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GUIDELINES FOR INDUSTRIAL BOILER PERFORMANCE IMPROVEMENT

Boiler Adjustment Procedures to Minimize Air Pollution and to Achieve Efficient Use of Fuel

Guidelines intended for use

- by personnel responsible for boiler operation to perform an efficiency and emissions tune-up
- by plant engineers to initiate maintenance and efficiency monitoring practices
- as a supplement to manufacturers

FEDERAL ENERGY ADMINISTRATION
ENERGY CONSERVATION AND ENVIRONMENT
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The contents of this manual are offered as guidance. The United States Government, its employees, and KVB, Inc. do not assume responsibility or liability for consequences arising from the implementation or failure to implement the guidance contained herein. The contents of this manual should not be construed as an endorsement by the Environmental Protection Agency or the Federal Energy Administration of any product or manufacturer.

SECTION 1.0

INTRODUCTION

The purpose of this manual is to provide general guidelines for use by industrial boiler operators to reduce stack emissions of nitrogen oxides and improve boiler operating efficiency. These guidelines deal primarily with boiler adjustments which are typically within the control of boiler operators and plant engineering personnel. However, other techniques are also described in the Appendices which will usually require the assistance of outside combustion specialists due to the more critical dependence on specific boiler design, operating conditions and fuel characteristics.

Since efficiency and emissions are sensitive to many of the same boiler operating parameters, it is essential that both of these areas be simultaneously treated in one integrated set of guidelines. The recommended procedures in this report are based on the results of U.S. Environmental Protection Agency (EPA) and Federal Energy Administration (FEA) sponsored programs (Refs. 1 and 2) during which various nitrogen oxides reduction methods were evaluated in the field and improvements in boiler efficiency were demonstrated.

Oxides of nitrogen are a major contributor to the total air pollution problem existing in industrial areas. Generally referred to as "NO_x", this gaseous pollutant includes both nitric oxide (NO) and nitrogen dioxide (NO_2), although NO_2 generally comprises only five percent or less of the total NO_x emissions from boilers. These compounds plus the new substances formed when they combine with other pollutants in the air are an important element in what is commonly referred to as "smog".

Boilers used in industry produce a significant fraction of the total industrial emissions of NO_x. In fact, industrial boilers produce 50 percent of the NO_x emitted from all stationary industrial combustion sources (Ref. 3). A reduction in emissions from just this single industrial source would obviously contribute greatly to improving the national air quality.

Industrial boilers currently account for over 15 percent of all the energy consumed in the United States, or more than 11 quadrillion Btu's per year (Ref. 2). An increase in industrial boiler efficiency would therefore significantly impact energy conservation nationwide as well as reduce industries' fuel costs. The EPA and FEA sponsored field test programs revealed that improvements in efficiency of up to several percent were frequently possible by simply adjusting the fuel/air ratio to minimize stack gas heat losses.

During the two-year EPA field test program, substantial reductions in nitrogen oxides emissions were achieved through careful adjustment of existing boiler equipment. Usually little or no deleterious effects on combustion controls or boiler reliability occurred when the optimum adjustments were established. In fact, substantial improvements in boiler efficiency often accompany "low NO_x" operation. However, adjustments for improved efficiency occasionally conflicted with attempts to reduce emissions, requiring a tradeoff between emissions and fuel usage, or preferably the application of alternate NO_x emission controls.

This guide begins with a simplified discussion of the fuel burning process to provide the boiler operator with a basic understanding of NO_x formation in the boiler and the major combustion-related factors important to efficiency. With this background, the techniques for reducing NO_x and improving boiler efficiency are then discussed in detail and instructions are provided to assist the boiler operator in applying them to a particular boiler installation. Emphasis is on reducing the boiler excess air to the lowest practical level. This will require that the operator have a working knowledge of the boiler's combustion control system and the required flue gas analysis instrumentation necessary to perform the boiler adjustments safely and effectively. *It is important that this entire guide be read and understood before attempting any boiler adjustment or modifications.*

IMPORTANT NOTICE

To be generally applicable to all industrial boiler installations, these guidelines could not be prepared as a self-contained document. Due to the wide variety of combustion control systems, burner designs and furnace geometries in use, and the variation in operating demands, it will be necessary that these guidelines be supplemented by other information sources available to boiler operating personnel. These might include:

- The Plant Engineering Staff
- Boiler Operating and Maintenance Manuals
- Boiler Equipment Manufacturers and Their Service Organizations

In addition, local and national boiler safety codes must be observed at all times. Any apparent contradiction between these codes, the boiler manuals, and the guidelines, must be resolved before proceeding. It is also intended that these guidelines be used for equipment fired with conventional fuels (i.e., hard coals, #2 through #6 fuel oils, and natural gas.) Although many of the concepts and recommendations will be applicable to other fuels, these may require special considerations and procedures which have not been addressed in these guidelines.

SECTION 2.0

FUNDAMENTALS OF COMBUSTION

The heat energy in all fossil fuels (coals, fuel oils, and natural gases) is released during the combustion process as the carbon and hydrogen in the fuel react with oxygen to produce a high temperature flame. The burning of carbon and hydrogen with oxygen would ideally produce an exhaust gas consisting of carbon dioxide (CO_2) and water vapor (H_2O) which are considered harmless combustion byproducts. Unfortunately, real combustion systems differ from this ideal situation due to the more complex make-up of the fuel itself plus the non-ideal characteristics of the actual burning process. As a result, the exhaust products from industrial boilers contain additional gaseous and solid materials, some of which are identified as serious enviornmental pollutants (see Appendix D). Some are products of incomplete combustion and are important from an efficiency standpoint, since they represent a waste of available heat that is lost from the boiler stack.

Air is the convenient and non-varying source of oxygen for nearly all industrial combustion processes. The composition of air is roughly 21% oxygen (O_2) and 78% nitrogen (N_2) by volume with traces of other gases including argon and carbon dioxide. Under perfect combustion conditions, there is a so-called "theoretical amount" of air which will completely burn a given amount of fuel with no excess air remaining. In practice, however, more air than the theoretical amount must be supplied to the burner to ensure complete burning of the fuel. The actual quantity of excess air required at a particular boiler depends on many factors such as fuel type and composition, furnace design, boiler firing rate, and the design and adjustment of the burners. If enough air is not provided, unburned fuel, smoke and other products of incomplete combustion such as carbon monoxide (CO) and soot are emitted from the stack, resulting in pollution, wasted fuel energy, and a potential for explosion. In the case of coal fired boilers, the quantity of unburned fuel in the refuse also increase. If too much excess air is supplied to the burner, the boiler efficiency will be reduced because some fuel is used simply to heat the unneeded air which is exhausted out the stack. The amount of excess air can also influence the formation and emission of nitrogen oxides (NO_x) as discussed in a later section.

2.1 FURNACE EXCESS AIR

Excess air is a primary boiler operating variable and an important element in the following discussions. It is therefore appropriate to include a brief discussion of this term and the methods available for determining the quantity of excess air at the boiler.

Accurate fuel and air flow measurements would provide a direct determination of the boiler air/fuel ratio and excess air, but these measurements are frequently not available at industrial boiler installations. An alternate means for determining boiler excess air utilizes measurements of specific gases in the stack and the known relationships between their concentration and percent excess air for a particular fuel.

Excess air in the boiler is evident from the presence of oxygen in the flue gas. This oxygen content is customarily referred to as excess oxygen, excess O_2 or stack O_2. However, the terms "excess air" and "excess O_2" should not be confused to mean the same thing. As the excess air is increased at the boiler, one would expect that the oxygen concentration in the stack gases would also increase, and, indeed, this is the case. Figure 1 shows this relationship between excess O_2 and excess air for typical natural gas, oil and high grade coal fuels.

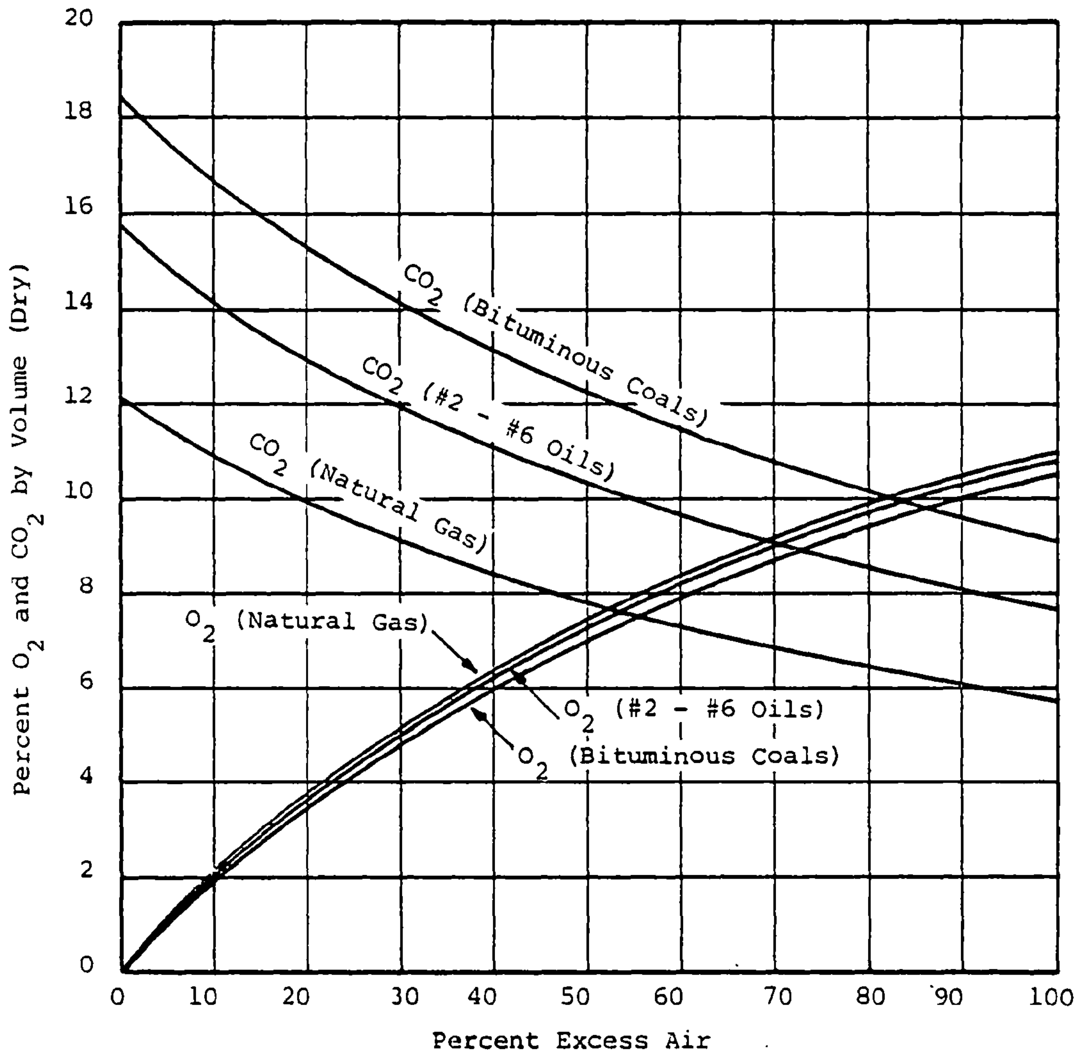

Figure 1. Relationship between boiler excess air and stack gas concentrations of excess oxygen (O_2) and carbon dioxide (CO_2) for typical fuel compositions.

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Some boiler operators are accumstomed to judging boiler firing conditions based on stack CO_2 measurements (as opposed to using excess O_2) and the CO_2 versus excess air dependence is also shown in Figure 1. While both approaches are equally valid for determining boiler excess air, the use of excess O_2 is preferred for the following reasons:

1. The relation between O_2 and excess air is not highly affected by fuel composition. This is evident in Figure 1 where the O_2 versus excess air curves for natural gas, oil and coal fuels are nearly coincident. On the other hand, CO_2 versus excess air curves exhibit a wide variation with fuel type.

2. Measurement of CO_2 requires a much greater precision than excess O_2 measurements to obtain the same accuracy in excess air. This is especially true when firing with low excess air which is generally the preferred condition for high boiler efficiencies. For example, suppose it is desired to establish the excess air to within $\pm$ 2 percent excess air. If the boiler is operating in the region of 20 percent excess air on oil fuel, the CO_2 would have to be measured to within $\pm$ 1.5% accuracy (13.0 $\pm$ .2 percent CO_2), while an O_2 measurement accuracy of only $\pm$ 8% (3.7 $\pm$ .3 percent O_2) would be required.

3. CO_2 is a product of combustion whereas excess O_2 is more immediately associated with excess air.conditions in the boiler. The excess O_2 measured in the stack gases is the actual surplus of oxygen in the furance available for the combustion process. As lower and lower excess air is present in the furnace, the excess O_2 approaches zero (regardless of fuel type) while the CO_2 increases, approaching some constant value which is dependent on the fuel composition.

4. Instrumentation for excess O_2 measurements is generally less expensive and more reliable as a class than CO_2 instrumentation. Many continuous CO_2 instruments are of a NDIR type which is more expensive and not very portable.

In following sections of this manual, excess O_2 will be used exclusively as an indicator for excess air. It is strongly recommended that the use of excess O_2 be adopted by all boiler operators. However, for those who still prefer to think in terms of CO_2, it is possible to convert O_2 to CO_2 using curves such as those in Figure 1 for the particular fuel being fired.

One final note concerns the interpretation of boiler excess air as it relates to excess air at the burner. For boilers with a single burner, the percent excess air at the <u>burner</u> is said to be the same as the <u>boiler</u> excess air (percent excess air at the stack). For multi-burner boilers, the situation can be complicated if the fuel and air are not equally distributed to all the burners. With equal fuel and air distribution, the fuel/air ratio and percent excess air at all burners is the same and equal to the percent boiler excess air. However, when the fuel and/or air varies from burner to burner (due to dissimilar air register settings, eroded fuel injection orifices, coal pipe obstructions, etc.), the fuel/air ratio and burner excess air will also vary. The use of "overfire" air or other air injection ports away from the burner region will of course result in less excess air at the burner than indicated by the stack O_2. This situation generally occurs only with stoker fired boilers where the concept of burner excess air is not usually applicable due to the non-uniform or time-dependent nature of solid fuel bed burning. In this case, stack excess O_2 is still an important measurement.

Casing or setting air leaks on induced or balanced draft units can also distort the O_2 readings. In these cases comparison of overfire O_2 and stack O_2 readings can verify the presence of air infiltration to the furnace.

2.2 NITROGEN OXIDES

Combustion temperatures on the order of 3500°F are reached in the flame zone of industrial boilers. When oxygen and nitrogen are both present at such high temperatures, a fraction of these will combine to form NOx. Nitrogen oxides formed in this manner are difficult to prevent altogether, since all three ingredients (oxygen, nitrogen and high temperature) are integral parts of the combustion process. Nitrogen is the major constituent in the combustion air and its elimination would be very impractical. Most of the NOx reduction techniques described in following sections are generally viewed to be effective as a result of lower peak flame temperature, reduced availability of oxygen in the flame or a combination of both. Oxygen and temperature are important flame parameters affecting stability, radiant heat release, combustible burnout, flame appearance and other boiler operation related factors. Therefore, the successful application of NO_x reduction techniques involve more than just reducing NO_x emission levels.

Equal consideration must be given to these other factors to assure safe, reliable and efficient operation. This aspect of implementing low NO_x firing will involve a certain amount of subjective interpretation of flame conditions in the furnace coupled with an evaluation of boiler efficiency, steam conditions and other boiler operational factors.

Nitrogen oxides produced by the combining of atmospheric nitrogen and oxygen under the influence of high flame temperatures is generally referred to as "thermal NO_x". Conventional solid and liquid fuels (even some natural gas fuels) contain quantities of nitrogen bearing compounds. A fraction of this nitrogen also combines with oxygen in the flame to produce what is called "fuel nitrogen NO_x" or simply "fuel NO_x". This "fuel NO_x" plus the "thermal NO_x" make up the total NO_x emitted from the stack. In some cases with a high nitrogen content fuel, the "fuel NO_x" can contribute more than half of the total NO_x emissions.

The formation of "fuel NO_x" is not presently well understood. There is some evidence that "fuel NO_x" can be reduced by lowering the available oxygen in the flame. Switching to a fuel which contains less nitrogen has also produced lower total NO_x; however, this is not always predictable for fuel variations within the same fuel type (i.e., #6 oils, bituminous coals, etc.). It should also be mentioned that measurements of total NO_x at the stack or furnace outlet will not distinguish between "thermal NO_x" and "fuel NO_x". NO_x variations measured under various boiler operating modes may result from combined effects on both NO_x components.

Finally, while oxygen availability and flame temperature appear to be the major combustion parameters affecting NO_x formation, the absolute levels of NO_x emitted from the stack will also depend on a variety of other factors. As described later on, different types of fuels generally exhibit a different range of NO_x emissions. This is due to differences in fuel nitrogen already mentioned plus fundamental differences in the fuel burning characteristics, general requirements of the associated burning equipment (stoker versus oil gun) and so on. For a particular fuel composition, boiler-to-boiler variation in NO_x emissions also suggest the importance of burner and furnace design and the specific flow patterns of the flame within the furnace. At any given boiler with a constant fuel, the NO_x emissions are also generally dependent on firing rate.

2.3 BOILER EFFICIENCY

The term "boiler efficiency" as used in this manual pertains to the thoroughness by which the boiler extracts the total available heat energy from the fuel. Some loss of heat from the boiler is unavoidable and as a consequence, boiler efficiency is always less than 100%. However, some of these efficiency losses can be minimized or eliminated by proper operating and maintenance practices.

Boiler efficiency losses arise from four major sources:

1. Heat carried away (out the stack) by the hot flue gases. This loss is usually called "dry flue gas" loss. Hotter stack temperatures and larger quantities of excess air increase this loss.

2. Latent heat of water vapor present in the flue gas. (Water vapor results from the combustion of hydrogen contained in the fuel and from moisture present in the fuel and combustion air.) This loss arises from the fact that water <u>vapor</u> contains more heat energy than an equal weight of <u>liquid</u> water. The latent heat would be recovered only if the water vapor were allowed to condense out before the flue gases leave the boiler. Since this would be impractical in conventional boiler systems, (due to corrosion problems and reduced plume rise), the latent heat is not considered recoverable.

3. Unburned fuel and products of incomplete combustion. These include solid combustibles in refuse, carbon carryover from the furnace, and all other solid and gaseous combustible material carried away in the flue gases. This loss is usually referred to as "combustible loss" or "unburned fuel loss." Improperly adjusted burning equipment or an inadequate quantity of excess air can lead to rapid increases in combustible losses.

4. Heat lost from the boiler jacket through its insulation. This is generally termed "radiation loss" and includes heat radiated to the boiler room and the heat picked up by the ambient air in contact with the boiler surfaces. The quantity of heat lost in this manner is fairly constant at different boiler firing rates and as a result, becomes an increasingly higher percentage of the total heat losses at the lower firing rates. Deteriorated insulation and furnace wall refractory will also increase these losses at all loads.

Figures 2 and 3 illustrate how the various efficiency losses are affected by changes in excess O_2 and firing rate. These results are based on actual measurements at a 13,000 lb/hr boiler fired with natural gas but the general trends are also representative of many natural gas, oil and coal fired boilers. Of course, the actual values of the various efficiency losses will be different depending on specific fuel properties, boiler/burner design, operating conditions, etc.

At each firing rate the highest boiler efficiency is achieved by firing with the lowest practical excess O_2. For the particular example in Figure 2, the point of maximum efficiency occurred at about .5% excess O_2 where the total efficiency losses were at a minimum. (Excess O_2 levels at peak efficiency can vary significantly from boiler to boiler and with different fuels. These can be determined at a boiler by a test procedure described in Sections 3.0 and 4.0.) A further reduction in excess O_2 caused rapid increases in carbon

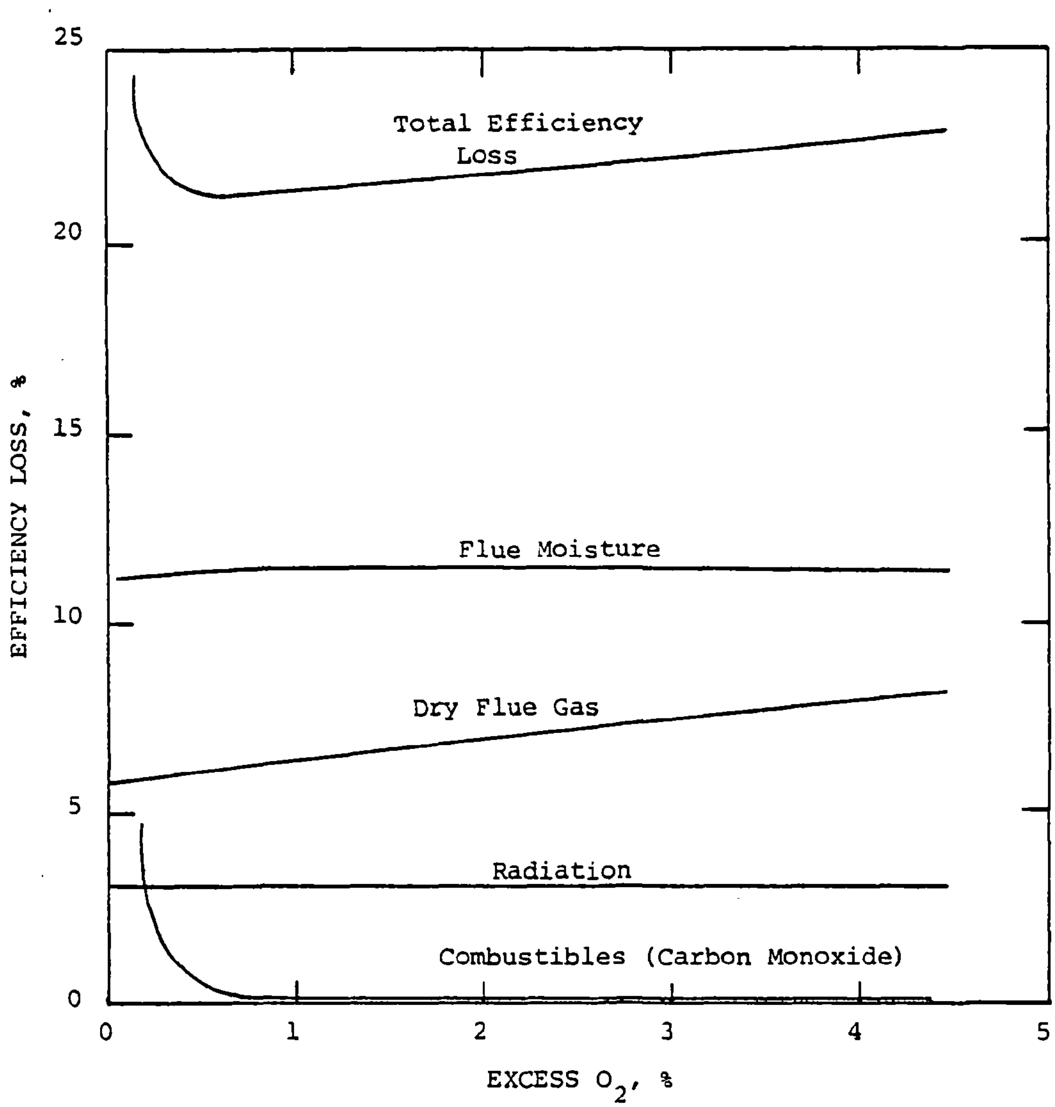

Figure 2. Variation in boiler efficiency losses with changes in excess O_2.

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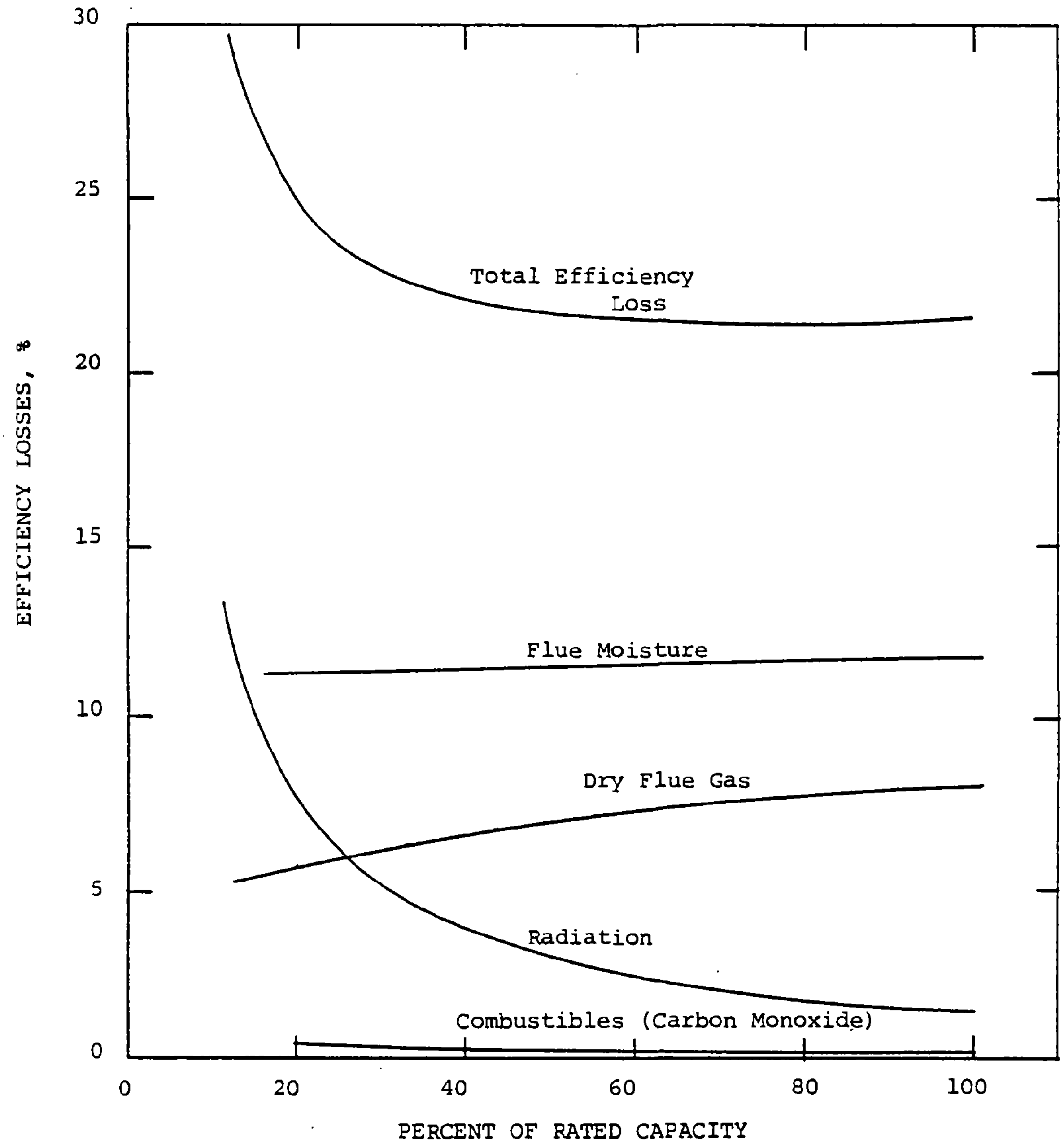

Figure 3. Variation in boiler efficiency losses with changes in boiler firing rate.

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monoxide and other combustibles which resulted in a very rapid deterioration in efficiency.

With high excess O_2, some fuel is used to heat unneeded excess air to the stack temperature where it is carried out the stack (resulting in higher "dry flue gas" losses and reduced efficiency). It might at first seem that large quantities of excess air would mix with the flame and cool it, resulting in a lower stack gas temperature. In practice, however, the reverse is true. High excess air does cool the flame and cool the furnace. But, at the same time, the boiler must fire more fuel to generate the same quantity of steam and proportionately greater amounts of air are fed through the burner. Consequently, greater amounts of gas pass through the boiler so quickly that they retain their heat instead of transferring it to the tubes. This explains why stack temperatures generally increase as the excess O_2 is raised, contributing to reduced efficiency.

It would be desirable to operate at the point of peak efficiency at each firing rate to minimize fuel wastage. However, as described later in this manual, there are certain limitations in typical boiler combustion controls which require that boilers be operated at some point slightly below peak efficiency to avoid combustibles and potentially unsafe conditions.

Figure 3 illustrates that there are significant changes in efficiency losses as the firing rate is varied. Especially obvious are the "radiation loss" which increases at lower firing rates and the "dry flue gas" loss which increases at higher firing rates. These characteristics and the "total efficiency loss" curve shown in the figure are very representative of many industrial boilers. Lowest losses (highest efficiencies) occur over the range of firing rate from approximately 50% to 80% of capacity. Operating the boiler in this range as much of the time as possible would therefore be desirable from a fuel efficiency standpoint.

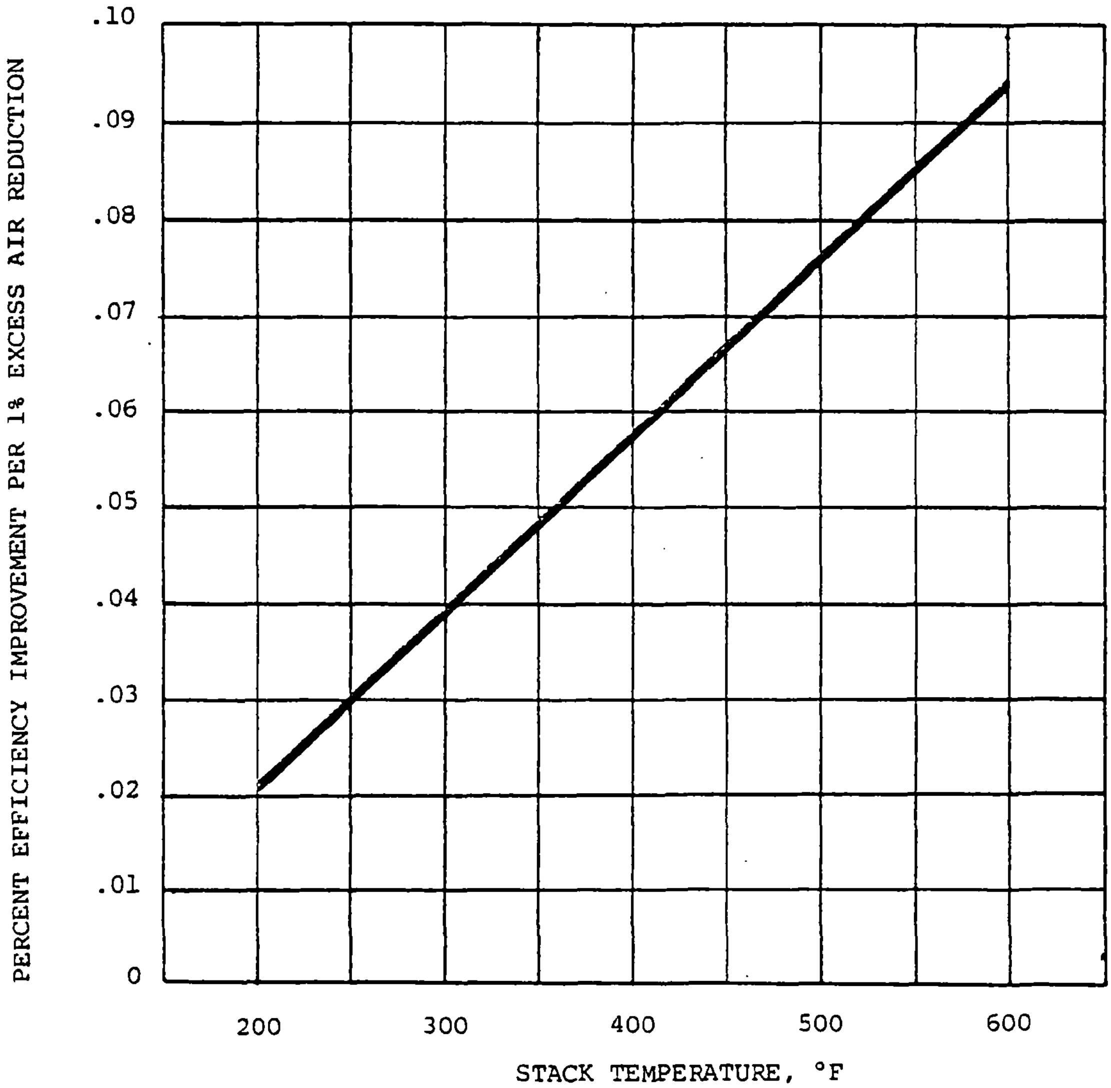

Figure 4. Curve showing percent efficiency improvement per every one percent reduction in excess air. Valid for estimating efficiency improvements on typical natural gas, #2 through #6 oils and coal fuels.

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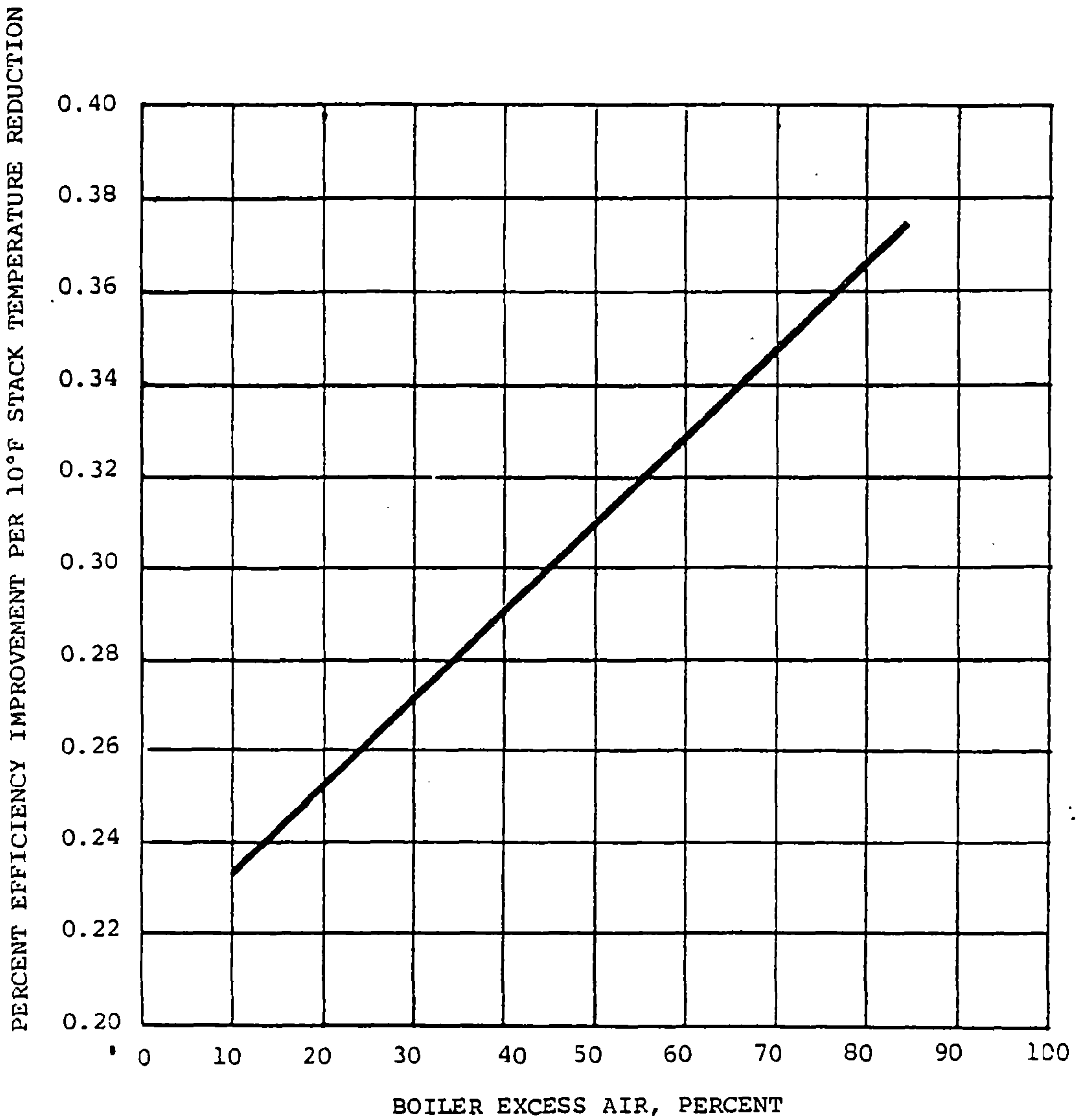

Figure 5. Curve showing percent efficiency improvement per every 10°F drop in stack temperature. Valid for estimating efficiency improvements on typical natural gas, #2 through #6 oils and coal fuels.

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Later in this manual, the basic approach and test equipment necessary to identify the point of maximum efficiency will be described in detail. Once this information is available for a particular boiler, it can be used together with NO_x emissions measurements to determine the optimum boiler operating practice for high efficiency and reduced NO_x.

The efficiency improvement for a boiler at each firing rate will depend on the reductions in excess O_2 possible and the stack temperatures. To aid in determining the actual efficiency improvements, Figure 4 gives the approximate percent efficiency improvement corresponding to each 1% reduction in excess air. Since reductions in excess O_2 will be measured directly, use Figure 1 to convert excess O_2 to excess air and then determine the efficiency improvement at the proper stack temperature. For example, if the excess O_2 was reduced from 6% to 3.5%, from Figure 1 it is determined that the excess air dropped from 40% to 20%, a 20% total change. If the stack temperature was 400°F, the efficiency improvement was 20 times .058 or 1.16 percent.

Reductions in stack temperature will also generally occur as the excess O_2 is lowered. To account for this effect, perform the previous calculation using the initial stack temperature and add to this improvement the efficiency improvement obtained from Figure 5. This additional improvement from Figure 5 is the effect of reduced temperature and is determined using the final lower excess air level. To illustrate, if in the previous example, the stack temperature dropped from 400°F to 370°F, as the excess O_2 was lowered from 6% to 3.5%, the effect due to the 30°F lower stack temperature would be 3 times .252 which equals .76 percent. The total improvement in efficiency is then 1.16 plus .76 for a total improvement of approximately 1.92 percent. Figures 4 and 5 can be used to estimate efficiency improvements achieved at constant firing rates on natural gas, #2 through #6 oils and common bituminous and subbituminous coals.

Some boiler operators who use these guidelines may find that their boilers' efficiency can be improved by 1 or 2 percent which might at first seem to be a small improvement having little effect on total fuel costs. However, even for the smallest boilers, these seemingly small improvements can lead to significant annual fuel savings which easily justifies the time and effort spent in achieving the improvements. Consider, for example, a 10,000 lb/hr boiler that is operated year-round with an average annual loading of one-half full capacity. If the efficiency is improved by 2 percent over the boiler operating range, the annual fuel consumption will decrease by 2.5 percent, assuming the boiler efficiency is approximately 80 percent. (Percent fuel reduction equals efficiency improvement times 100, divided by the efficiency.) If the boiler is fired with #6 oil costing $2.00 per million Btu, the annual fuel savings would be nearly $2,800. For larger boilers, this savings would increase in proportion to the size of the boiler ($28,000 for a 100,000 lb/hr boiler and so on).

SECTION 3.0

PREPARATION FOR BOILER TESTS

To reduce NO_x emissions and improve boiler operating efficiencies, it will be necessary to determine how NO_x and efficiency vary as boiler adjustments are made. To successfully accomplish this will require a preliminary boiler inspection to assess the existing condition of the furnace, burner equipment and firing parameters. Completing any necessary repairs and adjustments will insure that the subsequent efficiency and emission results are representative of the most favorable, as-designed, condition of the boiler. In some cases, this first step will itself directly lead to efficiency improvements and reduced NO_x emissions.

The other essential part of the efficiency improvement/NO_x reduction guidelines involves the actual testing to establish the optimum boiler adjustments. Discussion items will include boiler instrumentation, visual furnace observation, stack emission measurements and data sheets. Some of these areas involve procedures and equipment which have not traditionally been a part of routine boiler operating practice. Since much of this material may be new to most industrial boiler operators, a discussion of these items before describing the step-by-step test procedure would be helpful.

3.1 PRELIMINARY BOILER INSPECTION

Even when boiler equipment is in poor operating condition, "best" boiler settings for improved efficiency and reduced NO_x emissions can still be found under these conditions using the test procedures in the following section of the manual. However, it is stressed that these efficiency and NO_x emission improvements obtained under a deteriorated state of the boiler can be substantially less than the improvements achieved when the boiler equipment is in proper working order. To attain maximum fuel savings and lowest stack emissions, it is essential that the condition of the boiler be examined prior to testing and that any necessary repairs or maintenance be completed.

A comprehensive list of maintenance items which can affect boiler efficiency and NO_x emissions is provided in Reference 4. This list is a useful supplement to the manufacturer's boiler operating and maintenance manual and both should be used to ready the boiler for the efficiency and emission tests. Prior to making extensive adjustments and/or repairs, the manufacturers' field service department or other combustion consultants should be consulted. Some of the more common items to be included in the preliminary boiler inspection are summarized below.

3.1.1 Burners

For oil firing, make sure that the atomizer is the proper design and size for the type of oil and burner geometry. (There may have been a mix-up between boilers when oil tips were removed at the cleaning bench.) Inspect the oil tip passages and orifices for excessive erosion and remove any coke or gum deposits to assure a proper oil spray pattern. Check to see that oil temperatures at the burner are at recommended levels. (See Section 4.3.) Atomizing steam, if used, must be at the proper pressure. Make sure that burner diffusers are not burned off or broken and are properly located with respect to the oil gun tip. Also check that the oil gun is positioned properly within the burner throat. Any damaged or missing burner throat refractory should be replaced. Oil strainers should be in place and clean.

When firing natural gas, inspect the gas injection orifices and verify that all passages are unobstructed. Filters and moisture traps should be in place, clean, and operating to prevent plugging of gas orifices. Proper location and orientation of diffusers, spuds, gas canes, etc. should also be confirmed. Look for any burned off or missing burner parts.

Pulverized coal burner components such as pulverizers, feeders, conveyors, and primary/tempering air ducts must all be working properly. Coal fineness should be within recommended limits. All coal pipes should be cleared of any coal and coke deposits. Check burner parts for any signs of excessive erosion or burn-off. For stoker boilers, the grates must be no excessively worn causing poor burn-out in the bed or high carbon carryover. Make sure that spreaders are working properly and are in the correct location. Confirm the proper positioning of all air proportioning dampers. Proper coal sizing is also important. To minimize unburned carbon losses, the cinder reinjection system must also be operating correctly.

3.1.2 Combustion Controls

All fuel valves should be inspected to verify proper movement and clean internal surfaces. Gas and oil valve surfaces may erode with time. There should not be excessive "play" in control linkages or air dampers. Fuel supply inlet pressures to all pressure regulators should be adequate to assure constant regulator outlet pressures for all firing rates. Atomizing steam or air systems also deliver proper flows. Correct any control elements which fail to respond smoothly to varying steam demand. Unnecessary cycling of firing rate due to improperly adjusted regulators or automatic master controllers can waste fuel. All gauges should be functioning and calibrated to aid in identifying any control problems as they occur. *All safety interlocks and boiler trip circuits must be operable.*

3.1.3 Furnace

Inspect gas-side boiler tube surfaces for excessive deposits and fouling. These lead to higher stack temperatures and lower boiler efficiencies. Poor firing conditions may be the cause of tube deposit problems but proper operation of sootblowing equipment should also be checked. Periodic cleaning of tube surfaces may be a practical solution when burners and sootblowers are found to be operating as designed.

Repair any leaks in the boiler gas passages and baffling. Furnace refractory and insulation should also be inspected and any casing leaks and cracked or missing refractory repaired.

Furnace inspection ports must be cleaned and operable since visual flame observations will be an essential part of the boiler testing. Inspection ports should provide a view of the burner throat, furnace walls and leading convection passes.

3.2 STACK INSTRUMENTS

Boiler adjustments to improve efficiency and reduce nitrogen oxide emissions cannot be attempted without proper stack instrumentation. To successfully carry out these tests in a safe manner, it will be necessary to measure the following quantities at the stack:

- excess oxygen (or carbon dioxide)
- carbon monoxide
- oxides of nitrogen
- opacity (smoke density)
- stack temperature

These measurements must also be accompanied by visual furance observations to assure acceptable flame conditions.

3.2.1 Excess Oxygen

Excess oxygen concentration in industrial boiler stacks can vary from a fraction of one percent to 10% or more depending on boiler design, type of fuel, burner adjustments and firing rate. As described in Section 2.3 the lowest practical excess O_2 is usually the preferred condition for highest efficiency. It will be shown later that NO_x emissions also are generally reduced by operating with lower excess O_2.

Oxygen can be measured using portable analyzers when the boiler is not already equipped with O_2 meters. Reasonable accuracies can be obtained with an Orsat analyzer by an experienced technician using fresh chemicals. Other handheld chemical-absorbing type analyzers and "length of stain" (color-sensitive tubes) devices are commercially available. Portable or mounted electronic instruments with high accuracies are also available.

Whether using a built-in O_2 analyzer or a portable instrument, their proper calibration is essential for accurate readings and successful boiler adjustments. Follow the recommended calibration procedure for the instrument and adjust the frequency of calibration as necessary to minimize calibration "drift." By all means, start with a fresh calibration when beginning the boiler tests. When calibration gases are required, cross check newer gases, when delivered, with older ones to catch any errors in the calibration gas itself. For analyzers involving absorbing chemicals (such as Orsat analyzers), make sure the absorbing chemicals are fresh and establish a routine for renewing chemicals based on the number of samples analyzed and the age of the chemicals. These general remarks concerning instrument calibration also apply to the other stack measurements.

3.2.2 Carbon Monoxide

On natural gas fired boilers, carbon monoxide (CO) is the primary indicator of incomplete combustion and will usually determine the lowest practical excess O_2 for the boiler. Carbon monoxide concentration in the stack gases should not exceed 400 ppm once the final boiler adjustments are made. For purposes of testing,

*Some city ordinances, industry codes and insurance organizations require that CO not exceed this value.

occasional CO levels of up to 1000 or 2000 ppm can be acceptable provided adequate boiler monitoring and flame observation are possible to assure stable conditions. Use caution at these conditions. Further reducing the excess air will result in very rapid increases in CO and other combustibles which can lead to smoking, flame instability, furnace pulsation and boiler explosions.

Carbon monoxide measurements on oil and coal fired boilers are not generally mandatory since smoking or excessive carbon carryover will usually precede any substantial CO emissions. However, this cannot always be anticipated. For example, high CO levels have been measured in cases where burner equipment has deteriorated or malfunctioned (burned off impellers, plugged oil tips, insufficient overfire air, etc.). High CO emissions can also be encountered at high excess O_2 levels where the air flow has been increased to the point of influencing flame stability. For this reason, it is recommended that CO measurements be included on all boilers to assure that there are no burner equipment problems complicating the efficiency and NO emission test results.

The CO analyzer should be capable of measuring up to 2000 ppm and should also have sufficient sensitivity to measure down to the 100 ppm range. Orsat analyzers have traditionally been used for CO determinations but difficulties in accurately reading the lower CO concentrations (less than 1000 ppm) has spurred the use of handheld "length of stain" type detectors which reportedly provide the necessary sensitivities and measurement range. Portable or mounted electronic instruments are also available.

3.2.3 Oxides of Nitrogen

To assist in selecting NO_x instrumentation with the proper range of measurement, the following table shows the range of NO_x emissions found during field testing at industrial boilers throughout the country (Refs. 1, 2 and 5, and other sources.) These NO_x emission levels generally correspond to boiler firing rates near 80 percent of rated load. Since NO_x usually increases with firing rate, these values are close to the highest NO_x emissions found during normal boiler operation. Note that higher NO_x emissions also generally occur on boilers equipped with combustion air preheaters.

Fuel Type	Typical Range of NOx Emissions, ppm: Without Air Preheaters	With Air Preheater
Coal:		
Pulverized	300-600	400-800
Stoker	200-400	250-450
Cyclone	800-1100	900-1500
Fuel Oils:		
#2	50-250	100-300
#5 (PS 300)	200-400	200-600
#6	200-400	200-600
Natural Gas:	50-200	100-400

Total NO_x emissions from industrial boilers consist mainly of nitric oxide (NO) with the remainder made up of small quantities of nitrogen dioxide (NO_2). Since NO comprises more than 90% of total NO_x and accurate NO_2 measurements are difficult, NO measurements are often taken as representative of total NOx emissions from the boiler. There are a number of commercially available electronic instruments capable of measuring NO in concentrations typical of industrial boilers. They may differ significantly in measurement method, accuracy and price. Selection should be made with the guidance of a reliable vendor. Less expensive hand-held "length of stain" detectors sensitive to total NO_x (NO plus NO_2) are also available.

To properly interpret NOx emission results, the measured NO_x reading obtained from the analyzer must be corrected to account for diluting effects of excess air in the flue gas. This is important when boiler excess air is varied and it is desired to know the resulting effect on NO_x emissions. For example, as excess air is raised, NO_x formation in the furnace may increase, but at the same time, the additional air will dilute the flue gas and measured NO_x readings at the stack may actually be reduced.

To illustrate this point further, suppose a large air fan is installed at the boiler outlet to inject large quantities of outside air into the flue gas. The operator could then adjust the fan to dilute the stack gases and obtain any desired NOx concentration less than the furnace outlet concentration. However, if NOx readings are corrected to some standard excess air (or excess O_2) condition, the "corrected" NOx values will be the same regardless of how much diluting air is added. The purpose of correcting NOx readings is not to prevent the use of diluting air fans or other similar devices. The primary purpose is to provide a consistent basis of comparing NO_x emissions and to eliminate the diluting effect of excess air when making these comparisons.

The accepted industry practice is to correct NO_x readings to a standard condition of 3% excess O_2. To do this, multiply the measured NO_x reading in ppm (measured on a dry or moisture-free basis) by an O_2 correction factor which is easily calculated. To determine the O_2 correction factor, divide 18 by the quantity 21 minus the percent excess O_2 measured in the stack, as shown below:

$$O_2 \text{ correction factor} = \frac{18}{21 - \%\ O_2}$$

For example, if the NO_x reading in the stack is 200 ppm and the excess O_2 at the same time is measured as 5.0%:

Corrected NO_x equals raw NO_x multipled by the O_2 correction factor, or,

$$\text{Corrected } NO_x = (\text{raw } NO_x) \times (O_2 \text{ correction factor})$$

$$= 200 \times \frac{18}{21 - 5.0}$$

$$= 200 \times \frac{18}{16}$$

$$= 200 \times 1.125 = 225 \text{ ppm}$$

Remember that the corrected NO_x will not necessarily remain constant as boiler excess air is varied (since NO_x formation is not constant). Raw NO_x readings must be obtained at each O_2 level and then corrected for the corresponding O_2.

3.2.4 Stack Opacity (Smoke Density)

Smoking with oil and coal fuels is a certain indication of flue gas combustibles or unacceptable flame conditions and should always be avoided. Some oil and coal fired boilers (especially larger capacity boilers) are equipped with a smoke detector which can be very useful in providing indications of poor stack conditions when properly calibrated. Ultimately, acceptable stack conditions are always confirmed by visual observation of the stack.

Accurate smoke measurements can be made on smaller boilers using inexpensive portable hand pump, filter paper testers. These provide spot check measurements but cannot be used for continuous stack monitoring. These devices use the smoke spot number or ASTM smoke scale (ASTM D2156) and can be very helpful in setting up optimum boiler operating conditions.

3.2.5 Stack Temperature

Tube deposits and fouling on the external tube surfaces of a watertube boiler or similar gas side conditions in the gas tubes of a firetube boiler will inhibit the absorption of heat in the boiler and lead to lower efficiencies. This condition will be reflected in high flue gas temperatures when compared to "clean" conditions at a similar firing rate and boiler excess air. The resulting loss in boiler efficiency can be closely estimated on the basis that a 1% efficiency loss occurs with every 40°F increase in stack temperature. It should be mentioned that water side deposits resulting from inadequate water treatment would also eventually lead to higher stack temperatures, however, tube failures due to overheating generally occur before any substantial efficiency losses are evident.

Stack temperature measurements are an easy and effective means for monitoring boiler tube cleanliness conditions. Stack temperatures should be periodically compared to values obtained during start-up or following a boiler tube wash to determine any deviations from "clean" baseline temperatures. Since stack temperature usually increases with firing rate and excess air, these comparisons should be performed at similar boiler operating conditions. In the absence of any previous data, the stack gas temperatures will normally be about 150 to 200°F above the steam temperature in a saturated steam boiler at high firing rates. Naturally, this does not apply to boilers equipped with economizers or air preheaters. The boiler manufacturer should be able to supply a normal range of stack temperatures for the particular boiler design. When higher stack temperatures are measured, boiler tube cleaning may be warranted.

3.3 FLAME APPEARANCE

The appearance of an industrial boiler's flame can provide a good preliminary indication of combustion conditions. It is difficult to generalize the characteristics of a "good" flame since there is a certain amount of operator preference and variations due to burner design involved. This is especially true for stoker-fired coal boilers. For other types of combustion equipment, flames of a definite appearance have usually been sought. Short, bright, crisp, and highly turbulent oil and pulverized coal flames have been desired. Blue, slightly streaked, or nearly invisible flames have been sought for gas fuels. (However, operation with low NO_x emissions at reduced excess O_2 levels may result in a different flame appearance as discussed on the next page.) Stability of the flame at the burner and minimum furnace vibration are also universally desired. For underfed stoker boilers, an even bed and absence of carbon streamers are important criteria.

All too often, good flame appearance is achieved by operating with excess O_2 levels higher than necessary for safe, clean firing. Reducing the excess O_2 to the lowest practical levels for the boiler is the primary concern of these guidelines.

At the other extreme, firing with insufficient excess O_2 has also been encountered at industrial boiler installations. This condition is usually limited to natural gas firing where very high combustibles can occur with improper burner settings and inadequate combustion quality checks. These guidelines are intended to assist in correcting both conditions.

When firing with the lowest practical excess O_2, approximately the same amount of heat energy is released in the furnace for a given amount of fuel heat energy input. However, this process may take a longer period of time and utilize more furnace volume before the fuel is completely burned. The result of low excess O_2 firing is a flame which may have the following typical characteristics:

- Flames that actually grow in volume and more completely "fill" the furnace
- Flames exhibiting a lazy "rolling" appearance. Instead of intense, highly turbulent flames, low O_2 flames may appear to flow somewhat slower through the furnace.
- The overall color of the flame may change as excess O_2 is lowered. Natural gas flames become more visible or luminous with yellow or even slightly hazy portions. Coal and oil fires become darker yellow or orange and may appear hazy in parts.

These characteristics are, for the most part, contrary to flame conditions traditionally desired by industrial boiler operators for clean, dependable firing. While this might seem discouraging, it is stressed that safety, reliability, and low particulate and soot emissions can still be achieved with low O_2 firing. This is true only if the required stack measurements are made and recommendations in these guidelines are followed. It should be mentioned that in many cases, firing with low excess O_2 will not necessarily produce any drastic changes in flame appearance.

You may find that the boiler is already being fired with the lowest practical excess O_2. If this is the case, these guidelines will still be of benefit by helping to assure that high efficiencies and low NO_x emissions will be maintained.

3.4 STACK SAMPLING TECHNIQUES

To obtain measurements of excess O_2, CO, NO_x, and smoke, most of the analyzers previously mentioned require that a sample of flue gas be withdrawn from the stack and delivered to the analyzer. Some analyzers require a continuous flow of sample until a "steady" reading is obtained, while others require only a small volume of sample at one time. An exception are analyzers mounted "in-stack" with detector elements located in the flue gas stream. Regardless of the analysis technique, it is essential that the portion of the stack gases analyzed be a representative sample of the bulk of the stack gas flow.

The location of the sampling site at which the sample of flue gas is obtained is as important as the selection of proper measurement devices. Air leakage into the gas ducts on negative draft boilers can dilute the flue gas, and consequently, measurements will not give true indications of furnace conditions. Air leakage in air preheaters poses the same problem. When selecting a sampling site, choose it upstream of the air preheater or any known air leaks when possible. Seal all known air leaks upstream of the sample location.

The sample site should also be removed from an area where the flue gas is highly turbulent, such as immediately downstream of bends, dampers, or induced draft fans. Flue gases can stratify or form "pockets" which can lead to errors especially when samples are withdrawn from a single point in the duct. When a single-point sample probe is used, it is recommended that readings at several points in the duct be compared to determine the most representative probe location. When existing sample ports are not adequate, it is well worthwhile to drill or cut out new ports to obtain accurate, reliable measurements.

Flue gas temperatures are also subject to stratification in the ducts and a representative location of the thermometer or other temperature sensors should be verified. The location should be close to the boiler outlet since temperature losses can occur in the flue gas ducting, especially in uninsulated sections.

3.5 BOILER TEST PROCEDURES

The two major aspects of the boiler testing are (1) determining the optimum boiler firing conditions over the turndown range, and (2) making the burner adjustments necessary to maintain these optimum conditions during normal automatic operation. The step-by-step test procedures in the following section deal mainly with the first aspect.

The second part of the testing is very dependent on the particular design of the boiler controls. To successfully accomplish the burner adjustments will require a working knowledge of the control system. For example, its design will dictate to a large extent the number of firing rate conditions necessary to be examined. An adjustment at one firing rate may affect conditions at other firing rates and these effects must be recognized and anticipated. It would not be desirable to improve efficiency and NO_x emissions at one firing rate only to create poor conditions at another. It is not within the scope of these guidelines to supply detailed combustion control knowledge. Rather, it is intended that the boiler operation and maintenance manual supplied with the boiler will provide the necessary information and that any further questions can be directed to the plant engineering staff, the boiler manufacturer or other combustion specialists.

It is also assumed in these guidelines that it will not be necessary to elaborate on appropriate methods for varying burner excess air. Again, this will be dependent on the design of the burner and controls and can involve any number of air flow control devices such as forced draft fan inlet dampers, windbox dampers or stack draft dampers. Final adjustments to achieve the correct excess O_2 can involve adjustments to jackshaft control linkages, fuel valve cam profiles, fuel/air set points, etc.

The key word in applying combustion modifications is CAUTION. Be careful while making any adjustments and know at all times the impact on fuel flow, air flow, or the control system. Make sure that all boiler safety interlocks and trip circuits are functioning. Consult plant engineering personnel or the boiler manufacturer if you have any uncertainty about the procedures or expected outcome of any adjustment. Flame appearance can give many clues as to combustion conditions--observe the fires, but don't rely solely on flame appearance. As described is Section 3.3, flame appearance can change for low NO_x operation. Carefully watch boiler instrumentation and the stack while making changes. If in doubt, always check for combustibles (CO) in the flue gas. Conducting these tests may require additional manpower so that controls and instrumentation, flame appearance, and stack conditions can be monitored simultaneously during adjustments. All personnel should be familiar with the test objectives and fully instructed regarding their part in the test.

To obtain maximum benefit from the boiler tests, all pertinent test data should be recorded. The permanent record of boiler operating conditions and stack measurements will not only document the boiler's efficiency and emission characteristics, but also enable future comparisons to help diagnose any efficiency or emission problems. The test data should be recorded on prepared data sheet forms and include the following items:

1. Identification of boiler, fuel type, date of tests and names of operating personnel involved.
2. Steam, feedwater and fuel conditions (flow rates, pressures and temperature) to document boiler firing rate and steam generation.
3. Combustion control position and burner settings.
4. Furnace pressures, temperatures, and damper settings.
5. Stack measurements (O_2, CO_2, CO, NO_x, smoke, temperature). Make note of sample probe position.
6. All relevant comments on flame appearance, carryover and furnace conditions.
7. Record any new permanent changes made to combustion controls or burner settings.

The actual boiler readings included will of course depend on the available instrumentation. Make sure that adequate data are obtained so that exact boiler operating conditions can be repeated for future comparative purposes. A sample data sheet is shown in Figure 6, but additions or deletions will most likely be necessary for each particular boiler. It may be worthwhile to review the final form of the data sheet with the engineering staff and incorporate any additional data entries that may be of mutual interest.

Readings should be recorded only after steady boiler conditions are reached. This is usually indicated by steady stack temperature, fuel input, steam conditions (pressure and temperature and drum level). Steady excess O_2 readings in the stack are a good indication that fuel and air flows have stablized.

It is very desirable that these tests be conducted at normal steam pressures. This will assure that stack temperatures and furnace temperatures are representative of normal operating conditions. Since it will usually be necessary to control the boiler firing rate manually during the tests to obtain stable conditions, this may pose some problems in satisfying normal steam demands. When alternate

NO_x REDUCTION TEST

PLANT ______________________ TESTS BY ______________________

BOILER NO. ______________ FUEL ______________ DATE ______________

Test No.					
Time					
Steam Flow, lb/hr					
Steam Pressure, psi					
Steam Temp., °F					
Fuel Flow, cfm, gpm, lb/hr					
Fuel Pressure, psi					
Fuel Temp., °F					
Atomizing Pressure					
Combustion Air Temp., °F					
Flue Gas Temp., °F					
Windbox Pressure, "H_2O					
Furnace Pressure, "H_2O					
Stack Pressure, "H_2O					
Fan Settings					
Air Register Settings					
Burner Positions					
Smoke Density					
O_2, %					
CO, ppm					
NO_x, ppm					
Flame Appearance: NOTES:					

Figure 6. Sample data sheet.

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steam generating capacity is available, modulate the loading at other boilers to maintain constant system pressures. When this is not possible, it may be necessary to make provisions to dump unneeded steam or temporarily interrupt plant processes.

SECTION 4.0

EFFICIENCY IMPROVEMENT AND NO_x REDUCTION TECHNIQUES

The principal method described in this manual for improving boiler efficiency and reducing NOx emissions involves operating the boiler at the lowest practical excess O_2 level. These O_2 levels will be at some operating margin above the absolute "minimum O_2" which is at the threshold of smoke or combustible emissions formation. Although peak boiler efficiency will occur close to the minimum O_2, it is not practical to operate at this condition unless the boiler is equipped with highly sophisticated combustion controls and flame quality monitoring to prevent any small deviations into unsafe or unacceptable combustible conditions. Since these control features are not typical of most industrial boilers, some margin or operating "cushion" above the minimum O_2 will be necessary to accommodate normal variations in fuel properties and atmospheric conditions, repeatability and response characteristics of the combustion control system, and other operational factors.

This manual provides general guidelines for determining the lowest practical O_2 levels for a particular boiler. This will require that the minimum O_2 and the appropriate operating margin above this minimum O_2 be established and evaluated with respect to typical levels for the type of fuel and burning equipment used. If minimum O_2 levels are found to be excessive, then burner adjustments are recommended as a possible means for reducing the burner's minimum O_2 requirement. High minimum O_2 can also result from improper maintenance of burner equipment (plugged orifice, broken diffusers, etc.) but these problems will be minimized by performing the preliminary boiler inspection (Section 3.1).

The advantage of operating with low excess oxygen from the standpoint of efficiency has previously been described in Section 2.3. It was shown that with lower excess O_2, the "dry stack gas losses" are minimized leading to highest efficiencies.

The advantages of low excess O_2 with respect to NOx emissions are illustrated in Figure 7. The curves in the three graphs show how NOx emissions changed as the excess O_2 was varied on a variety of gas- oil- and coal-fired boilers. It is immediately apparent that NOx emissions can vary significantly from boiler to boiler even when compared at the same excess O_2. For the most part, NO_x emissions were reduced as the excess O_2 was lowered.

Coal fired boilers had the highest NO_x emission levels and the NO_x was generally found to be more sensitive to changes in excess oxygen than the average oil or gas fired units. The fuel nitrogen content of coal is the major factor in these higher emissions. Industrial boilers fired with natural gas showed the lowest sensitivity of NO_x to excess oxygen changes. In some cases, NO_x actually increased as excess O_2 was lowered. When this occurs, it is still desirable to operate at low excess O_2 for high efficiency but attempts should be made to reduce NO_x emissions by burner adjustments (see Section 4.3). Alternate NO_x controls are also described in Appendix A.

Setting up a boiler for low excess O_2 firing will be accomplished through a systematic, organized series of tests. Following a test that documents "as found conditions," the lowest possible level of excess oxygen for the boiler will be established. The lowest level should be found at several firing rates within the boiler's operating range. The actual number of firing rates tested will depend on the design of the boiler control system. Enough firing rates should be tested to assure that after the final control adjustments are made, the optimum excess O_2 conditions are maintained at all the intermediate firing rates. At each firing rate tested, the

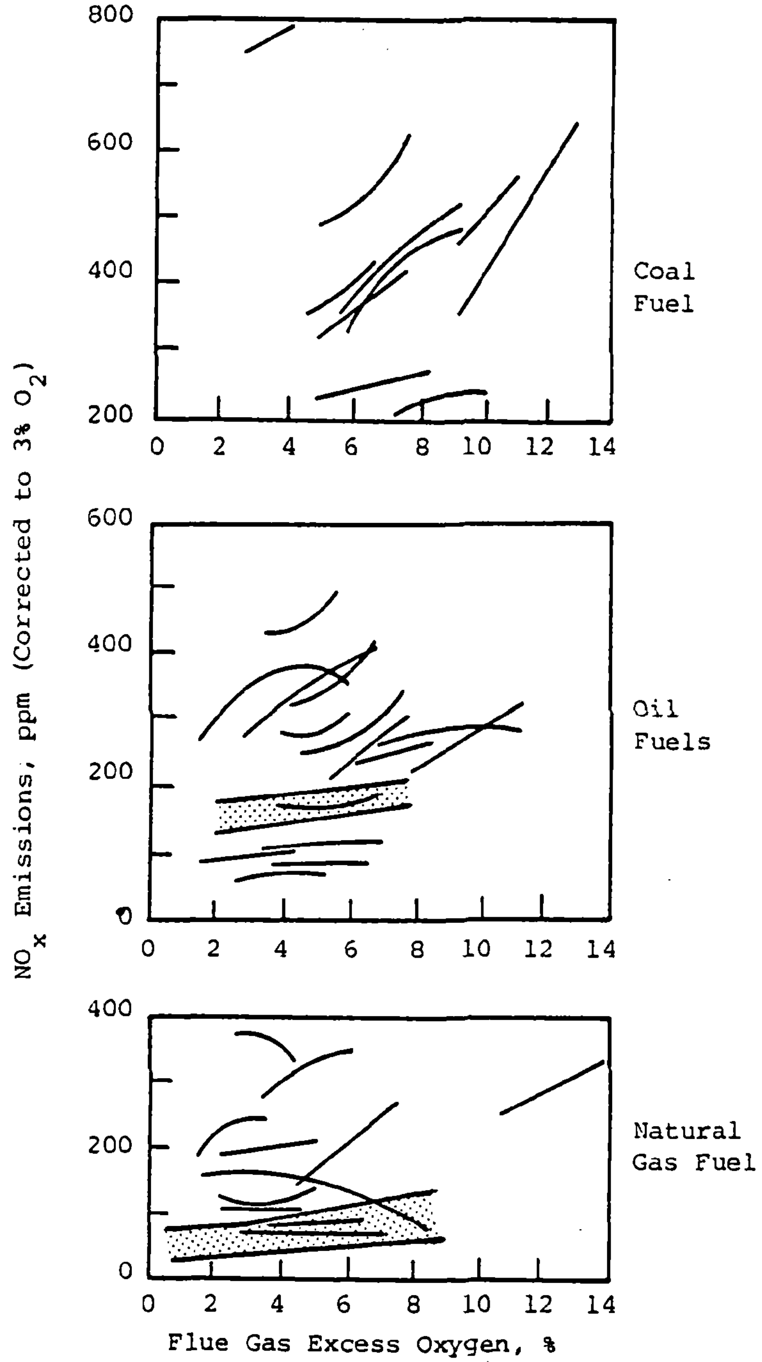

Figure 7. Effect of excess oxygen on nitrogen oxides emissions. Single lines for watertube boilers; shaded areas represent all firetube boiler data.

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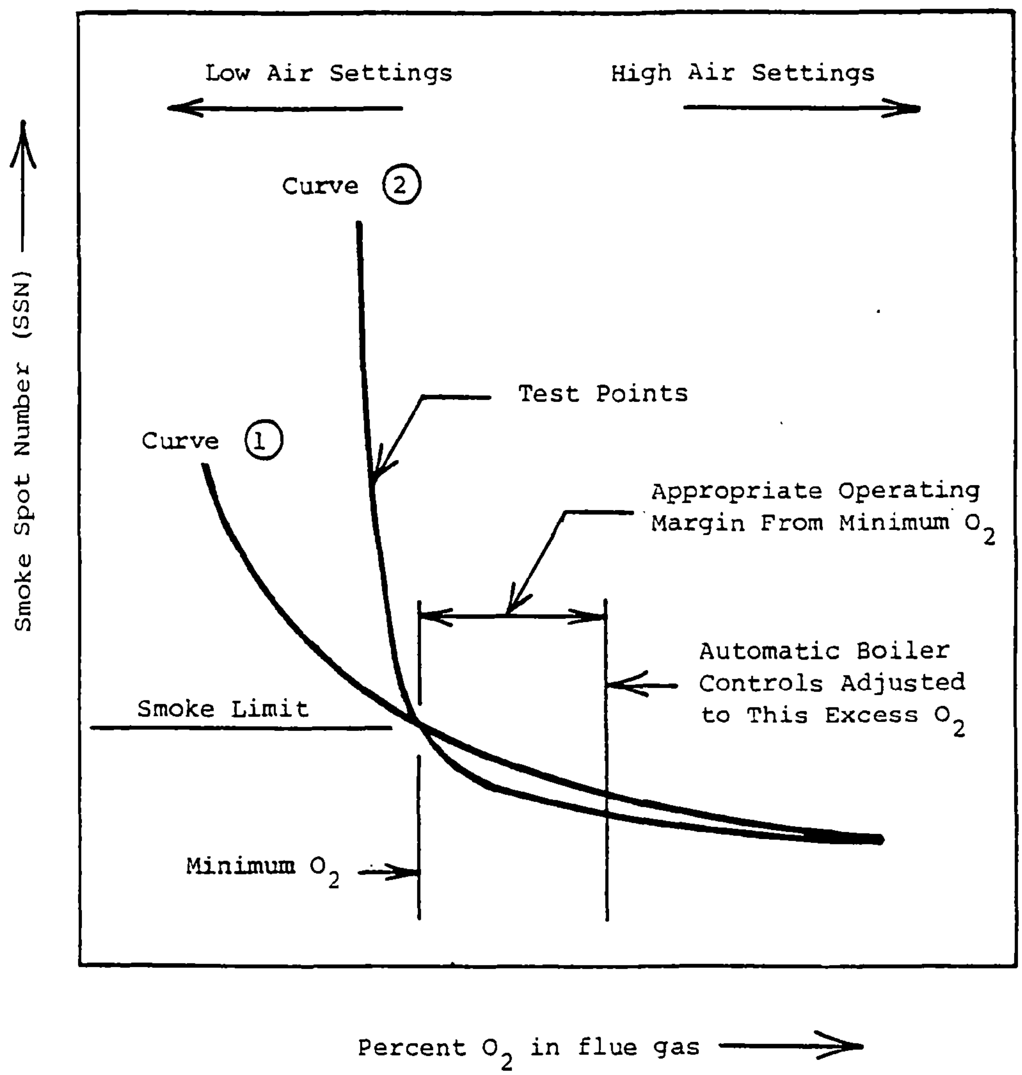
excess O_2 should be varied over a range from 1 or 2% above the normal operating point down to the point where the boiler just starts to smoke or the CO emissions rise above 400 ppm. This low excess O_2 condition is referred to as the smoke or CO threshold (limit) or simply the "minimum O_2." The smoke limit applies to coal and oil firing since smoking will generally occur before CO emissions reach significant levels. The CO limit applies to gas fuels and is the lowest possible excess O_2 level while maintaining carbon monoxide below 400 ppm.

The smoke limit for coal or oil fuels is the lowest possible excess O_2 level where acceptable stack conditions can still be maintained. In terms of the Smoke Spot Number (SSN) scale, the maximum desirable smoke number on coal fuel for acceptable stack conditions is SSN 4 (measured downstream of the dust collector). For fuel oils, the maximum smoke levels are (Ref. 6):

Fuel Grade	Maximum Desirable SSN
No. 2	less than 1
No. 4	2
No. 5 (light and heavy), and low-sulfur resid	3
No. 6	4

When performing the boiler tests to determine minimum excess O_2, curves such as those in Figures 8 and 9 will be constructed. Based on measurements obtained during the tests, these curves will show how the boiler smoke and CO levels change as the excess O_2 is varied. Each of the figures contain two distinct curves to illustrate the extremes in smoke and CO behavior which may be encountered. The curves labeled (1) exhibit a very



Curve 1 - Gradual smoke/O_2 characteristic

Curve 2 - Steep smoke/O_2 characteristic

Figure 8. Typical smoke-O_2 characteristic curves for coal or oil-fired industrial boilers.

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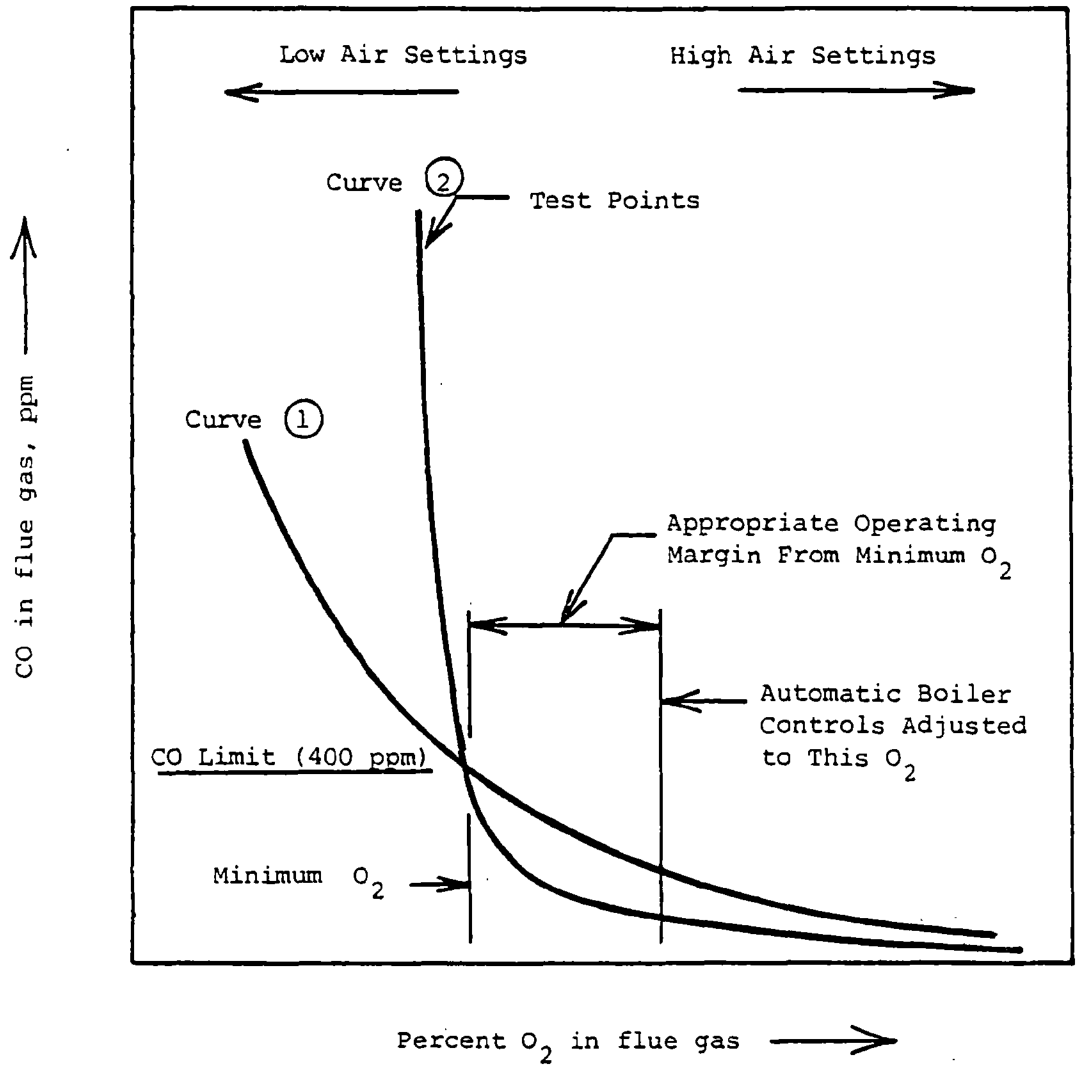

Curve 1 - Gradual CO/O_2 characteristic

Curve 2 - Steep CO/O_2 characteristic

Figure 9. Typical $CO-O_2$ characteristic curves for gas-fired industrial boilers.

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gradual increase in CO or smoke as the minimum O_2 condition is reached. In contrast, the curves labled (2) are gradual at first but as the excess O_2 is reduced further and minimum O_2 is approached, the smoke or CO emission increases rapidly. In this case, unpredictably high levels of smoke or CO or potentially unstable conditions can occur with small changes in excess O_2 and extreme caution is required. When making O_2 changes near the smoke or CO limit, do so in very small steps until there are enough data to show whether the boiler has a gradual or steep characteristic curve for smoke and CO [curve (1) versus curve (2)]. It is important to note that the boiler may exhibit a gradual smoke or CO behavior at one firing rate and a steep behavior at another.

High minimum O_2 may be an indication of a burner malfunction or other fuel or equipment related problems. But it should also be realized that different burner designs and fuels will in general have different minimum O_2 requirements. Many burners will also exhibit higher minimum O_2 at lower firing rates. For these reasons it is difficult to specify in these guidelines a range of minimum O_2 levels which would be considered normal. However, based on numerous minimum O_2 tests at industrial boiler installations, the following table has been prepared to assist in judging whether the minimum O_2 levels that are measured are typical values.

Fuel Type	Typical Range of Minimum Excess O_2 At High Firing Rates
Natural gas	0.5 - 3.0%
Oil fuels	2.0 - 4.0%
Pulverized coal	3.0 - 6.0%
Coal stoker	4.0 - 8.0%

Boiler start-up records showing initial excess O_2 conditions can provide a valuable comparison with current minimum O_2 conditions when they are available. If it is apparent that current minimum O_2 levels are higher than the expected levels, there may be a need for maintenance or repairs which should be completed before attempting the followint excess O_2 optimization procedure.

Once the minimum O_2 is established, the next step will be to determine the appropriate O_2 margin or operating "cushion" above the minimum O_2 where the boiler can be routinely operated. This will be the lowest practical O_2 for the boiler and will be the optimum setting for high efficiency (and in most cases, lowest NO_x emissions). The O_2 margin above the minimum O_2 is necessary to account for uncontrollable variations in the excess O_2 resulting from:

1. Rapid boiler modulation which could result in smoking or combustibles without an adequate O_2 margin.
2. Non-repeatability or "play" in the automatic controls (excessive "play" should be corrected).
3. Normal variations in atmospheric conditions which can also change excess O_2 on units not equipped with temperature and pressure-compensated combustion air systems. This is a very important factor which is often neglected. (Extreme variations in ambient conditions can easily produce changes in excess O_2 of 1% or more.)
4. Changes in fuel properties which may require varying amounts of excess air.

Typical O_2 margins above the minimum O_2 may range from 0.5% up to 2.0% O_2, depending on the characteristics of the particular boiler control system and fuels. If in doubt, consult the boiler manual or the manufacturer. When the boiler is going to be operated at a constant firing rate for extended periods, the lowest possible O_2 margin should be selected.

A simple test to determine whether there is excessive "play" (or poor repeatability) in the boiler controls can be made by simply repeating a firing rate condition, allowing the fuel and air controls to function in a normal manner. When performing this test, approach the particular firing rate from both the "high side" and "low side", (i.e., from higher and lower firing rates). A comparison of stack excess O_2 after the boiler has stabilized indicates whether there is excessive wear or tolerance problems in air dampers, control shafts, valve cams, controllers, etc. Excess O_2 should repeat to within a few tenths percent excess O_2.

Atmospheric variations are reflected in excess O_2 variations due to changes in air density at the forced draft fan inlet as the air pressure and temperature change. The fan will deliver a certain <u>volume of air</u> to the burner, but as the air density changes, the <u>pounds of air</u> supplied to the burner will vary, thus changing the burner excess air and excess O_2. When combustion air is supplied from the boiler room, maintaining constant boiler room temperatures will minimize this problem, but atmospheric pressure effects are unavoidable.

The boiler adjustments described below are intended for boiler operators who will make their own NO_x reduction and boiler efficiency improvement adjustments. For those who do not prefer to make their own adjustments, manufacturer's service organizations and combustion consultants perform these adjustments in what generally is referred to as a combustion "tune-up." More information on "tune-up" costs, what they include, and special requests to the tune-up crew are found in Reference 4 , "Industrial Boiler Users' Manual -- Methods and Equipment for Efficiency Improvement." This reference also describes other operating and manufacturer practices that improve efficiency, and efficiency improvement equipment currently available.

4.1 STEP-BY-STEP BOILER ADJUSTMENT PROCEDURE FOR LOW EXCESS O_2 OPERATION

1. Bring the boiler to the desired firing rate and put combustion controls on "Manual." Make sure all safety interlocks are still functioning. It is often convenient to use a felt tip pen to mark the linkage setting to retrace the direction and position of the adjustments.

2. After the boiler has stablized, observe flame conditions and take a complete set of boiler and stack readings. This will serve to document the existing operating conditions at the particular firing rate. If the current excess O_2 is found to be close to the lower range of typical minimum O_2 values in the previous table and if CO and smoke are at acceptable levels, it is quite possible that the boiler is already operating near the optimum excess O_2 at this particular firing rate. It may still be desirable to proceed through the following steps to determine whether lower excess O_2 levels are practical. In any event, do not assume that O_2 settings at other firing rates are also close to the optimum.

3. Raise the excess air until the stack excess O_2 has increased by 1 or 2 percent. Take readings after the boiler has stablized and note any changes in flame conditions.

4. Return excess air to the normal level and then begin to slowly reduce the excess air in small steps. Watch the stack for any signs of smoke and constantly observe the flame. Take a set of stack readings following each change. Do not attempt to reduce the air by throttling the burner air registers as this alters the fuel and air mixing characteristics and complicates the tests. Watch out for low windbox/furnace pressure emergency shutdown safety interlocks ("fuel trip" set points) at low firing rates.

5. Continue to reduce the excess air stepwise until one of the following limitations is encountered:

- Unacceptable flame conditions such as flame impingement on furnace walls or burner parts, excessive flame carryover or flame instability.

- High carbon monoxide (CO) in the flue gas. The CO limit is 400 ppm but higher levels not exceeding 1000 to 2000 parts per million are tolerable during the tests. Use caution since CO can increase very rapidly with small changes in excess air.

- Smoking at the stack. Do not confuse smoke with water vapor, sulfur, or dust plumes which are usually white or gray in appearance. The smoke limit for No. 2 oil is a Smoke Spot No. less than 1 and for No. 6 oil or coal the smoke limit is Smoke Spot No. 4. Higher smoke might be tolerated for test purposes but remember to observe any local air pollution ordinances.

- Incomplete burning of coal fuels leading to high carbon carryover or increased quantities of solid combustible matter in the refuse.

- Equipment related limitations such as low windbox/ furnace pressures or built-in air flow limits.

6. Obtain as many readings of CO, excess oxygen, smoke number and nitrogen oxides as necessary to establish curves similar to the samples in Figures 8 and 9. Plot the data on a chart or graph paper. Correct NO_x emissions to 3% O_2 (see Section 3.2.3) and plot on the same graphs to see how NO_x varies with excess O_2.

7. The lowest or minimum excess O_2 requirement for the boiler was determined in Step 6 but do not adjust the burner controls to this value. While this may be the point of maximum efficiency and lowest NOx, it is usually impractical to operate the boiler right on the verge of the combustible or smoke threshold.

Compare the minimum O_2 value to the expected value provided by the boiler manufacturer. Typical values of minimum excess O_2 for various fuels are also given in a previous table (Section 4.0). If the minimum O_2 is substantially higher than the typical values, burner adjustments may be possible to improve the fuel and air mixing, thereby allowing operation at lower O_2 levels. (See Section 4.3.)

8. Establish the margin in excess O_2 above the minimum O_2 required for fuel variations, load changes, and atmospheric conditions. Add this margin to the minimum excess O_2 and reset the burner controls to maintain this excess O_2 when operating on automatic.

This is the lowest practical excess O_2 for the boiler at the particular firing rate. The boiler efficiency at this condition is as close as practical to the peak efficiency which usually occurs near the minimum excess O_2. For most boilers, NO_x emissions will be reduced at the new excess O_2 setting. However, if NO_x emissions increase from previous levels, it is still desirable to operate at this low excess O_2 for high efficiency but attempts should be made to lower NO_x by burner adjustments . Alternate NO_x reduction techniques requiring special boiler modifications, engineering design, and economic analysis should also be considered (see Appendix A).

9. Repeat Steps 1 through 8 for each firing rate to be tested. For some control systems it will not be possible to set up the optimum excess O_2 at each firing rate since control adjustments at one firing rate may also affect conditions at other firing rates. In this case, use some judgment to choose the best settings that give good performance for a range of firing rates. A trial-and-error approach involving repeated tests may be necessary. If one firing rate is predominant, the setting should be made to optimize conditions at that rate.

10. After the control adjustments have been completed, verify that these new settings will be acceptable during sudden load changes which may occur in daily operation. While making rapid load pick-ups and drops, observe the flame and stack to establish

any unacceptable conditions. Utilize stack continuous monitors (O_2, CO, opacity) when available. If undesirable conditions are detected, reset the combustion controls to provide a slightly higher excess O_2 at the particular firing rates. Verify these new settings in a similar fashion. Make sure that the final control settings are documented under steady boiler operating conditions for future reference.

11. It may be advisable not to perform any adjustments at or near "low fire." The quantity of excess air at these conditions is usually dictated by flame ignition characteristics and stability which can be critical and difficult to evaluate.

If the boiler operates near "low fire" a large fraction of the time due to sporadic steam demand, the manufacturers' service organization or other consultants can be helpful in establishing the best excess O_2 levels.

12. When an alternate fuel is fired, perform these tests and adjustments for the second fuel. In some cases it may not be possible to achieve optimum excess O_2 on both fuels at all firing rates. In these cases, use judgment to set up the best conditions at normal firing rates.

4.2 EVALUATION OF THE NEW LOW O_2 SETTINGS

After the boiler has been set up for low O_2 operation and returned to normal automatic firing, it is good practice to pay extra attention to the boiler for the first month or two until confidence is gained in the new operating mode. Watch for any signs of unusual furnace tube fouling or flame patterns which might be corrected by further burner adjustments. During the next boiler shutdown, thoroughly inspect the burner and furnace surfaces. Be alert for any equipment or operating changes that may alter the minimum O_2, fuel flow, or air flow. These might include changes in fuel properties, inadvertent changes in burner settings, new boiler control set points, air control damper deterioration, and air preheater pluggage.

To assure continuous high boiler efficiency and low NO_x emissions, periodically make combustion quality spot checks. Compare stack measurements of O_2, CO, smoke, temperature, and NO_x to the readings obtained during the low O_2 testing. The more often this is done, the less likely that a poor condition will develop to the point where large fuel wastage and increased air pollution results. A complete boiler maintenance inspection and audit should also be performed periodically as outlined in Section 5.2.

4.3 BURNER ADJUSTMENT

Burner and fuel system adjustments described here are separate from excess air or combustion control adjustments made in the previous section. They include such items as changes in:

1. Burner air register settings (on swirl or circular type burners)
2. Oil burner tip position with respect to the burner throat
3. Oil gun diffuser position with respect to the burner tip and burner throat
4. Coal spreader position
5. Fuel oil temperature
6. Fuel and atomizing pressures
7. Coal particle size

These burner adjustments, where applicable, can be useful in reducing minimum O_2 requirements of the boiler (resulting in lower operating excess O_2 and improved efficiency) and can also lead to lower NO_x emissions. Lower NO_x can be a result of operating at lower excess O_2. In addition, some of these adjustments can have direct effects on NO_x which are evident when there has been no change in excess O_2, combustibles, and smoke.

The effects of these adjustments on NOx and minimum O_2 are variable from boiler to boiler and difficult to predict. The primary approach when making these adjustments is therefore a trial-and-error procedure, but it must be sufficiently organized to assure adequate stack and flame monitoring when the adjustments are being made. Observe the general precautions given for the excess air adjustments. These burner adjustments are best worked into the excess air adjustment tests (Step 7) since any burner adjustments must be completed before the final excess O_2 adjustments are made. Also the same stack measurements required when adjusting excess air will be necessary after each burner adjustment is made to determine whether the adjustment is producing the desired effects. Similar to the excess air tests, make all burner adjustments slowly to allow adequate time to evaluate each move. Be alert for any changes in burner settings or changes in fuel properties that might also affect the flow of air or fuel to the burner and produce uncontrolled shifts in excess O_2.

The range of adjustment possible for the various burner parameters listed above depends on the design of the burner and its particular operating characteristics. For example, it may be possible on one boiler to vary the air register settings from 50% to 80% open while at another boiler no adjustment is possible. In the second case, further opening the air register (reducing the air swirl) may cause flame instability while closing off the air register (more swirl) may widen the flame causing flame impingement on the burner throat or furnace side walls. The boiler manual may provide some helpful information concerning the range of adjustments possible for the boiler.

An important factor in obtaining complete combustion of oil fuel at low excess O_2 levels is to maintain the proper fuel oil temperature. The oil firing temperature is dictated by the desired fuel viscosity which must remain within the range recommended by the manufacturer. The following table gives typical viscosity ranges for various oil fuels but observe the range recommended for each specific burner.

	Usual Range of Firing Viscosity	
Atomization Method	Saybolt Seconds Universal	Equivalent Kinematic Viscosity, centistokes
Pressure	35-150 SSU	3-32 cs
Steam or Air	35-350 SSU	3-77 cs
Rotary	150-300 SSU	32-65 cs

To determine the proper oil temperature which gives the desired viscosity, use standard viscosity-temperature curves such as in Figure 10. When available, request viscosity characteristics of each specific fuel from the supplier.

Coal burning equipment is also designed to give good performance for particular coal particle sizes. The following table has been compiled from several boiler industry sources (primarily Refs. 7 and 8) and gives typical coal sizes for various burner designs.

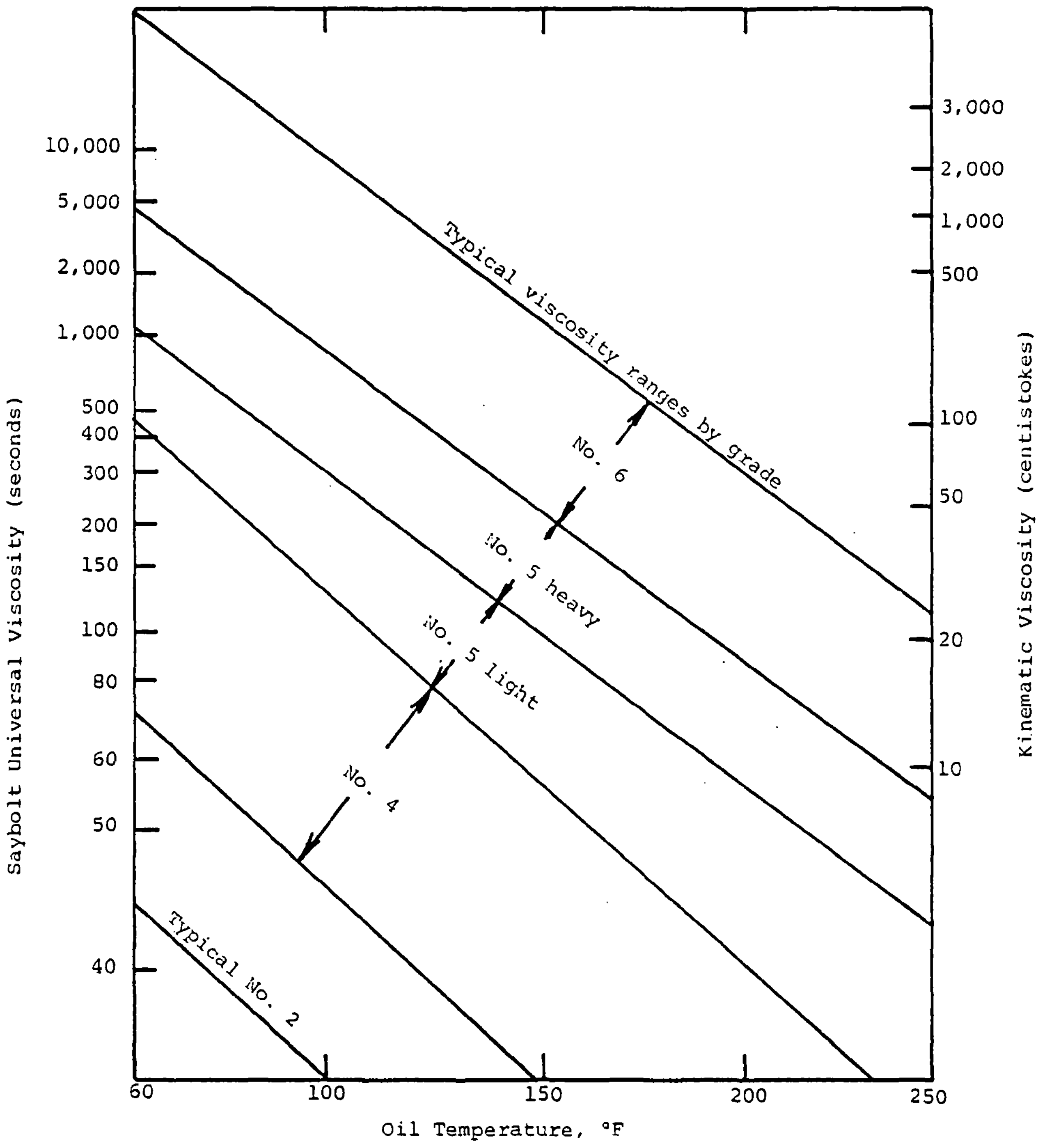

Figure 10. Typical viscosity-temperature relation for various grades of fuel oil (ASTM D396-75).

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RECOMMENDED COAL SIZES FOR
VARIOUS BURNER DESIGNS

	Firing Type	Coal Type	Sizing
Underfed	Single Retort	Coking and caking, Free burning	1 to 1-1/2" nut and slack (<50% thru 1/4" screen)
	Multiple Retort	Free burning	2" nut and slack (<50% thru 1/4" screen)
Overfed	Chain Grate	All except caking bituminous	1" nut and slack
	Traveling Grate	All except caking bituminous	1" nut and slack will handle fine coal
	Vibrating Grate	All types	1" nut and slack less fines preferred
Spreader Stoker	Stationary Grate	All types	3/4" nut and slack
	Dumping Grate	All types	3/4" nut and slack
	Traveling Grate	All types	3/4" nut and slack
	Vibrating Grate	All types	3/4" nut and slack Less fines preferred
	Pulverized Coal Burner	All types	70% thru 200 mesh screen
	Cyclone Burner	All types, subject to ash properties	95% thru 4-mesh screen

SECTION 5.0

MAINTAINING HIGH BOILER EFFICIENCY AND LOW NO_x

Once the optimum boiler adjustments have been achieved, there are two steps that should be taken to assure that high efficiencies and low NO_x emissions are maintained in day-to-day boiler operation. The first is the combustion efficiency spot check which can be worked into the daily or weekly operating routine. This provides an early indication of any efficiency related problems before large fuel wastage or extensive maintenance is required. The second step involves periodically performing a more comprehensive efficiency maintenance audit of the boiler equipment to identify any necessary maintenance or repairs needs.

5.1 COMBUSTION EFFICIENCY SPOT CHECK

A spot check of combustion conditions utilizing stack measurements of O_2, CO, smoke, and temperature is an effective preventive tool. Perform these measurements when the boiler is operating at steady conditions and compare the results to the measurements obtained during the previous boiler adjustment tests. Keeping a log of these data will help in identifying any deterioration in combustion efficiency and the possible causes. Many operators perform efficiency spot checks on a daily basis or even during each work shift.

Shifts in boiler excess O_2 might be attributable to problems in the air or fuel supply or might reflect changes in fuel properties. Other possibilities might include deterioration in furnace baffling or setting leakage, excessive tube fouling, air preheater pluggage or simply changes in atmospheric conditions. If the excess O_2 has remained constant but smoke or CO has increased, fuel specifications may have changed or there may be a problem with burner performance (oil tip pluggage, oil atomizing system problems, burned off or improperly adjusted burner parts, worn grate, overfire air system, etc.). Make sure that the proper oil temperature is being maintained. If stack temperatures have increased 20°F or more but excess O_2, CO and smoke has remained unchanged, this may be a preliminary indication of deteriorated furnace baffling, excessive tube fouling or sootblower malfunction.

5.2 PERFORMANCE MONITORING (BOILER LOG)

Efficiency spot checks are valuable for identifying efficiency degradation, but longer term performance monitoring (including documentation in a boiler log) is a more effective means of insuring peak efficiency. The objective of performance monitoring is to document deviations from desired performance as a function of time. This information should be obtained on a regular basis by the operator under steady load conditions. Data taken during load changes or under fluctuating load conditions will be inconsistent and of little value in assessing unit efficiency, however, control response should be noted during transient conditions.

If a widely fluctuating load is the normal condition, it may be necessary to make special arrangements to achieve steady boiler load for efficiency monitoring either through curtailing intermittent steam demands or taking load swings on other boilers. If the boiler master control is placed on manual operation, the fuel/air ratio should be as established by the control system. The performance recorded under these conditions will indicate deviation from desired fuel/air ratio and other performance deviations. By manually adjusting fuel/air ratio to the desired level, a second set of data can be obtained which represents performance deviations attributable to sources other than the fuel/air ratio such as surface cleanliness, boiler baffles, etc.

The actual readings to be taken and the frequency are determined by the size and complexity of the equipment and the manpower which can be justified in collecting and analyzing data. The usual practice at larger boiler houses is to record data hourly as a check on general performance. These hourly readings are to assure that the unit is operating normally and includes checking of safety and mechanical devices.

Efficiency related items which should be included in the boiler operator's log are:

1. General data to establish unit output
   - steam flow, pressure,
   - superheated steam temperature (if applicable)
   - feedwater temperature

2. Firing system data
   - fuel type (in multi-fuel boilers)
   - fuel flow rate
   - oil or gas supply pressure
   - pressure at burners
   - fuel temperature
   - burner damper settings
   - windbox-to-furnace air pressure differential
   - other special system data unique to particular installation

3. Air flow indication
   - air preheater inlet gas O_2
   - stack gas O_2
   - optional - air flow pen, forced draft fan damper position, forced draft fan amperes

4. Flue gas and air temperature
   - boiler outlet gas
   - economizer or air heater outlet gas
   - air temperature to air heater

5. Unburned combustible indication
   - CO measurement
   - stack appearance
   - flame appearance

6. Air and flue gas pressures
   - forced draft fan discharge
   - furnace
   - boiler outlet
   - economizer differential
   - air heater air and gas side differential

7. Unusual conditions
   steam leaks
   abnormal vibration or noise
   equipment malfunctions
   excessive makeup water

8. Blowdown operation

9. Sootblower operation

While this list may look extensive and time consuming, the operator of a firetube or comparable-sized watertube boiler (10,000 to 24,000 lb steam/hr) will find that the data list will reduce to:

steam pressure
feedwater temperature
steam, feedwater, or fuel flow
fuel supply temperature
boiler outlet gas temperature
boiler outlet O_2
FD fan inlet temperature
stack appearance
flame appearance
windbox air pressure
windbox-to-furnace air pressure differential
boiler outlet flue gas pressure
blowdown operation
unusual conditions or equipment malfunctions

If the unit is too small to justify a continuous O_2 analyzer, the excess air should be checked by Orsat analysis weekly. If the burner is serviced by an outside organization, the frequency should be at least monthly, and include an excess air determination. Carbon monoxide determination is particularly important on gas firing since high CO levels can develop without smoke formation, unlike oil or coal firing.

If steady load conditions are difficult to obtain, less emphasis should be placed on the boiler operator's log for efficiency-related maintenance items and regularly scheduled performance checks should be made under steady conditions on a monthly basis for smaller units and on a biweekly basis for larger units. On coal-fired units, monthly checks on ash combustible content should be made. On pulverized coal-fired units, coal fineness should also be checked monthly.

Analysis and interpretation of performance data is discussed in Section 5.4.

5.3 PERFORMANCE DEFICIENCY COSTS

The benefits obtained by maintaining high boiler efficiency are readily calculated knowing boiler fuel usage (W_f), efficiency achievable (E_A), efficiency differential between achievable and actual performance (ΔE), and fuel cost, (C)

$$\text{fuel \$ saving} = W_f \times \frac{\Delta E}{E_A} \times C$$

The units selected must be consistent, that is, if W_f equals million Btu/year, and C equals dollars per million Btu, the fuel saving will be in dollars per year.

Usually, achievable efficiency and ΔE will vary with boiler load. To evaluate annual fuel savings under varying load conditions, the fraction of operating time spent at each load must be estimated and multiplied by the fuel consumption rate and the ratio of $\Delta E/E_A$ for each load condition. The sum of the individual load calculations multiplied by fuel cost will then equal the annual fuel dollar saving.

To provide some estimate as to the value of a one percent efficiency change, consider a boiler operating at 10,000 lb/hr steam flow for 6,000 hours per year. The heat required to generate one pound of steam is approximately 1000 Btu divided by boiler efficiency as a decimal fraction. If efficiency is 80%, the annual fuel consumption would be

$$10{,}000 \times 6{,}000 \times \frac{1{,}000}{0.80} = 75{,}000 \text{ million Btu/year}$$

With fuel costs at $2 per million Btu/ the annual fuel bill would be $150,000.

If efficiency decreased to 79%, the fuel bill would be $151,900, or $1,900 higher.

If the boiler steam flow were 100,000 lb/hr and the efficiency decrease was 2%, the increase in annual fuel cost would be $38,000. Obviously, more effort can be justified in maintaining efficiency as boiler output increases and performance deterioration becomes greater.

Efficiency gains through reducing excess air or stack temperature are shown in Figures 11 and 12. A reduction in excess air is usually accompanied by a reduction in stack temperature. The actual temperature reduction is dependent on the initial stack temperature and the excess air reduction. A 20% excess air reduction will produce approximately a 30°F reduction if the exit gas temperature is in the 500°F to 600°F range, but only 15°F reduction if the exit gas temperature is in the vicinity of 300°F.

The combined effect can be determined by first evaluating the efficiency improvement for reduced excess air from Figure 11 and then adding the efficiency improvement for reduced stack gas temperature from Figure 12 evaluated at the lower excess air.

Solid combustible losses are of concern principally with coal firing as discussed previously. Carbon monoxide heat losses can become significant with gas or oil firing. Carbon monoxide in the flue gas at a level of 1000 ppm or 0.1% represents a heat loss of approximately 0.35%. Higher CO levels will produce correspondingly higher heat losses.

5.4 IDENTIFYING CAUSES OF PERFORMANCE DEFICIENCIES

Previous sections have dealt with establishing performance goals and monitoring performance to determine departures from desired performance. The specific deviations from expected performance can be of considerable value in determining the cause of the performance deficiency.

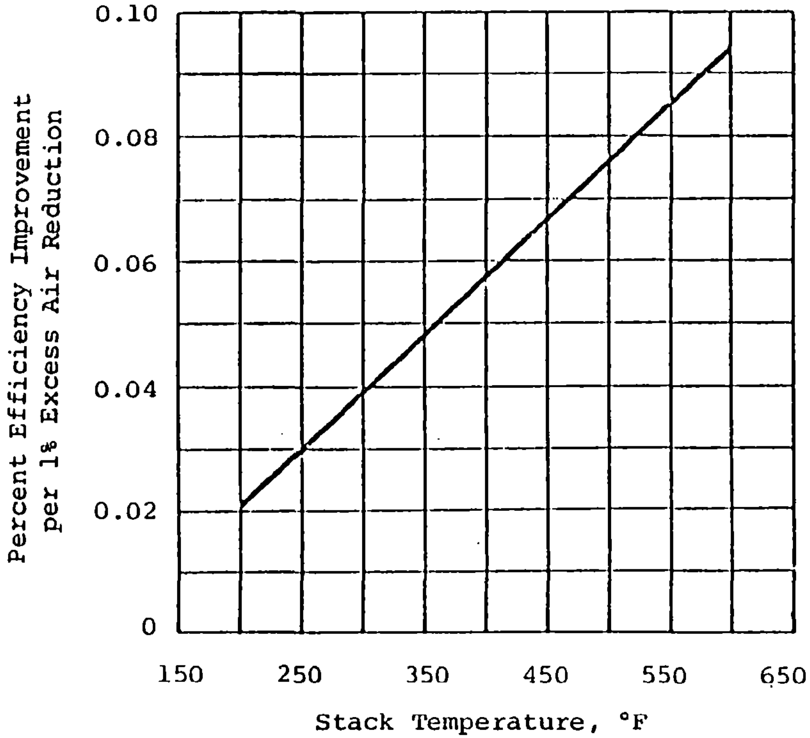

Figure 11. Percent efficiency improvement for every one percent reduction in excess air. Valid for estimating efficiency improvements on typical natural gas, #2 through #6 oils, and coal fuels.

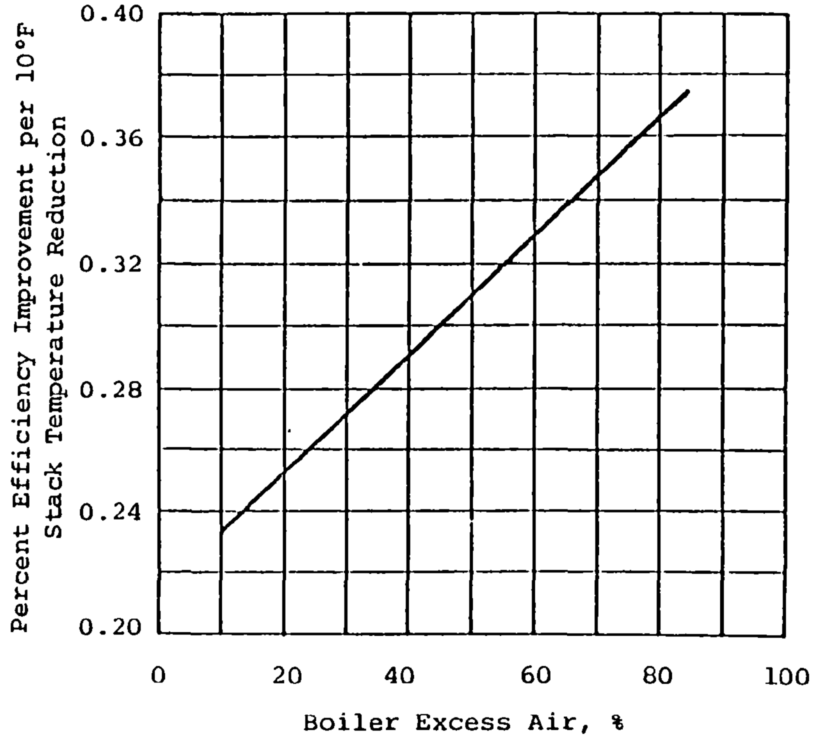

Figure 12. Percent efficiency improvement for every 10°F drop in stack temperature. Valid for estimating efficiency improvements on typical natural gas, #2 through #6 oils, and coal fuels.

Deficiencies can be heat transfer related, combustion related, or can result from unnecessary miscellaneous losses such as high auxiliary power consumption, excessive blowdown, steam leaks, or defective insulation.

5.4.1 Heat Transfer Related Problems

Poor heat transfer performance is indicated by high exit gas temperatures at normal excess air. This condition can result from a gradual buildup of gas-side or water-side deposits. Water-side deposits require a review of water treatment procedures and cleaning to remove deposits. Gas-side deposits can result from normal ash accumulations on heat transfer surfaces or may be the result of excessive carbon formation on oil-fired units. Heavy deposits may also be indicated by increased draft loss through the boiler, economizer, or air heaters. Soot blowers are normally installed on coal-fired units and on many heavy oil fired units. If the blowers are operating effectively, a decrease in exit gas temperature should be observed following blower operation. Visual examination of deposit patterns during an outage may disclose the need for increased blower pressure or relocation of blowers to provide more effective cleaning. Periodic off-line cleaning of radiant furnace surfaces, boiler tube banks, economizers, and air heaters may be necessary to remove stubborn deposits. Washing of rotary air heaters is recommended when draft losses increase by 1" water gage.

5.4.2 Combustion Related Problems

High excess air will be indicated by high stack O_2 readings and increased draft and pressure losses through the unit. Exit gas temperature and fan power will also be increased. The problem is most likely related to control system operation. Low fuel supply pressure with oil or gas firing, change in fuel heating value or viscosity may not be compensated for in simple positioning control systems. Leaking or plugged sensing lines in other control systems may cause errors in fuel/air ratio settings.

Low excess air will be indicated by increased CO, smoking or solid combustible content of fly ash in addition to low O_2 readings. The cause may again be control system related or may result from inability of fans to deliver enough air because of increased flow resistance through heat recovery equipment, obstructed inlet screens or dirt on air foil blades.

Unburned CO or smoke with normal or high excess air indicates burner system problems. In gas fired units, vaporized light oil contained in the gas can condense when the gas is expanded in a pressure reducing station. The condensed oil can carbonize in the gas burner and cause poor fuel distribution. Unbalanced fuel/air distribution in multiburner furnaces can also result in high CO formation.

Poor oil fires can result from improper viscosity, worn tips, carbonization on tips and deterioration of diffusers or spinnerplates.

Improper air register settings and deterioration of burner throat refractory can cause increased combustible losses with all fuels.

Stoker grate condition, fuel distributors, windbox air regulation and overfire air systems can affect carbon loss. Low fineness on pulverized coal units will increase carbon loss.

Obviously, many of the firing system maintenance items will require a boiler outage to repair. Any known problems should be placed on a maintenance list for correction at the next scheduled outage. Priority should be assigned on the basis of safety, reliability, and efficiency impact.

5.4.3 Miscellaneous Energy Losses

Casing leakage on balanced draft units will increase the air flow required for satisfactory combustion since this air infiltration does not contribute to combustion of the fuel. The excess air at the boiler outlet will be higher than normally required to burn the fuel and the condition may be mistakenly interpreted as poor burner performance.

The magnitude of the problem is difficult to determine unless the unit is out of service and can be pressurized for smoke testing. Fortunately most modern balanced draft units are constructed in the same way as pressurized units and are therefore less likely to have setting leakage problems than are older units.

Casing leakage on pressurized units is readily apparent and requires repair to prevent damage to casing and insulation. Escaping flue gas also poses a personnel hazard especially if the unit is located indoors.

Air heater leakage on tubular air heaters is normally less than 1% however low exit gas temperature can lead to cold end corrosion and increased leakage. Rotary air heaters (Ljungstrom type) require seals to prevent forced draft air from entering the gas stream. Since these seals are between stationary and moving parts, they are not perfectly tight and are also subject to wear. Leakage is normally 7 to 15% depending on the size of heater and pressure differential between gas and air. Worn seals or improperly adjusted seals can double leakage. Since the leakage in both tubular and rotary type heaters occurs after the gas has passed over the heating surface, there is no penalty in heat recovery, but the additional air flow which the forced draft fans must supply and the additional gas weight through induced draft fans, if present, represents additional auxiliary power consumption and could possibly influence unit capacity. Air heater leakage can be verified by excess air measurements entering and leaving the air heaters. Inspection of tubes or seals should be made at annual outages.

Coal pulverizer power can be excessively high if the pulverizers are in poor repair or if the coal is being ground too finely. Normally pulverized coal is ground to 70% thru a 200 mesh screen. If the fineness is increased to 80% thru a 200 mesh screen the power required will increase by 30%. It is particularly important to check pulverizer fineness following mill maintenance and reset for proper fineness. Monthly checks and re-adjustments should be made to avoid low fineness and high unburned carbon loss.

Excessive blowdown represents an unnecessary heat loss which can be avoided by monitoring boiler water concentration and maintaining solids level as high as permissible. Blowdown heat losses are discussed in Reference 4.

Steam leaks are obvious heat losses which should be corrected as quickly as possible. Small leaks inside the boiler may go undetected unless signs are found during an outage. Larger leaks may be detected by noise of escaping steam, increased vapor emission from stack or increased makeup water requirements. Water or steam leaks in coal fired boilers can cause extensive damage by fly ash cutting of nearby tubes if allowed to continue.

Missing or loose insulation increases heat loss and should be repaired as necessary.

Excessive soot blower operation consumes steam or air unnecessarily. The effectiveness of each blower should be determined and blowing pressure set at a minimum consistent with effective cleaning. The frequency should be determined by cleaning needs and not set on an arbitrary basis such as once per shift.

5.5 EFFICIENCY RELATED BOILER MAINTENANCE ITEMS

This section contains a review by boiler system of efficiency related maintenance items which should be considered by a boiler owner or operator in developing operating log and inspection requirements.

It is again appropriate to stress that any recommendations made in this report are not intended to replace any procedures which are required for safety reasons or recommended by the manufacturer to extend equipment life.

5.5.1 Fuel Supply System

Gas Firing. Since gas is a clean fuel and can be burned without any in-plant treatment, few problems are anticipated. The gas pressure regulator is the major component which might require attention.

Gas pressure on the downstream side of the regulator should be entered on the hourly log. Low pressure may indicate malfunction of regulator, plugging of upstream strainers or low pipeline pressure. High pressure or erratic pressure would indicate regulator malfunction. Deviation in gas pressure could influence fuel/air ratio depending on the type of control system.

Oil firing. The fuel oil supply system consists of tanks, pumps, strainers and a pressure regulating valve to supply oil to the flow control valve at the proper pressure. In addition, tank heaters are required with heavy oil firing to provide the proper viscosity for pumping, and preheaters are required to provide the proper viscosity for atomizing. If the oil supply is extremely variable, viscosity control devices may also be included in the system.

With oils that do not require preheating, the components requiring attention are the strainers and oil pressure regulators. Heavy oil systems additionally require attention to tank heaters and preheaters.

Oil supply pressure and temperature should be entered on the hourly log as well as flow rate if metered. Low oil pressure may be caused by too high or too low temperature at the pump inlet, plugged strainers, coking in the preheater, or regulator malfunction. Preheater fouling or coking may also be indicated by inability to maintain desired fuel oil temperature.

Deviations in fuel oil pressure could influence fuel/air ratio depending on the type of control system. Viscosity control is important to providing proper fuel atomization.

Coal firing. Most of the maintenance connected with the fuel supply system of stoker fired units is to keep the system functioning rather than efficiency related. With pulverized coal firing, the pulverizers and piping system performance can affect unit efficiency.

Hourly log readings should include pulverizer outlet temperature and pressure. Visual observation of the fires should be made to determine that fuel supply is reasonably uniform to all burners and that ignition point is normal. Monthly fineness checks should be made to determine that adequate fineness is being maintained. Annual inspection (or as recommended by the manufacturer) should be made to determine wear on grinding parts, classifiers and exhausters or fans. Wear on pulverized fuel pipes or riffle dividers should also be determined.

Poor grinding can increase carbon heat losses. Excessive grinding or worn pulverizers can increase power consumption. Low outlet temperature may indicate low pulverizer air flow, insufficient hot air, high moisture fuel, or wear on exhauster.

5.5.2 Controls and Instrumentation

Controls and instrumentation are the most critical areas in an efficiency-related maintenance program. The control function in maintaining the proper fuel/air ratio is essential to minimizing stack gas losses and unburned fuel loss. Accurate and reliable maintenance of boiler variables is also essential to monitoring boiler performance and analyzing equipment performance problems.

A variety of control systems are described in Reference 4. The components may be mechanical, pneumatic, or electronic, or combinations of various devices. Each type has certain weaknesses which require maintenance to assure satisfactory performance. Mechanical systems are subject to misalignment, binding, and wear which introduce errors in repeatability of settings. Pneumatic systems are subject to leakage or dirt in sensing and control lines. Electronic systems are subject to dirty contacts, insulation failure or circuit problems, and may be more sensitive to heat or vibration damage. The same types of problems are inherent in the various types of instruments used for performance monitoring.

The frequency of maintenance and calibration is best determined by plant operating and maintenance personnel based on records of malfunction, or drift in accuracy between calibration or periodic maintenance periods.

5.5.3 Fuel Burning Equipment

All types of fuel burning equipment have certain features in common: air registers or dampers, and parts subject to intense heat which are inaccessible during operation. These parts should be inspected annually for deformation, oxidation, or failure, or more frequently if outages occur. Hourly observation of fires is recommended to detect overheating of stoker, gas, oil, or pulverized coal burner parts or unusual flame patterns which may indicate burner problems.

Gas firing. Poor flame conditions may result from plugging of gas orifices in ring burners as a result of carbonization of light oil fractions contained in the gas which condenses when the gas is expanded and cooled in passing through orifices or pressure reducing stations. This condition is likely to develop in the lower burners of multiburner installations. Whenever burners are taken out of service in a multiburner boiler, the idle burner should be observed to determine that enough cooling air is supplied to prevent overheating of burner parts exposed to flame.

Oil firing. Oil gun tips will require periodic removal for cleaning. The frequency is a function of oil type and atomization method. The frequency is best determined by plant experience and may vary from once per shift to monthly. Tips should be checked for wear, nicks, or cracking.

Oil pressure should be checked at individual burners to assure that reasonable oil distribution is being achieved. Atomizing steam or air pressure, if used, should conform to manufacturer's recommendation.

Stoker firing. Mechanical condition of fuel distributers and grates should be checked if fires are burning unevenly. Excessive siftings through grates may indicate need for grate maintenance if fines content of coal is not abnormally high.

If an overfire air system is installed, the condition of nozzles should be determined during annual outages. During operation, the performance should be checked to determine that the required air flow is being developed.

Many stokers are equipped with cinder reinjection systems for returning ash collected in boiler hoppers or mechanical collectors to the furnace for reburning. This system can reduce unburned carbon heat losses by 2 to 5% and should be kept in good operating condition. Daily checks should be made to assure that hoppers are being emptied. Cold hopper spouts usually mean no flow. It is also usually possible to observe the flyash stream being injected into the furnace for flow indication. However, unless each hopper has a separate injection nozzle, there is no assurance that flyash is being reinjected from all hoppers.

Pulverized coal firing. The abrasive nature of pulverized coal requires some maintenace on deflectors or distributors which may be incorporated in the burner design. Oxidation may also occur.

These conditions should be checked during annual outages or more frequently if possible. Coke buildup on burner throats may occur with worn burner parts. Air register adjustment may be helpful in correcting coke formation conditions.

5.5.4 Heat Transfer Equipment

The principal efficiency-related maintenance aspects of heat transfer surfaces are surface cleanliness and good flue gas flow distribution. Flue gas-side cleanliness can be maintained by soot blowers and/or periodic water washing or mechanical cleaning. Water-side cleanliness can be maintained by proper water treatment and periodic chemical or mechanical cleaning.

Many older boiler designs used refractory or metal baffles to provide cross flow of gases in boiler tube banks. These baffles require periodic inspection and maintenance to provide the desired gas flow pattern. Missing baffle tile or plate will result in gas bypassing around heat transfer surfaces and increased boiler outlet temperature. More recent boiler designs are arranged for crossflow without requiring baffles. Gas distribution problems still can occur if localized heavy ash deposits plug gas flow lanes.

The boiler operator's log will indicate the rate of increase of exit gas temperature or draft loss which would determine the need for boiler cleaning. A sudden increase in boiler exit gas temperature possibly accompanied by a noticeable decrease in draft loss would indicate damage to cross flow baffles.

Many plants which have experienced problems with internal deposits leading to furnace tube failures have installed thermocouples to measure tube temperature at the failure location. If the tubes are clean, these thermocouples will read only a few degrees above saturation temperature. As internal deposits form, the thermocouple readings will become higher and indicate the need for chemical cleaning. If the annual inspection discloses significant internal deposits or there is evidence of tube wall overheating (bulges or swelling), furnace wall tube thermocouples would provide warning of poor water side conditions in the future.

Specific efficiency-related maintenance items to look for during an inspection outage are:

1. Soot or ash deposit formations on furnace walls which may indicate a need for burner adjustment or repair.

2. Evidence of furnace wall overheating (bulges or swelling of tubes).

3. General gas side cleanliness of boiler, superheater, economizer and air heater surfaces, and areas of heavy deposits which are not being cleaned by sootblowers.

4. Alignment of superheater elements (misalignment could contribute to ash plugging or increase gas flow resistance).

5. Condition of baffles or dampers in gas passages or air ducts.

6. Evidence of sootblower erosion on coal fired units which may be caused by high blowing pressure or excessive operation of blowers.

7. Water side inspection to establish cleanliness of boiler and mechanical condition of drum internals.

5.5.5 Fans

Some forced draft fans with curved or air foil blades lose considerable capacity if the blades become dirty. This type of fan should be cleaned as required to maintain capacity. Inlet screens should be examined frequently for blockage by rags, paper, or other material which would restrict air entry.

5.5.6 Air and Gas Ducts

Leakage from air ducts will increase fan requirements and may change fuel/air ratio depending on the control system design. Inward leakage on balanced draft units will increase induced draft fan loading and may restrict unit capacity.

5.5.7 Insulation

Heat losses from uninsulated ducts, boiler surfaces, or steam lines can increase heat losses significantly in addition to creating personnel hazards and uncomfortable working conditions. Missing insulation should be replaced as required.

SECTION 6.0

REFERENCES

1. "Field Testing: Application of Combustion Modifications to Control Pollutant Emissions from Industrial Boilers - Phase II," U. S. EPA Report No. EPA-600/2-76-086a, April 1976 (NTIS No. PB 253 500/AS).

2. "Assessment of the Potential for Energy Conservation through Improved Industrial Boiler Efficiency," Final Report - Volume I, U.S. Federal Energy Administration Contract No. C-04-50085-00, October 1976 (available from National Technical Information Service, Order No. PB 262-576).

3. "National Emissions Report 1973," U. S. Environmental Protection Agency, Report No. EPA-450/2-76-007, May 1976.

4. "Industrial Boiler Users' Manual--Methods and Equipment for Efficiency Improvement," U. S. Federal Energy Administration Contract No. C-04-50085-00, October 1976 (available from National Technical Information Service, Order No. PB 262-577).

5. "Systems Evaluation of the Use of Low-Sulfur Western Coal in Existing Small and Intermediate Sized Boilers, Interim Report #1," by KVB, Inc., Report No. 8800-140 under Contract No. EPA 68-02-1863, June 1975.

6. "Guidelines for Burner Adjustments of Commerical Oil-Fired Boilers," U.S. EPA Report No. EPA-600/2-75-069-b.

7. Combustion Engineering Company, Inc., Combustion Engineering--A Reference Book on Fuel Burning and Steam Generation, The Riverside Press, Cambridge, Massachusetts, 1947.

8. Babcock and Wilcox Company, Steam, Its Generation and Use, 38th Edition, 1972.

APPENDIX A

OTHER NO_x REDUCTION TECHNIQUES

Operation of most industrial boilers with low excess air will improve boiler efficiency as well as reduce NO_x stack emissions. Where further NO_x reductions are required or when efforts to improve efficiency lead to increases in NO_x, there are several NO_x reduction techniques that may be considered. When properly applied, they will usually involve little or no sacrifice in boiler efficiency (except for the reduced air preheat method). These techniques include:

1. Fuel-rich ("staged") combustion
2. Flue gas recirculation
3. Low NO_x burners
4. Change of fuels
5. Reduced air preheat

In most cases, applying any of these methods will involve modifications to existing hardware and boiler operating practices. The selection of the appropriate method will require the assistance of outside combustion specialists. Economic evaluations including cost/benefit studies and long term maintenance and operating costs will also be involved in selecting the most appropriate technique (see Appendix B). Whether or not a specific approach can be successfully applied will generally depend on the design and particular operating requirements of the boiler.

The following discussion is intended to familiarize boiler operators and owners with the various NO_x reduction techniques available. It is stressed that before any of these techniques is considered, the reduced-NO_x potential of existing equipment should be fully evaluated. This includes minimizing the burner excess air level and exploring possible burner adjustments as described in previous sections of the manual.

A-1. FUEL RICH COMBUSTION

Fuel-rich or "staged" combustion is mainly applicable to gas, oil and pulverized coal fired boilers with multiple burners (four or more burners). This technique usually involves terminating or reducing the fuel to one or more of the burners and equally distributing this fuel to the remaining burners to maintain the same overall firing rate. Full air flow is maintained at the burners with reduced or terminated fuel flow thereby causing the other burners to operate more fuel-rich. In this manner, the fuel-rich burners can actually be operated with less air than required for complete combustion. This requires the flame products to be effectively mixed with "make up" air from the out-of-service or reduced-fuel burners to complete the combustion elsewhere in the furnace. The fuel-rich flames provide an opportunity for a large portion of the fuel to burn in an O_2 deficient and relatively "cool" flame which reduces NO_x formation. When the flame products eventially mix with the make up air downstream in the furnace, the combustion gas temperature is already too low for additional NO formation but adequate to complete the burnout of smoke and combustibles.

An alternate approach involves maintaining normal fuel flow to all burners while directing a portion of the combustion air through auxiliary or "over fire" air ports located away from the burners. However, this requires redesign of the air handling parts of the boiler and therefore can be costly.

NO_x emission reductions of 25% to 40% have been demonstrated with fuel-rich firing (Ref. A-1) but it is seldom a straightforward technique in terms of implementation by the boiler owner/operator. It usually requires an extensive test program to establish the most effective fuel distribution pattern and to address potential problems such as reduced load capacity, flame stability, furnace heat release effects, flame impingement, and tube wastage. This work is best performed by combustion specialists with previous experience in fuel-rich firing techniques. However, this approach is relatively cost effective compared to other NO_x reduction techniques in that little or no hardware modifications are required with the burners out-of-service method of fuel-rich firing.

Where this technique is applicable, it is very attractive since it can involve little or no decrease in boiler efficiency for large reductions in NO_x. Efficiency penalties mainly arise when boiler excess air requirements increase to maintain acceptable stack conditions or combustible losses. In some cases the excess O_2 requirement will increase only a few tenths percent and the resulting efficiency penalty is extremely small.

A-2. FLUE GAS RECIRCULATION

A very effective means of reducing nitrogen oxides emissions involves recirculating a portion of the flue gas back into the combustion air. These recirculated gases absorb heat energy from the flame thereby lowering the peak flame temperature which reduces NO_x formation. Other effects on NO_x may result from increased flame turbulence due to higher mass flow through the burner and alteration of flame shape and heat release.

Adding a flue gas recirculation system can conceivably be done on most boilers but it usually requires considerable costs, engineering design and extensive equipment modification. The point where the flue gas is introduced into the combustion air must be carefully chosen and designed to assure thorough mixing of flue gas and air before it flows through the burners. Changes in burner design are sometimes necessary to retain flame stability.

Flue gas recirculation has been demonstrated to be generally more effective in reducing NO_x emissions from gas fired boilers (Ref. 1). Reductions in NO_x of up to 73% at gas fueled industrial boilers have been achieved. Reductions with fuel oil can be on the order of 30%.

Flue gas recirculation is less effective with heavy oil and coal fuel because they contain high levels of fuel nitrogen. The formation of NO from fuel nitrogen is not strongly influenced by gas recirculation. Flue gas recirculation can affect overall plant efficiency slightly due primarily to increased auxiliary power requirements (gas recirculation fans). A reduction in boiler excess O_2 is sometimes possible using flue gas recirculation but the increased auxiliary loads usually override this beneficial effect on boiler efficiency.

A-3. LOW-NO_x BURNERS

Retrofit burners are commercially available which are specially designed for low nitrogen oxides emissions. These "low-NO_x" burners incorporate some of the principles discussed in this manual to give a controlled slow burning, low-temperature flame. Some designs involve low excess O_2 operation which is also beneficial from a boiler efficiency standpoint. Interpreting low-NO_x burner test data from other boilers must be done carefully before considering the use of the burner at another installation. Many factors such as fuel composition, furnace geometry and combustion control precision are influential in the success of a low-NO_x burner. For instance, a low-NO_x burner design which works well on a single burner installation may not give beneficial results when used in a multiple burner unit, and vice versa. Careful selection by engineering personnel assisted by competent combustion specialists is necessary in choosing a low-NO_x burner best suited for any particular boiler. It is sometimes possible that an existing burner is capable of producing NO_x emission levels of a "low-NO_x" burner if properly maintained and adjusted.

A-4. FUEL CHANGE

Changing fuels can be an effective method for reducing oxides of nitrogen. This might involve changing from a higher nitrogen fuel oil to a lower nitrogen oil (i.e., No. 6 to No. 2) or by selecting oils of the same grade which have lower nitrogen content. For example, variations in the fuel nitrogen content of No. 6 oils of more than a factor of 3 can occur as a result of refining processes, blending and natural differences between oil fields.

Changing fuel types (i.e., from coal to oil or oil to gas) is considerably more complicated and the decision is usually controlled by other factors such as fuel availability and cost. Also it is not always practical because of physical limitations of the boiler. A boiler may require extensive burner modifications, new fuel handling equipment and increased sootblowing and ash handling facilities to burn a different fuel. Fuels such as natural gas and light distillate oils which potentially produce the lowest NO_x emissions may be expensive or in increasingly short supply. Different fuels characteristically exhibit modest differences in boiler efficiency and this factor should be taken into account in addition to raw fuel cost (on a million Btu basis) when comparing alternate fuels. These differences result primarily from dissimilar hydrogen content in the fuels with resulting differences in moisture content of the flue gas (moisture losses).

A-5. REDUCED COMBUSTION AIR PREHEAT

Many larger industrial boilers operate with preheated combustion air to increase boiler thermal efficiency and improve combustion. Unfortunately, heated combustion air results in higher flame temperatures which promotes higher nitrogen oxides emissions.

Combustion air preheaters are heat exchangers which extract heat from the flue gas to heat the incoming combustion air. Some preheaters are equipped with ducting for bypassing a portion of the air or flue gas around the preheater to control stack temperatures for corrosion purposes. This capability can also be used in some cases to lower combustion air preheat and effectively reduce NO_x emissions. The major drawback with this technique is that boiler efficiency is reduced as reflected by higher stack temperature (higher stack gas losses). The trade-off between efficiency and NO_x emissions is the major consideration.

This technique is most effective on natural gas and light fuel oils; however, reductions are possible with heavy oils and coal. Potential operational problem areas include flame stability and possible degradation in combustion conditions leading to increased furnace tube fouling.

REFERENCES

A-1. "Field Testing: Application of Combustion Modifications to Control Pollutant Emissions from Industrial Boilers - Phase II, U.S. EPA Report No. EPA-600/2-76-086a, April 1976.

APPENDIX B

COST OF COMBUSTION MODIFICATIONS TO CONTROL NO_x

The total cost of controlling nitrogen oxides emissions from industrial boilers by using combustion modifications is determined by the:

1. Initial capital cost
2. Annual capital cost
3. Annual operating cost

The amount of cost information available for combustion modifications on industrial boilers is very limited. Only very approximate estimates are available at this time. The most recent information on this subject appears in References B-1, B-2, and B-3.

In Reference B-2, it was estimated that many existing small industrial boilers could be modified to meet lower EPA new source standard levels for nitrogen oxides for about $10,000 per boiler. The combustion modification specified was a combination of staged combustion and low excess air firing. The report stated that a major portion of the expense on a multiple burner boiler would be implementing fuel-rich firing by removing selected burners from burner service and operating them with air only (see Appendix A of this manual). The cost would include testing expenses and minor equipment modifications such as oil burner tip enlargements. On a single burner boiler, the cost of installing secondary air ports would be about $10,000. If, for the $10,000 capital cost estimate, the maintenance and operational charges are assumed to be negligible, and capital cost is annualized to 20%, the annual charges would be $2,000.

In Reference B-2, the minimum cost for installing a flue gas recirculation system on a small boiler is estimated to be $30,000, which cost will clearly dominate the fuel penalty cost which is estimated to be one percent in efficiency for normal recirculation percentage flow. On a larger boiler (100 MMB/hr), the cost of flue gas recirculation would be of the order of $1,000/(MMB/hr). In Reference B-1, it was estimated that secondary air capability would add 2% to 4% to the total new boiler cost for boilers in the 300,000 lb/hr steam flow range (approximately $1,000,000 purchase price). If another booster air fan were required, the cost would be increased by about an additional one percent.

Reference B-3 discusses the cost of combustion modifications to reduce NO_x emissions from large electrical utility boilers. The actual costs are not applicable to industrial boilers but the relative expenses are. The reference states that low excess air firing per se would incur the lowest costs, staged combustion would be the next lowest, and flue gas recirculation would represent the highest cost. In general, the cost of applying any of the control methods to an existing boiler would be approximately twice that of a new unit design. The equipment (initial) costs increase with increasing boiler size, but the operating costs on a boiler output basis decline.

Additional cost information is given in Appendix C.

APPENDIX B

REFERENCES

B-1. "Field Testing" Application of Combustion Modifications to Control Pollutant Emissions from Industrial Boilers - Phase II," U.S. EPA Report No. EPA-600/2-76-086a, April 1976.

B-2. "Control of Oxides of Nitrogen from Stationary Sources in the South Coast Air Basin," prepared for Air Resources Board, State of California, KVB Report No. 5800-179, September 1974.

B-3. "NO_x Combustion Control Methods and Costs for Stationary Sources, Summary Study," U.S. EPA Report No. EPA-600/2-75-046, September 1975.

APPENDIX C

METHODS AND EQUIPMENT FOR EFFICIENCY IMPROVEMENT

The following discussion is extracted from Federal Energy Administration "Industrial Boiler Users' Manual" as an introduction to that reference. This document is a manual designed for boiler owners and plant engineers to assist them in the evaluation of efficiency improvement alternatives. These include maintenance practices and operational changes to improve boiler efficiency and boiler auxiliary equipment such as waste heat traps, improved combustion controls, low excess air burners, and others. The manual includes cost information, operating principles, performance data, and other helpful information for evaluating the various options available and discussing equipment modifications with manufacturers and dealers. The following excerpts summarize the topics which are discussed in detail in the main body of the manual.

C-1. BOILER MAINTENANCE AND OPERATIONAL MODIFICATIONS FOR EFFICIENCY IMPROVEMENT

Boiler maintenance practices are important in achieving or maintaining efficient operation. Poor maintenance resulting in degraded equipment operation in a manner that affects stack temperature, excess air level, combustibles, or other heat losses, can affect boiler efficiency and fuel consumption.

A boiler tune-up is one of the most cost-effective means of achieving efficient operation and saving fuel. Adjustment and maintenance of fuel burning equipment and combustion controls permits operation with the lowest practical excess air, thus reducing stack losses. Annual tune-ups can be performed by boiler operating personnel, service organizations, some local utilities, burner/boiler manufacturers, or engineering consulting firms. A routine tune-up on a 25,000 lb/hr boiler can typically be conducted by a burner manufacturer in a day or two at a cost of $300/day plus expenses.

Boiler tube cleanliness is important for efficiency heat transfer from the hot combustion gases to the water-side passages. Tube deposits and fouling on external tube surfaces of a watertube boiler will be reflected in high flue gas temperatures. An estimated 1% efficiency loss occurs with every 40°F increase in stack temperature. Some boiler operators perform their own tube washes while others rely on commercial cleaning and repair service firms that can charge as low as $200 or as high as $500 to clean a 10,000 lb/hr unit. The actual cost depends on the size of the unit, fuel type, furnace design, and extent of deposits.

Reducing the boiler steam pressure (where permissible) is an effective means of reducing fuel consumption by as much as 1 to 2 percent. Lower steam pressures give a lower saturated steam temperature, and without stack heat recovery, a similar reduction in final flue gas temperature will follow. These benefits can be achieved at little or no expense providing the process or equipment can accommodate lower steam pressures.

Blowdown is a customary procedure to remove boiler water with high impurity concentrations. It also represents a loss of sensible heat energy in the waste water. Improved blowdown practices or the use of automatic equipment can result in a fuel savings dependent upon current practice.

Load management is a tool in minimizing fuel consumption in a plant with several boilers. Since boiler efficiency varies with load, boiler design, equipment age, fuel, and other factors, there is an advantage to distributing load to the most efficient boilers and in operating boilers at loads where efficiency is highest. There also is merit to shutting some boilers down in swing seasons while operating process boilers at peak efficiency as opposed to operating all boilers at reduced load and performance.

A fuel change or fuel conversion is generally not thought of as a common means for fuel conservation since the decision is usually controlled by availability. However, different fuels do characteristically exhibit modest differences in boiler efficiency which should be taken into account in addition to raw fuel cost on a Btu per pound basis.

C-2. BOILER AUXILIARY EQUIPMENT FOR EFFICIENCY IMPROVEMENT

Previous paragraphs have briefly summarized methods of efficiency improvement and fuel conservation that can be accomplished with little or no capital expenditures. Although these methods are very cost effective, major improvements in efficiency can be accomplished more readily with equipment modifications that might require several years for return on investment.

The objective of this section is to briefly review the more commonly used efficiency improvement equipment so the potential user has an overall appreciation for the range of options from which to choose and the relative costs and efficiency improvement that can be expected.

The Equipment Synopsis section includes a description of the various off-the-shelf items that can be employed to improve boiler performance. These items can generally be divided into heat traps that lower the temperature of the stack gases, low excess air equipment that reduces stack gas flow, and other items that limit waste heat and radiation losses. Included for each item are:

- principle of operation
- performance potential
- cost information
- physical description

It must be emphasized that the efficiency improvement potentials discussed are not cumulative; that is, a combination of a heat trap and a low excess air modification will not result in an efficiency improvement that is the sum of each individual item acting alone.

The "Industrial Boiler Users' Manual" includes a brief final section on boiler selection to assist in the purchase of a new unit if it is shown to be more cost effective than utilizing auxiliary equipment on the existing unit.

The reader is cautioned that new equipment is marketed periodically which advertises an improvement in efficiency where the potential fuel savings is very dependent upon the specific boiler design and may not be realized at all in some cases. In other cases of misapplication or improper installation, the device may actually reduce efficiency. (For example, turbulators are one of the most attractive efficiency improvement devices for firetube boilers but they show little improvement in four pass unit efficiency and can actually reduce boiler draft and lead to CO formation if improperly installed.) Therefore, it is recommended that the equipment manufacturer or a combustion specialist be consulted before purchasing or installing such equipment.

C-2.1. Equipment Synopsis

Air preheaters are heat traps installed in the exhaust duct that transfer heat energy from the hot flue gas to the incoming combustion air supply. Unit efficiency will increase approximately 2.5% for every 100°F decrease in flue gas temperature. Additional performance benefits will result from improved combustion conditions in the furnace which may enable operation with lower excess air. Application is limited by corrosion considerations (i.e., lowest acceptable stack temperature), existing stack temperatures, maximum acceptable combustion air temperature, and associated increases in NO_x emission levels. Initial capital equipment costs range from $1,000 to $2,000 per MBtu/hr, depending on boiler capacity.

Economizers are heat traps that preheat boiler feed water using heat energy from the flue gas. Again, unit efficiency will improve 2.5% for every 100°F decrease in flue gas temperature. Corrosion considerations are the primary limitation with some consideration required for boiler operating pressure on low pressure boilers.

The choice between an air preheater and an economizer is made on the basis of the criteria set forth in Section 4.1 of the "Industrial Boiler Users' Manual." Economizers are generally preferred over air preheaters on small units. A combination of air preheaters and economizers is employed on large units with operating pressure above 400 psig. Economizer initial costs are comparable to that of air preheaters, but other factors of installation and operating cost are a consideration.

Turbulators are baffles installed in the secondary passes of a firetube boiler to increase turbulence and thereby convection heat transfer to the surrounding boiler water. As with the heat traps mentioned above, the improvement in boiler performance will be indicated by the decrease in stack gas temperature and the corresponding increase in steam generation. Turbulators cannot be used on coal fired units. Turbulator installations range from $500 to $2000 per unit, depending upon unit size, and are economically attractive to many firetube boiler operators.

Improved combustion controls and instrumentation are designed to reduce the operating excess air levels required for safe operation. The degree to which boiler performance is improved will depend on the previous stack gas excess air and temperature conditions and the reduced excess air and temperature possible with new controls and instrumentation. A changeover from the simplest jackshaft system to a cross-limited excess oxygen system can improve boiler performance by 2% and 5% for systems with and without heat traps respectively. Approximate installed costs range from $30,000 to $150,000, depending on the degree of sophistication and capacity of the unit.

Low excess air burners have been developed that achieve complete combustion on oil and gas fuel with as little as 1-3% excess air. Associated decreases in NOx and particulate emissions have also been reported. Sustained operation at such low excess air levels however is questionable and will require a very sophisticated combustion control system. Initial capital costs range from $200 to $700 per MBtu/hr with increasing size of the unit.

Packaged burner assemblies that come equipped with their own control system can reportedly operate with 2-3% excess O_2 levels and are available for retrofit replacements of the existing burner and control system. These are generally priced between $10,000 and $35,000 for a single burner unit.

Waste water heat recovery involves the recovery of waste heat energy contained in drum water blowdown and expelled condensate. This heat energy can be effectively used to preheat boiler feed water instead of just being discarded. Approximately a 10°F increase in feed water temperature will result in a 1% improvement in efficiency. Nominal costs for automatic blowdown systems and condensate recovery units are $1,000 and $8,000, respectively.

Insulation is employed to reduce radiation and convective heat losses from the boiler jacket and ductwork to the boiler surroundings. An estimate of these energy losses can be made based upon surface temperatures, air flow and surrounding conditions, and should be made prior to the purchase of new insulation where improvements appear marginal. The cost of improved insulation is highly variable and is a function of material used, desired skin temperature, and condition of existing insulation.

Sootblowers are employed to remove soot, slag and fly ash deposits from the tube surfaces that would otherwise retard heat transfer in the convective regions leading to higher stack temperatures. Manufacturers claim that up to a 1% efficiency improvement can be achieved by maintaining clean tube surfaces. A simple sootblower system will cost from $15,000 to $50,000.

APPENDIX D

COMBUSTION GENERATED AIR POLLUTANTS

The exhaust gases from all combustion devices contain a variety of byproducts, some of which are considered environmental pollutants. Some of these pollutants are immediately toxic in themselves while others pose indirect health hazards by virtue of their ability to react with other pollutants in the air to form more hazardous compounds. Furthermore, these pollutants also differ by the way they originate in the combustion processes. Some are more related to the composition of the fuel itself whereas others are dependent on the characteristics of the actual fuel burning process and as such are sensitive to the design and operating variables of the combustion device.

The United States Environmental Protection Agency (EPA) has presently identified six major pollutants and has established emission standards to protect the public health and welfare. These six "criteria" pollutants are:

1. Particulate matter
2. Sulfur dioxide
3. Nitrogen oxides
4. Carbon monoxide
5. Hydrocarbons
6. Oxidants

Below are brief descriptions of these substances including the principal health effects, their formation in boiler combustion systems and methods currently used to limit their emissions from boiler stacks. This information is included in the manual to familiarize boiler operators and others with the major aspects of combustion pollutants which have prompted action by the EPA and some state and local air quality agencies to limit these emissions from many sources. Frequently, emission regulations or pollutant-related operating criteria are imposed but the operators of the combustion devices are not acquainted with the underlying health and environmental concerns.

D-1. PARTICULATE MATTER

Particulate matter is the non-gaseous portion of the combustion exhaust, consisting of all solid and liquid material (except water droplets) suspended in the exhaust gases. They can be generally defined as any material that would not pass through a very fine filter. Particulates originating in the combustion process can range in size from submicron in diameter (less than one millionth of a meter) to diameters larger than a millimeter (thousandth of a meter). The larger particulates do not carry far in the atmosphere and usually fall to the ground near the source. The small particles, which may make up the bulk of particulate matter, can remain in the atmosphere for long periods of time and contribute to haze and obscured long-range visibility. These "fine particles" are potentially the most hazardous to health since they are easily carried into the small passages of the respiratory tract during normal breathing.

Particulate matter can be composed of a wide variety of materials including unburned fuel, sulfur compounds, carbon, ash constituents in the fuel (including many toxic metals), and even non-combustible airborne dust that enters the combustion system with the combustion air. Many of these materials by themselves are identified as health hazards and when dispersed in the air in fine particles, can be inhaled and subsequently absorbed into the body. High concentrations of particulate matter in the inhaled air can have more direct health effects by irritating or blocking the surfaces of the respiratory tract leading to temporary or permanent breathing impairments and physical damage. Oral ingestion of particulate matter is also possible from particulate fall-out onto vegetation and food crops.

The quantity and composition of particulates generated in boilers are influenced by several factors including the type of fuel being burned, the boiler operating mode, and combustion characteristics of the burners and furnace. Burner designs and operating modes that tend to promote thorough, efficient combustion generally will reduce the fraction of combustible material in the particulates. From a boiler operating standpoint, it is desired to minimize these fuel-derived materials since they represent wasted available fuel energy and can lead to troublesome internal furnace deposits or objectionable smoke at the stack. Burner air/fuel ratio is one of the more important operating parameters that can influence the quantity of combustible particulate material generated.

Natural gas and most oil fuels are referred to as "clean burning" fuels primarily due to their lower tendency to form solid combustibles (smoke, soot, carbon, etc.) and their low ash content. By comparison, some heavy oils and most coal fuels contain substantial quantities of ash which subsequently form the bulk of the non-combustible particulate matter generated in the furnace. For the case of coal, ash can compose up to 20 percent or more of the total weight of fuel burned. Preventing its accumulation on internal boiler surfaces is a major consideration in the design of the boiler.

In some boiler designs, most of the coal ash remains in the exhaust gases leaving the boiler, but the use of various particulate control devices allows low concentrations to be emitted from the stack. Current devices employ various techniques to remove particulates from the stack gases. These include filtration, mechanical separation and electrostatic precipitation. Many designs have proven to be capable of removing more than 99% of the particulates and are also applicable to oil fired boilers where particulate controls are required.

D-2. SULFUR DIOXIDE

SO_2 is a non-flammable, colorless gas that can be "tasted" in concentrations of less than 1 part per million in the air. In higher concentrations, it has a pungent, irritating odor.

Sulfur dioxide (chemical symbol, SO_2) is formed during the combustion process when sulfur (S) contained in the fuel combines with oxygen (O_2) from the combustion air. Sulfur trioxide (SO_3), is another oxide of sulfur which is also formed in this manner. SO_2 together with SO_3 comprise the total oxides of sulfur, generally referred to as "SOx." SO_3 is usually no more than 3 to 5 percent of the total SOx generated in the boiler.

Except for sulfur compounds present in particulate matter, all of the sulfur initially contained in the fuel is converted to SO_2 and SO_3. Before leaving the stack, SO_3 can combine with moisture in the exhaust gases to form sulfuric acid which condenses onto particulates or remains suspended in the stack gases in the form of an acid mist. In the atmosphere, a portion of the SO_2 is converted to SO_3 which similarly forms sulfuric acid by combining with moisture in the air. The SO_3 can also form other sulfur compounds such as sulfates.

The sulfates and acid mists can contribute significantly to reduced visibility in the atmosphere. Corrosion of materials exposed to the air and damage to vegetation are other major environmental effects. The health effects of sulfur oxides, sulfuric acids and some of the sulfates are primarily related to irritation of the respiratory tract. These effects may be temporary or permanent and include constriction of lung passages and damage to lung surfaces.

The quantity of SO_x generated in the boiler is primarily dependent on the amount of sulfur in the fuel and is not highly affected by boiler operating conditions or design. Regulating the quantity of sulfur allowed in the fuel is a primary method of controlling SO_x emissions. Stack gas "scrubbers" which remove SO_2 from the combustion exhaust gases can also be effective where "high sulfur" fuels are used.

D-3. NITROGEN OXIDES

Nitric oxide (NO) and nitrogen dioxide (NO_2) are the two forms of nitrogen oxides generated by boiler combustion processes. Together, these compounds are customarily referred to as total oxides of nitrogen or simply "NO_x". NO is a colorless, odorless gas and is not considered a direct threat to health at concentrations found in the atmosphere. NO_2 is a considerably more harmful substance. Although NO_2 comprises typically 5% or less of the NO_x emitted from boiler stacks, a large fraction of the NO is converted to NO_2 in the atmosphere.

NO_2 is a yellow-brown colored gas which can affect atmospheric visibility. It also has a pungent, sweetish odor that can be detected at concentrations sometimes reached in polluted air. In much higher concentrations (100 ppm) NO_2 can be fatal when inhaled. Prolonged exposures at much lower concentrations can cause cumulative lung damage and respiratory disease.

NO_x is formed spontaneously during the combustion process when oxygen and nitrogen are present at high temperatures. All three ingredients (oxygen, nitrogen and high temperature) are essential elements of the combustion process and it would therefore be very difficult to prevent the formation of NO_x altogether. Nitrogen is present in the combustion air and in the fuel itself. Minimizing the fuel nitrogen content has been shown to reduce NO_x but this is not currently a practical NO_x control approach. Most NO_x reduction techniques currently applied to boilers are effective as a result of lower peak flame temperatures in the furnace, reduced availability of oxygen in the flame or a combination of both. These techniques include low excess air operation, fuel-rich ("staged") firing and flue gas recirculation. While these approaches limit the formation of NO_x in the furnace, future techniques may be developed that "scrub" the NO_x from the exhaust gases before entering the stack. Fuel desulfurization processes and other fuel "cleaning" treatments may have some associated benefits in reduced fuel nitrogen content.

D-4. CARBON MONOXIDE

Carbon monoxide (CO) is a product of incomplete combustion and its concentration in boiler exhaust gas is usually sensitive to boiler operating conditions. For example, improper burner settings, deteriorated burner parts and insufficient air for combustion can lead to high CO emissions. CO measurements at the stack are often used as an indicator of poor combustion conditions.

CO is an invisible, odorless, tasteless gas. Exposure to CO-containing exhaust gases produces a well known "CO poisoning" which can be fatal. CO emitted from boiler stacks are dispersed in the atmosphere and together with CO from other sources are generally not in high enough concentrations to produce any immediate health effects (an exception might be in the vicinity of high density automobile traffic). However, there is concern that long-term exposures to these concentrations may cause eventual health problems.

D-5. HYDROCARBONS

Like carbon monoxide, hydrocarbons are indicative of incomplete or inefficient combustion and can be essentially eliminated from the boiler stack gases by proper operation of the fuel burning equipment. However, this may be misleading since, strictly speaking, hydrocarbons cannot be entirely eliminated and trace quantities of hydrocarbon compounds will nearly always be present, regardless of how the boiler is operated.

Due to the tremendous variety of hydrocarbon compounds involved and the unknown health effects of some of these even in much larger quantities, it is difficult to assess their environmental impact. Some of these hydrocarbons resemble actual components in the fuel and are rightfully called "unburned fuel," while others are entirely modified forms generated in complex chemical reactions during the combustion process.

It is known that hydrocarbon air pollutants are important ingredients in the formation of photochemical smog. Under certain atmospheric conditions, they can also be transformed into other derivatives which are potentially more hazardous. Some of the manifestations of smog such as irritation of the eyes and respiratory tract are in part directly associated with hydrocarbons and their derivatives.

D-6. OXIDANTS

The term "oxidant" is generally applied to oxygen-bearing substances that take part in complex chemical reactions in polluted atmospheres. These so-called photochemical reactions, which are often intensified in the presence of sunlight, involve nitrogen oxides and reactive organic substances (including hydrocarbons and their derivatives) as the principal chemical ingredients. These react to form new compounds including ozone and PAN (peroxyacyl nitrates) which are usually considered to be the major oxidants in photochemical air pollution ("smog"). The term oxidant is also sometimes used to include the original chemical reactants NO_x, hydrocarbons, and others.

While ozone and PAN are not generated directly in the boiler, the principal ingredients (especially NO_x) are supplied in part by exhaust gases from the boiler. By reducing the emission of these compounds from boilers and all the other combustion sources (automobiles, airplanes, etc.), their photochemical byproducts--the oxidants--will be reduced.

Photochemical oxidants produce adverse effects on vegetable matter which can affect growth, and the quantity and quality of agricultural yields and other plant products. Deterioration of various materials (especially rubber) is also a well known occurrence in polluted atmosphere which is attributed mainly to the presence of ozone.

A major effect on humans is irritation of the eyes. In quantities higher than typically found in polluted atmospheres, oxidants have an irritating effect on the respiratory tract producing coughing and choking. Headache and severe fatigue may be other side-effects. In lower concentrations found in polluted air, the effects appear less well defined. Aggravation of existing respiratory ailments such as asthma has sometimes been attributed to oxidants.

APPENDIX D

REFERENCES

D-1. Research and Education Association, "Pollution Control Technology," New York, New York, 1974.

D-2 National Tuberculosis and Respiratory Disease Association, "Air Pollution Primer," 1969.

APPENDIX E

CONVERSION FACTORS

SI Units to Metric or English Units

To Obtain	From	Multiply By
g/Mcal	ng/J	0.004186
10^6 Btu	GJ	0.948
MBH/ft^2	$GJ \cdot hr^{-1} \cdot m^{-2}$	0.08806
MBH/ft^3	$GJ \cdot hr^{-1} \cdot m^{-3}$	0.02684
Btu	gm cal	3.9685×10^{-3}
10^3 lb/hr* or MBH	GJ/hr	0.948
lb/MBtu	ng/J	0.00233
ft	m	3.281
in	cm	0.3937
ft^2	m^2	10.764
ft^3	m^3	35.314
lb	Kg	2.205
Fahrenheit	Celsius	$t_F = 9/5(t_c)+32$
	Kelvin	$t_F = 1.8K - 460$
psig	Pa	$P_{psig} = (P_{pa})(1.450X10^{-4})-14.7$
psia	Pa	$P_{psia} = (P_{pa})(1.450X10^{-4})$
iwg (39.2°F)	Pa	$P_{iwg} = (P_{pa})(4.014X10^{-3})$

*lb/hr of equivalent saturated steam

To Obtain ppm at 3% O_2 of	Multiply Concentration in ng/J by
Natural Gas Fuel	
CO	3.23
HC	5.65
NO or NOx	1.96
SO_2 or SOx	1.41
Oil Fuel	
CO	2.93
HC	5.13
NO or NOx	1.78
SO_2 or SOx	1.28
Coal Fuel	
CO	2.69
HC	4.69
NO or NOx	1.64
SO_2 or SOx	1.18
Refinery Gas Fuel (Location 33)	
CO	3.27
HC	5.71
NO or NOx	1.99
SO_2 or SOx	1.43
Refinery Gas Fuel (Location 39)	
CO	3.25
HC	5.68
NO or NOx	1.98
SO_2 or SOx	1.42

English and Metric Units to SI Units

To Obtain	From	Multiply By
ng/J	lb/MBtu	430
ng/J	g/Mcal	239
$GJ \cdot hr^{-1} \cdot m^{-2}$	MBH/ft^2	11.356
$GJ \cdot hr^{-1} \cdot m^{-3}$	MBH/ft^3	37.257
GJ/hr	10^3 lb/hr* or 10^6 Btu/hr	1.055
m	ft	0.3048
cm	in	2.54
m^2	ft^2	0.0929
m^3	ft^3	0.02832
Kg	lb	0.4536
Celsius	Fahrenheit	$t_C = 5/9\ (t_F - 32)$
Kelvin		$t_K = 5/9\ (t_F - 32) + 273$
Pa	psig	$P_{pa} = (P_{psig} + 14.7)(6.895 \times 10^3)$
Pa	psia	$P_{pa} = (P_{psia})(6.895 \times 10^3)$
Pa	iwg (39.2°F)	$P_{pa} = (P_{iwg})(249.1)$

*lb/hr of equivalent saturated steam

To Obtain ng/J of	Multiply Concentration in ppm at 3% O_2 by
Natural Gas Fuel	
CO	0.310
HC	0.177
NO or NOx (as equivalent NO_2)	0.510
SO_2 or SOx	0.709
Oil Fuel	
CO	0.341
HC	0.195
NO or NOx (as equivalent NO_2)	0.561
SO_2 or SOx	0.780
Coal Fuel	
CO	0.372
HC	0.213
NO or NOx (as equivalent NO_2)	0.611
SO_2 or SOx	0.850
Refinery Gas Fuel (Location 33)	
CO	0.306
HC	0.175
NO or NOx (as equivalent NO_2)	0.503
SO_2 or SOx	0.700
Refinery Gas Fuel (Location 39)	
CO	0.308
HC	0.176
NO or NOx (as equivalent NO_2)	0.506
SO_2 or SOx	0.703

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(Please read Instructions on the reverse before completing)

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16. ABSTRACT The document contains recommended procedures for improving industrial boiler performance to minimize air pollution and to achieve efficient use of fuel. It is intended for use by industrial boiler operators to perform an efficiency and emissions tune-up on boilers firing gas, oil, or coal. Portions of the guidelines are also intended for plant engineers interested in initiating preventive maintenance and boiler efficiency monitoring practices to maintain peak boiler operating efficiency. Several appendices to the guidelines contain background material on nitrogen oxides reduction techniques, the cost of combustion modifications, methods and equipment for efficiency improvement, and a discussion of combustion generated air pollutants. Earlier documents in this series are: EPA-600/2-75-069a (residential oil burners) and EPA-600/2-76-088 (commercial oil-fired boilers).

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air Pollution, Efficiency, Combustion	Air Pollution Control	13B,14A,21B
Nitrogen Oxides, Nitrogen Oxide (NO)	Stationary Sources	07B
Nitrogen Dioxide, Smoke	Combustion Modification	
Carbon Monoxide, Energy, Conservation	Energy Conservation	
Fuel Oil, Natural Gas, Coal	Excess Air	21D
Burners, Boilers	Boiler Tune-Up	13A
	Fuel Use	

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