by the atomizer widens as the oil flow rate is reduced. Thus, mechanical atomizers produce wider oil sprays and wider flames at lower burner firing rates, and may cause or exacerbate flame impingement problems at low loads.

5.5.2 Atomizing Steam Flow at the Burners

Steam-assisted atomizers are typically operated in either a constant steam supply pressure mode or in a constant steam-to-oil differential pressure (ΔP) mode. Regardless of the mode of operation, a primary factor affecting spray quality (SMD) is the quantity of atomizing steam delivered to the atomizer. Higher atomizing steam flow results in greater energy to break up the oil into fine droplets and lower SMD.

5.5.3 Steam-to-Oil Differential Pressure

For atomizers operating in a constant ΔP mode, the steam-to-oil differential pressure is the primary factor affecting SMD. Higher ΔP results in smaller SMD, as a result of increased mass flow of atomizing steam. Depending on specific atomizer design and operating ΔP, the SMD may increase, decrease, or remain essentially unchanged as the burner firing rate is reduced.

Atomizers designed specifically for operation at constant steam supply pressure, sometimes referred to as “Racer” mode, generally produce higher SMD compared to atomizers designed for constant ΔP mode. This is particularly true at high firing rates, where constant supply pressure may result in low atomizing steam flow. It is not uncommon to find Racer atomizers operating with zero or negative steam-to-oil differential pressure at the higher burner firing rates.

Of the various types of steam atomizer designs in commercial operation, the internal-mix atomizer is generally regarded as the best design for producing good spray quality over a wide burner turndown range.

Depending on the design of the atomizing steam supply system, adjustments may be possible to increase atomizer spray quality. The most obvious would be to increase the steam-to-oil ΔP or the steam supply pressure. Where such changes can be implemented relatively easily via an existing ΔP controller or manual adjustment of the steam pressure regulator, improvements in spray quality may be readily available. However, before attempting to operate atomizers outside of manufacturer-specified ranges, it is advisable to contact the manufacturer for guidance.

5.6 Flue Gas Recirculation (FGR)

Flue gas recirculation is commonly used as a NOx control technique on oil-fired boilers. In such applications, the FGR is injected into the combustion air prior to the windbox and acts as a diluent and heat sink in the combustion process to suppress NOx formation. Higher flow rates of FGR produce lower NOx emissions.

As discussed above, other forms of FGR are encountered at oil-fired boilers in which the recirculated flue gas is injected into the furnace hopper or upper furnace cavity for purposes of steam temperature control. This form of FGR, although possibly affecting the residence time in the furnace for carbon burnout, is not typically an important consideration for combustion or stack opacity. The discussion below pertains to FGR injected into the windbox.

5.6.1 FGR Flow Rate (% FGR)

The impact of increased FGR flow rates on combustion and opacity is very site-specific and cannot be generalized. The following are examples of impacts that have been observed:

1. High rates of FGR flow to the windbox can lead to flame instability or lift-off, which produces smoky flames and increased opacity. Alternatively, some burners may benefit from FGR as increased flow rates through the air registers increase burner mixing and combustion intensity, resulting in a lower tendency to smoke.

2. Increasing windbox FGR flow rate on tangential-fired boilers equipped with automatic control of windbox-furnace ΔP may cause more combustion air to be diverted to the auxiliary air compartments, resulting in fuel-rich combustion at the fuel nozzle and an increased tendency to smoke.

3. For boilers with marginal FD fan capacity, or boilers which are load limited due to insufficient air capacity, FGR will increase the windbox pressure further reducing FD fan capacity. This may require operation at lower excess O_2 levels with the associated increased risk of opacity problems due to insufficient air-fuel ratios at the burners during boiler upsets. Alternatively, it may be necessary to derate the unit in order to maintain sufficient excess air.

4. On boilers equipped with FGR and OFA, it may be possible to optimize these two techniques to minimize opacity while maintaining NOx emissions control. For example, if the burners tend to smoke when OFA ports are open, increasing FGR and closing down OFA may be a viable option.

5.6.2 FGR Fan Startup and Idle Conditions

When starting up the FGR fan(s), opacity spikes occasionally occur as ash deposits are purged from the FGR ducts. If this causes an opacity problem, it may be minimized by starting the fan at a lower load, ramping up the FGR fan more gradually, or leaving the FGR fan turned on at lower loads.

Particular problems may also occur after the FGR fan is turned off. Occasionally, air can leak backwards from the windbox, through the FGR fan and dampers, and into the flue gas duct. This can cause two problems:

1. If the probes for the boiler excess O_2 monitors are located downstream of the FGR take-off in the exhaust duct, the back-flow of combustion air can lead to erroneously high O_2 readings. Adjusting the boiler excess air to achieve the normal reading of excess O_2 may result in the burners operating fuel-rich, causing smoking.

2. If a substantial quantity of air is back-flowing through the FGR duct due to FGR shut-off dampers that are damaged or malfunctioning, thereby diverting air from the combustion process, the burners can be smoking even though the excess O_2 monitor shows adequate air flow to the boiler.

These are common problems on boilers equipped with FGR and can be easily overlooked as contributors to opacity problems.

5.7 Overfire Air (OFA)

5.7.1 OFA Flow Rate (% OFA)

Increasing the flow rate of air to the OFA ports results in a corresponding reduction in combustion air supplied to the burners. The reduced combustion air at the burners may result in smoky flames if the excess air becomes insufficient to burnout the fuel. Increased stack opacity will result when the air from the OFA ports does not effectively mix with the burner combustion products and burn up the remaining fuel. The flow rate of OFA that can be used without creating an opacity problem is specific to the design of the boiler, burners, and overfire air system.

In general, the use of OFA requires that the overall boiler excess air be raised to avoid smoking. The amount of excess air required must be established by boiler testing. Different excess O_2 versus load curves will typically be required for operation with and without OFA, and boiler excess air operating guidelines should be prepared accordingly.

5.7.2 OFA Port Adjustments

Overfire air systems may be equipped with flow control devices to bias air flow among individual OFA ports, aim the OFA air jets in the furnace, or alter the shape of the OFA jets to control penetration and mixing. Settings for the various parameters are usually optimized during commissioning of the OFA system. If smoking occurs during operation of OFA, the current adjustments should be compared to the prescribed values. If re-optimization of the OFA system is required due to continued smoking problems, it is advisable that they be made in conjunction with the manufacturer or a combustion consulting company.

5.8 Burner Adjustments

The adjustment of burner components can be a contributing factor in combustion-related opacity problems occurring during steady load and transient boiler operations. Alternatively, opacity problems related to burner adjustments may be rectified with a knowledge of the cause and effect relationship between specific burner adjustments and combustion conditions that affect opacity.

The following burner parameters may be adjustable, depending on the specific burner design:

- Total burner air flow
- Air spin or swirl
- Distribution of air among air zones or compartments
- Axial position of the oil gun and flame stabilizer

As discussed previously, the availability of these adjustments on a specific burner will vary from site to site. Specific problems that may be directly related to adjustment of these parameters are discussed below.

5.8.1 Air Register and Spin Vane Adjustments

For circular burners with air spin vanes or louver-type air registers, closing down the air register vanes or increasing the angle of the spin vanes will tend to broaden and shorten the flame. Opening the registers or reducing the spin will tend to narrow and lengthen the flame.

The types of problems related to air register adjustments, which can result in increased opacity, include:

1. Low air-fuel ratios at one or more burners, due to insufficient air flow through the air register.

2. Poor flame shape due to improper air register or spin vane position which under-swirls or over-swirls the flame. This may produce flame impingement or flame instability. It is important to note that poor flame shape can be due to other problems unrelated to burner adjustments, such as damaged flame stabilizers, deteriorated burner throat refractory, or poor oil atomization.

3. Poor burner light-off. This may be the result of burner air flow that is too high, which distorts or blows out the ignitor flame, or air flow that is too low and cannot support the ignitor or main flame or delays ignition. In either case, flame scanners may not be able to prove the flame.

4. Smoking during light-off or shutdown of the burner. This may be due to improper air register positions that do not provide sufficient air during oil gun purging, or are not properly coordinated with ignition of the flame.

5. Flames that stand-off from the burner or which oscillate between attached and detached from the burner throat. This may be caused by too much burner air or insufficient air swirl.

For circular burners with independent control of air spin and air flow control, adjustments of air registers to control flame shape (e.g., more or less air spin) can be made with minimal impact on total air flow. Alternatively, total burner air flow can be adjusted without impacting air spin and flame shape. For burners which use the same set of dampers to control air flow and spin — such as the common, louvered, single-register burner — flame shape (spin) and air flow will be simultaneously affected as the air register is adjusted. In this case, caution must be used so that one problem (e.g., flame impingement) is not traded off for another problem (e.g., smoking due to insufficient burner air flow).

5.8.2 Air Compartment Damper Positions

Air flow on tangential-fired burners equipped with corner windbox assemblies is controlled by air compartment dampers. The dampers generally modulate automatically with boiler load to maintain a prescribed windbox-to-furnace ΔP. As the dampers modulate, the proportioning of air between the fuel-air compartments and the auxiliary air compartments change. On some boilers, the air dampers are manually adjusted, and, therefore, the distribution of air among compartments may be at the discretion of boiler operators.

The distribution of air among the fuel and auxiliary air compartments affects the combustion process by changing the burner aerodynamics and the local air-fuel ratio.

When smoking problems occur, the position of all the dampers should be documented and compared to the manufacturer's specifications. At a fixed boiler load, all the auxiliary dampers should be at the same open position. Fuel air dampers are typically wide open at in-service elevations. Due to the synergistic effects of damper positions, burner performance, windbox pressure, and steam temperature control, it is generally not advisable to make fundamental changes in the air damper programming logic without assistance from the burner manufacturer or a combustion specialist.

A final note: The combustion process may extend well into the fireball at the center of the furnace, and in theory may diminish the impact of combustion conditions and adjustments at the burner. However, from experience, the burner oil atomization and air-fuel mixing process at the burners have a significant impact on the combustion process and on the opacity characteristics of a tangential-fired boiler. Thus, not only air damper positions, but oil atomization and flame stabilization are important factors affecting opacity on tangential-fired boilers.

5.8.3 Oil Gun/Swirler Assembly Inserted Position

The axial position of the atomizer and flame stabilizer relative to the burner throat impacts fuel and air mixing and can contribute to opacity problems:

1. If the oil gun is retracted too far from the burner exit, the oil spray can impinge on the burner throat causing clinkers and smoking. Build-up of the clinker and oil spray flowing back through the burner can pose a serious explosion or fire hazard.

2. If the oil gun is not positioned properly relative to the aerodynamic flow pattern of the combustion air, poor mixing of the oil and combustion air can result in smoky flames. Confirm that all oil guns are inserted per manufacturer's specifications.

3. When an oil gun is shut-off, the oil gun is retracted from the burner throat manually or automatically. In some instances the oil gun, oil gun guide tube, and flame stabilizer (swirler) are retracted. When the burner is lit-off, the oil gun and flame stabilizer assembly must be inserted to the prescribed light-off position.

Confirm that burner retract mechanisms are functioning, and that limit switches are set properly. For manual burner retracts, confirm that proper procedures for burner light-off are being followed.

Before making permanent changes to the axial alignment of burner components that are different from prescribed positions, consult with the burner manufacturer or a combustion specialist.

5.9 Burners Out of Service

When burners are removed from service for maintenance or for boiler turndown, boiler operators must be cognizant of potential impacts on combustion that the selection of idle burners and the air register positions on idle burners will have.

5.9.1 Air Register Positions on Idle Burners

Generally, air registers should be closed on out-of-service-burners, except during boiler startups when few burners may be operating. When air registers are open on idle burners, less combustion air is supplied to the active burners, causing the active burners to operate closer to the smoke point. If it is not possible to close the air register on the idle burner, the boiler excess O_2 should be increased. This is generally a more important factor on boilers with fewer burners where a single burner from service has more impact. However, this is also an important factor on larger boilers with greater numbers of burners when multiple burners are removed from service.

5.9.2 Burner Firing Pattern

When a burner is removed from service, it is common practice to shut down another burner in an “opposite” or “mirror image” position to maintain firing symmetry in the furnace. For example on tangential-fired boilers, opposite burners on the same burner elevation are removed from service. Operating with a non-uniform arrangement of active burners can lead to smoking problems because of imbalances in air distribution or fuel distribution to the active burners.

5.10 Soot Blowing

Sootblowing practices can be optimized to minimize opacity spikes and fallout of large particles during operation of boiler and air heater sootblowers.

When a sootblower is operated, a portion of the removed material will settle or redeposit onto downstream surfaces. The remainder will be re-entrained into the gas flow and, in sufficient quantity, will cause opacity excursions. The degree to which opacity is generated depends upon the deposit location, the amount of deposited material, the adhesion of the deposit to the surface, and the location, intensity, duration and sequencing of the sootblowers.

Strategies for minimizing opacity excursions during sootblowing are boiler specific, but bounded by two approaches:

1. Continuous sootblowing, where the objective is to time average the emissions to a lower (acceptable) value.

2. No sootblowing, where deposits are removed manually and by washing during boiler outages.

The viability of the second approach is strongly dependent upon the rate of deposit build-up, the effects of these deposits on boiler operation, and frequent opportunities for boiler washes. These requirements limit the no-sootblowing option to boilers firing low-ash, low-sulfur oils with good overall combustion and the flexibility for frequent boiler outages for cleaning.

In most instances, sootblowing will be required on regular intervals and the magnitude of opacity caused by sootblowing can be minimized by optimizing the sootblowing process.

5.10.1 Sootblowing Frequency

Sootblowing frequency may be dictated by a number of factors, including boiler duty cycle, the severity and build-up rates of boiler deposits, the occurrences of favorable atmospheric conditions (e.g., wind direction) for sootblowing, and the effectiveness of the sootblowers and their programmed operating cycle (sequencing).

Opacity spikes during sootblowing are unavoidable. However, more frequent sootblowing may reduce the magnitude of the opacity spikes as less deposits are allowed to accumulate between sootblowing episodes.

Optimization of sootblowing frequency should be done in conjunction with an evaluation and optimization of the sootblowing equipment and sequencing program (i.e., duration and order in which boiler sections are cleaned). Due to the complexity of the sootblowing process and the cause and effect relationship with opacity, it is advisable that evaluation and optimization of sootblowing for purposes of opacity reduction be conducted with specialists familiar with sootblowing technology and boiler deposition.

5.10.2 Optimization of Sootblowing Cycles

The sequencing and duration of sootblowing currently programmed in the sootblower controls, or as implemented through manual or semi-automatic sootblower operation, may not be optimum for controlling deposits in the various boiler sections and maintaining low opacity. Optimization for purposes of opacity reduction can involve a variety approaches, but the common elements are summarized in Table 5-3.

Table 5-3
Elements of a Sootblowing Optimization Program

(1)	Inspection and repair of sootblower equipment.
(2)	Internal inspection of boiler deposits, and recommendations for new or modified sootblowers or modified sootblower operating pressures.
(3)	Evaluation of opacity resulting from each set of sootblowers or from each region of the boiler as it is sootblown.
(4)	Testing of alternative sootblower sequencing and durations (based on opacity observations) to develop a modified sootblowing cycle which effectively cleans all boiler sections, including the air heater.
(5)	Implementation of the modified sootblowing cycle on a trial basis, including tests to determine optimum sootblowing frequency.
(6)	Permanent implementation of the modified sootblowing procedures, including training of operating personnel as appropriate.

5.11 Boiler Operating Mode

Different boiler operating modes can exhibit different types and causes of opacity problems as summarized below. Guidelines for troubleshooting the common types of opacity problems that occur during different boiler operating modes are provided in Section 8.

5.11.1 Boiler Startup

Often the most difficult combustion conditions for ignition, flame stability, and fuel burnout occur during start-up of the boiler. The combined effects of high air flows relative to fuel flows, cold combustion air temperatures, high radiant energy loss to the furnace walls, and little if any inter-flame heating reduce combustion rates in the flame zone and inhibit the burnout of any carbon particles outside of the flame envelope. Depending upon the boiler design, burner design, and specific operating conditions, incomplete combustion can result in high opacity from black plumes or white plumes.

5.11.2 Burner Light-Offs and Shutdowns

Smoke during burner light-offs may be related to problems with the ignitor, the main burner, the fuel supply system, or the overall control of combustion conditions in the boiler. Good light-offs require coordination and proper functioning of ignitors, flame scanners, burner air registers, fuel and purge steam valves, and atomizing steam valves. Ignitor problems can result from damaged or weak energy output from spark rods, faulty retract mechanisms for the ignitor and spark rod, worn or plugged atomizers, and damaged flame stabilizers (for the ignitor). Problems with main burners associated with oil atomizers and fuel supply conditions may first be evident during light-offs.

Smoking during burner shut-downs can likewise be the result of one or a number of problems related the combustion equipment. A common problem is opacity caused by the incomplete combustion of oil injected into the boiler during the burner purge cycle. During the purge process, the transient fuel flow can approach the full load flow rate, but typically with poorer atomization. The resulting fuel pulse is difficult to burn in an attached flame, even though the ignitor is on.

When removing an oil gun from service, it is extremely important to perform a proper and adequate purge procedure. As soon as the oil to a selected burner is shut-off, the steam purge to the oil gun should immediately commence. The steam purge through the oil gun provides a dual purpose. First, the stream traveling through the gun provides a cleaning action that causes any oil remaining in the gun barrels to be forced into the furnace. Second, the steam then acts to physically cool the atomizer to prevent overheating by the radiant heat from the furnace. The ignitor at that burner should be in service during the purge. Once the purge is complete, the oil gun should be retracted immediately to prevent overheating of the atomizer and tip of the oil gun. Prior to light-off of the oil gun, steam purging is also required for cooling purposes if the gun remains in the furnace for a significant period of time (e.g., > 1 minute) before the oil valve opens.

5.11.3 Load Changes

Opacity problems occurring during boiler load changes are often related to the design and performance of the boiler combustion control system. Automatic combustion control systems are normally configured to increase the air-fuel ratios at the burners during load transients. This is accomplished by having the air flow signal lead the fuel flow signal on load increases, and the fuel flow signal leading the air flow signal on load decreases. The necessary margins, in both delay timing and magnitude, are dictated by air fan and fuel flow responses to control signal changes.

An additional consideration, more associated with older turbines and load control systems, is the response of the turbine valves to pre-set load ramp rates. For example, older cam-operated turbine inlet valves have a tendency to develop flat spots in which the inlet valve flow area does not respond linearly to load demand. In such cases, maintaining an average linear load increase (e.g. MW/minute) results in periods of above-average valve movement to compensate for periods of below-average valve movement. The resulting perturbations in steam pressure can introduce significant combustion transients, and potential opacity excursions, as the control system tries to maintain steam pressure.

5.11.4 Steady Load

Opacity problems occurring during steady load are often exacerbated during transient boiler operation. Since it is usually more difficult to diagnose and rectify opacity problems during transient operation, it is preferable to first correct problems occurring under steady load. The cause of opacity problems at steady load may be burner-specific, or may be the result of adverse operating conditions impacting the combustion process at most or all of the burners.

5.11.5 Maximum Load and Turndown

Opacity problems occurring at maximum load may relate directly to load-limiting factors such as FD fan capacity (e.g., low excess air margin above the smoke point), fuel or atomizing steam supply system limits (e.g., poor oil atomization), or maximum burner ratings (e.g., flame impingement). Opacity problems at minimum loads may be due to deteriorated combustion conditions related to design of burners or oil atomizers, poor distribution of air and fuel to the burners, or increased acid condensation in the plume due to lower flue gas temperature and high excess air.

5.11.6 Sootblowing

Opacity problems during sootblowing are discussed above. Optimization of sootblowing procedures offers the potential for reducing or eliminating the severity and frequency of opacity exceedances during sootblowing

5.11.7 Boiler Shutdown

Similar to boiler startup, difficult combustion conditions for flame stability and fuel burnout occur during boiler shutdown. Similar problems related to high air flows (relative to fuel flows), cold combustion air temperatures, high radiant energy loss to the furnace walls, and minimal flame interaction can inhibit the burnout of fuel. Whereas specific problems related to burner light-off are of concern during boiler startup, analogous problems with burner shutdowns are of concern when ramping the boiler down and taking it off line.

5.11.8 Co-Firing Gas and Oil

Simultaneous firing of natural gas and oil (co-firing) is becoming more prevalent in the utility industry. In this regard, a number of oil-fired boilers have converted to co-firing capability to take advantage of the price differential between gas and oil, and inherently lower particulate matter emissions with gas firing. During co-firing each burner (or burner elevation) in the boiler typically fires either gas or oil, although in some instances gas and oil are fired simultaneously in the same burner. In many boilers converted from oil-only to gas and oil firing, the maximum boiler load when firing gas is less than MCR due to operating limitations such as high tube metal temperatures and restricted gas supply. In these instances, co-firing is commonly used to achieve maximum load.

Co-firing requires careful control of air-fuel ratios among the gas- and oil-fired burners to avoid opacity due to air-starved combustion. Such conditions can occur during steady-state operation or transient operating conditions, e.g., during load ramps or when switching fuels. For gas-and oil-fired burners operating at the same heat input, different quantities of combustion air are required to produce the same excess air conditions in the flames for each fuel. To achieve balanced excess air among the burners, the air damper (or air register) settings or fuel flow for either the gas or oil burners will have to be adjusted accordingly (if capable, the burner management system may be programmed make the appropriate burner adjustments automatically). The alternative is to increase overall excess air to the boiler such that all burners have adequate air for complete combustion. This approach is not recommended for long-term operation due to the heat rate penalty associated with unnecessarily high excess air. Troubleshooting the special problems associated with co-firing that can lead to opacity problems is discussed in Section 8, Symptom No. 9.

Visible particulate matter emissions (i.e., smoke) have been observed in rare instances with 100% gas firing. The situation is normally caused by low air/fuel ratio at the burners, or severe maldistribution of gas flow to individual burners resulting from damaged gas elements (pokers and spuds). If visible emissions are present when firing gas, the burners should be inspected to confirm that the gas pressures are uniform among the burners, and the air dampers are at recommended settings. If nothing unusual is noted, the gas injection elements (particularly the gas spuds) and other burner components should be inspected at the earliest opportunity.

5.12 Chemical Additives

The types of chemical additives and their applications at oil-fired boilers are discussed in Section 7.3. Selecting the appropriate additive for a specific problem and determining the optimum injection scheme and dose rate are critical elements of a successful additive injection program. Guidelines in these areas are beyond the scope of this report. It is recommended that operating companies considering the use of additives engage in discussions with more than one additive supplier, request references for similar applications, contact references, and solicit competitive bids for additive supply. Moreover, the opinion of an independent third party familiar with additives and the types of problems that are targeted for additive use may be very beneficial.

At utility boilers with established additive injection programs, maintaining the proper dosage rate is perhaps the most important factor that can impact opacity. The potential impacts will depend on the type of additive and the way it is injected. In general, opacity problems can occur as a result of:

1. Additive overdosing, in which the excess additive or its byproducts result in an increase in stack particulate matter emissions and opacity.

2. Additive underdosing, in which insufficient additive results in the targeted problem recurring (e.g., large ash deposit accumulations, high carbon emissions, high SO_3, and acidic particulate matter).

Regardless of the type of problem being addressed with additive, there is usually an optimum dose rate as a function of boiler load, based on tradeoffs between ash chemistry, particulate emissions, acid neutralization, etc. Moreover, when fuel properties change (e.g., different sulfur or vanadium content), the optimum additive dosage rate generally changes. It is advisable that the dose rate be re-evaluated on a regular basis and confirmed by similar tests or observations used in establishing the original additive injection rate. It is also recommended that the additive rate be automatically controlled as a function of boiler load such that overdosing or underdosing do not occur over the operating range of the boiler.

5.13 References

1. *Residual Fuel Oil User's Guidebook Volume 2: Residual Oil-Fired Boilers.* EPRI AP-5826, August 1988.

6

MAINTENANCE FACTORS AFFECTING OPACITY

Sections 4 and 5 described how design of boiler components and plant operating practices at oil-fired boilers can impact stack opacity. This section describes why maintenance of critical equipment components — including inspections, calibrations, and repairs — is an important aspect of opacity mitigation.

Table 6-1 summarizes the boiler systems and the related inspection and maintenance items that have the greatest potential to impact stack opacity. Also listed in the table are the report sections where discussion of the inspection and maintenance items can be located.

Table 6-1
Maintenance Factors Affecting Opacity

Boiler System	Inspection and Maintenance Items	Section
Oil Gun and Atomizer	Inspection and cleaning	6.1.1
	Atomizer replacement frequency	6.1.2
Burner	Burner throat refractory	6.2 Table 6-3
	Air and fuel nozzles (tangential-fired)	
	Burner tilts (tangential-fired)	
	Air registers; compartment dampers	
	Flame stabilizers	
	Radial/axial alignment of burner components	
	Retract mechanisms	
	Ignitors	
	Flame scanners	

Table 6-1
(*Continued*)

Boiler System	Inspection and Maintenance Items	Section
Overfire Air (OFA) System	OFA port nozzles or throats	6.3
	OFA flow control dampers	
Fuel and Atomizing Steam Supply	Oil and steam control valves	6.4
	Oil and steam pressure regulators	
	Steam purge valves	
	Oil pumps and oil heaters	
	Oil and Steam Pressure gauges at burners	
Combustion Air Supply	FD fans and control dampers	6.5
	Air ducts and biasing/crossover dampers	
Sootblowers	Wall blowers	6.6
	Convective pass blowers	
	Air heater sootblowers	
Boiler Deposits	Boiler internal inspection	6.7.1
	Boiler water wash	6.7.2
Air Heater	Air heater elements and seals	6.8.1
	Air heater wash	6.8.2
	Steam coil air heater maintenance	6.8.3
Flue Gas Ducts and Stack Liner	Low-temperature ductwork and stack liner	6.9.1
	Flue gas recirculation shutoff dampers	6.9.2
Instrumentation and Controls	Combustion controls	6.10
	Burner management system	
	Excess O_2 monitors	
	Opacity monitors	
Additive Injection	Storage, pumps, blowers, piping, nozzles, flow meters, flow controllers	6.11
Furnace Inspection Ports	Furnace view port repair and cleaning	6.12
	Furnace flame camera maintenance	

6.1 Oil Gun and Atomizer

The combustion characteristics of an oil burner are directly dependent upon the condition and cleanliness of the oil gun and atomizer components. Damaged or worn atomizer components, or parts that have accumulated a carbon "build-up," may dramatically degrade the performance of the burner and the boiler. It is necessary that each oil gun and its atomizer components be physically disassembled and cleaned on a scheduled basis by trained personnel. Purging oil guns with steam is not a substitute for periodic disassembly and cleaning.

6.1.1 Inspection and Cleaning

The equipment manufacturer should furnish detailed instructions for inspection and cleaning of oil guns and atomizers. If not available on-site, request the manufacturer to provide new copies and distribute them to operating and maintenance personnel. It is good practice to inspect and clean the oil gun and atomizer whenever the gun is taken out of service.

An oil gun and atomizer inspection program should include the procedures summarized in Table 6-2.

Table 6-2
Oil Gun and Atomizer Inspection Procedures

(1)	After the oil gun is removed from the burner and cooled, remove the atomizer.
(2)	Inspect the internal oil gun passages for oil or carbon deposits. Deposits are usually the result of inadequate oil gun purge during burner shutdown. Remove the deposits. Advise operating personnel of the potential deficiency of oil gun purging.
(3)	Inspect the machined surfaces at the end of the oil gun that mate with the atomizer. Damaged surfaces may result in oil leaks or degraded atomizer performance due to cross-over of atomizer streams.
(4)	Disassemble the oil atomizer. Inspect metal-to-metal sealing surfaces, atomizer exit holes, and internal passages for excessive wear, nicks, cracks, etc. See additional recommendations under Atomizer Replacement Frequency below. Replace atomizer components that are damaged or have excessive wear.
(5)	Clean atomizer components, including internal and external deposits, which can adversely impact oil atomization. Internal deposits may indicate problems with the oil strainers, coking of oil left in the oil gun barrel due to inadequate purging, or excessive atomizer temperatures (inadequate purging) depending on the location and type of deposits.
(6)	Re-assemble the oil atomizer, using torque and anti-seize thread compound on the retaining nut as specified by the manufacturer.
(7)	Avoid damaging the surface of the atomizer when transporting the gun to the burner front.

Atomizer components are heat treated to extend their service life under the erosive conditions typical of normal operation. When mechanical failures or excessive erosion occur, they are most often traceable to overheating atomizer components at some point in the burner operating cycle. Use of adequate steam purging during burner shutdown and light-off procedures will prevent overheating when the gun is inserted into the burner. Refer to Section 5.11.2, Burner Light-Offs and Shutdowns, for a discussion of oil gun purging.

6.1.2 Atomizer Replacement Frequency

After extended use it is normal to find erosion of the exit hole(s) and internal passages of atomizers due to the abrasive properties of the oil. In addition, oil gun handling, repeated assembly/disassembly of atomizers for maintenance, and heating/cooling experienced in the boiler will produce nicks, scratches, and general wear of atomizer components over time. Distortions of the metal-to-metal sealing surfaces between atomizer components are a particular concern, and are not always evident by visual inspection.

Eventually, the wear will become significant enough that atomization quality will deteriorate and replacement of the atomizer is required. Atomizers typically require replacement after 2,000 to 8,000 hours or operation, depending on the abrasive characteristics of the oil, oil gun purge procedures, atomizer design, and materials of fabrication. Highly abrasive oil ash, inconsistent purging during burner light-offs and shutdowns, and poor atomizer cleaning practices can significantly decrease atomizer life.

Determining when atomizer wear has reached the point where replacement is necessary may be based on one or more of the following:

1. Visual inspection of the atomizer.

2. Gauging of critical atomizer dimensions (e.g., using a go/no-go gauge on exit orifices, supplied by the manufacturer).

3. Deteriorated combustion conditions (e.g., smoky flames) that cannot be attributed to other sources.

4. Differences in atomizing steam pressure or oil pressures among burners that developed over time.

5. Flow calibration checks requested from the manufacturer.

Due to the critical importance of the atomizer on combustion and opacity, it is best to replace atomizers whenever excessive wear is suspected. Once a replacement frequency for atomizers is determined, procedures should be implemented to ensure that all atomizers are changed out on a consistent basis. While it is preferable to change out all atomizers at the same time to avoid combustion non-uniformities caused by operating with combinations of new and old atomizers, operators of boilers with large numbers of burners may find it more practical to change out atomizers over a period of time as guns are routinely cleaned or per a prescribed time table. The latter approaches require that records be kept of each atomizer and when it was last replaced.

6.2 Burner Inspection and Repair

The burner inspections and repairs that should be performed during scheduled boiler outages are summarized in Table 6-3.

Table 6-3
Burner Inspections and Repairs

(1) *Burner throat refractory.* Cracked or missing refractory should be repaired or replaced to match the burner manufacturer's specified refractory contour. Missing refractory can alter flame shape and adversely affect combustion.
(2) *Air and fuel nozzles (tangential-fired).* Replace or repair damaged or excessively worn burner nozzles, otherwise air-fuel mixing can be affected and result in flame impingement, unreliable burner light-offs, or smoky flames.
(3) *Burner tilts (tangential-fired).* Inspect, adjust, and repair burner tilt linkages and drives. Confirm that internal linkages to all air nozzles are intact. Broken linkages can cause air nozzles to sag, resulting in poor air-fuel mixing.
(4) *Air registers; compartment dampers.* Inspect and repair air register dampers, linkages, drives, spin vanes, air zone dividers and other components that control air flow and air swirl. Confirm smooth operation of moving parts. Malfunctioning air registers can adversely affect flame shape, air-fuel ratio, and boiler excess air requirements.
(5) *Flame Stabilizer.* Inspect flame stabilizer for damage and replace if necessary. The flame stabilizer is critical for flame shape, flame stability, and smoke suppression.
(6) *Radial/axial alignment of burner components.* Verify that alignment of the flame stabilizer, oil gun, and oil atomizer are per manufacturer's specifications. Improper alignment can cause flame impingement, damage to burner parts, and may pose a fire or explosion hazard.
(7) *Retract/drive mechanisms.* Confirm that retract mechanisms for oil guns and air register drive mechanisms are functional and achieve the proper positions on repeated activations.
(8) *Ignitors.* Clean and inspect ignitors per manufacturer's guidelines, paying special attention to ignitors that have been troublesome in the past. For example, confirm operation of retracts, limit switches, and spark rods and inspect for damaged flame stabilizers and worn atomizers. Unreliable ignitors result in repeated light-offs that increase the likelihood for opacity spikes or excessive smoking during steady-state operation.
(9) *Flame scanners.* Troubleshoot and repair malfunctioning or unreliable main flame scanners. Unreliable scanners increase the likelihood for opacity spikes due to random burner trips and failed burner light-offs.

6.3 Overfire Air (OFA) System

Inspect OFA flow control dampers and OFA port nozzles/throats, and perform maintenance as necessary. Confirm that OFA port shut-off dampers and biasing dampers operate smoothly, and that drive mechanisms, if used, provide proper positioning on repeated activations. Calibrate OFA air flow control instrumentation. Proper control of overfire air flow and distribution of air among individual OFA ports is important for minimizing smoke and maximizing NOx reductions when OFA is in use.

6.4 Fuel and Atomizing Steam Supply

1. Inspect and repair automatic burner oil, atomizing steam, and purge steam shut-off valves and local pressure regulators that exhibited sluggish or erratic operation during burner light-offs and shutdowns. Repair or replace manual oil and steam shut-off valves on the burner front as required.

2. Perform maintenance on the main oil and atomizing steam control valves, differential pressure control valve, and main steam and oil pressure regulators that may have caused instabilities in fuel or steam flows during transient or steady boiler operation.

3. Replace missing insulation on steam and oil lines. Missing or inadequate insulation on steam lines may reduce atomizing steam quality and degrade oil atomization. Poor insulation of oil lines may result in excessive temperature losses between the oil heater and the burners, making it difficult to maintain proper oil temperature (viscosity) at the burners for good atomization.

4. Diagnose and correct problems with oil heaters that prevent proper fuel oil temperature.

5. Diagnose and correct problems with oil pumps that require mechanical atomizers or steam atomizers to operate at off-design conditions in order to make maximum boiler load.

6. Calibrate the oil and steam pressure gauges at burners.

6.5 Combustion Air Supply

The proper functioning of FD fan dampers and actuators, cross-over damper between combustion air ducts, and other dampers used to distribute air to the windbox (e.g., windbox compartment dampers) is important for maintaining good combustion and reducing opacity. An internal and external walkdown and inspection of the air supply system, including stroking of all automatic dampers, should be performed during boiler inspection and maintenance outages.

6.6 Sootblowers

1. Prior to washing the boiler and air heater, inspect boiler internal deposits and air heater deposits to confirm adequacy of existing sootblower coverage and effectiveness. Confirm condition of the sootblower nozzles.

2. Inspect and repair sootblower components as required to restore to manufacturer's specifications.

3. Confirm correct operating pressures for sootblower medium (e.g., steam) at the sootblowers.

6.7 Boiler Deposits

6.7.1 Boiler Internal Inspection

Inspection of boiler deposits and ash accumulations is an integral part of diagnosing opacity problems related to sootblowing, load ramps, and other boiler operating modes where ash entrainment in the flue gas is the root cause. The location, quantities, and physical properties of the ash deposits provide indications of sootblower coverage and effectiveness. In addition, accumulations outside regions of sootblower coverage can be the major sources of intermittent or random opacity spikes during boiler load changes.

Internal boiler inspections should be conducted immediately after the boiler has come off line and cooled (i.e., prior to any washing). The items included in an inspection are summarized in Table 6-4.

6.7.2 Boiler Cleaning

Following the boiler inspection, the boiler deposits should be physically removed from the boiler by washing or other means.

For boilers that experience SO_3 condensation plumes, periodic boiler washing can be an effective means of controlling the severity of the plumes. Removing the deposits, which act as catalysts to promote the conversion of SO_2 and SO_3, can produce instantaneous reductions in the condensation plume. As the plume gradually returns, the frequency of washing can be adjusted as necessary.

Table 6-4
Boiler Inspection Items

(1)	*Deposits on and around burner throats and nozzles.* Clinkers and carbon deposits indicate flame impingement, which may be related to burner components that have deteriorated or are out of adjustment.
(2)	*Tube ruptures and distorted tubes in the burner zone.* Existing steam leaks or incipient tube failures, particularly in the burner zone, can cause smoking problems if leaks impinge on flames and quench the combustion.
(3)	*Tube wall deposits in the main furnace cavity from the burner region to the furnace exit.* Localized carbonaceous deposits in the burner zone are the result of flame impingement or improper burner shutdown procedures. Widespread tube deposits, which may range from friable to molten slag, reflect the ash properties of the oil, and may indicate the need for more frequent boiler washing. For excessive deposition, chemical analysis of the oil ash and deposits may be necessary to determine the specific causes. Depending on the nature and cause of the deposits, fuel additives may be appropriate.
(4)	*Deposits on superheater and reheater tubes, economizer surfaces, and on floors and walls in the convective pass.* Excessive deposition on superheater tubes may indicate inadequate sootblower coverage. Accumulations of loose deposits in low-velocity regions (e.g., floors and corners) and on economizer tubes should be documented and targeted for removal during boiler washing. Large chunks of material may indicate that sootblowing of convective pass tubes is too infrequent or not effective, leading to large buildups that break off and cannot be entrained by the flue gas. As above, chemical analysis of the oil ash and deposits may be necessary to determine the specific causes of persistent and excessive tube deposits. Depending on the type of deposits, use of fuel additives may be effective in reducing rates of deposit build-up making them more amenable to removal during sootblowing. Deposits should be physically removed during the boiler outage.
(5)	*Air heater deposition.* Refer to Section 6.8 below.
(6)	*Low-temperature ductwork, stack breaching, and stack liner.* Refer to Section 6.9 below.
(7)	*Economizer hopper or other ash collection sites.* Accumulations in hoppers can be re-entrained by the flue gas and be swept out the stack, contributing to opacity or stack fallout problems.

6.8 Air Heater

The large surface areas of regenerative air heaters, which establish their effectiveness in extracting waste heat from the exhaust gases, also make the air heaters effective particulate collectors. Factors that may lead to high quantities of deposits on the air heater surfaces include: (1) inadequate sootblowing, (2) operation below the acid dew point, or (3) improper use of back-end corrosion additives. From an opacity standpoint, large quantities of deposits pose a problem when they produce large opacity spikes during sootblowing of the air heater. Partial plugging of air heater elements can also cause perturbations in boiler air flow as discussed in Section 5.2.8.

In addition to providing a high surface area for deposition, the coldest air heater surfaces can run at temperatures below the acid dew point; the temperature at which

SO_3 in the flue gas will begin to condense as sulfuric acid. As indicated in Figure 3-2, the acid dew point temperature is a strong function of the SO_3 concentration, such that even relatively low SO_3 concentrations can result in acid condensation, particularly at gas and metal temperatures typical of low-load operation. It is important to note that even when the air heater cold end average temperature (defined as the average of the flue gas outlet temperature and the air inlet temperature) is close to or above the acid dew point, some surfaces will be running below the acid dew point. The operating temperature margin between the cold end average and dew point temperatures should therefore be increased as the fuel sulfur content increases. The use of cold-end additives may also be considered to control air heater corrosion problems.

6.8.1 Inspection and Maintenance

The condition of the air heater elements, seals, and soot blowers should be inspected during every boiler inspection outage. For opacity control, repairs should be made as necessary to maintain air heater leakage rates and heat transfer efficiency within manufacturer's specifications.

Excessive air heater leakage and damaged or missing heat transfer elements can increase the severity of SO_3 condensation plumes by lowering the stack gas temperature. In addition, lower stack gas temperature can increase the accumulation of acidic particulate matter on duct surfaces and the stack liner (see below).

6.8.2 Air Heater Wash

A water wash of the air heater should be performed during boiler outages to remove material that was not removed during normal sootblowing.

6.8.3 Steam Coil Air Heater Maintenance

Inspect the steam coil heater for leaks or pluggages. Leaks can cause wetting of the air heater surfaces and accelerate ash deposition, corrosion, and plugging.

Perform repairs as necessary to maintain steam coil heater performance. From an opacity standpoint, this is particularly important for boilers experiencing SO_3 condensation plumes, where use of the steam coil heater to raise flue gas temperature can reduce the severity of the plume.

6.9 Flue Gas Ducts and Stack Liner

6.9.1 Low-Temperature Ductwork and Stack Liner

Inspect for ash accumulations and deposits in the low-temperature ductwork, stack breaching, and stack liner. Deposits in these areas can contribute to opacity as they shed-off and are entrained by the flue gas during transient boiler operations. This may lead to random opacity puffs which do not correlate with a particular operating condition. However, the greater problem may be fallout of larger particles in the vicinity of the plant.

The nature of the deposits may provide evidence of malfunctioning equipment upstream. Deposits that are wet, or puddles on the duct floor, may indicate damaged air heater sootblowers or a malfunctioning sootblower shut-off valve. Excessive accumulation of back-end additive on duct surfaces may indicate over-dosing of additive.

During boiler outages, ash accumulations in ducts should be swept or washed out. Deposits on stack liners should be washed off, particularly if the plant is experiencing a particulate fallout problem.

6.9.2 Flue Gas Recirculation Shutoff Dampers

Proper functioning of FGR shutoff or isolation dampers should be confirmed to prevent leakage of combustion air back to the flue gas duct when the FGR fans are idle, bypassing the windbox and burners. Combustion and opacity problems created by excessive air leakage are discussed in Section 5.6.2.

6.10 Instrumentation and Controls

Instrumentation and controls that have a direct impact on opacity should be given a high maintenance priority:

- *Combustion controls.* Air and fuel flow control systems, air-fuel ratio controllers, atomizing steam pressure controllers, and excess O_2 bias controllers should control to the specified set points without excessive swings or spiking during steady load and transient operating conditions. If excessive instabilities are evident then the control components responsible must be identified and corrected. For example, large swings in excess O_2 (e.g., greater than $\pm$ 0.3% at steady load) can cause excessive opacity and may be traced to control problems in the combustion air system, fuel supply system, or both.

- *Burner management system.* Maintenance personnel should confirm that the burner management system properly sequences: (1) lightoff of ignitors during burner lightoff and purging during burner shutdown, (2) opening and closing of fuel and atomizing steam valves, (3) opening and closing of purge steam valves, and (4) opening and closing of air registers. Also, proper positioning of valves, dampers, and air registers should be confirmed.

- *Excess O_2 monitors*. Perform inspection and maintenance procedures specified by the manufacturer. Excess O_2 monitors should be calibrated frequently, e.g., once per day for automatic calibration systems and once per week for manual calibration. Problems in maintaining calibration should be tagged and corrected by maintenance personnel at the earliest opportunity.

- *Opacity monitors.* The opacity monitor should be calibrated and zeroed at least once per day for automatic calibration systems. The calibration frequency of manual systems should be based on calibration drift determined from experience. Confirm that the opacity monitor reads zero with the boiler shut down and the fans off. When in doubt about the accuracy of the opacity monitor, it is recommended that the opacity reading be confirmed by visual observation.

6.11 Additive Injection

If an additive injection system is used, all components should be inspected, including additive storage silos and tanks, pumps, blowers, piping, flow meters, flow controllers, and injection nozzles. Further, inspections should be performed during boiler outages to confirm that the additive is deposited uniformly on the desired heat transfer surfaces and ductwork.

6.12 Furnace Inspection Ports

Furnace view ports should be cleaned and repaired as necessary to provide boiler operators with maximum visual access to the burner zone, furnace cavity, and convective pass. Visual inspection of these areas on a regular basis is an integral part of an opacity reduction program.

Furnace flame cameras can provide operators with insight into combustion-related problems related to opacity or indicate that other sources of opacity may be involved. The cameras should be maintained to provide good flame visualization.

7

OPTIONS FOR REDUCING OPACITY AND PARTICULATE MATTER EMISSIONS

This section reviews technical options for reducing opacity and particulate matter emissions, and provides general guidance on selecting the appropriate option(s) to solve a specific opacity or PM emissions problem. The options are discussed below in the following order of priority.

- Modification of operating and maintenance practices
- Upgrading of combustion equipment, instrumentation, controls, and boiler components
- Chemical additives
- Change in fuel specification
- Retrofit of particulate matter control equipment

7.1 Modification of Operating and Maintenance Practices

When an opacity problem is the result of specific boiler operating and maintenance (O&M) procedures, modifying the responsible procedures will usually be the most direct, quickest, and least costly solution to the problem. Furthermore, if deficiencies in O&M practices are an underlying cause or a significant contributor to an opacity problem, more expensive options such as equipment upgrading or use of chemical additives may not overcome these deficiencies, or the effectiveness of these options may be severely reduced. Moreover, if the cause of an opacity problem is directly related to design deficiencies of critical combustion hardware or other boiler equipment, it may not be possible to eliminate the problem through changes in O&M practices. Consequently, understanding the cause and effect relationship between opacity problems and O&M, determining whether O&M practices are at fault in a particular opacity problem, and modifying the pertinent O&M procedures to solve the problem should be the first priority in an opacity mitigation program.

Sections 5 and 6 describe the operating and maintenance factors, respectively, that affect opacity and should be reviewed by first-time readers to gain a familiarity with the numerous ways in which O&M procedures can contribute to high opacity or PM emissions problems. Consistent with the high priority on O&M solutions to opacity problems, the opacity troubleshooting guidelines contained in Section 8 emphasize operating and maintenance procedures in the diagnosis and remediation of opacity problems. Table 8-2 summarizes the potential causes of specific opacity problems, and will assist readers in locating information on relevant O&M procedures.

7.1.1 Implementing Revised O&M Procedures

When specific O&M procedures have been determined to be the cause of an opacity problem, and corrective actions have been identified through application of the troubleshooting guidelines in Section 8, new operational and/or maintenance procedures must be implemented by O&M personnel. Depending on the involvement of operating and maintenance personnel in the opacity troubleshooting effort, and depending on the nature of the corrective action(s), the implementation may proceed in different ways. The following is an outline of a general approach to implementing new or revised O&M practices, which can be refined according to the specific situation:

- Review the troubleshooting results and proposed corrective actions with cognizant O&M personnel.
- Define new or revised operating and/or maintenance procedures in conjunction with O&M personnel, recognizing that changes in operating practice may impact maintenance requirements, and visa versa.
- Prepare written guidelines for boiler operators and maintenance personnel. Conduct training as appropriate.
- Implement the revised procedures on a trial basis to demonstrate their effectiveness. Solicit feedback from cognizant O&M personnel on problems and successes achieved. As appropriate, document opacity problems and the application of modified operating procedures and maintenance during the trial period. Identify a contact person responsible for implementation and follow-up.
- Revise the O&M guidelines, and issue final procedures for operators and maintenance personnel. Modify O&M manuals as required.
- Conduct periodic follow-up evaluations to confirm adherence to modified procedures and their effectiveness.

Areas where this approach has been implemented to reduce opacity problems include:

- Burner lightoff, shutdown, and purging procedures. Specific issues that have caused problems include length of the purge required to thoroughly clean the oil guns; coordination of ignitor-on, air register position, and purge; and functioning of the burner retracts and air register drives.

- Burner management during boiler startup and shutdown, including the sequence of burner light-offs, oil and atomizing steam pressures, air damper (register) settings for out-of-service burners, overfire air port settings (open or closed), and transition from manual to automatic burner operation.

- Disassembly, inspection, and cleaning of oil guns and atomizers. Establishing replacement frequency of worn atomizer components.

- Optimization of sootblowing to minimize excess opacity events.

- Routine on-line inspection of critical combustion parameters such as oil and atomizing pressures at the burners; positions of air registers and overfire air port dampers; oil gun insert positions; and flame appearance.

- Excess O_2 control as a function of load, fuel, number of burners in service, and during transient conditions such as sootblowing, fast load ramps, and burner changeouts.

- Maintaining proper set point for oil temperature to maintain specified viscosity for good oil atomization.

7.1.2. Training of Plant Personnel

Training of operating and maintenance personnel is an integral part of implementing a modified O&M practice to reduce opacity. In addition to targeting the training to a specific O&M problem, training courses of broader scope which address the full range of operational and maintenance procedures should be considered. Such training would be complementary to the guidelines presented in this report. Specifically, for opacity control, such training can reinforce the guidance on how to recognize and avoid conditions that produce opacity exceedances. Moreover, if an unacceptable condition occurs, an effective training course teaches prudent, expedient methods for correcting the problem.

An O&M training course benefits the utility company in a number of ways that are complementary to the objectives of this report. For example, training can:

1. Provide an opportunity for cross-communication among, and promote a common understanding by plant operating, maintenance, and supervisory personnel on issues related to opacity control.

2. Promote consistent operating and maintenance practices among individual boiler operators and maintenance technicians in all areas that can impact opacity.

3. Provide a basis for prioritizing maintenance items that have a direct impact on opacity.

Often there are natural, conflicting goals within and among different plant departments, which may indirectly contribute to an opacity problem and/or hamper solutions. For example, an operating priority to minimize heat rate (e.g., emphasis on operating the boiler with minimum excess air) may be at odds with a low maintenance priority placed on combustion controls calibration and burner repairs. A properly planned training course can help establish mutually compatible company goals as they impact opacity.

7.2 Equipment Upgrading

As indicated above, this option should only be considered after it has been concluded that modifying operating and maintenance practices cannot solve the opacity problem. However, it should be emphasized that upgraded equipment, if selected as the solution, will not eliminate the importance of O&M in maintaining low opacity and PM emissions.

7.2.1 Combustion Equipment

When opacity problems are the result of the design of the combustion system and cannot be overcome by O&M procedures, new or modified combustion equipment may be required. To minimize cost, the recommended approach is to replace or upgrade the critical combustion equipment components, while retaining as much of the original equipment as practical.

Table 7-1 identifies the primary burner components and the major opacity problems they can cause due to component design. The opacity problems are identified in terms of opacity symptoms defined in Section 8.

Table 7-1
Burner Component Design Deficiencies and Related Opacity Problems

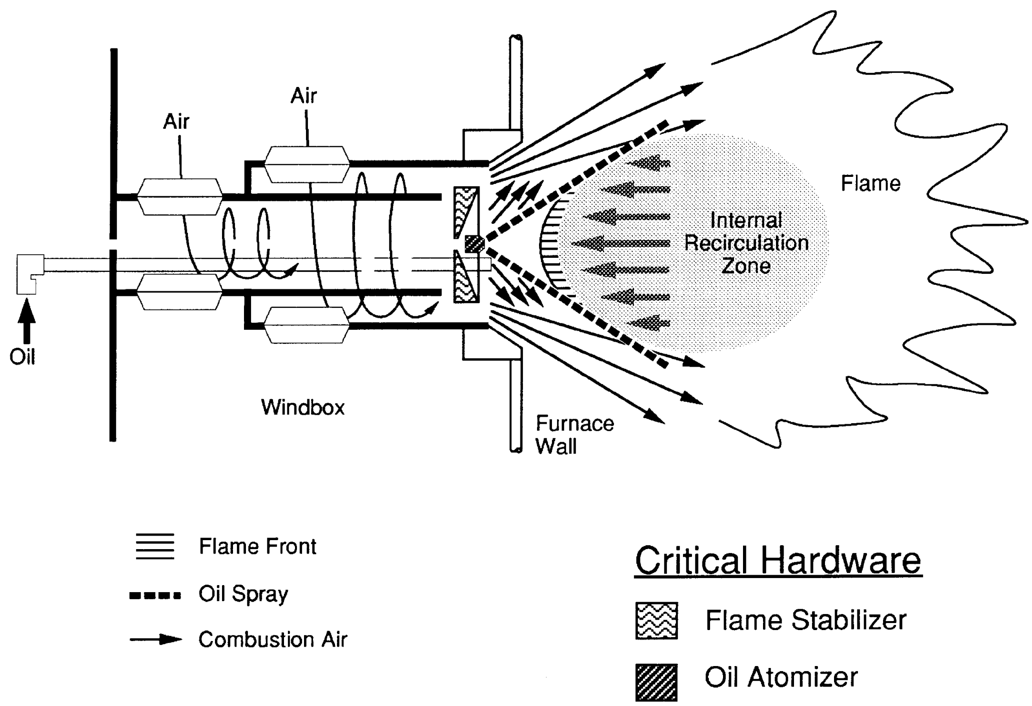
Burner Component	Design Deficiency	Opacity Symptom*
Ignitor system	Poor atomization (#2 oil)	1, 6, 7
	Poor flame stabilization	
	Unreliable ignitor operation (e.g., weak spark)	
	Unreliable main flame ignition and detection	
	Unreliable insert/retract	
Oil atomizer - warm-up fuel	Poor atomization	1
	Spray too wide or too narrow	
Oil atomizer - main fuel	Poor atomization	1, 3, 4
	Spray too wide or too narrow	
Oil gun and retract mechanism	High pressure drop in oil gun results in poor atomization	1, 3, 4, 6
	Unreliable insert/retract	
Flame stabilizer	Poor flame stabilization	1, 3, 4
	Flow pattern produces flame that is too wide or narrow	
Flame scanner	Unreliable flame detection	1, 6
Air register (wall-fired burners)	Unable to adjust air flow among burners	1, 2, 3, 4, 5, 6, 7, 9
	Poor aerodynamics impedes fuel-air mixing	
	Unreliable air register drive	

*Refers to Symptoms 1 through 10 in Section 8.

7.2.1.1 REACH Technology.

A majority of combustion-related problems encountered in oil-fired boilers are due to poor atomization of the fuel and poor mixing of the air and fuel at the burner. REACH technology (*R*educed *E*missions and *A*dvanced Combustion *H*ardware) consists of an integrated flame stabilizer/oil atomizer design that was developed by EPRI and others to reduce particulate matter emissions and opacity on oil-fired boilers (Reference 7-1). The concept was to retain as much of the existing burner as possible, thereby minimizing retrofit costs. REACH can be installed on all burner types to reduce PM and opacity at a fraction of the cost of burner replacement. The primary components of REACH technology, a compound-curved-vane flame stabilizer (swirler) and oil atomizer, are illustrated in Figure 7-1.

REACH for Wall-Fired Boilers (Reference 7-1)



REACH for Tangential-Fired Boilers (Source: EPT)

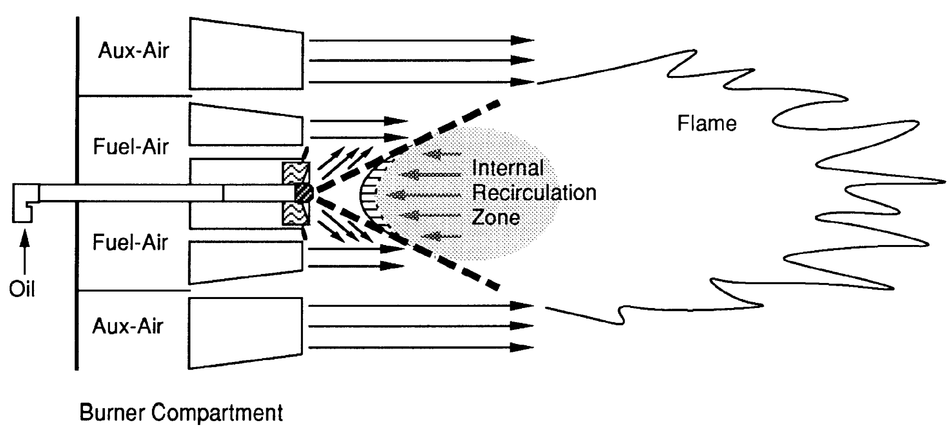


Figure 7-1
Critical combustion components of REACH technology.

7.2.1.2 Low-NOx Burners.

Total burner replacement may be warranted: (1) for older boilers in which the air register and other primary burner components have deteriorated beyond repair, (2) when existing burners are not physically compatible with new fuel requirements (i.e., cannot accommodate gas firing elements for gas conversion due to physical constraints), or (3) when existing burner design deficiencies cannot be overcome by component upgrading alone. Since virtually all oil-fired utility boilers in the U.S. are subject to NOx regulations, low-NOx burner designs may be considered for retrofit. Low-NOx burners are offered commercially by a number of suppliers and designs vary, reflecting differences in design and engineering philosophy and commercial experience. Readers desiring more information on low-NOx burner options are referred to Reference 7-2.

The opacity and PM emissions characteristics of a new, retrofitted burner will depend on design factors discussed in Section 4. Consequently, factors such as oil atomization, control of fuel and air mixing, flame stabilization, flame shape, reliable ignition, and reliable mechanical operation will determine the opacity characteristics of a new burner. However, a new burner will not necessarily solve existing opacity problems unless the underlying causes of opacity are addressed in the burner design.

7.2.2 Other Boiler Components

In addition to the burner, the design of other boiler components can impact opacity and PM emissions as discussed in Section 4. Table 7-2 summarizes the boiler components, common design deficiencies, and the primary opacity problems that can result. Design factors that are not typically amenable to upgrading for purposes of opacity reduction (e.g., furnace and windbox geometry and burner arrangement on firing walls) are omitted from the table. Upgrading of one or more specific components may be required.

Table 7-2
Other Boiler Component Design Deficiencies and Related Opacity Problems

Burner Component	Related Design Deficiency or Opacity-Related Problem	Opacity Symptom*
Fuel Delivery System • Oil heaters. • Main oil control valve and pressure regulator. • Burner shutoff and purge valves. • Oil pumping system. • General piping arrangement.	• Insufficient oil heater capacity leading to high oil viscosity (poor atomization). • Poor control or transients in oil flow or supply pressures. • Leaky or sluggish valves result in inconsistent burner shutdowns and light-offs. • Low oil supply pressure. • Poor oil circulation at the burner front. • Non-uniform oil flow among burners. • Large quantities of oil during purging of the oil gun.	1, 3, 4, 6, 7, 9
Atomizing Steam System • Steam pressure control. • Shutoff and crossover valves. • General piping arrangement. • Steam source.	• Low or variable steam supply pressure; poor control of steam-oil ΔP at the burners. • Non-uniform steam pressure and flow among burners. • Poor quality steam at burners. • Inadequate oil gun steam purge.	1, 3, 4, 6
Combustion Air System • Windbox flow distributors and partitions. • Windbox dampers. • Steam coil air heaters.	• Poor air distribution in the windbox leads to air imbalances among the burners. • Undersized steam coil heaters increase back-end acid formation.	4, 5
Overfire Air (OFA) System • Flow control devices. • Air port geometry. • Flow directional devices.	• Non-uniform distribution to OFA ports causing imbalances in boiler excess O_2. • Poor mixing of OFA with furnace gases causing poor carbon burnout. • Poor control of air distribution between OFA and burner zone.	1, 4, 9
Instrumentation and Controls • Excess O_2 monitor. • Opacity monitor. • Fuel meter. • Combustion air meter. • Air-fuel ratio control. • Oil temperature control. • Burner management system (BMS). • Control room recorders and alarms for critical combustion parameters.	• Inaccurate O_2 and opacity readings. • Inaccurate fuel and air flow meters and/or outdated air-fuel ratio controllers result in unreliable air-fuel ratios at the burners. • Inaccurate oil temperature control or viscosity controller impacts oil atomization. • Poor burner light-offs and shutdowns due to BMS failures. • Undiagnosed combustion problems due to insufficient control room instrumentation.	1, 2, 3, 4, 5, 6, 7, 9
Sootblowers • Sootblower placements. • Sootblower design.	• Inadequate sootblower coverage and intensity can cause excessive deposit buildup and releases during load ramps and sootblowing cycles.	8, 10
Chemical Additive Systems • Flow control. • Injection system design. • Additive selection.	• Improper additive selection or dosage rate, and poor distribution of additive, can lead to increased opacity and PM emissions.	8, 10

*Refers to Symptoms 1 through 10 in Section 8.

7.3 Chemical Additives

Chemicals added to the oil or injected into the flue gas are promoted by additive vendors to solve a variety of power plant operating problems, including reduction in carbonaceous particulate matter and stack opacity, control of boiler ash deposition, and control of corrosion of boiler surfaces. A wide variety of chemical compounds have been tested by utility companies and in some cases have been implemented on a continuous basis.

Additives may be classified according to three different principal applications:

1. Combustion enhancement

2. Control of high-temperature deposition and corrosion

3. Control of low-temperature corrosion

The exact mechanisms by which additives work are poorly understood and complex. Moreover, utility experience has shown that results are not always predictable. Application of an additive to solve one or more problems can, if improperly selected or applied, produce other problems, including adverse consequences for opacity mitigation.

For the three applications above, the impacts of additive use on opacity and PM emissions are summarized below. For additional information on the effectiveness of additives for corrosion and ash deposition control, it is recommended that readers consult Reference 7-3.

7.3.1 Combustion Enhancement

A number of chemical compounds have proven to increase the burning rates of oil in utility boilers, thereby reducing the emissions of carbonaceous particulate matter and stack opacity. Metallic, organo-metallic, and organic compounds have been evaluated over the years for reducing carbon emissions on combustion turbines and oil-fired boilers. At least one form of additive — aqueous solutions of calcium nitrate — has produced consistent results on oil-fired boilers. Typically, the additive is injected into the fuel oil in proportion to the fuel flow. A flow rate is recommended by the additive supplier, but should be confirmed by testing various rates and measuring the carbon reduction or improvement in opacity. The automatic adjustment of additive feed rate (relative to fuel flow) is important to avoid overfeed at reduced loads.

An example of the response of opacity and particulate matter mass to the injection of a calcium nitrate additive is illustrated in Figure 7-2. An aqueous solution of calcium nitrate was injected directly into the fuel line feeding the boiler. These results are from a 400-MW tangentially-fired boiler burning a 0.9% sulfur oil. The particulate matter mass is based on the quantity of particles collected on greased impact plates inserted into the flue gas duct, and provide a measure of the relative amount of larger, cenospheric particulate matter. Maximum and minimum opacity values are shown, corresponding to the "band" in opacity as measured by the opacity monitor. In this case, the opacity reductions were substantial and occurred almost immediately after additive injection commenced.

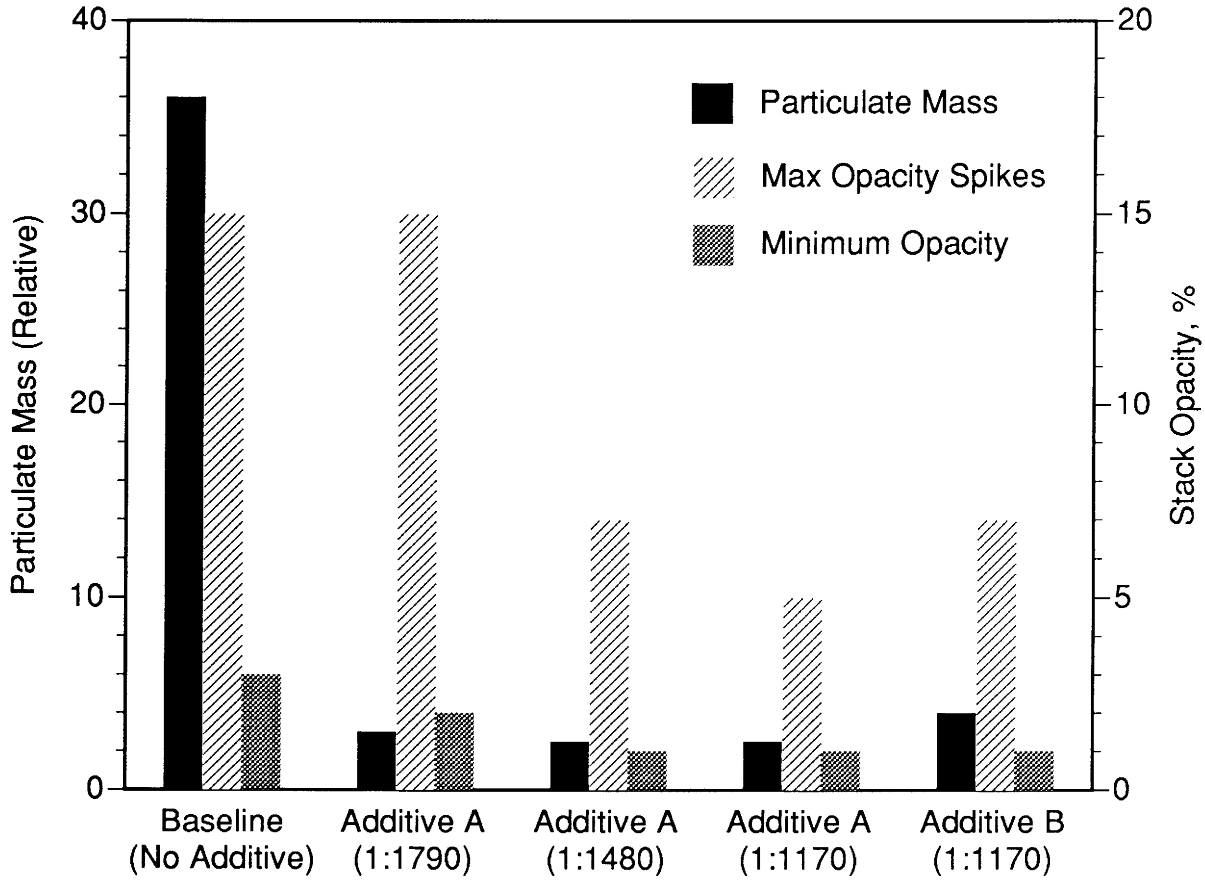


Figure 7-2
Example of effectiveness of calcium-based combustion additive in reducing opacity and cenospheric particulate matter (Source: EPT).

Since combustion-enhancing additives are targeted towards burning out the carbonaceous component of particulate matter, they are more effective in reducing particulate matter emissions and opacity when greater quantities of unburned carbon are present. Thus, when good combustion conditions result in small quantities of unburned carbon in the ash, the opacity improvement due to combustion additives will be significantly diminished. Tests to determine the carbon content of ash (e.g., via direct carbon analysis of samples collected during PM emissions source testing) is advisable in order to estimate the potential benefit of combustion additive.

The cost of injecting additive depends on: (1) commercial delivered prices, which vary among vendors and geographical location, (2) additive dosage rate required to achieve the desired emissions or opacity reduction (commonly expressed as gallons of additive per 1000 gallons of oil burned), and (3) the fuel consumption of the boiler. For a 100-MW oil-fired boiler operating at 50% annual capacity factor with continuous injection of calcium-based combustion additive, the costs may range from \$100,000 to \$200,000 per year for additive alone. Savings due to lower furnace excess O_2 and heat transfer benefits of the additive, if realized, may partially offset these costs. On the other hand, other adverse side effects of additive (see below) may add to the costs.

Regardless of the specific economic circumstances, it is advantageous to minimize carbon emissions by other means to the greatest extent possible, before committing to long-term additive use. Reducing carbon emissions by modifying operational and maintenance practices or implementing low-cost-combustion system upgrading are generally more cost-effective than additive use, and to the extent that they are effective will minimize the additive requirement and cost.

Combustion additives form deposits on furnace walls and convective pass tube surfaces over time. In some applications, this has required additional sootblowing and/or more frequent furnace washes. The simultaneous use of other additives to prevent excessive surface deposition is occasionally recommended by additive suppliers to mitigate this effect. However, to date, the effectiveness of this approach is not well documented.

It is important to recognize that un-reacted additive and additive by-products add to the total PM mass emissions at the stack, and can increase total PM emissions if their increased mass is greater than the reduction in carbon emissions achieved. This can actually lead to increased opacity or plume visibility during some boiler operating modes compared to baseline conditions without additive. For this reason, and due to the potential for increased mass emissions during sootblowing, the impact of combustion additives can be contrary to the objectives of an opacity reduction program. To confirm the net benefit of combustion additives, it is recommended that tests of candidate additive(s) be conducted on the subject boiler before making a long-term commitment to additive use.

7.3.2 Control of High-Temperature Deposition and Corrosion

Additives such as magnesium oxide and magnesium hydroxide are used to prevent corrosion of high-temperature tubes when firing oils with high vanadium content. While the chemical and physical processes involved in high-temperature corrosion are complex, it is sufficient to know that significant corrosion will occur when the tube deposits are molten. Magnesium compounds mixed with the ash in proper proportions have the effect of shifting the melting point of the tube deposits to higher temperatures, producing a dry, non-corroding deposit on the tube surfaces.

With regard to opacity problems, additive formulations are offered which are intended to bind with the vanadium in the ash deposits to reduce their ability to catalytically convert SO_2 to SO_3 as the flue gasses flow over and around the tube deposits. The result is a lower concentration of SO_3 in the stack gasses and a reduced potential for formation of SO_3 condensation plumes. In addition, the more friable nature of tube deposits may result in more effective cleaning of tube surfaces during sootblowing, or lower ash buildup rates on convective pass tubes between sootblowing, which may be beneficial in mitigating high opacity problems encountered during sootblowing and load ramps.

As with the oil ash, some of the additive injected with the fuel remains suspended in the flue gas and exits the stack without depositing on boiler surfaces. This material will contribute to the total particulate mass emissions and may result in a detectable increase in opacity. Additive compounds and solid by-products contained in the ash deposits will also contribute to the quantity of solids re-entrained into the flue gases during transient operations and sootblowing.

Typically, an oil-based magnesium oxide (or hydroxide) slurry is injected into the fuel oil in proportion to the fuel flow, and at a flow rate determined by the ash metal and sulfur content. As with the combustion additives, automatic adjustment of additive feed rate to fuel flow is important to avoid considerable over-feed at reduced loads. Recommended additive injection rates are provided by the suppliers, but should be verified by visual inspection of tube deposits during boiler outages and by comparing opacity records over time when operating with and without additive.

7.3.3 Low-Temperature Corrosion

Injection of chemicals (typically compounds of magnesium) are used to reduce the corrosion of air heater surfaces by condensed sulfuric acid. The approach is to coat the air heater surfaces with a magnesium oxide (or hydroxide) layer, such that condensing acid will react to form magnesium sulfate. Magnesium sulfate is a non-corrosive solid, readily removed by sootblowing and washing.

A fraction of magnesium compounds, if injected with the oil, will eventually end up on air heater surfaces. However, the injection rate must be relatively high for sufficient quantities of the material to reach the air heater and provide acid protection. The alternative, which is the more common approach, is to pneumatically inject powdered magnesium compounds between the economizer outlet and the air heater inlet. The injection system is designed to disperse the powder into the flue gas before reaching the air heater. The size of the magnesium particles is selected to ensure a high rate of impaction on the air heater surfaces. While effective coverage of air heater surfaces has been demonstrated with such systems, the storage, pneumatic transport, and injection systems introduce operational and maintenance requirements, which may be more extensive compared to the pumping, metering, and mixing systems used for oil additives.

With respect to opacity and PM emissions, the following must be considered when designing an additive injection system. With powdered additive injection upstream of the air heater, a portion of the additive remains suspended in the flue gas downstream of the air heater and may produce incremental increases in particulate emissions and opacity. Additive injection rates that are too high will exacerbate this problem and can also lead to excessive buildup of magnesium deposits on the air heater which can cause increased opacity spikes during air heater sootblowing. Consequently, as with the other types of additive applications, it is important to control the additive dose rate as a function of boiler load or fuel input to ensure that overdosing does not occur that would lead to excessive opacity or PM emissions.

7.4 Fuel Specifications

The relationship between specific oil properties and opacity problems are discussed in Section 5.1 and summarized as follows:

- Vanadium and sulfur content impact the severity of SO_3 plumes, but also affect boiler deposition and related problems (e.g., opacity problems due to use of corrosion inhibiting additives and problems during sootblowing or load changes).
- Asphaltene content, Coking Index, and Conradson Carbon are indicators of an oil’s tendency to form carbonaceous particles during combustion, and therefore they impact smoking problems related to poor carbon burnout.
- Oil ash contributes to total PM emissions and opacity during steady boiler operation. Additionally, the composition and quantity of ash determine deposition on boiler surfaces and related problems (e.g., opacity problems due to use of additives for ash deposition control, and problems during sootblowing or load changes).
- Nitrogen content impacts the degree of NOx control required, and may have adverse consequences on opacity and PM emissions when operating requirements for NOx control are contrary to those for minimizing opacity and PM emissions.
- Oil viscosity specifications may be a consideration in opacity and PM emissions control, when marginal oil heaters are not able to provide the necessary oil temperature (viscosity) at the burners for proper oil atomization.

Modifying the oil purchase specifications for one or more of these properties may be a valid technical approach to solving opacity and PM emissions problems, if opacity troubleshooting (Section 8) implicates oil properties as a cause of the problems. The ability to alter fuel oil specifications to reduce opacity or PM emission problems is site specific and often contingent on a number of factors that may be beyond the control or jurisdiction of the plant. Such factors include availability and market prices for residual fuel oils and the status of the utility company's long-term oil purchase contracts. Oils that are low in sulfur, vanadium, asphaltene, and nitrogen are often classified as higher quality oils that demand a premium price. Nevertheless, depending on the severity of opacity and PM problems and the associated costs, it may be justifiable to change one or more fuel specifications.

7.5 Retrofit of Particulate Matter Control Equipment

In a worst-case situation where all other avenues to control opacity and particulate matter emissions are exhausted, operators of oil-fired boilers may be required to retrofit particulate emissions control devices. Options available include mechanical dust collectors (i.e., multiclones and cyclones), electrostatic precipitators (ESPs), and fabric filters. In addition, wet ESPs are under development for collection of sulfuric acid mist, although the technology has a high capital cost and is not proven in the United States for application at oil-fired boilers.

Particulate control devices have been used at a number of oil-fired boilers in the United States. In this regard, approximately 45% of the oil-fired boilers (over 200 units) are equipped with particulate matter control devices (Reference 7-4). Of this total, 54% are mechanical dust collectors, 41% are ESPs, and the remaining 5% are fabric filters. Mechanical collectors were installed primarily for control of opacity or large-particle fallout in the vicinity of the plant. A number of the units equipped with ESPs were coal-fired boilers converted to residual oil firing. The units with fabric filters were primarily coal-fired units that also burned residual fuel oil.

If retrofit particulate control devices are required, the most likely candidates are mechanical collectors. Regardless which collector is considered, the retrofit cost will be significant and perhaps prohibitive. For example, considerable space is required between the boiler exit and the stack for any dust collector, and space is a premium item not available at many oil-fired plants. Moreover, dust collectors may significantly increase pressure drop in the flue gas ductwork. Thus, upgrading of forced draft (FD) and induced draft (ID) fans, or conversion of boilers from forced to balanced draft, may be required.

7.6 References

1. *REACH: Reduced Emissions and Advanced Combustion Hardware*, EPRI Project 2869-13, Final Report October 1995. See also: *Applications of REACH Technology to Reduce NOx and Particulate Matter Emissions at Oil-Fired Boilers*, in Proceedings of the EPRI-DOE-

EPA Combined Utility Air Pollutant Control Symposium, August 25–29, 1997, EPRI Report TR-108683.

2. *Retrofit NOx Control Guidelines for Gas- and Oil-Fired Boilers, Version 2.0,* EPRI Final Report TR-108181, June 1997.

3. *Residual Fuel Oil User's Guidebook, Volume 2: Residual Oil-Fired Boilers*, EPRI Final Report AP-5826, August 1988.

4. *Oil- And Gas-Fired Boiler Emissions Data Base.* EPRI Project RP2869-11, Reference Document, February 25, 1993.

8

TROUBLESHOOTING OPACITY PROBLEMS

8.1 Introduction

This section of the report provides a guideline for troubleshooting opacity problems at oil-fired boilers. For purposes of diagnosis and remediation, opacity problems addressed in the troubleshooting guidelines are broken down into the following ten "symptoms."

1. Black smoke during unit startup
2. White dense smoke during unit startup
3. Black smoke, intermittent during load changes
4. Black smoke during steady operation
5. White, faint smoke (SO_3 condensation)
6. Black smoke (opacity spikes) during burner light-off
7. Black smoke (opacity spikes) during burner shutdown
8. Opacity problems during sootblowing
9. Black smoke when co-firing oil and gas
10. High opacity during load ramp-ups

For each symptom, potential causes of the opacity problem are described. Further, recommendations are provided for making observations and conducting diagnostic tests to identify the root cause(s) of the opacity problem, and for selecting an appropriate course of action to solve the problem. Table 8-1 is an outline of the opacity troubleshooting guideline which follows, and Table 8-2 is a "road map" of where to find additional information in the previous sections of this report for each of the symptoms and causes described.

Table 8-1
Outline of Opacity Troubleshooting Guideline

	Symptom	Potential Causes
1	Black Smoke During Unit Startup	• Burner light-off problems • Low burner air flow • High burner oil flow • Poor oil atomization • Flame impingement
2	White Dense Smoke During Unit Startup	• Burner air-fuel ratios too high • Atomization fluid flow too high
3	Black Smoke, Intermittant During Load Changes	• Problems evident during steady operation worsen • Individual burner(s) starved for air • Poor oil atomization • Overall boiler excess air too low • Combustion controls out of calibration
4	Black Smoke During Steady Operation	• Insufficient total air flow to boiler • Inaccurate excess O2 instrumentation • Fuel properties changed • Individual burner(s) starved for air • Poor oil atomization • Flame impingement • Over-swirled or under-swirled burners • Damaged combustion equipment • Ruptured boiler tube
5	White, Faint Smoke (SO3 Condensation)	• SO3 condensation plume • Excess O2 too high • Flue gas temperature too low • Boiler deposits
6	Black Smoke (Opacity Spikes) During Burner Light-Offs	• Delayed ignition of main flame • Insufficient burner combustion air • Plugged oil gun or atomizer • Total air flow to the boiler too low • Oil surge • Cold oil delivered to burner • Flame scanner problems
7	Black Smoke (Opacity Spikes) During Burner Shutdown	• Ignitor not operating during purge • Insufficient burner air flow during purge • Steam purge rate too high • Air flow to active burners too low • Oil and air flow transients
8	Opacity Problems During Sootblowing	• High solids loadings • Sootblowing not optimized • Sootblowing decreases burner atomizing steam pressure • High opacity extends over opacity averaging time
9	Black Smoke When Co-Firing Oil and Gas	• Individual burners starved for air • Imbalance in fuel flow among oil and gas burners
10	High Opacity During Load Ramp-ups	• Boiler ash deposits dislodged • Loose ash accumulations entrained by flue gas • Low-temperature deposits • Chemical additives

Table 8-2
Where to Find Additional Information

Opacity Symptom		Potential Causes		Additional Information (Report Section)		
				Design Factors	Operating Factors	Maintenance Factors
1	Black Smoke During	1a	Burner light-off problems	N/A	5.11.2	6.1, 6.2
	Unit Startup	1b	Low burner air flow	N/A	5.2.5-6, 5.3, 5.7, 5.8, 5.9.1	6.2, 6.5, 6.9, 6.10
		1c	High burner air flow	N/A	5.2.5, 5.3, 5.8, 5.9.1	6.2, 6.9, 6.10
		1d	Poor oil atomization	4.1.1.1-2, 4.1.2.2	5.2.2-3, 5.4, 5.5	6.1
		1e	Flame impingement	4.1.2.2	5.8	6.1, 6.2
2	White Dense Smoke	2a	Burner air-fuel ratio too high	N/A	5.2.5, 5.3, 5.8, 5.9.1	6.2, 6.5, 6.10
	During Unit Startup	2b	Atomization fluid flow too high	5.2.2	5.2.1-3, 5.5	6.1
3	Black Smoke, Intermittent	3a	Problems evident during steady operation	N/A	5.2.1-8, 5.3-5.5, 5.7, 5.11.4	6.1-5, 6.8.1, 6.10
	During Load Increase	3b	Individual burner(s) starved for air	4.1.1.2, 4.1.2.3	5.2.4-5, 5.2.8, 5.3, 5.8	6.2, 6.10
	or Decrease	3c	Poor oil atomization	3.2.2, 4.1.1.1	5.2.1-3, 5.5	6.1, 6.4
		3d	Overall boiler excess air too low	N/A	5.2.8, 5.3, 5.6.2	6.5, 6.10
		3e	Combustion controls out of calibration	4.1.3.2	N/A	4.1.3.2, 6.10
4	Black Smoke During	4a	Insufficient total air flow to boiler	4.1.3.1, 4.1.3.2	5.2.8, 5.3, 5.6.2	6.5, 6.10
	Steady Operation	4b	Inaccurate excess O_2 instrumentation	4.1.3.2	5.3	6.1
		4c	Fuel properties changed	3.2.1, 4.1.1.1	5.1, 5.4	6.4
		4d	Individual burner(s) starved for air	4.1.1.2, 4.1.2.3	5.2.5, 5.2.8, 5.8.1, 5.8.2	6.2
		4e	Poor oil atomization	3.2.2, 4.1.1.1	5.2.2, 5.2.3, 5.5	6.1, 6.4
		4f	Flame impingement	4.1.1.2, 4.1.2.2	5.8, 5.9.1, 5.9.2	6.2
		4g	Over-swirled or under-swirled burners	4.1.2.2	5.8.1, 5.8.3	6.2
		4h	Damaged combustion equipment	N/A	5.2.4-7, 5.8, 5.9	6.2, 6.3
		4i	Ruptured boiler tube	N/A	N/A	6.6, 6.7.1
5	White, Faint Smoke	5a	SO_3 Condensation Plume	3.2.1.2, 3.2.6	5.1.1, 5.12	6.7
	(SO_3 Condensation)	5b	Excess O_2 too high	4.1.3.2	5.3	6.1
		5c	Flue gas temperature too low	N/A	N/A	6.8.1, 6.8.3
		5d	Boiler deposits	N/A	5.1	6.7

Table 8-2
(*Continued*)

Opacity Symptom		Potential Causes		Additional Information (Report Section)		
				Design Factors	Operating Factors	Maintenance Factors
6	Black Smoke (Opacity	6a	Delayed ignition of main flame	4.1.1.1-3, 4.1.2.3	5.1, 5.2, 5.8, 5.11.2	6.1, 6.2, 6.10
	Spikes) During Burner	6b	Insufficient burner combustion air	4.1.1.2, 4.1.2.3, 4.1.3.1	5.2.5-6, 5.3, 5.8.1-2, 5.9.1, 5.11.2	6.2, 6.4, 6.5, 6.10
	Light-Offs	6c	Plugged oil gun or atomizer	N/A	5.1.1, 5.4.1-3, 5.11.2	6.1.1-2, 6.4
		6d	Total air flow to the boiler too low	4.1.3.1-2	5.3.1-2, 5.11.3	6.5, 6.10
		6e	Oil surge	4.1.3.2	5.1, 5.2.1, 5.4	6.1.1, 6.4, 6.10
		6f	Cold oil delivered to burner	N/A	5.1.2, 5.4	6.4
		6g	Flame scanner problems	N/A	5.8.1, 5.11.2	6.2
7	Black Smoke (Opacity	7a	Ignitor not operating during purge	4.1.1.3	5.11.2	6.2
	Spikes) During Burner	7b	Insufficient burner air flow during purge	N/A	5.2.5, 5.8, 5.11.2	6.1
	Shutdown	7c	Steam purge rate too high	N/A	5.11.2	6.4, 6.10
		7d	Air flow to active burners too low	N/A	5.2.5, 5.3.1-2, 5.9.1	6.5, 6.10
		7e	Oil and air flow transients	4.1.3.1	5.2.1, 5.5.1-2, 5.11.2	6.4, 6.5, 6.10
8	Opacity Problems	8a	High solids loading	N/A	5.10.1-2	6.6, 6.7
	During Sootblowing	8b	Sootblowing not optimized	N/A	5.10.1-2	N/A
		8c	Decreased atomizing steam pressure	N/A	5.5.2	6.4, 6.6
		8d	High opacity over opacity averaging time	N/A	5.10.1-2	6.6
9	Black Smoke When	9a	Individual burners starved for air	4.1.1.2	5.2.5, 5.8, 5.11.8	6.2
	Co-Firing Oil and Gas	9b	Imbalance in fuel among oil and gas burners	4.1.2.3	5.2.1, 5.11.8	6.1, 6.4, 6.10
10	High Opacity During	10a	Boiler ash deposits dislodged	3.2.4	5.6.2, 5.11.3	6.6, 6.7, 6.8
	Load Ramp-Ups	10b	Loose ash accumulations entrained	3.2.4	5.10.1-2, 5.11.6	6.6, 6.7, 6.8
		10c	Low-temperature deposits	3.2.5	3.2.5	6.9.1-2
		10d	Chemical additives	3.2.3	3.2.3, 5.12	6.11

8.2 Opacity Troubleshooting Guideline

Symptom No. 1: Black Smoke During Unit Startup

1a. Problems during light-off of ignitors, warm-up oil guns, or main oil guns.

Diagnostic Tests and Observations	*Corrective Actions*
If opacity spikes occur when lighting-off an ignitor or burner, but low opacity returns with steady burner operation or with the ignitor off, the problem may be related to ignitors, burner light-off procedures, or hardware. For diagnosis of light-off problems, refer to Symptom No. 6: Black Smoke During Burner Light-offs.	Refer to Symptom No. 6: Black Smoke During Burner Light-offs. If burner light-off is eliminated as the cause of the problem, proceed with the diagnostic and corrective actions below.

1b. Insufficient flow of combustion air to active burners.

Diagnostic Tests and Observations	*Corrective Actions*
Confirm that burner air registers on *active* (in-service) burners are set to specified positions for startup. Confirm that burner air registers on *inactive* (idle) burners are set to specified positions for startup. Inspect flames through furnace view ports to confirm proper operation.	Review burner manufacturer's specifications or plant's established procedures for adjusting air registers for startup. Set air registers accordingly. Issue new or revised guidelines for startup, as required.
For boilers equipped with overfire air (OFA), confirm that OFA flow control dampers are set to specified positions for startup.	Review established procedures for adjusting OFA during startup. Set OFA dampers accordingly. If there are no established procedures for OFA, and OFA is not required for NOx control during startup, close OFA ports during startup.

1b. Insufficient flow of combustion air to active burners. (continued)

Diagnostic Tests and Observations	*Corrective Actions*
Confirm that there is sufficient excess air at the active burner(s) for combustion. The air through active burners equals the total combustion air supplied to the boiler, minus the quantity of air passing through idle burners and open OFA ports. The air to each active burner should exceed the theoretical amount of air for complete combustion (i.e., stoichiometric air requirement), and can be determined in a number of ways depending on available plant instrumentation. A simple procedure, based on total air and fuel flow data commonly available from control room instrumentation, is provided in Test Procedure No. 1 in Section 8.3.	If there is not sufficient air supplied to active burners, increase the air by: (a) Increasing the total air flow to the boiler. (b) Closing air registers on idle burners. (c) Further opening air registers on active burners. (d) Closing overfire air ports, if allowed. (e) One or more of the above. Issue new or revised startup guidelines, as required.

1c. Oil flow too high through active burners.

Diagnostic Tests and Observations	*Corrective Actions*
Check the average oil flow per burner. It is generally recommended that the oil flow per burner during startup be maintained between 40% and 60% of the maximum burner fuel flow. The actual fuel flow per burner may be determined from the oil atomizer performance curves provided by the manufacturer (e.g., curves of oil pressure vs. flow) or may be estimated using Test Procedure No. 2 in Section 8.4.	Reduce total oil flow to the boiler and/or place more burners in service so that the firing rate per burner is in the proper range. Issue new or revised startup guidelines, as required.

1c. Oil flow too high through active burners. (continued)

Diagnostic Tests and Observations	*Corrective Actions*
Confirm that the oil flow among active burners is approximately uniform. If one (or more) burners has much higher fuel flow than other burners, it may be the cause of smoking, particularly if there is marginally sufficient combustion air at the burners (see guideline above for determining adequacy of combustion air). To evaluate fuel flow among burners use calibrated pressure gages mounted on the oil and steam lines at each burner as close to the oil gun as possible. Compare fuel oil supply and return pressures, and pressure of atomizing steam (if used) among the burners. Large differences in oil or steam pressure (e.g., 20%) among burners may indicate a significant variation in fuel flow.	Install calibrated pressure gauges at the burners to monitor oil and atomizing steam conditions. Verify calibration of existing gages, as necessary. If non-uniform fuel and atomizing steam conditions are evident: • Inspect oil atomizers and oil guns for pluggage, excessive wear, or physical damage. • Make sure the correct atomizer components are installed. Verify manufacturer’s part number stamped on each component. • Confirm proper functioning of valves, including automatic oil control valve, atomizing steam valve, purge steam valves, manual isolation valves, and manual steam-oil crossover valves.

1d. Poor oil atomization.

Diagnostic Tests and Observations	*Corrective Actions*
For mechanically-atomized oil atomizers, confirm that oil supply and return pressures are at proper values for the particular burner fuel flow rate, based on manufacturer's atomizer performance curves. For steam-atomized oil atomizers, confirm that the steam-to-oil pressure differential and the individual steam and oil pressures are at manufacturer's specifications for the particular burner fuel flow rate.	If oil and/or steam pressures at all burners operating off common pressure-regulated headers are above or below prescribed levels, check and adjust oil and/or steam supply header pressure regulators If pressures are higher than normal on only one or a few of the burners in service, this may indicate a plugged atomizer. See below for atomizer inspection. Clean and re-install atomizer. If pressures are lower than normal on only one or a few of the burners in service, this may indicate worn atomizers. See below for atomizer inspection. Replace worn atomizers. Non-uniform pressures among burners may be due to non-uniform pressure losses in steam or oil piping. Adjustment of individual burners may be necessary to compensate. Permanent piping modifications may be required.

1d. Poor oil atomization. (continued)

Diagnostic Tests and Observations	*Corrective Actions*
Confirm that the oil temperature at the burner is sufficient to maintain oil viscosity within the manufacturer's specified range. Measure oil temperature at the burner front. Use a standard oil viscosity vs. temperature chart to determine the appropriate temperature for the specific oil. Recommended oil viscosity at the burners for residual fuel oils typically ranges between 100 and 150 Saybolt Universal Seconds (SSU).	If oil viscosity is below manufacturer's recommended level, raise oil temperature set point. Make sure that hot oil is recirculated to the burner front and that the oil has achieved a sufficiently high temperature prior to lighting off burners. If the oil heater(s) cannot maintain required oil temperature at the burners, inspect oil heater internals and clean out as necessary. Verify steam supply conditions to the oil heaters. Replace missing steam lagging or insulation on oil lines.
Disassemble and inspect oil atomizer components and oil gun internal passages. Confirm that multiple atomizer components are installed properly. Verify part numbers on individual components. Inspect atomizer components for excessive wear or damage. Worn atomizer flow passages may cause imbalances in oil flow among burners and/or poor fuel atomization. Worn sealing surfaces may allow crossover or leakage of atomizer streams. Indications of excessive wear include: • Rounding of sharp edges on atomizer parts. • Distortion of passages and orifices (e.g., discharge orifices out-of-round). • Flat mating surfaces that have become uneven due to gouging, oil erosion, etc. Cracked or corroded parts.	Replace worn or damaged atomizers. Review atomizer maintenance practice, including atomizer replacement frequency. Increase atomizer inspection and replacement frequency as required.

1d. Poor oil atomization. (continued)

Diagnostic Tests and Observations	*Corrective Actions*
Inspect internal and external atomizer surfaces for carbon deposits. Deposits that interfere with external atomizer jets or flow through internal passages are of particular concern. Inspect oil gun internal passages for coking or oil residue, which may indicate inadequate purging of the gun during burner shutdown. Confirm that oil gun guide tube seal air pressure is adequate to prevent oil blowback. Confirm that proper procedures are being used for oil gun purge, shut-down, light-off, and oil gun retract.	Extend duration of oil gun purge during shutdown of the burner. Increase the frequency of atomizer cleanings. Increase oil gun guide tube seal air pressure. Train burner equipment operators on proper burner purge, shutdown, and light-off procedures. If excessive coking of atomizer persists, contact the burner manufacturer or atomizer supplier.
Verify that the oil supply, oil return, or atomizing steam supply hoses are connected to the proper inlet ports on the oil gun stationary union.	Reverse the supply hoses at the oil gun, if they are found to be installed wrong.
Confirm that the proper atomizer design is being used for the specific application.	Contact the manufacturer to verify that the appropriate atomizer is in use. Atomizer components may have been accidentally switched between boilers, or incorrect parts may have been shipped by the supplier. Implement new procedures to prevent accidental mixing of atomizer components and verification of future atomizer parts deliveries. Convert from low-pressure mechanical atomization or racer steam atomization (constant steam pressure) to constant steam-to-oil *differential* pressure.

1e. Flame impingement on burner throats or furnace walls.

Diagnostic Tests and Observations	*Corrective Actions*
Visually inspect flames during light-off and operation of suspect burner(s). Determine whether flames are impinging on burner throats, air nozzles, adjacent boiler walls, or opposite boiler walls.	If flame impingement persists after other corrective actions above have been performed, isolate and secure the problem burner(s). Inspect for and remove clinkers. Clean the oil guns and atomizers and confirm proper adjustment of air registers, swirl vanes, and flame stabilizer/oil gun axial position in the burner throat. Re-start the burner. If the boiler experiences chronic flame impingement problems, consult the manufacturer for design or operational modifications.

Symptom No. 2: White Dense Smoke During Unit Startup

2a. Air-fuel ratios at active burners are too high. Burning oil drops are quenched by excess air.

Diagnostic Tests and Observations	*Corrective Actions*
Inspection of furnace may show hazy, diffuse flames and extensive yellow haze throughout the burner zone. Make the following boiler adjustments in sequence, while observing opacity and plume visibility, observing furnace flame conditions and monitoring excess O_2 and CO emissions: 1. If total fuel flow is less than 30% of MCR, gradually reduce the total air flow to the boiler to the minimum air flow (e.g., 25% of MCR). If total fuel flow is greater than 30%, gradually reduce air flow, but maintain percent air flow above the percent fuel flow. 2. Gradually close down air registers on active burners and/or open up air registers on idle burners. 3. Increase oil flow to active burners. For each of the above actions, note the conditions under which smoking is eliminated or minimized.	Establish new boiler operating procedures for startup, based on the results of diagnostic testing. Optional: Estimate the quantity of excess air at the active burner(s) using Test Procedure No. 1 in Section 8.3. There is no definitive criteria for determining when excess air is too high. However, knowing the excess air levels at which smoking occurs or is eliminated can help in formulating new boiler operating guidelines.

2b. Too much atomization fluid for steam or air atomized burners. There is quenching of the flame or carry-over of small oil droplets out of the flame zone.

Diagnostic Tests and Observations	*Corrective Actions*
Confirm that atomizing steam (or air) pressures, and differential pressures above oil pressure, are at manufacturer's specifications for the given burner oil flow rate. Confirm that the proper atomizer is installed. Make sure that warm-up atomizers and main oil atomizers are not mixed up. Perform diagnostic checks related to poor atomization under Symptom No. 1, Black Smoke During Unit Startup.	Adjust burner atomizing pressures to prescribed levels. Perform oil atomizer maintenance as required. If problem persists, contact the burner or oil atomizer manufacturer for assistance.

Symptom No. 3: Black Smoke, Intermittent During Load Changes

3a. Problems evident during steady load conditions may worsen during load changes. Diagnose and correct the problems when at steady load rather than under transient boiler operation.

Diagnostic Tests and Observations	*Corrective Actions*
Perform diagnostic tests and observations described under Symptom No. 4, Black Smoke During Steady Operation.	Refer to corrective actions under Symptom No. 4.

3b. One or more burners may be starved for air.

Diagnostic Tests and Observations	*Corrective Actions*
For wall-fired boilers confirm that burner air registers are set to prescribed positions for the particular loads. For tangential-fired boilers, confirm that fuel-air dampers, auxiliary-air dampers, and windbox pressure are at prescribed values. Verify by visual furnace port observations that there are no flame impingement problems or excessively smoky individual flames.	Adjust air registers to prescribed positions. Revise operator guidelines, making sure that practices that led to improper air register adjustments are addressed. If only a few flames are smoky or are impinging on burner or furnace surfaces, there may be atomization problems and/or burner air registers or spin vanes may need to be adjusted on specific burners. Overall boiler excess air may be too low. See below.

3c. One or more burners may have poor atomization.

Diagnostic Tests and Observations	*Corrective Actions*
Verify that oil and atomizing steam pressures at the burners are uniform. Atomizing steam and oil pressures should be within ±5% among burners.	If oil and atomizing steam pressures vary more than ±5% among burners, perform diagnostic and correction actions for Poor Oil Atomization under Symptom No. 1.
Confirm that proper oil temperature is maintained as boiler load varies. The dynamics of the oil heating system may cause oil temperature to “lag” during load increases or to “overshoot” during load drops.	Evaluate the response of automatic oil temperature control system. Calibrate, repair, or upgrade as necessary. Consider installation of an automatic oil viscosity control system with sufficient response time.

3d. Excess air set point is too low for load increases. There is not sufficient excess air to maintain good combustion during normal transients in burner fuel and air flows which accompany load changes.

Diagnostic Tests and Observations	*Corrective Actions*
Review boiler records or observe boiler operations as necessary to determine the range of loads, the rate of load changes, and the type of load changes (e.g., load increase or decrease) where smoking problems occur. Determine on control room instrumentation if boiler air flow is lagging oil flow or visa versa when smoking occurs. If smoking occurs during load increases, raise the excess O_2 set point by 0.5% increments up to a maximum of 1.5% above the initial O_2. For each incremental change in set point, repeat the load ramp over the problem load range and observe changes in severity of smoking.	If a higher excess O_2 set point eliminates smoking, implement a higher excess O_2 for load increases. If the problem persists with higher excess O_2, request technical support to troubleshoot the combustion controls. If necessary, reduce the allowable rate of load change when on automatic load dispatch.

3e. Combustion controls, fuel control valve, or air flow control system need recalibration or adjustment.

Diagnostic Tests and Observations	*Corrective Actions*
If smoking occurs only during load decreases, the problem is likely due to poor control of fuel and air flow by the boiler automatic control system. Observe on control room instrumentation if oil flow decreases prior to air decrease upon rapid load reduction. Watch for air/fuel crossover or erratic trends which may cause low O_2 during load change. On tangential-fired boilers, confirm that windbox-furnace ΔP is trending with load per manufacturer's specifications.	Request technical support to troubleshoot the combustion controls. Inspect and repair oil control valve, actuator, and related control components. Inspect and repair FD fan dampers, actuator, and related air flow control components. If necessary, reduce the allowable rate of load change in automatic load dispatch system.

Symptom No. 4: Black Smoke During Steady Operation

4a. Insufficient total air flow to the boiler.

Diagnostic Tests and Observations	*Corrective Actions*
Inspect flames through furnace view ports. Flames that are smoky, dull orange color (not bright and crisp), and/or longer than normal may indicate insufficient air flow to the boiler. Raise excess O_2 set point by 0.5% O_2 increments up to a maximum of 1.5%, while monitoring plume appearance, opacity, and flame conditions. Determine the excess O_2 level that produces acceptable opacity. Repeat these tests at other load points as required. If it is necessary to operate with excess O_2 levels that are higher than typical in order to maintain low opacity, there may be other underlying problems. Perform other diagnostic tests below. Measure CO (or combustibles) in the flue gas. High CO (> 100 ppm) indicates insufficient combustion air or a combustion problem caused by one or more of the conditions below.	Implement a higher excess O_2 on a permanent basis, or on a temporary basis until other potential causes of smoking are evaluated. Confirm that CO emissions have returned to low levels (< 50 ppm).
For units equipped with overfire air (OFA), confirm that OFA flow control dampers are at prescribed settings for the particular load.	Adjust OFA dampers to prescribed settings.

4a. Insufficient total air flow to the boiler. (continued)

Diagnostic Tests and Observations	*Corrective Actions*
If boiler fan capacity is not sufficient to maintain adequate O_2 at high loads to prevent smoking, determine the highest practical load where there is sufficient excess O_2 to avoid smoking.	Reduce the maximum load on the boiler to a point where excess O_2 is sufficient to avoid smoking. Request assistance from Engineering and/or Plant Performance departments to troubleshoot the air limitation problem.

4b. Inaccurate Boiler Excess O_2 instrumentation.

Diagnostic Tests and Observations	*Corrective Actions*
Check calibration of the excess O_2 monitor. Confirm consistency between local and control room O_2 readings. If accuracy of the monitor is suspect, measure the O_2 concentration in the duct with separate instrumentation and compare to the control room reading.	If calibration of the O_2 monitor has drifted, re-calibrate the monitor and increase the frequency of calibrations. If the problem persists, contact the instrument manufacturer for assistance.
Stratification in the flue gas duct or air in-leakage can lead to O_2 measurements that are not representative of overall furnace conditions. Unless large stratification (e.g., > 1% O_2 variations across the duct) has been documented in the past or is a known characteristic of the boiler, review recent changes in boiler operation or maintenance items that may have caused such a condition, including burners out of service for repairs, flue gas recirculation fan outage (causing back flow of combustion air to the exhaust duct), and boiler casing or expansion joint leaks.	If large stratification of O_2 in the exhaust duct is a chronic problem, consider installing multiple O_2 monitors across the duct. Large variations in excess O_2 in the exhaust duct that is a chronic or intermittent problem can result from imbalances in air-fuel ratio among the burners. There may be insufficient air flow to one or more burners and/or fuel flows may not be uniform among burners — see item 4d.

4c. Fuel properties may have changed due to blending of fuels on site, stratification of oil in storage tanks, or delivery of off-spec oil.

Diagnostic Tests and Observations	*Corrective Actions*
Physical or chemical properties of the oil may have changed which increase the oil's tendency to form smoke. Obtain an analysis of the current oil being burned, including values for the following parameters: • Viscosity • Asphaltene, Coking Index, or Conradson Carbon • Sulfur • Vanadium • Ash Confirm that oil burn temperature is adjusted to provide burner manufacturer's recommended oil viscosity at the burners (typically 100 to 150 SSU). Switch to a previous oil, if possible, and compare opacity under similar boiler operating conditions.	Operate with higher excess O_2 to minimize opacity until problem oil is expended. Reevaluate and, if appropriate, modify the fuel purchase specification to avoid delivery of problem oils in the future. Consult EPRI fuel oil management resources (References 8-1 and 8-2) to confirm that oil problems are not due to blending of incompatible oils.

4d. Insufficient air flow to one or more burners.

Diagnostic Tests and Observations	*Corrective Actions*
Inspect the flames through the furnace view ports. A smoky flame may indicate too much fuel (see below) or insufficient combustion air due to an improper air register adjustment. Confirm by visual inspection that air registers are opened to prescribed positions for normal operation on all burners. For tangential-fired boilers, confirm that air compartment dampers are set at the same positions at all burners, or biased according to plant practice. Confirm that air registers are closed on burners that are out of service for maintenance or turndown. Measure CO (or combustibles) at multiple points in the flue gas duct upstream of the air heater. Localized pockets of high CO (>100 ppm) may indicate one or more of the problems below.	Open air registers on active burners to prescribed positions. Re-calibrate automatic damper controllers or burner register drives (e.g. adjust limit switches) as required. Close air registers on idle burners. Confirm that CO emission have returned to low levels (<50 ppm).
Fuel flows may not be uniform among burners causing one or more burners to operate with insufficient excess air. Confirm that oil and atomizing steam pressures are uniform (within ±5%) from burner-to-burner.	Shut-down suspect burners and inspect oil guns and atomizers. See other diagnostic and corrective actions related to poor oil atomization under Symptom No. 1.

4e. Poor oil atomization.

Diagnostic Tests and Observations	*Corrective Actions*
Refer to diagnostic tests and observations for Poor Oil Atomization under Symptom No. 1.	Refer to Corrective Actions for Poor Oil Atomization under Symptom No. 1.

4f. Flame impingement on burner throats or furnace walls.

Diagnostic Tests and Observations	*Corrective Actions*
Visually inspect flames during steady boiler operation. Inspect for flame impingement on burner throats, air nozzles, furnace tube walls, or furnace refractory surfaces. Identify the problem burner(s). Remove from service suspect burner(s). Remove any clinkers (if possible), and clean and inspect the oil gun and atomizer components. Re-start the burner and observe flames. Confirm that all burner mechanical parts are functioning properly, including oil gun retract mechanisms, air register actuators, damper drives, etc. Perform diagnostic tests and observations above to eliminate poor atomization or insufficient air flow to the suspect burner(s) as possible causes. Also, determine whether flames are over-swirled or under-swirled per the guidance below. On tangential-fired boilers, confirm that the windbox-to-furnace differential pressure and auxiliary-air and fuel-air compartment dampers are at normal positions for the given boiler load.	If flame impingement persists after other corrective actions herein have been performed, or if the boiler experiences chronic flame impingement problems, consult the burner manufacturer for burner design or operational modifications.

4g. Over-swirled or under-swirled air flow to the burner.

Diagnostic Tests and Observations	*Corrective Actions*
Circular burners with spin vanes or louver-type air registers vanes will impart different amounts of spin to the combustion air depending on the adjustment of the vanes. Flames that flare too wide may have air registers or spin vanes that are "pinched down" too far, creating too much spin and causing the flames to broaden. Alternatively, when air registers or spin vanes are open too far, less spin may cause flames to lengthen and penetrate too far into the furnace. The cause and effect relationship between vane settings and flame shape depend on the specific burner design. Consult the burner manufacturer's burner operating manual for guidance. Confirm that air register positions or spin vane adjustments are in accordance with manufacturer's recommendations or established plant practice.	If it is suspected that register or spin vanes are not properly adjusted, *gradually* make adjustments on suspect burner(s) and observe the impact on flame shape. Monitor stack opacity, excess O_2, and CO (or combustibles) while making adjustments. If vane adjustments are successful in eliminating smoking, document new air register vane settings and revise boiler operator guidelines accordingly. CAUTION: Changing air register or spin vane positions can affect burner pressure drop and air flow through the burner. This may result in non-uniform air-fuel ratios among burners which can ultimately lead to smoking. Generally it is preferable that all burners have similar air register or spin vane settings. However, burner-to-burner variations in fuel or air flow may require different adjustments on selected burners.

4h. Damaged, deteriorated, or malfunctioning combustion equipment.

Diagnostic Tests and Observations	*Corrective Actions*
If the smoking problem persists after performing the above diagnostic tests and observations, the cause may be damaged, deteriorated, or malfunctioning combustion equipment. If not already done, inspect all burner front equipment for proper operation including, oil gun retract mechanisms, air register drives, overfire air port drives, and burner tilt mechanisms. Schedule an internal inspection of windbox and burner equipment. Items to inspect include flame stabilizers, windbox dampers and air registers, windbox partition plates and turning vanes, burner throats and throat refractory, overfire air ports, and burner nozzles and linkages. Verify that flame stabilizers and oil atomizers are at the proper axial positions when in the fully-inserted positions.	Repair or replace damaged or malfunctioning equipment.

4i. Ruptured boiler tube or other internal steam or water leaks.

Diagnostic Tests and Observations	*Corrective Actions*
Smoking may be the result of boiler tube leaks quenching flames. Visually inspect the burner zone. Perform normal checks (e.g., high makeup water flow) to identify possible steam tube leak.	Remove problem burner(s) from service. Schedule outage for tube repair.
Boiler tube leaks not in the burner zone or leaking sootblower steam valves can cause opacity spikes. Walk down the boiler to locate leaks on active sootblower steam lines.	Repair sootblower systems.

Symptom No. 5: White, Faint Smoke (SO_3 Condensation)

5a. SO_3 condensation plume. SO_3 combines with moisture in the flue gas to produce a visible white plume. Problem is worse for high sulfur (>1%), high vanadium (>100 ppm) oils.

Diagnostic Tests and Observations	*Corrective Actions*
Observe the visible characteristics of the stack plume. It is advisable that stack observations be performed by experienced or certified stack observers. SO_3 condensation plumes typically exhibit the following characteristics: • The color of the plume varies from white to blue to light brown, depending on the angle of the sun with respect to the observer and the stack. • The plume may be detached from the end of the stack, may be attached, or alternate from detached to attached with changes in boiler operation or ambient conditions. • The plume is continuous over periods of hours when operating at a fixed boiler load. However, plume opacity may change with changes in ambient humidity and temperature.	Oil properties, notably sulfur and vanadium content, affect SO_3 formation. Switching to a lower sulfur oil and/or oil with a lower vanadium content will reduce the SO_3 condensation plume, but may not eliminate it. For a given oil, the severity of the plume may be affected by changes in boiler operating conditions. Evaluate the impact of specific operating factors as described below. Plume visual appearance alone may not be definitive in distinguishing an SO_3 condensation plume when solid particulate matter is also contributing to opacity. Sources of particulate matter may include fuel or "back end" chemical additives, oil ash, and carbonaceous particulate matter. Sophisticated sampling and analysis by an outside testing firm is required to determine with certainty the contribution of SO_3 to stack opacity. However, tests and observations performed by plant personnel as described below can be effective in diagnosing and mitigating an SO_3 plume.

5b. Furnace excess O_2 is too high. SO_3 formation in the boiler increases with higher levels of excess O_2. Significant reductions in SO_3 occur when the excess O_2 is lowered to below 1.0%. While many boilers are not capable of operating at these low O_2 levels, there may be benefits from reductions in excess O_2 at higher O_2 levels.

Diagnostic Tests and Observations	*Corrective Actions*
Reduce the excess O_2 in increments of 0.5% or less, while monitoring plume appearance, opacity, CO emissions, and furnace flame conditions. A decrease in stack opacity or plume visibility indicates that the SO_3 formation is reduced. If opacity or CO emissions increase as the O_2 is lowered, this probably indicates that the O_2 is already close to the minimum value for good combustion and further reductions in O_2 should not be attempted. Use caution, since lowering O_2 too far will cause smoking and increased opacity due to carbonaceous particulate matter from incomplete combustion. Consider hiring an outside combustion specialist to assist in the tests. Repeat the above test at various loads on the boiler where the SO_3 condensation plume is particularly troublesome. If the minimum O_2 to avoid black smoke is considerably higher (e.g., by < 0.5% O_2) than previous experience for the same boiler load, there may be combustion-related problem(s). Refer to Symptom No. 4, Black Smoke During Steady Operation. Eliminating these problems may enable operation at lower O_2 with beneficial effects on the SO_3 condensation plume.	If lowering the excess O_2 has a beneficial effect on the SO_3 condensation plume, without adversely effecting combustion conditions or other stack emissions, implement lower excess O_2 operation on a trial basis. Be aware that lower O_2 operation can create adverse affects such as flame impingement on boiler surfaces and increased potential for smoking during transient boiler operation. Consider hiring an outside combustion specialist to independently evaluate low-O_2 operation. Formal stack testing may be warranted to confirm that PM emissions and CO emissions remain within acceptable levels before implementing lower-O_2 operation on a permanent basis.

5c. Flue gas temperature is too low. When the flue gas temperature drops below the acid dew point, a visible sulfuric acid plume (SO_3 plume) is formed. Raising the flue gas temperature at the stack exit may reduce the visibility of the plume at the stack exit, and may eliminate false opacity monitor readings due to acid condensation at the opacity monitor port.

Diagnostic Tests and Observations	*Corrective Actions*
Compare the actual flue gas temperature measured at the outlet of the air heater to the acid dew point. Refer to Figure 3-2. If the flue gas temperature is at or below the acid dew point, condensation of sulfuric acid and formation of an attached SO_3 condensation plume will occur. Note that flue gasses will typically cool 10 to 20°F between the air heater and stack exit. If the boiler is equipped with an air-side steam coil heater upstream of the main air heater, or equipped with air heater bypass, operate these for diagnostic purposes to increase the temperature of the air heater gas outlet temperature in increments while observing the plume and opacity monitor readings. Correlate changes in gas temperature with changes in plume appearance and opacity. Confirm that air heater leakage is within specifications by performing a standard air heater leak test (e.g., based on gas-side O_2 measurements at the inlet and outlet of the air heater). Excessive leakage can lower the air heater outlet gas temperature by 10 to 40°F and increase SO_3 condensation.	Operate the steam coil heater (or air heater bypass) on a temporary basis to determine effects of higher flue gas temperature on the SO_3 condensation plume. If there are benefits which offset the adverse impacts on unit heat rate, consider permanent changes to increase flue gas temperature. Perform air heater maintenance (repair air heater seals, replace damaged or missing air heater elements, etc.) to reduce air heater leakage. Restrict unit turndown to avoid opacity problems due to SO_3 condensation at low loads.

5d. Deposits on boiler heat transfer surfaces. Ash deposits on boiler high-temperature heat transfer surfaces promote the conversion of SO_2 to SO_3 due to catalytic components of the ash.

Diagnostic Tests and Observations	*Corrective Actions*
Compare the severity of the SO_3 condensation plume before and after a water wash of the boiler (including washing of the superheater and reheater sections). A significant reduction in plume visibility after washing implicates boiler ash deposition/catalytic conversion of SO_2 as a causative factor. Following the boiler water wash, monitor plume appearance and opacity over time.	Water wash the boiler when the SO_3 condensation plume becomes unacceptable. Based on observations of plume appearance over time, schedule regular outages for water washing. Repair malfunctioning sootblowers. Consider hiring an outside consultant to evaluate sootblower performance and operating practices. For base loaded units, consider implementing intermittent cycling duty or periodic load ramps. Changes in flue gas temperature occurring during load changes tend to dislodge ash accumulations on boiler surfaces.
Chemical additives are marketed to solve a wide variety of boiler problems, including control of ash deposits and SO_3. Results with additives have been inconsistent and site-specific. Refer to the main body of the report for a description of additive types and discussion of utility experience.	Contact additive suppliers and solicit competitive bids for additive trials. Implement an additive injection program on a trial basis, with adequate monitoring to confirm benefits and identify potential long-term side effects.

Symptom No. 6: Black Smoke (Opacity Spikes) During Burner Light-Offs

6a. Delayed ignition of main oil flame (Excessive time for ignition from time main oil supply valve opens).

Diagnostic Tests and Observations	*Corrective Actions*
Review burner manufacturer's specifications and boiler operator's procedures for adjusting air registers or dampers for light-off. Confirm that air registers or dampers are set to specified light-off positions. Stroke automatic burner air register drives to confirm repeatability of light-off positions.	Set air register to light-off position. Confirm reliability of light-off. Issue new or revised operator or maintenance guidelines, as required.
Verify that oil guns and flame stabilizers are fully inserted when the oil valve opens. Verify proper oil and atomizing steam pressures at the oil gun.	Move oil gun assembly to the full inserted stop position, if manually positioned. Repair or adjust stops on automatic oil gun retract mechanism, if necessary. Document new limit switch positions for future reference.
Verify that ignitors operate correctly, independent of main flames: • Visually inspect ignitor flame appearance with main flame off. Confirm strong, continuous flame. • Verify operation of ignitor insert/retract mechanism, if used. • Verify that ignitor flame ignites quickly after ignitor fuel valve opens. • Confirm that ignitor fuel and atomizing air pressures are at manufacturer's specified values. • Confirm that ignitor combustion air supply pressure is within spec. • Confirm spark intensity and operation of flame sensor (e.g., pressure switch or flame rod).	If inspections reveal off-spec conditions, correct per manufacturer's instruction manual. If ignitor flame is smoky or unstable, but other inspections do not reveal a problem, inspect and clean fuel elements (e.g., oil atomizer or gas element). If ignitor problems persist, contact the manufacturer for assistance.

6b. Insufficient flow of combustion air to the burner.

Diagnostic Tests and Observations	*Corrective Actions*
Confirm that the burner air register is set to the specified light-off position on the subject burner (see above). Inspect air register positions on idle burners for one of the following conditions: 1. If air registers on too many idle burners are open, this may result in an insufficient margin of excess air at the subject burner to accommodate transients during light-off. Close air registers on some or all idle burners and repeat burner light-offs. 2. Alternatively, if not enough air registers on idle burners are open, too much excess air at the subject burner may produce high air velocities which blow out the ignitor flame or prevent ignition of the main flame. Open air registers on some or all idle burners and repeat burner light-offs. To understand which of the previous two conditions may be occurring, it is helpful to estimate the quantity of excess air at the subject burner. Refer to Test Procedure No. 1 in Section 8.3.	Prepare or revise guidelines for air registers during light-off. Different guidelines may be required for situations when there are few versus many burners already in service.
For boilers equipped with overfire air (OFA) ports, confirm that OFA flow control dampers are set to specified positions for the specific load and boiler operating condition.	Review established procedures for adjusting OFA. Set OFA dampers accordingly.

6c. Partially plugged oil gun or atomizer.

Diagnostic Tests and Observations	*Corrective Actions*
When a smoking incident occurs while attempting to light-off a specific burner, pull the gun and disassemble and inspect the oil atomizer and internal gun passages. Light-off the burner to confirm proper operation. If smoking during light-off is a chronic problem regardless of the burner, review oil gun and atomizer shutdown (purging) procedures and inspection/maintenance practices. Confirm that guns and atomizers are cleaned each time prior to lighting-off.	Implement changes in oil gun and atomizer maintenance, as required (see Section 6.1 for recommended atomizer and oil gun maintenance procedures).

6d. Total air flow to the boiler too low (during the transient).

Diagnostic Tests and Observations	*Corrective Actions*
Raise excess O_2 set point by 0.5% increments up to a maximum of 1.5–2% and repeat burner light-offs at each step.	If smoking is eliminated, prepare and implement new excess O_2 guidelines for light-off.

6e. Surge in total oil flow to the boiler above total oil demand value.

Diagnostic Tests and Observations	*Corrective Actions*
Observe fuel and air flows in the control room (strip charts) during light-offs.	Reduce the speed at which the oil supply valve is opened, if possible. If smoking persists during light-offs, opacity spikes may be due to oil and/or air transients through active burners. Request technical support to troubleshoot combustion controls.

6f. Cold oil delivered to the oil gun.

Diagnostic Tests and Observations	*Corrective Actions*
Review the oil piping arrangement to determine if unheated oil from an unpurged (stagnate) oil line is delivered to the oil gun during light-off.	Consider piping modifications to eliminate stagnate oil lines or reduce the amount of cold oil delivered to the gun during light-off.

6g. Flame scanner problems.

Diagnostic Tests and Observations	*Corrective Actions*
Unreliable main flame scanners and/or ignitor flame detectors can result in multiple opacity spikes due to unsuccessful light-offs. In addition, multiple light-off attempts and burner purge cycles can degrade atomizer performance due to increased oil and coking deposits. Make sure flame scanner cooling air is turned on and that the flow rate is set per manufacturer's specifications (or flame scanner head is below the maximum allowed temperature).	Request technical support to troubleshoot flame scanners and related instrumentation (e.g. "interlocks").

Symptom No. 7: Black Smoke (Opacity Spikes) During Burner Shutdown

7a. Ignitor not in service during purging of oil gun.

Diagnostic Tests and Observations	*Corrective Actions*
Verify that ignitors operate correctly independent of main flames. Verify by furnace view port observation that the ignitor flame is on prior to initiating purge of the oil gun and is turned off after the purge is complete.	Repair malfunctioning ignitor(s). Modify or adjust BMS logic to prevent initiation of oil purge without proven ignitor flame. For purge sequencing that is performed manually, review operator procedures and revise as necessary.

7b. Insufficient air flow to the burner during purging of oil gun.

Diagnostic Tests and Observations	*Corrective Actions*
Verify that the burner air register is open during purge.	Modify or adjust BMS logic to prevent initiation of oil purge with closed air register. For purge sequencing that is performed manually, review operator procedures and revise as necessary.

7c. Steam purge rate too high.

Diagnostic Tests and Observations	*Corrective Actions*
Excessive purge rate may result in a large “slug” of oil leaving the gun, which cannot completely burn up in the furnace. This may be particularly the case for mechanical atomizers (all gun passages contain oil) and for oil piping arrangements with large volumes of oil between the purge valve and the oil gun. Evaluate opacity during burner shutdowns when the purge steam valve is opened gradually by hand. If the oil steam purge valve is automatically actuated, adjust the valve for slower opening or for test purposes use a downstream manual valve for throttling purge steam. Install pressure gages near the oil gun inlets to monitor purge steam pressure.	For manually-operated purge steam valves, train operators to open the valves gradually. For automatic valves, slow down the valve opening speed. If it is not possible to slow down the valve, consider installing flow restrictors (e.g., orifices) in the purge steam line to reduce the purge steam flow. After changing the purge steam valve speed or installing flow restrictors, longer steam purges may be required to clean the oil from the gun. Determine appropriate duration of purge by observing the flame during the purge (e.g., extend the purge well beyond the last flame “sputtering”) and by inspecting the internal passages of the oil gun and atomizer to confirm that there is no oil remaining.

7d. Air flow to active burners too low.

Diagnostic Tests and Observations	*Corrective Actions*
When a burner is shutdown, the oil flow to active burners increases. When the air register on the shutdown burner is open for the steam purge, the active burners may be starved for air. Raise the excess O_2 set point by 0.5% increments up to a maximum of 1.5% and repeat burner shutdown procedures. Monitor opacity to determine the required excess O_2 to prevent smoking. Confirm that the air register on the shutdown burner is closed after the oil gun steam purge is complete (steam purge valve closed) and the ignitor is turned off. After a burner is successfully shutdown, it may be necessary to operate with a higher excess O_2 to avoid smoking due to changes in furnace mixing and/or distribution of fuel and air among active burners. This requirement is more likely encountered at small boilers with relatively few burners. Raise the excess O_2 set point by 0.5% increments up to a maximum of 1.5% above the initial value, and observe opacity to determine the minimum O_2 required to eliminate smoking.	Revise excess O_2 operating guidelines for burner shutdown. Modify or adjust air register control logic or manual operating procedures to ensure that air register position is properly synchronized with burner shutdown.

7e. Oil and air flow transients through active burners.

Diagnostic Tests and Observations	*Corrective Actions*
Check for leaking oil shut-off valves.	Repair leaking valves.
If smoking persists during burner shutdown after evaluating the above factors, the problem may be related to transients in oil and/or air flow through the active burners.	Request technical support to troubleshoot combustion controls.

Symptom No. 8: Opacity Problems During Sootblowing

8a. High dust loading due to boiler deposits dislodged during sootblowing.

Diagnostic Tests and Observations	*Corrective Actions*
Confirm that supply pressures for the sootblowing medium (e.g., steam) are within manufacturer's specifications. Verify mechanical operation of sootblowers.	Adjust the supply pressure of sootblowing medium to manufacturer's specification. Perform required repairs or maintenance of sootblower systems.
Perform an internal boiler inspection to evaluate sootblower coverage and effectiveness. Confirm that nozzles and other furnace-side components are in good working order. Consider technical assistance from the sootblower manufacturer or an outside consultant.	In conjunction with the manufacturer, determine if increased sootblower pressures at troublesome regions of the boiler, more sootblowers, or different sootblower designs are needed.

8b. Sootblowing not optimized. Increased dust loading during sootblowing is unavoidable, but optimizing sootblower operations may reduce the quantity of particulate matter and magnitude of opacity spikes during sootblowing.

Diagnostic Tests and Observations	*Corrective Actions*
Consider conducting a sootblowing optimization program with outside technical assistance from a consultant or the manufacturer. The objectives are to identify specific boiler surfaces or sootblowers that create the highest opacity and determine the optimum sootblowing duration or sequencing to reduce the *magnitude* of opacity spikes. Elements of an optimization program may include: • Monitoring sootblow cycles to correlate opacity spikes with specific regions of the boiler. • Manually actuating sootblowers to individual tube banks or boiler regions to determine optimum sootblow duration	Implement on a trial basis, modified sootblowing cycles with extended or reduced sootblow duration on individual tube banks, or repeated sootblows, based on the diagnostic observations. Re-evaluate the sootblowing procedure as the boiler deposits gradually re-equilibrate over time. Increase the frequency of sootblowing to prevent large buildups of ash between sootblows.

8c. Atomizing steam supply to burners decreases during sootblowing. Auxiliary steam consumption for sootblowers may reduce atomizing steam pressure at the burners causing poor oil atomization.

Diagnostic Tests and Observations	*Corrective Actions*
For steam-atomized burners, observe atomizing steam pressure at the burners when steam sootblowers are in service. Determine if atomizing steam pressure decreases as sootblowers are activated.	Increase steam pressure upstream of the atomizing steam pressure regulator. Raise furnace excess O_2 prior to sootblowing to promote burnout of poorly atomized fuel. Request technical assistance to evaluate options for isolating atomizing steam supply from sootblower steam line conditions.

8d. Duration of high opacity extends over the averaging period of the opacity limit, causing an opacity exceedance.

Diagnostic Tests and Observations	*Corrective Actions*
Reduce the magnitude of sootblowing opacity spikes through corrective actions above. If baseline opacity is high prior to sootblowing, perform tests and observations under Symptom 4, Black Smoke During Steady Operation. If the opacity regulation is based on an averaging period (e.g., not to exceed a specified limit on a 6-minute average), it may be possible to avoid opacity exceedances by terminating sootblowing before the time-averaged opacity reaches the limit, and resuming sootblowing only after the average opacity drops back down.	Time the sootblowing to occur over multiple averaging periods so that the average opacity in any one averaging period does not exceed the limit. Provide boiler operators with a real-time indication of time-averaged opacity (with an alarm), consistent with the averaging period of the opacity regulation.

Symptom No. 9: Black Smoke When Co-Firing Oil and Gas

9a. Insufficient combustion air at one or more burners. Burners firing the same heat input (Btu/hr) with natural gas or fuel oil will generally require different amounts of combustion air to ensure complete combustion.

Diagnostic Tests and Observations	*Corrective Actions*
Visually inspect the burner flames when burning natural gas in some burners and oil in other burners (i.e., co-firing). Smoky flames or flames that are detached, pulsating, or longer than normal may indicate insufficient combustion air. High CO emissions (>50 ppm) also indicate air deficiency. Raise the excess O_2 set point by 0.5% increments up to a maximum of 2.0%, while monitoring flame appearance and opacity.	If a higher O_2 set point eliminates the smoking, implement a higher excess O_2 on a temporary basis while the next set of tests and observations are carried out.
Request technical support to evaluate the BMS logic for controlling air and fuel to each burner when co-firing gas and oil. Determine the distribution of fuel and combustion air between the gas-fired and oil-fired burners for different modes of co-firing normally experienced. Take into account air flow to the overfire air ports, if used. Use standard combustion calculations to determine the air-fuel ratios and excess air at the burners. Confirm that there is adequate excess air at the burners for complete combustion.	If the gas or oil burners do not have sufficient combustion air, it may be necessary to implement manual or automatic biasing of air registers or windbox dampers on a burner-by-burner basis according to the fuel being burned. Request technical support to define and evaluate options. As a rule of thumb, during co-firing the excess air at the burners firing a particular fuel should be the same or higher than the boiler excess air for the particular fuel when all burners are firing that fuel.

9b. Imbalance in fuel flow among burners.

Diagnostic Tests and Observations	*Corrective Actions*
Confirm that the oil and natural gas flow rates to individual burners are consistent with the guidelines established by the burner manufacturer or achitect engineer for co-firing modes (e.g., equal heat input per burner for oil or gas). Check calibration of plant fuel flow meters. As a cross-check, compare total fuel flow rates obtained from fuel flow meters to the flow rates determined from the flow vs. pressure calibrations of the oil atomizers and gas fuel elements.	As necessary, adjust fuel supply regulators, adjust oil and atomizing steam pressures, calibrate fuel control valves, etc. to achieve uniform fuel flows.
Check physical condition of gas injection spuds and confirm there are no signs of heat damage, e.g., failing welds or "fatigue" type cracks radiating from the fuel discharge orifices.	Replace spuds as soon as condition is detected.

Symptom No. 10: High Opacity During Load Ramp-Ups

10a. Boiler ash deposits dislodged and swept out of the boiler during load increases. Rising temperatures at higher loads tend to dislodge boiler deposits due to thermal expansion. Higher flue gas velocities entrain ash particles.

Diagnostic Tests and Observations	*Corrective Actions*
Observe stack opacity before, during, and after load ramp-ups. High opacity due to entrained particles from boiler surfaces typically exhibit the following characteristics: 1. Stack emissions may be brown, gray, or whitish in color. The plume is attached at the stack. 2. Opacity increases gradually or immediately after starting to raise load. Shedding or entrainment of particles may create opacity "puffs" during the load ramp. 3. Opacity gradually decreases after steady load is attained. It may take an hour or more to achieve a stable opacity reading after the load ramp, as particles continue to shed off surfaces and migrate through the boiler. Black smoke may indicate combustion-related problems. Refer to Symptom No. 3, Black Smoke, Intermittent During Load Increase or Decrease.	Optimization sootblowing frequency and procedures to reduce ash accumulation in the boiler. Refer to Symptom No. 8, Opacity Problems During Sootblowing. Reduce the rate of load change during load ramp-ups. Increase minimum load to reduce the amount of ash accumulation in the boiler. Implement stepped load ramps which allow for recovery of low opacity at intermediate loads. If a particulate control device (electrostatic precipitator) is present, confirm that hoppers are emptied and routine inspections and maintenance have been performed.

10b. Loose ash accumulations in the boiler are entrained by the higher flue gas velocities.

Diagnostic Tests and Observations	*Corrective Actions*
Inspect the boiler and exhaust ductwork for loose ash accumulations. Inspect flat horizontal surfaces, corners, and areas downstream of bends and flow obstructions. Inspect duct work, hoppers, and dampers in the flue gas recirculation system.	Clean-out loose ash deposits. Consider turning vanes, deflector vanes, or other flow devices to eliminate stagnate gas zones or to keep potential deposition areas swept with flue gas. Consider new, repositioned, or modified sootblowers, where appropriate. Empty ash hoppers (e.g., economizer outlet hopper) on a regular basis. If spikes in opacity occur when starting the flue gas recirculation fan, consider starting the fan at a lower load or ramping the fan into service more slowly.

10c. Low temperature deposits are swept out the stack. Depending on the severity of such deposits, they may or may not contribute significantly to stack opacity.

Diagnostic Tests and Observations	*Corrective Actions*
Inspect air heater surfaces, downstream ductwork, and stack liner for deposits. Deposits that are wet or dry may be contributing to the problem.	Wash the stack and clean out other areas where ash is deposited. Empty the ash pit at the base of the stack. Empty ash hoppers in electrostatic precipitators. Wet deposits in air heater outlet ducts and in the stack may indicate substantial sulfuric acid condensation. To minimize acid condensation, refer to diagnostic and remedial measures under Symptom No. 5, White, Faint Smoke (SO_3 Condensation).

10d. Excessive additive injection. Chemical additives used to enhance combustion, reduce boiler deposits, or control acid corrosion can contribute substantially to total dust loading.

Diagnostic Tests and Observations	*Corrective Actions*
Confirm with the additive supplier that additive composition and injection rates are appropriate for the current fuel and boiler loading. Verify calibration of the additive pumps under actual line pressure conditions. Verify that automatic additive pumps maintain required injection rates at all loads. Confirm that over-dosing is not occurring at low loads.	Review and revise additive injection procedures as necessary.

8.3 Test Procedure 1: Estimating Air-Fuel Ratios at Active Burners

Maintaining a sufficient quantity of excess air at the burners for combustion is one of the most important requirements for avoiding smoking on oil-fired boilers. However, often during transient boiler operating conditions (e.g., boiler startup and shutdown) it is difficult for boiler operators to determine whether active burners have sufficient excess air because of the variety of burner conditions that are simultaneously occurring: burners firing warm-up guns, burners firing main oil guns, idle burners with air registers open, and idle burners with air registers closed. The excess O_2 monitor and the fuel and air flows may indicate a large amount of excess air in the boiler, but the actual excess air at active burners may be considerably less, depending on the distribution of air among in-service and out-of-service burners.

A simplified computational approach is provided below for estimating the air-fuel ratios at active burners. The results will be useful in diagnosing boiler smoking problems due to insufficient or excessive air at the burners, particularly during boiler startup and shutdown operations.

The approach is directly applicable to wall-fired and tangential-fired boilers in which air registers (dampers), when “open”, are always open to approximately the same position on all burners, resulting in approximately the same air flow through each burner. In cases where air flows among burners are substantially different, more complex estimations are required and beyond the scope of this procedure. Such may be the case on tangential-fired boilers in which all auxiliary air dampers are modulated together (regardless of whether the burner is in-service of shut-down), but the fuel-air damper is only open on in-service burners.

The procedure as written below may be too complex for use by boiler operators to evaluate burner operating conditions on a real-time basis. However, plant engineering or O&M supervisory personnel may find the procedures useful for diagnosing smoking problems and for developing burner operating guidelines for the boiler operators.

8.3.1 Computational Approach

The approach requires a knowledge of the relative air and fuel flows to the boiler (obtained from the air and fuel flow charts in the control room) and a knowledge of the burner firing pattern (i.e., how many burners are in service) and the air register positions (i.e., opened or closed) at all burners.

Assumptions:

- Air registers, when open on active and inactive burners, are open to the same position (e.g., wide open).
- Fuel flow is distributed uniformly among active burners.
- All burners are normally in service when the boiler is at full load.
- Air leakage through closed air registers is small (i.e., less than 10% of full-open flow). If higher leakage rates are known or suspected to occur, interpret results more conservatively as explained below.

For boilers equipped with overfire air (OFA) ports, see special considerations for OFA below.

Definitions:

N1 = Boiler's total number of burners.

N2 = Number of burners in service at the test condition (air registers open and firing oil).

N3 = Number of idle burners with air registers open at test condition (air registers open and fuel valve closed).

A = Boiler combustion air flow at test condition, expressed as a percentage of full load boiler air flow. This value is read off of the air flow indicator in the control room.

F = Boiler oil flow at test condition, expressed as a percentage of full load boiler fuel flow. This value is read off of the fuel flow indicator in the control room.

Calculation:

The first step is to estimate the air flow at each burner that has open air registers. The air flow is expressed as a percentage of the burner's air flow at full load. This is calculated as follows:

$$\text{Burner Air Flow} = \frac{A \times N1}{N2 + N3}, \%$$

Next, estimate the fuel flow to each active burner, as a percentage of the burner's fuel flow at full load:

$$\text{Burner Air Flow} = \frac{F \times N1}{N2}, \%$$

Now compare the above two calculated values. If the Burner Air Flow and Burner Fuel Flow are the same, this means that the air-fuel ratio and percent excess air at each active burner are approximately the same as at full load. This may not provide adequate excess air at lower loads due to less efficient combustion, and it may be necessary to increase the air or reduce the fuel to active burners in order to avoid smoking. Also, bear in mind that air leakage through out-of-service burners with air registers closed will result in less air at the active burners than predicted, and an extra margin of Burner Air Flow above the Burner Fuel Flow is required to account for this.

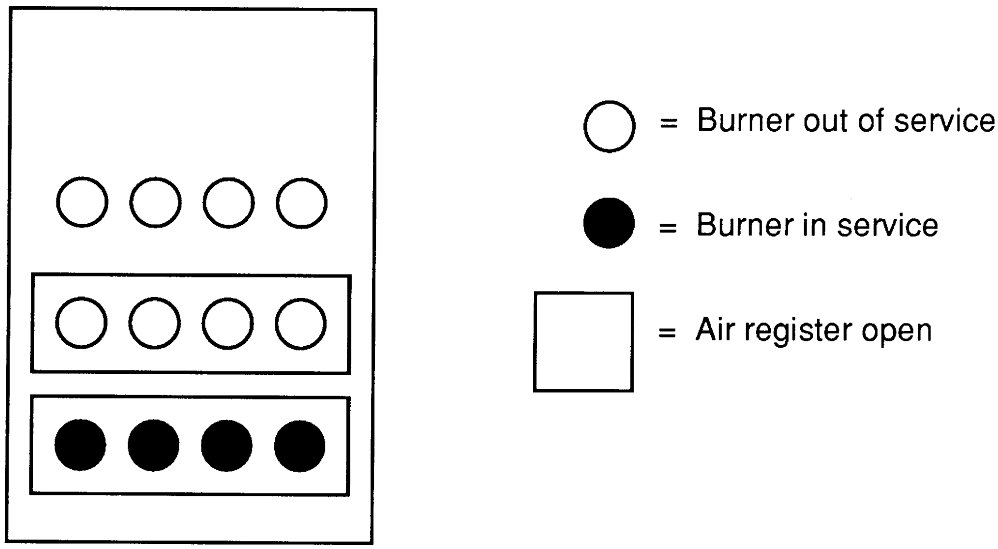
In general, the ratio of Burner Air Flow to Burner Fuel Flow should be maintained between 1.2 and 2.0 during startup, shutdown, and low load operation — that is, 1.2 to 2.0 times the air-fuel ratio at full load. The minimum ratio that can be maintained without producing black smoke, and the maximum ratio that can be maintained without producing white smoke, are site-specific and, if necessary, can be determined experimentally for each boiler.

Example:

A boiler is in a load ramp-up mode with the following conditions:

N1 = 12 total burners in the boiler.
N2 = 4 burners in service (air registers open and firing oil).
N3 = 4 idle burners with air registers open.
A = 40% of full load boiler air flow
F = 15% of full load boiler fuel flow

The firing configuration is illustrated as follows:



For this operating condition:

Burner Air Flow = (40 × 12)/(4 + 4) = 60% of full load air flow

Burner Fuel Flow = (15 × 12)/4 = 45% of full load fuel flow

The Burner Air Flow is well above the Burner Fuel Flow, indicating that there is sufficient excess air at the burner.

If the total boiler fuel flow (F) were raised from 15% to 20%, the Burner Fuel Flow would increase from 45% to 60%, equivalent to the Burner Air Flow. In this case, there may not be sufficient excess air at the burners and smoking may occur, even though the total air to the boiler (A) and the O_2 reading from the boiler oxygen monitor ($>>$ 10% O_2) may seem high enough.

If another burner were put into service on the middle burner elevation without increasing boiler fuel flow, the Burner Fuel Flow would drop to approximately 36%. This may be acceptable, unless combustion problems are known to occur at this burner turndown condition. It is recommended that burner fuel flows be maintained between 40% and 60% of full load flow until all burners are put into service.

Another approach may be to raise the total boiler air flow, say to 50%, and then raise boiler fuel flow to 20% with the four lower burners in service. This condition would result in:

Burner Air Flow = (50 × 12)/8 = 75%

$$\text{Burner Fuel Flow} = (20 \times 12)/4 = 60\%$$

At this point another one or two burners could be put into service to continue raising load.

8.3.2 Considerations for Boilers Equipped with Overfire Air (OFA)

For boilers equipped with OFA ports, the above procedure is applicable when the ports are closed. When the OFA ports are open, the procedure must be modified to account for the air flowing through the OFA ports, which reduces the air flow to the burners. Normally, OFA ports are closed during boiler startup and shutdown.

It is necessary to know the approximate air flow through the OFA ports. If in doubt, ask the manufacturer. Commonly, the OFA flow rate is specified as a percentage of the total boiler air flow at full load when all burners are in service. Based on this information, the approximate *fraction* of combustion air flowing through the OFA ports is estimated as follows:

$$\text{OFA Air Flow} = \frac{1}{\frac{(100-\text{OFA})}{\text{OFA}} \times \frac{(\text{N2}+\text{N3})}{\text{N1}} \times \frac{\text{N4}}{\text{N5}} + 1}$$

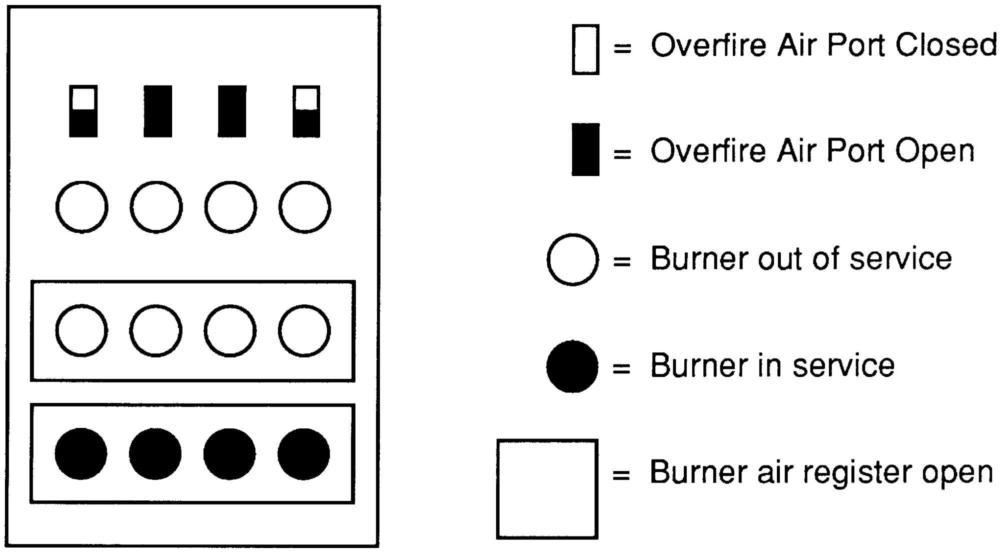
where,

OFA = Percentage of air flowing through the OFA ports at full boiler load when all the overfire air ports are open and all burner air registers are open.
N4 = Number of overfire air ports in the boiler.
N5 = Number of overfire air ports that are open, or the equivalent. For example, if two of four OFA ports are open, N5 = 2. If all four OFA ports are 25% open, N5 = 1.
N1, N2, and N3 are as defined above.

For the previous example, if the boiler were equipped with four overfire air ports with a total OFA flow capacity at full load of 20%, then the burner air and fuel flows are calculated as follows:

N1 = 12 total burners in the boiler.
N2 = 4 burners in service (air registers open and firing oil).
N3 = 4 idle burners with air registers open.
N4 = 4 OFA ports in the boiler.
N5 = 3 (2 OFA ports wide open and 2 OFA ports half open).
A = 50% of full load boiler air flow.
F = 20% of full load boiler fuel flow.
OFA = 20% at full boiler load when all burners are in service

The firing configuration is illustrated as follows:



The *fraction* of combustion air flowing through the OFA ports is:

$$\text{OFA Air Flow} = \frac{1}{\frac{(100-20)}{20} \times \frac{(4+4)}{12} \times \frac{4}{3} + 1} = 0.22$$

That is, 22 percent of the total boiler combustion air is flowing through the OFA ports. The Burner Air Flow is 22% less than calculated previously or:

$$\text{Burner Air Flow} = (50 \times 12)/(4+4) \times (1-.22) = 58.5\%$$

The Burner Fuel Flow is the same as computed previously:

$$\text{Burner Fuel Flow} = (20 \times 12)/4 = 60\%$$

Operation with OFA reduced the Burner Air Flow such that it is lower than the Burner Fuel Flow, indicating that the burners are starved for air. The boiler air flow should be raised so that the ratio of Burner Air Flow to Burner Fuel Flow falls within the recommended range (1.2 to 2.0). If the OFA ports are not required for NOx control, the preferred option would be to close the OFA ports.

8.4 Test Procedure 2: Estimating the Firing Rate of Individual Burners

During boiler startup and shutdown operations, a general rule of thumb is to maintain the firing rates of individual burners between approximately 40 and 60 percent of the burner rated capacity until all burners are put into service. Lower firing rates often lead to deteriorated combustion conditions and smoking, depending on the turndown characteristics of the burner and oil atomizer. Higher firing rates can increase the likelihood of smoking due to insufficient burner air flow or low atomizing steam pressures. The acceptable range of burner firing rates during boiler startup and shutdown is site-specific, and values different than above may be deemed acceptable based on past experience for a specific boiler.

Assuming approximately uniform fuel flow among active burners, the fuel flow to each burner, expressed as a percentage of the burner's full load fuel flow, can be estimated as follows:

$$\text{Fuel Flow Per Burner} = F \cdot N/n$$

where,

- F = Total fuel flow to the boiler (expressed as a % of boiler fuel flow at maximum load).
- N = Number of burners in service at maximum load.
- n = Number of burners in service at the test condition.

The total fuel flow to the boiler (F) can be conveniently read off of the fuel flow chart in the control room, if the input signal and flow measurement device have been properly maintained and calibrated. Make sure that the oil flow signal represents the actual oil burned. Depending on oil piping arrangements and locations of flow instrumentation, the indicated total oil flow may include oil returned to the oil tank or elsewhere (e.g., due to spill-return atomizer operation or recirculation of oil from the burner front at low loads).

Alternate ways to determine the percent burner fuel flow are possible, using other fuel flow instrumentation that may be available to the boiler operators. For example, if the total fuel flow rate is measured in terms of lb/h or gallons/hr, then "F" in the above equation can be calculated by dividing the reading by the value measured at full boiler load.

Example:

The boiler is in startup with four of twelve burners operating. The fuel flow to the boiler is 15% of the full load boiler flow. The fuel flow to each burner is calculated as follows:

Fuel Flow Per Burner = 15 · 12/4 = 45%

Thus, the four burners in service are operating with 45% of their full load firing rate. In order to avoid low burner firing rates, the total fuel flow to the boiler should be raised before putting additional burners into service.

8.5 High Particulate Matter Mass Emissions

High particulate matter (PM) mass emissions may be evident from PM emissions measurements that are periodically required to determine compliance with emission regulations. Such testing is usually conducted according to standardized test procedures (e.g., EPA reference methods) which specify steady boiler load conditions during the test. As such, they may underestimate the maximum PM emissions that occur during normal boiler operation, when boiler loads and other operating factors affecting PM emissions are varying.

As noted in Section 1, there is no direct correlation between opacity and PM. Consequently a high PM emissions problem may or may not be accompanied by an increase in opacity. However, some of the same diagnostic and corrective actions recommended for opacity problems may also apply to problems of high PM emissions, particularly when high PM emissions result from poor combustion conditions that lead to high carbon emissions.

For oil-fired boilers equipped with particulate control devices, high PM emissions at the stack may indicate O&M problems related to the control device. Such problems are not addressed herein. Readers should consult the particulate control manufacturer or other specialists to diagnose and solve such problems. However, if high PM emissions are the result of unusually high PM concentrations entering the control device, the discussion below is relevant.

For diagnosing and rectifying high PM emissions problems that occur during sootblowing and load ramp-ups, readers are referred to Section 8, Symptoms No. 8 and No. 10.

Carbon, sulfates, and ash are the primary constituents of PM emissions from oil-fired boilers. When chemical additives are used, un-reacted additive and additive byproducts may also contribute to PM emissions. The ash component is an unavoidable consequence of the ash composition of the oil and in general can be reduced during steady state boiler operation only by reducing the ash specification of the oil.

To a large degree, sulfates are a function of the sulfur content of the oil — higher-sulfur oil results in a higher sulfate content in the particulate matter. In addition, boiler operating conditions that favor the formation of SO_3 and sulfuric acid (high excess oxygen concentration and vanadium deposits) will increase the sulfate content of the particulate matter. It is also important to note that the sampling procedure used to collect PM samples can affect the *measured* sulfate concentration. PM samples collected at lower temperatures — particularly near or below the acid dew point — can contain substantial quantities of sulfate and sulfuric acid artifacts and indicate erroneously high PM emission concentrations. Such artifacts may or may not be considered as part of the total PM mass emissions by regulatory authorities.

High carbon emissions are often the cause of high PM emissions. Up to 80% of the PM mass emissions may be carbon when poor combustion conditions lead to carbon burnout problems. Consequently, diagnostic tests to evaluate causes of high PM emissions usually focus first on determining the concentration of carbon in the PM emissions.

8.5.1 Diagnostic Tests

Microscopic and chemical analysis of PM samples can be used to determine the presence of cenospheric carbonaceous particles and the overall carbon content in the particulate matter mass. For boilers equipped with particulate control devices, PM samples collected upstream of the control device should be analyzed. Engineering and consulting companies have developed diagnostic procedures specific to PM emissions problems and should be considered to provide assistance in PM diagnostic and remedial programs.

The causes of high carbon emissions cannot be generalized, because of the numerous design, operating, and maintenance factors that may be involved. In general, the diagnostic actions listed under Symptom No. 4 in the Opacity Troubleshooting Guideline, Black Smoke During Steady Operation, are applicable in diagnosing causes of high carbon emissions.

Large cenospheric particles (e.g., > 100–200 microns) in combination with high carbon implicates poor oil atomization as a contributing factor in high PM emissions. Diagnostic tests listed under Symptom No. 1 in the Opacity Troubleshooting Guideline, Item 1d, Poor Oil Atomization, should be performed.

8.5.2 Corrective Actions

- If high unburned carbon is the problem, follow the corrective actions under the sections of the Opacity Troubleshooting Guideline referenced above. Implement new or modified O&M procedures as appropriate.

- Repeat PM emissions measurements using the highest PM filter temperatures allowed. If using an out-of-stack filter approach (e.g., EPA Reference Method 5), determine the highest filter temperature that will be accepted by the responsible regulatory authority. For in-stack or out-of-stack filter sampling, make sure that the flue gas temperature is maintained as high above the acid dew point as possible. Avoid sampling at temperatures below the acid dew point. Higher filter and flue gas temperatures may eliminate a portion of the sulfate and acid artifacts on the PM sample and may "bring PM emissions into compliance." Also, use the highest oven temperature allowed when drying samples prior to analysis. Generally, heating the PM samples to drive off condensables is worthwhile if only a 10–25% reduction in mass emissions is needed for compliance. However, up to 50% water has been found on PM samples for some sources with high concentrations of sulfuric acid in the flue gas.

- Evaluate options for reducing opacity and PM emissions as discussed in Section 7, according to the recommended order of priority.

8.6 Acidic Particulate Matter Emissions (Stack Fallout)

The emission of relatively large, acidic particles (often referred to as "acid smut" or "acid fallout") have caused public relations, legal, and environmental problems for owners and operators of many oil-fired power plants. Such problems have been particularly acute for plants operating in urban areas and burning fuel oils with moderate to high sulfur content (e.g., > 0.5% sulfur). The fallout particles can create a nuisance as they coat downwind surfaces with "dust." More importantly, the particles can damage various surfaces (painted, metallic, fabric, etc.) that they settle upon, due to their corrosion and staining characteristics.

Stack fallout particles typically consist of one or more of the following types:

1. Large individual cenospheric carbon particles that may have adsorbed sulfuric acid as they passed through the boiler from the burner zone. Cenospheres greater than 50-100 micrometers in diameter are of particular concern.

2. Agglomerates of cenospheric particles and/or oil ash that are dislodged from boiler surfaces randomly or during specific events (e.g., sootblowing and load ramps).

3. Corrosion products formed on the air heater, low-temperature ductwork, and the stack liner. Such particles are highly acidic (e.g., pH may be less than 2) and may contain carbon, ash, and metals. The particles are released during air heater sootblows or may shed-off randomly or continuously from other surfaces.

The nature of the fallout particles and the factors that contribute to their emission are very site-specific, and the optimum diagnostic approach and solution will vary from one site to the next.

8.6.1 Diagnostic Test

A program to determine the cause of a fallout problem may consist of one or more of the following:

- Collection and analysis of fallout particles. Microscopic and chemical analysis can determine which of the above types of particles are contributing to the fallout problem. Companies specializing in combustion-related engineering services have developed sampling and analysis procedures specifically for diagnosing fallout problems, and should be considered to augment in-house expertise.
- Correlation of fallout episodes with specific boiler operating modes. Conduct a systematic effort to document emission of fallout particles and changes in boiler operation. For plants with multiple boilers, perform tests to isolate each boiler from consideration, as necessary. Monitor and record wind direction and velocity to confirm that reported fallout problems in the vicinity of the plant originate from the plant and not from other sources.
- Internal inspection of the boiler(s). Deposit accumulations; conditions of the air heater surfaces, ductwork, and stack liner; and the condition of combustion equipment can provide information to help pinpoint the specific source of the fallout particles. Comparison of microscopic and chemical analyses of boiler deposits and fallout particles may provide further confirmation of fallout sources within the boiler.

8.6.2 Corrective Actions

- If large, cenospheric, carbonaceous particles are implicated as contributors to fallout, follow the corrective actions in the Opacity Troubleshooting Guideline referenced above for reducing high PM emissions due to unburned carbon.
- Evaluate options for increasing the air heater gas outlet temperature to above the acid dew point. Options include installation or upgrading air-side steam coil heaters, modifications to the air heater, and increasing the boiler’s minimum load.
- Optimize sootblowing to minimize the quantity of mass emissions during each sootblowing cycle. Refer to Section 5.10. Coordinate sootblowing with wind direction to avoid particle fallout on sensitive areas.
- Evaluate chemical additives as a means of reducing ash deposition, increasing carbon burnout, reducing conversion of SO_2 to SO_3, neutralizing acid condensed on low-temperature boiler surfaces, and increasing the pH of particulate matter emissions. Consult with more than one additive supplier to determine options.

- Burn lower sulfur fuel oil.
- Establish a program for boiler washing and cleaning out ductwork and the stack.
- Install air heater elements that are more corrosion resistant, if air heater corrosion products are involved in fallout.
- Install particulate control equipment. Refer to Section 7.5.

8.7 References

1. *Methods for Assessing the Stability and Compatibility of Residual Fuel Oils*, EPRI Final Report GS-6570, November 1989.

2. *Development of Fuel Oil Management System Software, Phase 1: Tank Management Module,* EPRI Final Report TR-100311, January 1992