Gas-side Corrosion in Oil-fired Boilers

Prepared for the

Romanian Energy and Electricity Authority (RENEL)

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Section 1

Introduction

This topical report has been prepared by Bechtel Corporation to summarize the results of studies performed for the Romanian National Electricity Authority (RENEL). These studies were conducted under contract with the United States Agency for International Development (USAID). The overall objective for the USAID support to RENEL is to improve the efficiency of the Romanian power generating sector. In response to specific requests by RENEL, studies were conducted in the following technical areas:

- Heavy fuel oil combustion and gas-side corrosion
- Boiler feedwater treatment and water quality control
- Ash handling in coal-fired power plants and soil reclamation at full ash storage piles

Study results in each of these areas are presented in separate topical reports. This report contains findings of studies of issues associated with the use of heavy residual oils to fuel boilers in power generating and district heating plants in Romania.

Specific objectives of this study were to perform the following:

- Relate Western practices and experience in residual oil-fired boilers
- Describe alternative combustion systems to alleviate gas-side corrosion and improve combustion efficiency
- Suggest methods to reduce adverse effects in RENEL's plants

1.1 BACKGROUND

About 42 percent of the thermal generating capacity in the RENEL system is fueled with fuel oil, gas oil, and natural gas. Over the past two decades, 13 to 23 percent of the annual electricity production was derived from burning oil. About 27 to 32 percent of the annual thermal output for district heating was also obtained from fuel oils. The normal operating procedure is to burn domestic natural gas in the plants as long as it is available. (Domestic and industrial users have priority for natural gas.) Because of the limited natural gas supply, the plants burn residual fuel oil 6 to 8 months per year.

Residual oil from domestic refineries constitutes the largest portion of the oils burned in these plants. Crude oil for the refineries is obtained from domestic wells or is imported from the Middle East. The fuel oil received from the refineries is characterized by high viscosity (732 Cs at 50°C) excessive amounts of sulfur (2.8 to 4.2 percent), vanadium (80 to 150 ppm), coke (10 to 20 percent), and asphaltene (3 to 10 percent). These impurities create serious problems in the power plants:

- Severe corrosion of metals exposed to the flue gas (vanadium corrosion in the high-temperature sections, such as superheaters and reheaters; sulfuric acid corrosion at the low-temperature section, such as the air preheaters, flue gas duct work, and induced-draft fans)
- Scale deposits on the convective section components, extending to the air preheaters
- Poor combustion efficiency since the currently installed burners are not suitable for burning the poor quality residual fuels (inadequate atomization and air-fuel ratio control)
- Excessive atmospheric pollution

These problems have led to poor energy efficiency, reduced plant availability, and excessive maintenance costs. For reasons of the Romanian national economy, it is not possible to avoid the use of poor quality fuel oil. RENEL is, and has been in the past, conducting some experiments to find a reasonable solution to these problems. At the same time, RENEL has requested assistance from USAID to provide a review of Western practices with residual oil-burning power plants and to suggest potential alternatives for alleviating the problems. The study covered in this report was undertaken in response to this request.

1.2 REPORT ORGANIZATION

This report on gas-side corrosion and fuel combustion consists of five sections. In addition to this introductory section, this report contains the following:

- Section 2 summarizes the findings of the study and presents the conclusions and recommendations derived from the investigations.
- Section 3 discusses western experience with burning fuel oil in power plants.
- Section 4 discusses corrosion and environmental problems in oil-fired boilers.
- Section 5 presents the plan of action for RENEL recommended by the study team.

Section 2

Summary, Conclusions, and Recommendations

2.1 SUMMARY

A significant portion of RENEL's power generating and district heating boilers are fired with heavy residual fuel oil which contains significant vanadium contamination and a high percentage of sulfur. Oil firing is used in the winter, when the much cleaner burning natural gas is not available for power generation. Boilers in these plants were designed for much better grade of residual fuel than that currently available in Romania. For example, the design is based on 1 percent sulfur, whereas the current supply has as much as 4.2 percent sulfur. Also, the currently available oil has high viscosity and contains vanadium and asphaltene. The boilers are equipped with burners that have mechanical atomizers not suitable for burning such heavy oils.

When burning this poor grade oil, the plants experience sticky deposits on the boiler heat transfer surfaces and serious corrosion damage from vanadium and sodium compounds. The cold-end ducts and the air preheaters suffer corrosion from excessive sulfuric acid attack.

The shortage and high cost of better grade fuels forced many Western power plants to start using poorer fuel oils as well. They have also experienced similar corrosion problems. To remedy these problems, the Western utility companies and research institutions have undertaken studies and research programs to gain a better understanding of the causes and mechanisms of these corrosion problems. Based on the results of studies and experiments, a number of methods for limiting corrosive damage have evolved and have been successfully implemented. The appendices contain a number of papers relating, in detail, to the results of recent research in Western countries.

Plants designed for lighter fuel oils have found that complete combustion of the heavy oils, particularly those containing asphaltene, is difficult to achieve. The use of more excess air did improve the combustion efficiency but worsened the corrosion. However, significant improvements were achieved with improved atomization. Dual fluid burners, using steam or air assist, have reduced the unburnt carbon. Atomization, and with it combustion, was also significantly improved when 5 to 10 percent of water was emulsified into the oil. Both methods achieved complete combustion with less excess air, which improved the corrosion problems.

Vanadium and sodium compounds, found in most oils, cause lowering of the ash melting point and form highly corrosive deposits in the superheater and reheater tubes. It was found that adding finely ground alumina or magnesia to the oil led to chemical reactions that produce high melting point compounds of vanadium and sodium. These compounds then form loose, noncorrosive deposits that can be readily removed with sootblowing.

Corrosion research found that high temperature steels with high chromium content have oil ash corrosion rates that are a factor of 6 lower than the conventional 2-1/4 Cr-1 Mo steel commonly used in superheater and reheater surfaces. The cost of 13 Cr steel is only moderately higher than the conventional alloys. The 50Cr-50Ni alloy has the lowest oil ash corrosion rates. This alloy, although not suitable for tube material, can be afforded for tube support.

Vanadium was found to act as a catalyst, promoting the oxidation of SO_2 to SO_3. When combined with moisture, the SO_3 forms sulfuric acid vapor which then condenses on cold surfaces in the air preheater and the ductwork leading to it. Binding up the vanadium into more complex compounds prevents the catalytic oxidation of sulfur. The lower vapor pressure at SO_2 - SO_3 equilibrium concentration results in lowering of the dew point temperature. The benefit is a lessening of the cold-end corrosion. Frequent washing and design changes, such as installation of the steam heater in the flue gas duct, may be performed to reduce cold-end corrosion.

Many of the Western power plants have also introduced modern automated control systems. These systems allowed improved control of combustion parameters and contributed to the lessening of corrosion rates.

Oil transportation, handling, and storage can add to the impurity content, and blending of incompatible batches may lead to increases in the detrimental asphaltene concentrations. Analyses of oil samples at the receiving station and in the storage tanks are necessary to maintain current knowledge of the oil properties. These analyses also help to avoid blending incompatible oils and to make proper adjustments in the combustion parameters.

After suitable trials and testing, many of these improvements could be incorporated in RENEL's plants. Improvements in oil atomization and upgrading of combustion controls should receive high priority.

Appendix E contains the outline of a program for RENEL's use in planning and executing a suitable test series to demonstrate the value of introducing steam-atomized oil burners, and using low cost additives to improve plant efficiency and reduce corrosion problems. A listing of required equipment is also included.

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2.2 CONCLUSIONS

Corrosion in the boilers and associated equipment is causing severe operational and economic hardship at RENEL's residual oil-fired power and district heating plants. Results of corrosive attack were clearly evident at all the plants visited during the data gathering trip to Romania. There is an urgent need to alleviate these problems and thereby improve both the efficiency and the economics of the energy supply system.

Recent Western experience in full-scale power plants and development efforts, resulted in more satisfactory combustion efficiencies and a reduction in corrosion damage to gas-side equipment in residual oil-fired boilers. There are several steps that evolved from these activities. These steps could be beneficially introduced in RENEL's oil-fired plants to reduce the outage rates and maintenance costs for repairs of boilers experiencing serious corrosive attacks. These steps are as follows:

1. The existing mechanical atomizers are inadequate for producing small enough oil droplets and dispersion with the available residual oils to ensure proper combustion at low excess air to minimize corrosive attack. Steam-assisted atomization and the use of water emulsions should be tested to determine their benefit for combustion efficiency improvements and lessening of corrosion.
2. High temperature corrosion, resulting from a low melting point mixture of vanadium and sodium compounds, could be reduced by using finely ground alumina or dolomite additives. These additives promote the formation of high melting point, less corrosive compounds of these elements. Such methods, in conjunction with improved atomization, should lead to reduced equipment failure rates and lower maintenance costs. The alumina or dolomite additives may be less costly than the AKOM additive, currently being tested by RENEL.
3. Cold-end corrosion due to the presence of sulfuric acid may be lessened by limiting the formation of SO_3. This may be achieved by minimizing the excess oxygen in the flue gas and by binding up the vanadium in complex compounds (see item 2 above). This process will minimize the catalytic effects that cause the formation of SO_3 in excess of normal equilibrium with SO_2. Frequent washing of the surfaces exposed to the flue gas is also beneficial.
4. Changing the materials used in the superheaters and reheaters from chrome-molybdenum steel to high chromium ferritic alloys could increase the service life and reduce the maintenance requirements at moderate costs.

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5. Indiscriminate mixing of fuel oils from diverse sources is a frequent source of stratification and high asphaltene content. Full characterization of the fuel oil is necessary to establish proper handling and storage procedures and to make adjustments in the combustion parameters.
6. A reliable and fast responding control system is essential to maintain close control of the combustion system parameters, mainly excess air.
7. Detailed plant-by-plant studies and test work are required to determine the most cost-effective combination of remedies to alleviate the high and low temperature problems.

2.3 RECOMMENDATIONS

Bechtel has reviewed the findings of the study and the conclusions reached and offers the following recommendations:

1. Reducing excess oxygen is a prerequisite to reducing corrosive attacks, hot or cold. As the highest priority item, RENEL should initiate test work on steam-atomized oil burners in a suitably sized boiler. The tests should be carefully planned to cover the full range of oils (possibly including emulsions) used in their plants.
2. RENEL should undertake an experimental verification of the value of alumina or dolomite additives for changing the characteristics of ash deposits and reducing the catalytic effects of vanadium on SO_3 formation. The relative effectiveness and economic merits of these additives, compared with the currently tested AKOM additive, should be established. The test program outlined in Appendix E is intended to confirm the suitability of improved oil atomization, tight excess air control, and low cost additives to eliminate the serious corrosion problems experienced in RENEL's oil-fired boilers.
3. Incorporation of corrosion prevention measures will involve a major plant retrofit program, requiring significant capital investment. It is recommended that RENEL commission a comprehensive evaluation and planning effort to establish the following:
    a. The needed remedial and retrofit work in each unit (or plant)
    b. The schedular priority for this work, based on the importance of each unit, to meet the electrical and thermal loads and the remaining unit service life

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c. Conceptual and preliminary engineering data for the highest priority units to support preparation of cost estimates and economic analysis

d. A tentative schedule for activities to be carried out in the near term (say 5 years)

e. The capital required to implement the plans and the amount of subsidy and/or outside investment that needs to be secured

Results of this planning effort should provide a well-supported rational basis for RENEL to approach the Romanian government and/or international lending agencies to secure the capital required to implement the plans.

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Section 3

Western Experience with Burning Fuel Oil in Power Plants

3.1 HISTORICAL EVOLUTION

The American Society for Testing of Materials (ASTM) standard classification has six oil grades. The viscosity and fraction of higher hydrocarbon chains increase from grades 1 through 6. The No. 1 and No. 2 fuel oils are distillates, mainly used as light fuel in gas turbines and small internal combustion engines. There are four grades of residual oils. The No. 4 and No. 5 (light) oils have moderate viscosities and can be normally handled and burned without preheating. The No. 5 (heavy) and No. 6 oils are quite viscous and require preheating to allow handling and efficient combustion in burners.

Residual oils, following the refining process, have been used as fuel for some time. It is a convenient fuel from a handling and storage point of view. However, the problems of slag deposits and boiler tube corrosion, caused by impurities such as sulfur, vanadium, nickel, and sodium, have occurred since the earliest times. As early as 1949, experiments have shown that additives, such as alumina and dolomite, have changed the characteristics of the deposits to a friable consistency and made them more readily removable.

Owing to ready availability and low cost of fuel oils in the 1950s and 1960s, numerous power plants, originally designed to burn coal, were converted to oil firing. These types of converted plants make up most of the oil-fired plant inventory in the United States. In the same period, several natural gas-fired plants were also equipped with provisions to burn oil during periods when the natural gas supply was low. Because of a similarity in furnace geometry, the coal plants could be converted without loss of steaming capacity. However, the comparatively smaller boilers, designed for natural gas firing, could only operate under a reduced steaming rate when fired with oil.

In the late 1960s, the cost of fuel oil declined to a level, where it became an economically attractive alternative to burning coal. In this period, a new generation of boilers, designed specifically for oil burning, entered the market. These boilers were of large capacity, 500 to 1,000 MW, and were designed for superheater outlet temperatures in the range of 540°C to 565°C, with pressures of 180 bar or above.

In the early 1970s, when the oil prices were comparatively low, attempts were made to burn crude oil directly. Many units were equipped for this fuel. After the 1973 embargo, crude oil burning fell largely by the wayside, to the point that, today, there are no crude burning plants in operation.

After 1970, several utilities attempted to burn low sulfur residual oils, mainly from the Middle East. They had varying degrees of success but with a whole new set of problems.

In direct response to environmental regulations, blended residual oil with low sulfur content became the standard fuel for utility power generation. Reduction in NO_x emissions was accomplished by the introduction of flue gas recirculation (Figure 3-1) which reduced the flame temperature, and with it the thermal NO_x formation. Plants that did not have this feature were retrofitted with the necessary ductwork and fans. The other method for reducing NO_x emissions was to specify fuels with low fuel-bound nitrogen, the other major contributor to NO_x formation.

The third regulated emission in the United States is that of particulate matter, which causes stack opacity and, under adverse circumstances, soot fallout. Burning techniques and periodic sootblowing are the main sources of particulates leaving the stack. Many of the units either already had electrostatic precipitators or were retrofitted with them to limit particulate emissions. The most effective technique for reducing particulate emissions is efficient atomization of the fuel which leads to nearly complete combustion of carbon. Experimental methods have demonstrated the effectiveness of this approach and currently more and more of the plants are making the necessary changes to implement it.

Because of the rapidly increasing oil prices following the 1973 oil embargo, and the almost concurrently enacted stringent air quality regulations, the construction of oil-fired power plants has essentially ceased. The existing plants were relegated to peaking or intermediate service. Today, oil accounts for only about 3 percent of the total fuel burned in power plants in the United States.

Over the past decade, the quality of residual fuel available to power plants has declined steadily. This is occurring partly because of the declining availability of premium grade crude oils. Another factor is that new refinery techniques, such as hydrocracking and catalytic cracking, are yielding more high quality light fractions with corresponding lower quality residuals, which leads to lower demand for residual oils for power plants in the United States.

Solutions for corrosion problems, operational difficulties, and elimination of adverse environmental impacts due to sulfur, NO_x and particulate emissions are being sought, and research in these areas is continuing. These efforts are described in Section 4.2.

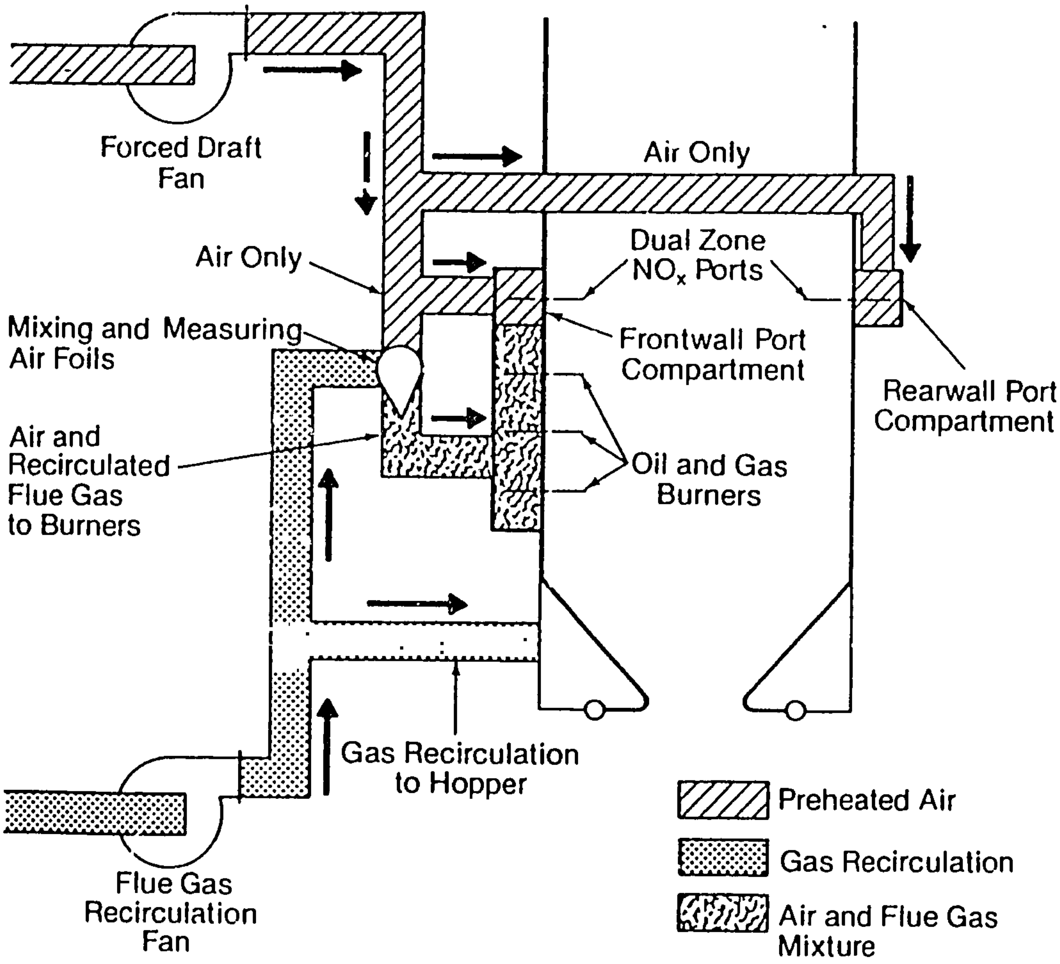

Figure 3-1 Flue Gas Recirculation Low NO_x System for Oil and Gas Firing

3.2 DESIGNS FOR OIL FIRING

In the period before the 1970's there were few utility boilers designed specifically for oil firing. A majority of oil firing experience was derived from coal- and gas-designed boilers that were retrofitted for oil firing in the 1950s and 1960s. Valuable experience was gained during this period about the operational and performance differences between coal and gas firing and the oil-fired boilers. This experience lead to a new generation of boilers specifically designed to burn oil, mainly heavy refinery residuals.

The new boilers were of large capacity; they were producing steam at high subcritical or supercritical pressures and were either drum types or once-through design. Some of the subcritical boilers had dual drums and a furnace division wall. The subcritical drum boilers used natural or assisted water circulation. Both opposed and tangentially configured burner arrangements were used. All used flue gas recirculation for steam temperature control which provided the side benefit of reducing NO_x emission rates.

The new boilers used the experience gained in the earlier retrofitted units. However, the experience in the new boilers is of equal importance, particularly since the quality of residual fuel has been steadily declining, creating new problems and the need to find an economic solution to these problems. The key items are summarized below.

The tubing used in the furnace walls is of major importance because of the high heat absorption rates in the oil-fired boiler furnace portion. Tubing made of alloys, such as SA-213, T11, with better high temperature properties have proven to give better and longer service life. Ribbed tubes in the region around the burners have been useful in preventing or slowing departure from nucleate boiling (DNB).

Corrosion effects, both internally and externally, have a significant impact on the tube life. It was recognized that there are at least two different types of corrosion attacks on the tube surfaces and on the air preheaters. External corrosion was found to be increased by a number of factors which create deposits of ash and at times carbonaceous residue on the hot furnace and superheater surfaces. On the cooler surfaces in the economizer and air preheater, corrosion is caused by the presence of condensed sulfuric acid. These problems and effective preventive methods are discussed in greater detail in Section 4.1.

It was found that superheater tubes made of high chromium alloy steels had longer service life.

There have been contrasting experiences with austenitic and ferritic steel tubes. In some boilers, austenitic stainless steels with significant nickel content had long service life. In other instances, the high chrome ferritic steels were found to be more effective in limiting corrosion damage.

The boilers designed for oil firing incorporated a membrane wall in the furnace, providing a gas-tight casing, which eliminated the air inleakage in balanced draft boilers. This reduction of air inleakage and the use of low excess air firing methods helped to reduce the oxidation reactions with vanadium and sulfur. Before the advent of membrane walls, the furnace was enclosed in an airtight casing, made of sheet or plate steel. The casing operated at a relatively high temperature, even though there was refractory installed on the inside. Joints in the refractory and fractures due to differential thermal expansion have allowed flue gas to come in contact with the casing, leading to corrosion and increase in air inleakage.

Several improvements in the treatment of the back pass have been made and have proven to be valuable. The first of these is the replacement of resistance welded tubing with seamless tubing in the boiler economizer. Resistance-welded tubes were prone to leakage. Water leaks in the backpass are especially harmful in boilers burning high sulfur oils, since this aggravates cold end corrosion.

Extended surfaces and staggered tube patterns are highly susceptible to sulfur corrosion. Bare tubes and in-line arrangements were found to be much more reliable and less susceptible to corrosion damage. Plugging of the gas passages between the staggered tubes caused increased gas-side pressure drops. Erosion and cracking at the termination points have created problems with economizers in oil-fired boilers. Although the bare tube and in-line configuration is less efficient for heat transfer, the efficiency loss may not be significant in comparison with the performance of extended surface tubes with clogged gas passages. Tube ends of the economizer should be fully baffled. This results in better heat transfer, minimizes tube erosion, and reduces the casing temperature.

Improved sealing of the backpass casing was found to be most effective in reducing air inleakage and heat loss. There are a number of ways to accomplish this, and the options need to be evaluated from boiler to boiler. Increased insulation thickness in the backpass and the ducting to the air preheater reduces the heat loss and results in higher flue gas temperatures leading to the air preheater, thereby keeping the temperature above the acid dew point.

3.3 CURRENT WESTERN PRACTICES

Successful and trouble-free power plant operation with heavy fuel oils depends on accurate knowledge of the properties of the fuel, appropriate adjustments in the combustion parameters, and the level of care exercised in its handling and storage.

3.3.1 Fuel Oil Properties Determination

Fuel properties directly related to the handling and combustion of fuel oil in power plants include gravity, heating value, viscosity, water and sediment content, and pour, flash and fire points. The presence of sulfur, ash, and other contaminants is also a source of important information. The ASTM has developed a series of test methods and procedures to determine these characteristics. Table 3-1 contains a listing of these standards.

Table 3-1
ASTM Tests for Fuel Oil Analysis

Standard No. 1*	Method of Test for
D 56	Flash point by tag-closed tester
D 88	Viscosity, Saybolt
D 92	Flash and fire points by Cleveland open cup
D 93	Flash point by Pensky-Martens closed tester
D 95	Water in petroleum products and bituminous materials by distillation
D 97	Pour point
D 129	Sulfur in petroleum products (bomb method)
D 189	Carbon residue, Conradson, of petroleum products
D 240	Heat of combustion of liquid hydrocarbon fuels by bomb calorimeter
D 287	API gravity of crude petroleum and petroleum products (hydrometer method)
D 341	Viscosity/temperature charts, standards for liquid petroleum products
D 445	Viscosity of transparent and opaque liquids (kinematic and dynamic)
D 473	Sediment in crude and fuel oils by extraction
D 482	Ash from petroleum products
D 524	Carbon residue, Ramsbottom, of petroleum products
D 1266	Sulfur in petroleum products (lamp method)
D 1298	Density, specific gravity, or API gravity of crude petroleum and liquid petroleum products (hydrometer method)
D 1322	Sampling petroleum and petroleum products
D 1551	Sulfur in petroleum oils (quartz-tube method)
D 1552	Sulfur in petroleum products (high-temperature method)
D 1796	Water and sediment in distillate fuels by centrifuge
D 2161	Viscosity conversion of kinematic to Saybolt Universal or to Saybolt Furol
D 2622	Sulfur in petroleum products (X-ray spectrographic)
D 2709	Water and sediment in distillate fuels by centrifuge

Source: * All listed standards are also approved ANSI standards.
Steam, Its Generation and Use; Babcock and Wilcox Co., 1992.

Gravity of the fuel oil is indicative of its grade and heating value. It can be determined by using a standard hydrometer and then correcting the reading to 16°C, which is the standard reference temperature. In the United States, the gravity is expressed in degree scale of the American Petroleum Institute (API). Heavy fuel oils may have an API gravity degree of 7 to 22. A typical No. 2 distillate would have an API gravity of 28 to 40 (see Table 3-2)

Table 3-2
API Gravity, Specific Gravity, and Density at 60°F (15.6°C)

Deg API	Specific Gravity	Density lb/gal*
10	1.0000	8.328
15	0.9659	8.044
20	0.9340	7.778
25	0.9042	7.529
30	0.8762	7.273
35	0.8498	7.076
40	0.8251	6.870
45	0.8017	6.675

Source: kg/m^3 = lb/gal x 120.
Steam, Its Generation and Use; Babcock and Wilcox Co., 1992

Determining the **heating value** is a complex process which requires expensive equipment. It was found, however, that the heating value is closely related to gravity. For normal industrial use, such as in power plants, the heating values tabulated against API gravity (see Table 3-3) may be sufficiently accurate.

Table 3-3
Heating Values of Fuel Oils vs. API Gravity at 60°F (15.6°C)

Deg API	Heating Value			
	Gross		Net	
	Btu/lb(a)	Btu/Gal(b)	Btu/lb(a)	Btu/gal(b)
5	17,980	155,470	16,990	146,860
10	18,260	152,280	17,270	144,000
15	18,500	149,030	17,480	140,750
20	18,740	145,880	17,660	137,510
25	18,940	142,820	17,830	134,350
30	19,130	139,660	17,980	131,300
35	19,300	136,720	18,110	128,350
40	19,450	133,760	18,230	125,390
45	19,590	130,910	18,340	122,530

Source: (a) kJ/kg = Btu/b x 2.33. (b) kJ/L = Btu/gal x 0.279.
Steam, Its Generation and Use; Babcock and Wilcox Co., 1992

Viscosity is a measure of flowability, and, as such, it is an important parameter in the operation of equipment used for handling and burning the oil. In the U.S. petroleum industry, the Saybolt viscosimeter is used for determining the viscosity of fuel oils. The use of a kinematic viscosity index is increasing in the petroleum industry. Conversion between these indices and those of Redwood 1 in England and the Engler, used in other European countries, can be readily done using the tables shown in Appendix A.

The **pour point** of an oil is the lowest temperature at which it flows under standard conditions. Under laboratory conditions, the pour point is 2.8°C higher than the solidification temperature. Wax content of the oil affects the pour point. Higher wax fractions cause higher pour-point temperatures. Pour points of most U.S. domestic heavy oils range from -3.5°C to 18.3°C. Some oils refined from high paraffin foreign crude may have pour points as high as 53°C. Some high pour-point residual oils do not follow the normal viscosity/temperature relations and become highly fluid only a few degrees above the pour point. To avoid problems of handling high pour-point oils, it is necessary to keep tanks at a higher temperature, and all equipment in contact with the oil during transfer must be free of cold spots.

The **flash point** is the temperature at which heated oil vapors flash when ignited with an external flame. If the heating continues, the point where sustained burning is maintained is called the **fire point**. Heavy fuel oils can have a flash point as high as 120°C, thus they do not represent a fire hazard, unless they are contaminated with volatile fraction.

The **sulfur** content of the heavy oils is in direct relation to the chemically bound sulfur in the crude. In most instances, 70 to 80 percent of the crude sulfur content is bound in a variety of organic compounds and is concentrated in the residual oil. In the United States, the Environmental Protection Agency has set limits for sulfur content, these limits vary regionally. High sulfur content creates severe corrosion problems in equipment where the flue gas temperature approaches the dew point of sulfuric acid.

The **ash content** is the result of oxidation of organometallic compounds contained in the crude oil. These compounds are concentrated during the refining process and cannot be easily removed with any physical methods, such as centrifuging of filtering. In heavy residual oils, the ash content may be 0.2 to 1.5 percent. There are as many as 25 different metals in crudes. Iron, nickel, calcium, aluminum, and sodium are the most prevalent. Although it is usually in small amounts, vanadium is one of the most troublesome metallic contaminants. If the ash is allowed to accumulate on boiler surfaces, those containing nickel, vanadium, and sodium can create severe corrosion problems.

Contaminants such as water, sediments, and sludges are found in all grades of fuel oil; however, the percentage can be significant in residual oils. Water is usually the result of condensation or leakage into tanks from the surroundings or from leaky steam coils. Sediments come from dirt carried along in the refining process plus dirt picked up during transportation and storage. Normally, there are only small quantities of water and sediment in the oil that do not create problems. However, oil taken from the bottom of tanks may have excessive amounts that can cause pluggage of screens, pipe lines, and burner nozzles. Excessive water could cause burner instabilities. The total amount of water and sediments is usually determined from centrifuge tests. An extraction process is used to measure sediments and distillation to determine the water content.

Sludge, found in some heavy fuel oils, is a mixture of organic compounds that have precipitated after mixing different batches of heavy oil. The two main groups are the asphaltenes and wax. The asphaltenes disperse in the oil after precipitation and can be the cause of plugging. Neither the asphaltenes nor the wax can be detected by normal test methods because they are soluble in solvents, such as benzol or toluene. While wax can be eliminated by heating, the asphaltenes can not be removed with any methods that are practical in power plants.

3.3.2 Sampling Practices

It is a recommended practice to sample the fuel oil received at the plant to ascertain that it meets specifications. There are two sampling methods designed to collect representative samples during the unloading operations. Drip sampling collects continuous samples from the unloading line through a small nipple and valve. A total of 1 to 4 liters of samples are collected in the course of unloading. With slug sampling methods, small quantities of oil (0.23 - 0.47 liters) are periodically withdrawn from the unloading line. When unloading barges or oil tankers, which takes several hours, sampling should be done every 30 minutes. If trucks or railroad tank cars are unloaded, the sampling frequency should be done every 5 minutes. With slug sampling, the total sample is blended to obtain a representative average.

It is also necessary to sample the oil stored on site periodically, and before starting to feed the oil to the firing system. The objective here is to detect any changes in the oil during storage and to determine the combustion characteristics to make any necessary adjustments in the firing system settings. Samplings of storage tanks, barges, or tankers are taken though an opening on the top. One sample needs to be

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taken from the oil about 0.3 m below the surface and one about 0.3 m from the bottom. Depending on the depth of the load, one or more samples should be taken from intermediate depths. In barges or tankers, the sampling routine needs to be repeated in each compartment. To obtain representative average characteristics, the samples are blended. If there is a suspicion that stratification may have taken place, the top and bottom samples may be separately tested.

It is highly desirable to have a well-equipped laboratory at the plant to ensure complete and accurate analyses and tests of the collected samples.

3.3.3 Fuel Oil Storage and Handling

Fuel handling practices affect boiler operation by adversely affecting atomization or by modifying fuel properties that ultimately result in poor combustion characteristics. Fuel-related operational problems which are attributable to fuel handling include carbon burnout, proper atomization, and particulate emissions.

A residual oil-fired storage and handling system includes a tank farm storage area, fuel heating and pumping facilities, and a fuel distribution network to supply the oil to the boilers of the plant or to the burners of one boiler. On boilers using mechanically atomized burners, a second, high-pressure pump would be located upstream of the burner supply lines. Steam or air atomized burners generally permit operation with the fuel supply pressures provided by the forwarding pumps. For mechanically atomized systems, return flow oil lines may be required to return excess oil to the inlet of a high pressure pump, the fuel forwarding pump or the oil supply tank. Return flow systems are commonly used with wide range, mechanical atomizers. In systems where heated oil is returned to the storage tank, the oil temperature in the tank should be monitored to prevent overheating. Tank oil temperature must remain below the oil's flash point to prevent a hazardous situation.

Utility oil tank storage facilities typically have multiple fuel forwarding pumps that provide simultaneous forwarding, transfer, or heating operations from one tank to another or to recirculate and heat the oil within a single tank (see Figure 3-2). Prior to delivery to the burners, the fuel is strained and filtered to eliminate dirt, sediment, and contamination that can erode pump and atomizer parts. The amount of filtration and location of strainers or filters within the fuel system are selected according to the quality of fuel burned and the requirements of the pumps and atomizers. In general, high pressure, high flow components are more severely affected by erosion from ash and contaminants in the oil and, as a result, require better filtration.

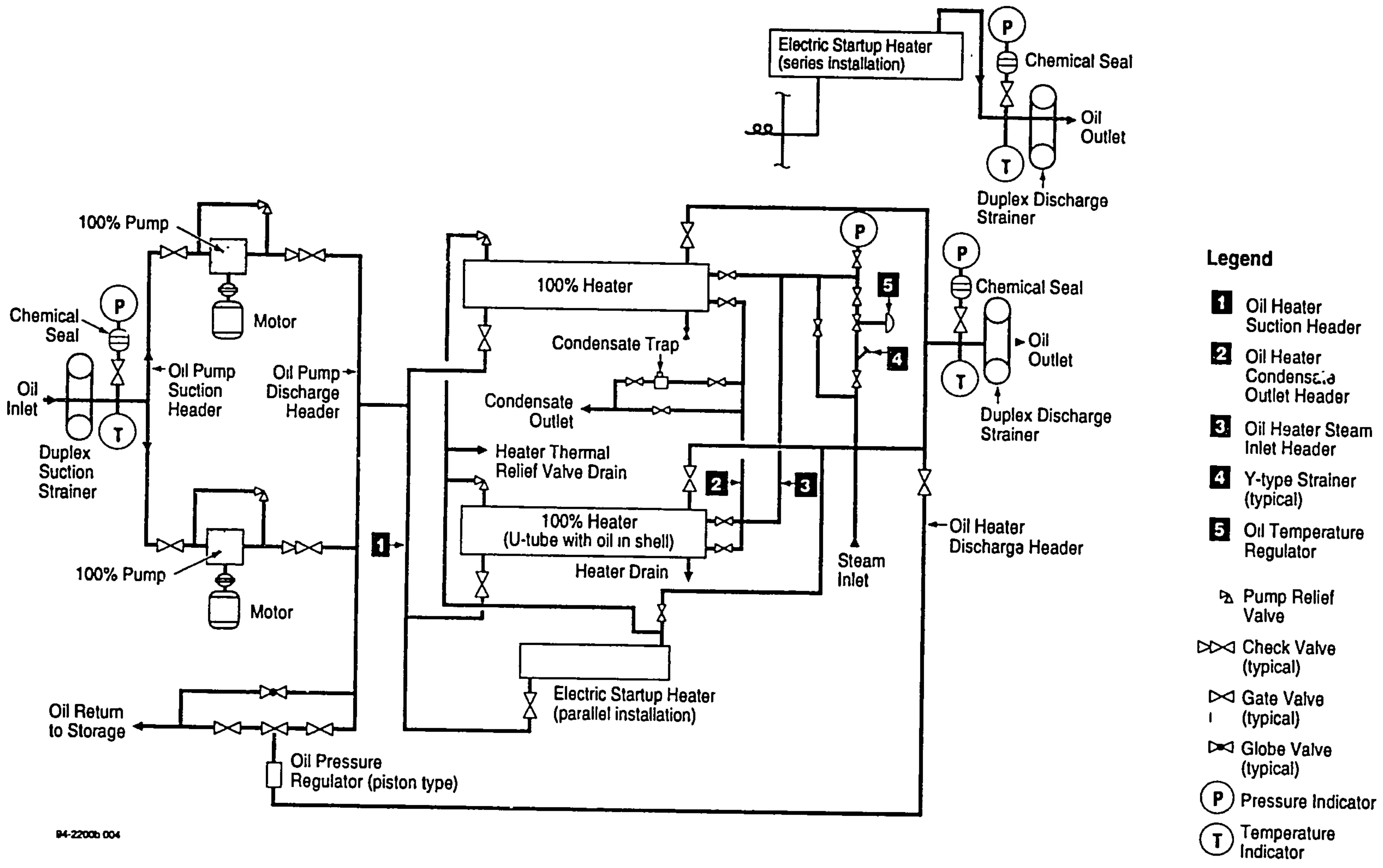

Figure 3-2 Duplex Pumping, Heating, and Straining (PHS) Set

Residual fuel oil properties vary significantly, but all require preheating to permit acceptable atomization or pumping. Fuel temperature is the primary factor affecting the viscosity of a residual fuel oil. Poor or inadequate atomization can result from low fuel temperatures. The viscosity requirements for effective atomization are specified by the atomizer manufacturer, with 100 to 50 Saybolt Universal seconds being the typical range for most atomizers. Temperatures in the order of 200°F may be required for proper atomization of residual fuel oils. A low fuel temperature will raise the viscosity (increasing friction losses) and reduce the energy available for atomization.

Non-uniform oil properties can occur when fuel is stored in a large tank because of stratification or incompatibility problems. Stratification is caused by fuel settling or by variations in quality between fuels which were delivered at different time and not well mixed. Stratification or settling occurs because residual fuel oils are composed of the heaviest components of crude oils, and the high molecular weight hydrocarbons (asphaltenes in particular), along with water and ash, can settle out, given sufficient time. High sulfur oils are also susceptible to high sedimentation and sludge formation. Heating of the fuel during long-term storage can accelerate the separation process. Incompatibility between two residual oils can result in the precipitation of asphaltenes from the blended oil, forming a heavy tar-like sludge. A large layer of sludge can be a significant problem for a utility fuel system. Typical problems associated with sludge-like oil include plugging of filters and strainers, poor pumping (high viscosity) characteristics, poor atomization, and poor combustion properties. Avoiding the formation of a sludge layer in tanks or proper elimination of sludge deposits are essential for proper boiler operations.

Additional details about the operation and maintenance of the fuel storage and supply system are presented in Appendix B.

3.3.4 Burners for Heavy Fuel Oil

Efficient combustion of fuel oil requires that it be injected into the hot furnace as fine mist, consisting of micron size particles. Breaking down of the oil into particles is called atomization. Atomization and dispersal of the oil is the function of the burners. Burner designs have evolved as a result of intensive development effort and lengthy operating experience. Modern power plants are using two major types of burners, namely, ones with mechanical atomization and others that use steam or air to assist the atomization. The latter group is referred to as "dual fluid" burners.

Mechanical atomizers use the pressure of the oil itself to provide the energy for atomization. These atomizers require relatively high oil pressures for proper performance. Three commercial versions of these atomizers are in common use.

The first type is the Uniflow atomizer used in small and medium-sized stationary boilers and in marine boilers. It is a simple unit with few parts, and is simple to operate. The fuel is introduced into ports that discharge it tangentially into a whirl chamber. From here, it is spun out and is injected into the furnace as a finely atomized conical spray. For a 20 to 23 thermal MW burner, an oil pressure greater than 2 MPa is required.

The return flow atomizer (Figure 3-3) is the second type. It is used in stationary or marine boilers that require a wide capacity range. These burners eliminate the need to change the sprayer plates or the number of active burners during operation. A wide range of operation is possible by maintaining constant flow through the sprayer plate slots and returning the excess oil to low-pressure part of the oil pipes during low load operation. The oil pressure required for this burner is either 4.14 MPa or 6.9 MPa. Maximum burner capacity is in the order of 59 thermal MW.

The third type is called stem mechanical atomizer. This type combines straight mechanical atomization at high loads and at low loads the atomization is augmented with steam. The required oil pressure is between 1.4 and 2.1 MPa depending on the capacity requirements. The steam pressure at the atomizer is kept 70 to 100 kPa above the oil pressure, not to exceed 0.86 MPa. Such burners have maximum capacities of about 24 thermal MW.

To avoid solidification of heavy residues with residual oils at cold spots, a certain number of steam atomizers should be included in the battery of mechanical atomizing burners. These atomizers should be included to help avoid operational difficulties at initial boil out and for operation at very low loads.

Steam atomizers are preferred with heavy residual fuels. They have better and safer operating characteristics. These atomizers typically produce a finer spray because the rapid expansion of the steam, when released into the furnace, contributes to the reduction of oil droplet size. **In a number of designs, air may be substituted for steam if the energy balance does not allow diversion of steam to the atomizers.** Several steam atomizer designs are available with capacities up to 88 thermal MW. Depending on the design, oil pressures as much as 2.1 MPa may be required, although the required oil pressures tend to be lower than those required with mechanical atomizers. The maximum steam pressure may be as high as 1 MPa.

There are four common steam atomizer designs, characterized by different operating ranges, steam consumption, and atomization quality.

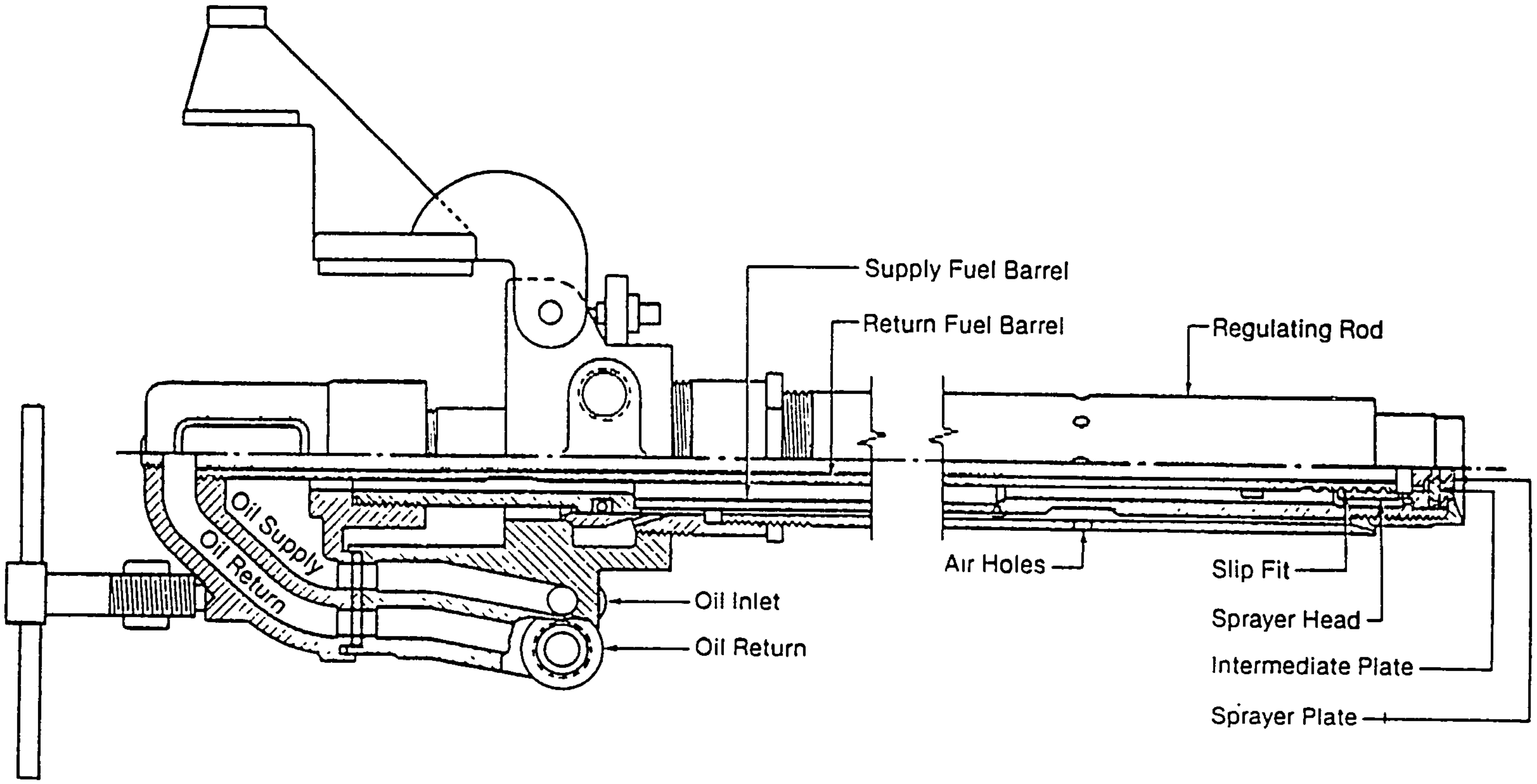

Figure 3-3 Mechanical Return Flow Oil Atomizer Assembly

The Y-jet is designed for a wide range of firing without changing the number of burners in service, or the size of sprayer plates. In these burners, the oil and steam are ducted separately and are blended immediately before the sprayer plate, just before entering the furnace. The maximum oil pressure at the atomizer ranges from 420 kPa to 620 kPa. This is a constant pressure differential design, requiring steam pressures to be maintained at 280 kPa over the oil pressure throughout the operating range. The steam consumption is in the order of 45 g per kg of oil.

A refinement of the Y-jet atomizer is known as the Racer atomizer. Its main use is in installations where large turndown ratios and low steam consumption are necessary. The oil pressure at maximum capacity is 2.1 MPa. Steam pressure is held constant over the entire load range at 1 MPa. The steam requirement is 10 grams per kilogram of oil.

The other two burner types, the T-jet and I-jet (Figure 3-4), are also capable of wide range of operation. However, they differ from the previously described ones by the fact that the oil and steam are mixed in a chamber before passing through the sprayer plate. The oil pressure ranges from 620 to 760 kPa, depending on the fuel characteristics and the load. These atomizers are also of the constant pressure differential type, requiring steam pressures of 160 kPa to 280 kPa above the oil pressure. The steam pressures can be adjusted for best atomization performance. The steam requirement may be as high as 90 grams per kg of oil. The atomizing performance tends to improve with higher steam consumption.

Steam atomization has the key advantage of promoting more complete carbon combustion at lower excess air requirement. The benefit is better boiler efficiency, and less carbonaceous deposits on water walls and superheater tubes. Since these carbonaceous deposits contribute to the hot corrosion problems, reduction of these deposits will increase the service life of the water wall and superheater surfaces. With less excess air, less SO_3 is produced and, consequently, the problem of cold end corrosion is also somewhat lessened. Disadvantages of steam atomizers include lower power output since some of the steam is diverted from the turbine, which reduces the overall plant efficiency. There is also an irrecoverable loss of steam, placing increased load on the boiler water treatment systems.

3.3.5 Use of Oil Additives

Additives in the form of magnesium oxide (MgO) or hydroxide are the most commonly used fuel chemicals to raise the fusion temperature of corrosive deposits in the boiler. Raising the temperature of vandates prevents them from adhering to tube surfaces and corroding the surface of the tube. This makes the deposits less

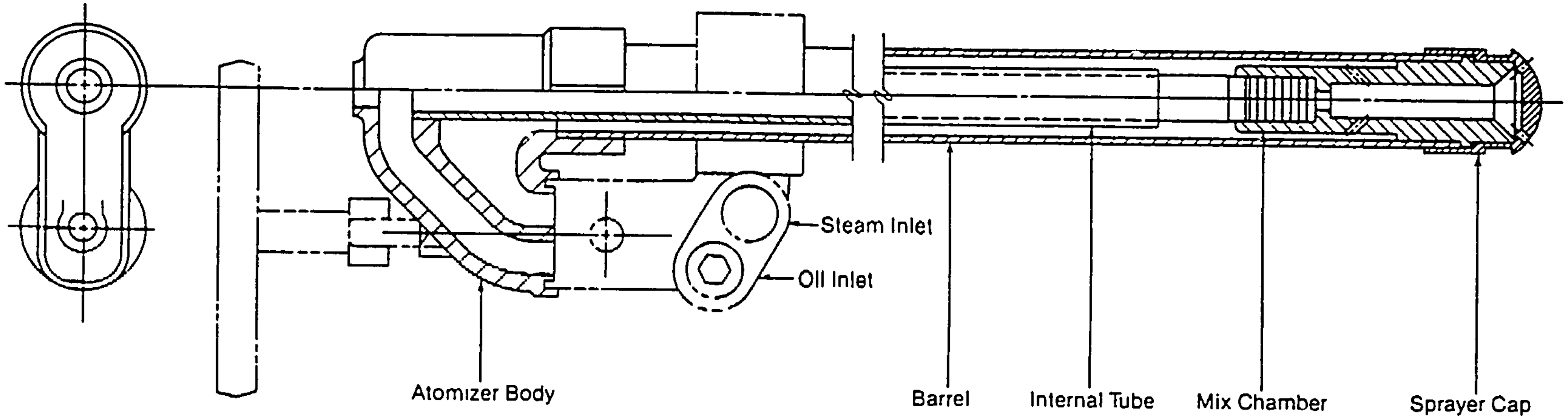

Figure 3-4 I-Jet Atomizer Assembly

sticky and easily removable by soot blowing or simply by remaining entrained in the flue gas.

Vanadiun and vanadium plus sodium oxides with low fusion temperatures are the primary cause of boiler corrosion in the superheater and reheater sections of boilers. By adhering to the tubes they also act as a catalyst for converting SO_2 to SO_3, thereby creating corrosion problems in the cooler parts of the boiler. These magnesium compounds reduce the amount of vanadium adhering to the tubes. In reducing the vanadium, these compounds reduce the catalytic effect and also neutralize the acid effect by forming MgSO4 with the sulfur.

Magnesium-based fuel additives are produced by a number of manufacturers and come in different forms. These different forms depend on the producer and the means of application to be employed for their introduction into the furnace. Each case should be treated on its own merits in selecting the form and the means of introduction.

In North America as well as in Europe, virtually all utilities firing a heavy grade residual fuel oil use magnesium additives. Their success has been documented in a number of papers on the subject.

Magnesium additives are available from a number of European suppliers who are near to Romania, and therefore transportation costs should be reasonably low.

The typical addition rate is 72 parts Mg to 102 parts of V. This rate will vary with the form of the additive (i.e., with Mn added, organometallic form, etc.) and also with the vanadian-to-sodium ratio in the oil. Some experimentation with the optimum ratio will be required and a good oil analysis on an as-fired basis is also necessary.

As part of the study on gas-side corrosion, Bechtel was requested to provide information and knowledge of operating experience with fuel additives used as combustion promoters, and, in particular, one marketed under the name of Akom Aktivator (AKOM). This additive system is currently being tested at one of RENEL's oil-fired plants.

To obtain more information on this additive, the company's representatives in the United States were contacted, as well as the chairman of the Fuel Oil Users Workshop Group of the Electric Power Research Institute (EPRI). Information relating to the product and the results of its application were received from both sources. In addition, other sources in the industry were contacted to find out more about the product and their experience with it.

The combustion promoter, AKOM, is an electrolytic solution injected into the combustion air preceding the burners. The solution is transported by bubbling compressed air through the containers of solution into a side stream branch of the main combustion air duct.

The results expected are a more complete burning of the oil, producing less unburned carbon. This condition should, in turn, result in more efficient operation of the boiler, less particulate emissions from the chimney, and reduced carbon buildup on the furnace walls. This last item is of primary importance to RENEL since many of the operational problems are attributable to this buildup.

A paper presented at the 1990 EPRI fuel oil utilization workshop gives the results of tests on a 530 MW boiler in Spain. One other item referred to in the paper was an increased conversion of SO_2 to SO_3 in the flue gas, as well as other chemical specimens that were increasingly oxidized.

There is some question as to the mechanism by which the promoter works, whether it is by hydroxyl radicals or by metal catalysts, and no one has provided a satisfactory answer. The chemical composition of the product is not known, and the manufacturer, for proprietary reasons, does not furnish this information.

Through further investigations, it was determined that presently there are no installations of this combustor feed equipment in North America, although AKOM is pursuing work currently in Puerto Rico with a utility. As a result, there was no one to contact for experience with this additive.

AKOM provided a list of installations, all of which are in Europe. AKOM also provided two reports, one from a technical evaluation by Sulzer and the other from the installation in Romania. The technical report explained the probable mechanism by which the solution acted to achieve the results claimed, and the report from Romania indicated the effects of the solution on boiler operation.

The list of installations indicates that most of them have been on boilers of small size. The larger utility size installations have all been in Spain, and, of these, only two units have been installed. The other units are under construction. As a result, this report cannot provide much in the way of operating experience with utility size boilers for this product.

The report presented to EPRI was reviewed in detail, and AKOM provided additional information in the form of graphs showing the testing on the Spanish boilers which gave additional information over and above the data presented in the paper. From this information, the results appear to be inconclusive as to performance of the combustion promoter. These inconclusive results were due to the fact that, sometime during the testing, MgO was added, as well as the promoter which tended to obscure the effect of the promoter alone.

The conclusions reached alter this limited review are as follows:

- A great deal of operating experience with utility size boilers does not yet exist.
- The same results can probably be obtained with better burner designs and a proper pre-treatment of the oil prior to delivery to the burners, (i.e., viscosity control).
- Significant conversion of SO_2 to SO_3 is an undesirable effect when burning high sulfur oil because it leads to higher corrosion within the boiler setting.
- At this time, the funding for installation and operating costs of the system could probably be better used by installing new burners and oil conditioning equipment.

3.3.6 Emulsions

The combustion of high asphaltene fuel oils in older boilers has led to several problems which include excess carbon carryover, high excess air requirements to avoid smoking, and degraded boiler efficiency. Several utilities have conducted test programs with emulsions of heavy residual oils and water to achieve more complete combustion with problem fuels. Adding water to the fuel decreases boiler efficiency. However, emulsions are credited with improving the fuel burnout. The conversion of the water in the fuel to steam helps break up the fuel droplet. Increased atomization of the liquid fuel enhances burnout by decreasing the mean fuel droplet size, thus reducing residence times required for complete combustion.

Emulsions have been evaluated by utilities in cases where burnout was not achieved by improving atomization, or the cost of installing new burners or using higher quality fuels could not be justified. The substitution of an increased operating expense for the emulsion vs. the capital expense of reburnering a unit can be an attractive trade-off on older boilers scheduled for retirement. Utilities view emulsions as a short-term solution to an emissions compliance and performance problem.

Most emulsions contain from 5 to 10 percent water by weight in the fuel oil. Water is finely dispersed as small droplets within the oil. Dispersion of the water in the oil

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may be produced by specific emulsion equipment or, in some cases, by the normal flow of the oil-water mixture through high-pressure pumping equipment.

Heavy fuel oils are typically preheated and atomized at the proper viscosity to produce a fine spray of droplets. Large droplets will be formed if the fuel is not heated to the proper viscosity or is poorly atomized. The larger drops may not be totally combusted, leading to the formation of large porous cenospheres of unburned carbon and ash. This problem is most often encountered with heavy residual oils of high asphaltene content.

Utility operating practice is to use all conventional means to bring the atomization process up to the original design operating condition, and produce the optimally sized fuel droplets. These measures are not always sufficient to overcome the following:

- Atomization problem due to limitations in adjusting the burner or oil gun operating parameters
- Constraints in the boiler dimensions or residence time that affect flame length and shape

The water droplets in the fuel are typically much smaller than the emulsion droplets formed by the atomization process. The presence of liquid water droplets enveloped by the oil droplets in the hot flame zone leads to superheating of the water, at temperatures well under the vaporization point of the heavy fuel oil. The rapid expansion of the internal liquid water into vapor causes the larger fuel droplets to explode. The explosions break up the original large emulsion droplets into smaller diameter droplets and, hence, aid the atomization process.

The potential benefits and disadvantages of emulsified fuels are often dependent on the type of combustion system and fuel used. When a hard-to-atomize fuel can be burned in a furnace or boiler without excessive particulate or carbon carryover problems, then use of an emulsified fuel will offer few advantages.

The primary attraction of emulsions is the potential reduction in carbonaceous particulate for emission compliance purposes. The gains in boiler efficiency are typically small.

There is a greater potential for boiler efficiency gain by reducing the excess air level. High excess air levels result directly in high flue gas losses from the boiler and reduced boiler efficiency. Improved carbon burnout with emulsions may permit operation at a lower excess air level without smoking and with improved boiler efficiency.

Reduction of excess air levels with emulsion use has been the primary basis for efficiency gains claimed by the various emulsion or equipment suppliers.

A disadvantage in the use of a water-in-oil emulsion is the efficiency penalty associated with the water content. The efficiency penalty is the result of the energy loss associated with vaporizing the liquid water.

Section 4

Corrosion and Environmental Problems in Oil-fired Boilers

The use of fuel oil in utility power plants was initially promoted by transportation and handling benefits in comparison with coal. At pre-embargo crude prices, there was also an economic incentive in comparison with coal. With high-grade crudes and refinery practices which relied heavily on distillation processes, the residual oils supplied to power plants had lower ash content and lower concentration of contaminants, such as sulfur and heavy metals (e.g., vanadium and nickel).

In recent times, the depletion of high-grade crude supplies and the escalation of crude prices, in general, have forced the use of lower grade crude oils. Also, the refinery technology to maximize the valuable distillate fraction obtainable from a barrel of crude has made significant progress to the point where the residual fuel oil shipped to the plants represents a smaller and smaller fraction of the crude. Since most of the contaminants are retained in the residual oils, the impurity content is steadily on the rise. Table 4-1 shows the concentrations of metallic contaminants in residual oils from crude oils from a number of major sources. Table 4-2 illustrates the distribution of sulfur among the various grades of refinery products derived from a Kuwaiti crude.

The decline of residual oil quality has brought with it increasing problems with the handling and preparation of fuel oils in the power plants and aggravation of corrosion in the boilers.

The nature of these problems and remedies that were found effective in Western utility power plants are discussed in this section. Issues related to handling and storage of fuel oils were discussed previously in Section 3.3.3. That section also addressed the problem of the presence of difficult-to-burn asphaltenes that can create sticky deposits on boiler surfaces that make removal of corrosion-causing deposits even more difficult.

This section concentrates on the corrosion problems. A number of technical papers related to experience with oil ash corrosion are included in Appendix C.

4.1 BOILER CORROSION

Although the nature of corrosion has been well understood for some time, prevention and mitigating measures are continuously evolving as a result of intensive research activities and experience in various power plants. Oil-fired boilers are subject to rapid corrosion throughout the entire flue gas path. The nature of corrosive damage, the agents promoting corrosion, and the mechanisms vary in the hot and cold sections of the path.

Table 4-1
Vanadium, Nickel, and Sodium Content of Residual Fuel Oils
(parts per million by weight)

Source of Crude Oil	Vanadium	Nickel	Sodium
Africa			
1	5.5	5	22
2	1	5	–
Middle East			
3	7	–	1
4	173	51	–
5	47	10	8
United States			
6	13	–	350
7	6	2.5	120
8	11	–	84
Venezuela			
9	–	6	480
10	57	13	72
11	380	60	70
12	113	21	49
13	93	–	38

Source: Steam, Its Generation and Use; Babcock and Wilcox Co., 1992

Table 4-2
Sulfur Content in Fractions of Kuwait Crude Oil

Fraction	Distillation Range, °F	Total Sulfur %-by Weight
Crude oil	–	2.55
Gasoline	124-253	0.05
Light naphtha	257-300	0.05
Heavy naphtha	307-387	0.11
Kerosene	405-460	0.45
Light gas oil	477-516	0.85
Heavy gas oil	538-583	1.15
Residual oil	588-928	3.70

Source: Steam, Its Generation and Use; Babcock and Wilcox Co., 1992
* °C = (°F - 32 + 1.8)

4.1.1 High Temperature Corrosion

The basic mechanism of high temperature oil ash corrosion is the formation of low melting point mixtures that flux away the protective oxide layers from the fire-side surfaces of boiler components. From the corrosion point of view, the most troublesome mechanisms are those that contain ash with high percentages of vanadium and sodium. These elements tend to form mixtures of low melting point compounds in the flue gas. Some sodium vanadates melt at temperatures as low as 534°C, well below the metal temperatures in superheaters and reheaters in modern steam power plants.

The rate of corrosion tends to increase with service time of the tubes. As oxide scale forms on the inside of the tubes, the heat transfer resistance increases and, at a given load, the fire-side metal surface temperature increases. For example, in 200,000 hours at 534°C, a chromium/molybdenum steel will develop an internal oxide scale of approximately 0.6 mm thickness. Depending on the heat flux, the fire-side temperature may increase by 7°C to 35°C due to the heat transfer resistance of this scale. With ash deposits, the temperature increase is even more noticeable. Higher gas temperatures accelerate the oil ash corrosion by increasing the deposition of V_2O_5 and Na_2SO_4. The deposition of these compounds occurs by condensation of their vapors in the flue gas.

A secondary effect of V_2O_5 is that it acts as a catalyst, promoting the formation of SO_3. In contact with moisture, SO_3 forms sulfuric acid, the major cause of cold-end corrosion.

Residual oils from crudes that have low concentrations of sodium and vanadium appear to cause much less corrosion problems. These oils are appropriately called "trouble free."

Remedies

In countries where the option is viable, the simplest and most effective remedy is to tighten up the specifications for purchasing the fuel oil to limit the acceptable vanadium, sodium and sulfur content to a level that precludes heavy corrosive damage. Even in the United States, there are economic reasons that prevent full implementation of such a policy. Research efforts have, however, identified a number of less drastic remedies as discussed below.

Improved Atomization. The most frequent method to increase the combustion efficiency in utility boilers is to increase the percentage of excess oxygen. Unfortunately, in boilers fueled with residual oil, the increased excess oxygen promotes the formation of compounds that contribute to fire-side corrosion problems, as discussed above. More complete combustion with low excess air is promoted by finer atomization. The lack of available oxygen prevents the oxidation of V_2O_4 to the harmful V_2O_5 form. The oxidation of sulfur dioxide to trioxide is also limited. The benefit is reduction of corrosion damage in the cold end of the flue gas train.

There are three methods that can improve atomization of heavy fuel oils: (1) preheating the oil to a higher temperature, (2) using one of the versions of steam atomizers, and (3) adding a small quantity of water to the oil to form an emulsion.

With fuels containing a significant percentage of asphaltenes, raising of the oil temperature has not produced significant improvement in atomization and has not been in extensive use. Steam atomization has been more effective in reducing the oil droplet sizes and is now the standard method in the Western countries.

Several utilities in the United States have recently conducted successful full-scale experiments burning high heavy fuel oils with high asphaltene content. In these tests, the oil was burned with 5 to 10 percent water emulsified into the fuel. The experiments have proven that complete combustion of the carbon can take place at reduced excess air.

The theory behind the use of emulsions is that the water droplets are surrounded by the oil. As the emulsion enters the furnace, the water becomes superheated at a temperature below the oil vaporization temperature and is expanded rapidly (exploded), causing the fuel oil to break up into extremely small droplets, producing a very high surface-to-volume ratio.

The emulsion can be produced by special equipment installed at the plant or water may be added during the pumping process. Surfactants are helpful to improve the emulsification.

The emulsion burning concept was judged as a useful means for improving combustion and reduction of corrosion in older plants. Any contribution to improvement in boiler efficiency is yet to be confirmed. There are, at this time, no test results that would prove that the use of emulsions produces better atomization than that obtainable with steam atomization, nor have there been any comparisons regarding the economic value.

Additives. Dispersion of finely ground alumina or magnesium oxide in the oil was also found to be beneficial for limiting corrosion of fire-side surfaces. These additives react with vanadium to form compounds that have very high meting point temperatures and result in less harmful solid deposits. These deposits are also easily removed with normal sootblowing or periodic washing. Since magnesium and aluminum react with sulfur to form solid sulfates, it is important that dosages of the additives take into account these losses as well. A negative effect of these solid additives is that they contribute to the quantity of ash to be handled.

Corrosion Resistant Material. The report prepared by Paul and Seely (see Appendix B) contains the review and normalized date from a number of field tests on various superheater materials in corrosive service. Although these alloys are different from those used in RENEL boilers, the compositions are close enough to allow meaningful comparisons. Table 4-3 summarizes this information.

Table 4-3
Oil Ash Corrosion of Boiler Steels

Alloy	Corrosion Rates at 593°C-(mm/year)
2-1/4 Cr - 1 Mo	1.3
9 Cr - 1 Mo	0.5
13 Cr	0.2
18 Cr - 8 Ni-Ti	1.0
18 Cr - 8 Ni-Cb	0.8

The authors indicate that the average corrosion rate for 2-1/4 Cr - 1 Mo steels in oil-fired boilers was 0.25 mm/y. This would indicate that in severe cases, the corrosion rates could be five times higher than the average. The corrosion resistance of 2-1/4 Cr - 1 Mo steels should be comparable to those used in the RENEL plants. As evident from the table, chromium is clearly beneficial from the corrosion point of view. Conversely, the nickel content appears to be detrimental, perhaps due to reduction in resistance for sulfidation.

The corrosion resistance of the ferritic 13 Cr steel is probably equivalent to the HT9 types of steel used in some Romanian power plants. In the United States, this steel would increase the cost of a superheater by 35 to 50 percent. Based on performance, the modified 12 - 14 Cr steels would represent the best choice for use in highly corrosive environment.

Ferritic steel with a higher Cr content may have better corrosion resistance. However, it cannot be used in superheaters because of its insufficient strength and high temperature embrittlement.

Materials that appear to have the best resistance to oil ash corrosion are those which contain approximately 50 percent Cr and 50 percent Ni (e.g., those covered by ASTM A560). In a comprehensive study, the large body of data on hot ash corrosion of stainless steels and the 50 Cr - 50 Ni alloy was analyzed. The results were then correlated with the sodium and vanadium contents of the fuel oil. For an oil containing 150 ppm of vanadium and 200 ppm of sodium, the corrosion rates for stainless steels and nickel alloys was 4.9 and 4.3 mm/year. For the 50 Cr - 50 Ni, the corrosion rate was 0.8 mm/year.

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Unfortunately, the 50 Cr - 50 Ni alloy is extremely difficult to fabricate and is not suitable for tube fabrication. It is, however, available in castings and has been used successfully for hangers and supports in boiler and pipe hanger applications. The cost of cast supports made of this alloy is about twice as much as-that of standard FE-Cr-Ni heat resisting alloys.

The merits of changing to expensive corrosion resisting alloys depend on the expected service life of the component. For example, the cost of a superheater made of standard alloys in the United States is $1.5 million, and it is expected to have a service life of at least 25 years. Based on available corrosion data, if the superheater were to be used in a boiler firing high vanadium fuel oil, the service life would be reduced to as little as 5 years. On this basis, the use of premium corrosion resistant material could be readily justified. Such assessment should, however, use actual financial data to support any decision. In plants with short remaining service life, large expenses would be difficult to justify. It should be noted that the use of 50 Cr - 50 Ni for pipe hangers may still be justifiable, since the total cost of tube supports in a boiler is but a small fraction of the total boiler cost.

Sootblowing and washing of the superheater and reheater surfaces have dual benefits: removal of the corrosive deposits and reduction of the metal temperatures. Both of these tend to reduce the corrosion rates.

Instrumentation and control system improvements need to be considered as part of any boiler retrofit to ensure that the key combustion parameters (particularly the level of excess air) are maintained at their optimal settings over the entire load range, and any departure from the optimum is corrected expeditiously.

From the above discussion of remedies, it is evident that there are several ways to alleviate the hot corrosion problems. In most cases, it is necessary to employ more than one of the possible remedies. Because of differences in oil properties, boiler design, and operating parameters, it is necessary to test the effectiveness of remedies case by case.

4.1.2 Low Temperature Corrosion

The main cause of low temperature corrosion is the formation and condensation of sulfuric acid. This acid is formed when SO_3 combines with the ever-present moisture. The acid condenses into a liquid at the cold end of the flue gas path and causes severe corrosion of the air preheater and cold-end duct work. This phenomenon is evident with any sulfur-containing fuel.

In a normal combustion process, sulfur oxidizes to SO_2 and SO_3. In the vapor phase, these two compounds reach an equilibrium with greater than 95 percent of the sulfur appearing as SO_2 and the remainder as SO_3. At the lower vapor pressure resulting from such a small amount of SO_3, the sulfuric acid dew point is low enough to cause only minor corrosion in the air preheaters.

The problem is more severe in oil-fired boilers because the catalytic action of the vanadium and excessive amounts of free oxygen increase the concentration of SO_3 and with it. the vapor-liquid equilibrium temperature. While with coal, SO_3 reacts with ash particles in the flue gas, thus reducing the acid content; the oil ash tends to be less basic and therefore less effective in neutralizing the SO_3. Also, the quantity of ash is significantly less in oil-fire systems.

Remedies

Minimizing the excess oxygen and binding up the vanadium in compounds which reduces its effectiveness as a catalyst are helpful in reducing the rate of cold-end corrosion. These measures have been discussed in connection with hot corrosion problems.

The formation of acid smut, which is the result of sulfuric acid reaction with metal surfaces, and potential protective measures are discussed in some detail in Appendix D.

As evident from the above discussions, burning heavy fuel oils is not a simple matter. However, operating experience and intensive R&D efforts have successfully overcome most of the problems.

APPENDIX A

Viscosity Conversion Tables

Appendix A

Viscosity Conversion Tables

Table A-1
Saybolt Universal, Redwood No. 1, and Engler Viscosity Equivalents at Same Temperature

Saybolt Universal, s	Redwood No. 1, s	Engler, deg.
35	34	1.16
40	36	1.32
45	40	1.45
50	45	1.59
60	53	1.88
75	66	2.31
100	87	2.98
125	111	3.63
150	130	4.40
200	173	5.82
250	221	7.28
300	259	8.65
350	303	10.10
400	346	11.54
450	388	12.90
500	432	14.10
750	647	21.40
1,000	863	28.70
1,200	1,042	34.00
1,500	1,356	42.80
1,800	1,560	50.40
2,000	1,727	57.50
2,200	1,903	63.10
2,500	2,158	71.60
3,000	2,591	86.00
3,500	3,022	100.00

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Table A-1 (Cont'd)

Saybolt Universal, s	Redwood No. 1, s	Engler, deg.
4,000	3,500	113.00
4,500	4,000	127.00
5,000	4,450	143.00
5,500	4,900	157.00
6,000	5,325	172.00
6,500	5,765	186.00
7,000	6,210	201.00
7,500	6,680	215.00
8,000	7,100	229.00
8,500	7,520	244.00
9,000	8,010	258.00
9,500	8,450	272.00
10,000	8,950	287.00

Source: Standard Handbook of Powerplant Engineering

Table A-2
Saybolt Furol vs. Saybolt Universal

Saybolt Universal, s* at 100°F (37°C)	Saybolt Furol, s at 122°F (50°C)	Ratio
300	21	14:1
1,000	50	20:1
3,000	135	22:1
5,000	220	27:1
10,000	342	29:1

* Sometimes abbreviated SUS, or Saybolt Universal Seconds.

Source: Standard Handbook of Powerplant Engineering

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Table A-3
Kinematic Viscosity vs. Saybolt Universal

Kinematic, cSt at 100°C (37.8°C)	Saybolt Universal, s at 100°F (37.8°C)
2.68	35
4.27	40
7.37	50
14.37	75
20.60	100
32.00	150
53.90	250
64.30	300
75.50	350
86.30	400
97.20	450
107.90	500
118.70	550
129.50	600
140.30	650
151.00	700
161.80	750
172.60	800
183.40	850
194.20	900
205.00	950
215.80	1000
258.90	1200
323.80	1500
366.80	1700
431.50	2000
474.80	2200

Source: Standard Handbook of Powerplant Engineering

APPENDIX B

Fuel Oil Supply Operations and Maintenance

Appendix B

Fuel Oil Supply Operations and Maintenance

B.1 FUEL PRESSURE AND TEMPERATURE

Maintaining the proper fuel pressure and temperature, as well as uniform fuel properties by preventing stratification or sludge accumulation in tanks, can significantly affect boiler operation. Fuel oil handling and storage problems can be minimized by automatic viscosity/temperature control, fuel oil inventory control, length of time in storage and segregation of different oil purchases, and incompatibility tests prior to fuel blending. Mixing compatible oils in a storage tank produces consistent product quality and helps to reduce the frequency of tank cleanings. Frequent strainer or filter cleaning is required when the sludge is retained during transfer or recirculation of the oil.

The fuel pressure and temperature are critical factors in the atomization process. Depending on the type of atomization system utilized, low supply pressure, low fuel temperature, or high viscosity can limit atomization of fuel, causing fuel burnout problems, smoking, or excessive particulate emissions. The fuel temperature and associated viscosity is the most important factor in the operation of an atomizer. High fuel viscosity for either a mechanical or twin fluid atomizer impairs the formation of small droplets, because more energy is required to break up the thick fluid into a fine spray. When the mechanical or kinetic energy available from either the fuel pressure or the atomizing steam (or air) is insufficient, atomization deteriorates and large droplets result.

The trend in residual fuel oil quality is towards heavier and more difficult to burn fuels, due to changes in crude oil sources and refinery practices. New refining practices have been designed to increase the yield of distillate fuels, at the expense of the loss of lighter components in residual oils. As a result, one of the impacts of lower residual fuel oil quality on boiler operations has been a reduced tolerance for low fuel temperatures or high viscosity. In addition to the attention paid to the fuel oil temperature, inspection and maintenance of heat traced and insulated fuel oil piping should be performed frequently to ensure that the fuel is not abnormally cooled by heat losses.

B.2 STORAGE PRACTICES

Fuel oil quality is greatly affected by the storage practices in large tanks. Residual oil is not a homogeneous fluid, nor a completely stable material. Oil is a mixture of relatively heavy hydrocarbons which may have been extensively processed at the refinery. Long-term storage of residual oil can result in sedimentation or precipitation of ash and heavy hydrocarbons. Utilities recommend avoiding long-term heated storage of oil. Reducing the oil storage period is site specific and

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depends on the oil storage capacity, the need to maintain a fuel reserve, and the use or availability of other fuels. Some utilities are not able to economically or practically avoid long-term oil storage. Hot storage may be necessary in cases where a backup or reserve oil fuel must be available for immediate emergency use. Frequent turnover of oil batches in storage is desirable whenever possible. Recirculating or mixing oil which has been stored under long-term or hot conditions can help to reduce storage problems.

Frequent sampling of oil stored in large tanks is used to identify a fuel storage or separation problem. Advance knowledge of a fuel storage or quality problem is preferred to experiencing operational problems when a poor fuel is placed into service. Typically, a method where oil samples are obtained from the top, middle, and bottom third of the tank is recommended, with separate analysis of each sample. Critical values which may indicate a stratification problem are API gravity, viscosity, carbon residue, asphaltenes, ash, and sediment.

Asphaltenes are high molecular weight hydrocarbons (2,000 to 4,000 MW) which have high carbon-to-hydrogen ratios and high concentrations of sulfur, nitrogen, and oxygen. Asphaltenes are soluble in toluene and are insoluble in heptane, which is the basis of their determination in a fuel oil. Asphaltene concentrations are increased by thermal cracking or visbreaking petroleum processing of crude oil in the course of refining processes.

B.3 IMCOMPATIBILITY PROBLEMS

Incompatibility problems caused by mixing two different fuel oils have been characterized by precipitation or sedimentation, leading to the formation of a heavy sludge layer on the tank bottom. To prevent this sludge from forming, it is recommended that the different batches of fuel oils be separated during storage. To avoid mixing potentially incompatible fuels, careful inventory control will keep account of the various types of fuel, their properties, and where they are stored. Oils with a high asphaltene content (oils subject to thermal and vacuum distillation) are suspected of greater susceptibility to incompatibility and separation problems. Asphaltene components can be suspended in an aromatic oil in an emulsion state. When the oil is mixed with a high paraffin content oil (waxy oils which have a low asphaltene solubility), the emulsion can be broken, causing the asphaltene to agglomerate and fall out as a high viscosity, tar-like sludge. Sludge formed at the bottom of storage tanks can cause deposits and plugging in strainers, pumps, fuel heaters, valves, meters, and atomizers, as well as poor combustion characteristics.

B.3.1 Blending

Segregation of oil shipments is the obvious solution to the above problem, but this is not always possible for a facility with limited storage capacity or the need to blend fuels to meet operational constraints. Blending may be necessary to meet viscosity requirements or to meet a maximum fuel sulfur or nitrogen content requirement for emissions control. A tank of light, low sulfur oil is kept on hand by some utilities to blend with nonconforming oil shipments. Some utilities have relied upon stringent asphaltene content specifications (as low as 2 to 6 percent maximum) to avoid incompatibility, as well as combustion problems. Strict specifications may limit oil availability or result in higher fuel costs.

Blends of marginally incompatible oils may be successfully burned in a boiler if the blended fuel can be used in a reasonably short time. Utilities consuming fuel as rapidly as they buy seldom have compatibility problems due to the short storage time. The settling of asphaltenes in a tank requires time, and depends on the degree of fuel incompatibility and storage conditions. A potential sludge formation problem may be avoided if the blend can be rapidly used. In-tank mixing can also help to minimize asphaltene setting out of the fuel, when longer term shortage or incompatible blends are encountered.

Short-term temporary segregation of an incoming fuel shipment is an alternative that is often utilized as a means to avoid poor oil quality or fuel compatibility problems. The oil is segregated to allow sufficient time for determination of its critical fuel properties. This practice allows the plant engineers the opportunity to review the fuel analysis and recommend the proper firing conditions (fuel temperature) prior to its use. The oil can then be either burned or blended in storage.

A fuel blend is considered incompatible if a heavy sludge forms or asphaltene precipitation occurs during long-term or heated storage. Asphaltenes precipitate from a fuel blend when the total asphaltene content exceeds the total blend solvency of asphaltenes. This condition can occur when a high asphaltene fuel oil, such as a visbroken residual oil, is mixed with a low solvency, highly paraffinic oil. The Hot Filtration Sediment (HFS) test standard of the American Petroleum Institute (API) has been developed to determine the compatibility of fuel blends and is currently in draft form.

According to the standards, a 10-gram sample of fuel is filtered through a glass fiber filter at 100°C to capture insoluble components. The filter is then washed with paraffinic solvents (85 percent heptane/15 percent toluene and then 1005 n-heptane), dried at 110°C, and weighed. Sedimentation greater than 0.25 percent is considered unacceptable. Typical levels are at about 0.1 percent. Waxes and asphaltenes which are in solution cannot be detected by this methodology, only components which have precipitated or formed insoluble solids.

B.3.2 BMCI and TE

Predictions of blended oil incompatibility have been devised based upon the asphaltene content and the degree of asphaltene solvency exhibited by the blended fuel. Standard fuel sample tests have been developed to assess these parameters. The solvency of the fuel sample is based upon the Bureau of Mines Correlation Index (BMCI), while the solvency requirements of the fuel sample are based on the Toluene Equivalence (TE) test. BMCI is defined as follows:

$$BMCI = 87{,}552/(ABP + 460) + 473.7\,SG = 456.8$$

where: ABP = Average boiling point, °F
SG = Specific gravity, 60/60°F

BMCI is an indicator of the asphaltene solvency; the higher the value, the greater the solvent capacity and aromatics content of the fuel. It is based upon a scale of 100 (benzene) to zero (heptane or other paraffin). The BMCI of a fuel blend is simply the volume average BMCI of the components. As shown in Table B-1, the BMCI can also be approximated from the fuel viscosity and specific gravity.

Table B-1
BMCI Values

Specific Gravity	Viscosity (CS at 122°F)		
	30	100	460
0.99	80	76	70
0.95	60	56	50
0.91	38	33	28

The TE test is a measure of the solvency requirement of a fuel or fuel blend and is based upon a 100 (toluene) to zero (heptane) scale. A large value indicates a higher asphaltene content and a high aromatics content required to keep the asphaltene in solution. The TE test determines the amount of toluene in a toluene/heptane blend that is required to keep a fuel sample in solution and prevent the precipitation of asphaltenes. A 2-gram sample of fuel is dispersed in various 10 ml solutions of toluene/heptane mixtures and dropped on a filter disc. Examination of the spots for dark rings of insoluble asphaltenes determines the mixture with the minimum amount of toluene required, hence, the toluene equivalence. The TE of a blend is the average based upon the weight fraction of asphaltenes of the components, or for a blend of components 1 and 2.

$$TE_{blend} = \frac{Wt_1\ \%Asph_1\ TE_1 + Wt_2\ \%Asph_2\ TE_2}{Wt_1\ \%Asph_1 + Wt_2\ \%Asph_2}$$

The compatibility of a potential blend is predicted by calculating or determining the BMCI and TE of the blend. The blend BMCI and TE are compared and the blend considered compatible if the BMCI is larger than TE + K, where K is a constant. The value for K is typically 7 to 15 and gives some assurance that the blend is compatible. Comparisons of a number of fuel blends showed that a strong correlation was found for predicted compatibility (BMCI>te + 10; I.E., k = 10) and the hot filtration sediment test (compatibility = sediment ≥ 0.1 wt%). It should be noted that although one blend ratio of two oils may be compatible, another blend ratio may not. The key factor is that the amount of asphaltene solvent must be greater than the amount of asphaltene. BMCI and TE can be determined and the difference (BMCI - TE) plotted for a range of blends of two oils. Compatible mixtures are indicated when the difference is greater than the K constant.

Careful attention to the fuel properties of incoming shipments and frequent testing prior to blending can substantially minimize sludge formation. Even with this attention, sludge buildup in tanks may be experienced, particularly during long-term storage. The removal of an existing sludge formation in a tank can be achieved by the use of lighter, cutting oil to produce a fuel which can be acceptably pumped and burned in the boiler. A typical procedure used by utilities has been to first drain or pump out the top layer of acceptable oil. A cutting oil high in aromatics content is then added on top of the remaining oil and eventually mixed with the sludge. The asphaltenes are gradually dissolved into the oil until a pumpable mixture is formed. Once the sludge is pumpable, the mixture may be blended with other oil and burned in a boiler (if it can be burned in an acceptable manner) or disposed of as a waste.

B.3.3 Additives

Commercial additives are available to deal with sludge formation in storage tanks. Additives to prevent an incompatibility problem are added and mixed into a blend, frequently at the time of delivery. Additives to break down sludge are used in a manner similar to the cutting oil described previously.

On the RENEL units observed, the oil is heated by a steam in a shell and tube heat exchanger in a single-pass loop with the condensate returning to the boiler feedwater supply. This type of system can allow oil leakage into the condensate if there is a hole or crack in the tubes. The usual practice on Western units is to employ a reboiler or two-pass loop.

APPENDIX C

Corrosion and Environmental Data

APPENDIX C.1

Oil Ash Corrosion – A Review of Utility Boiler Experience

by

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OIL ASH CORROSION-
A REVIEW OF UTILITY BOILER EXPERIENCE

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ABSTRACT

A review of experience with oil ash corrosion is presented along with current design practices used to avoid excessive tube wastage. Factors influencing oil ash corrosion include fuel chemistry, boiler operation, and boiler design. These factors are interdependent and determine the corrosion behavior in utility boilers. Oil ash corrosion occurs when vanadium-containing ash deposits on boiler tube surfaces become molten. These molten ash deposits dissolve protective oxides and scales causing accelerated tube wastage. Vanadium is the major fuel constituent that is responsible for causing oil ash corrosion. Vanadium reacts with sodium, sulfur, and chlorine during combustion to produce lower melting temperature ash compositions, which accelerate tube wastage.

Limiting tube metal temperatures will prevent ash deposits from becoming molten, thereby avoiding the onset of oil ash corrosion. Tube metal temperatures are limited by the use of parallel steam flow and by limiting steam outlet temperatures. Operating a boiler with low excess air has helped avoid oil ash corrosion by altering the corrosive combustion products. Air mixing and distribution are essential to the success of this palliative action. High chromium alloys and coatings form more stable protective scales on tubing surfaces, which results in lower oil ash corrosion rates. However, there is no material which is totally resistant to oil ash corrosion.

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INTRODUCTION

Oil ash corrosion is not a new problem, yet it continues to constrain design practices of new boilers and cause tube failures in existing units. Oil ash corrosion first became an active problem in North America in 1950.[1] Several boilers that used mercury as a heat transfer fluid in part of their tube circuit saw high wastage rates of furnace wall tubes. The wastage was most pronounced in the bottom portion of the furnace where the static head of mercury caused saturation vapor pressures to be quite high resulting in tube metal temperatures of up to 663°C (1225°F). These high tube metal temperatures allowed the oil ash to become molten, causing rapid corrosion.

Molten oil ash deposits are now known to be an extremely corrosive agent and are responsible for causing oil ash corrosion. Corrosion occurs when the protective iron oxide layers, which naturally form on tube surfaces during boiler operation, are dissolved by molten vanadate compounds. The vanadate compounds are also good oxidation catalysts and allow oxygen and other gases in the combustion atmosphere to rapidly diffuse to the metal surface. As soon as the metal is oxidized the cycle starts over again and high corrosion rates result.

In the 20th century, boiler cycle efficiencies have been continually improved by using higher temperature and pressure steam. Figure 1 shows the trend in the design steam exit temperature of utility boilers over the years. As steam temperatures increased, the tube metal temperatures reached the level where oil ash deposits become molten and excessive corrosion occurs. Based upon this experience, most units ordered after 1965 limited to design steam exit temperatures to 540°C (1005°F) or below in order to avoid oil ash corrosion.

Oil ash corrosion in a modern utility plant occurs in secondary superheater and reheater tube sections, as shown in Figure 2. The secondary superheater and reheater tubes carry the highest temperature steam; these tubes are at the end of boiler circuit from which steam is collected and delivered directly to the turbine. Since these tubes have the hottest metal temperatures, they are most prone to oil ash corrosion.

During early work, from 1950 through 1965, the details of oil ash corrosion mechanisms and possible solutions were largely determined. Today, the fundamental understanding of oil ash corrosion and preventive measures remain essentially unchanged. In spite of our early understanding of the problem and an additional 25 years of experience, there continue to be failures attributed to oil ash corrosion. This paper reviews four decades of experience with oil ash corrosion and attempts to arrive at some engineering guidelines to better help in the ongoing fight against tube wastage in oil-fired boilers.

OPERATIONAL EFFECTS ON OIL ASH CORROSION

Metal Temperature

There is little doubt that increasing the tube metal temperature increases the corrosion rates of superheater and reheater tubes.[1-15] Increasing the temperature of tube surfaces in the boiler increases the chances of oil ash deposits reaching their melting point. Once deposits have become molten, further increases of the tube metal temperatures will also increase corrosion rates. Oil ash corrosion, as well as oxidation and many other corrosion processes, are thermally activated. Limiting the temperatures within the boiler is one method that has been used to alleviate corrosion.[5] Current boiler design practice limits the tube metal temperature of boilers burning residual oils, although the exact temperature limit varies among designers.[6]

Older boilers are more likely to suffer from oil ash corrosion. Tube metal temperatures will increase with operation time of the boiler.[16,17] Figure 3 shows how metal temperatures change with steam-side oxide thickness for typical steam cooled superheater and reheater tubes. Metal temperatures will increase with time as steam-side oxide scales grow. For example, an SA213-T22 (UNS K21590) tube will have an 0.066 cm (0.026 inch) thick oxide scale after operating at 593°C (1100°F) for 20 years.[18] As tube metal temperatures are increased, oil ash corrosion becomes more likely. Therefore, a unit can operate relatively trouble free for several years and then suddenly experience oil ash corrosion problems.

Gas Temperature

Oil ash corrosion is accelerated by higher flue gas temperatures.[5,6,7] Gas temperatures effect tube heat fluxes, change the deposition rates, and control vapor pressure of the corrosive vanadium and sodium compounds. Higher heat fluxes produce higher tube metal temperatures at the tube outside surface, as shown in Figure 3. Deposition of vanadium and sodium compounds occur principally by vapor condensation from the flue gas.[19] Higher gas temperatures increase the rate of vapor deposition V_2O_5 and Na_2SO_4.[19]

Figure 4 shows regions of gas and metal temperature where corrosion can be expected. This curve developed by Babcock & Wilcox allows boilers to be designed in the stable zone where corrosion is not expected to occur.

Excess Air

Lowering excess air used in fuel oil combustion can lower wastage rates of superheater and reheater tubes.[10,19-22] There is a critical partial pressure of oxygen below which oil ash corrosion does not occur.[23] Low excess air prevents vanadium compounds from being oxidized from V_2O_4 to V_2O_5[24,25], which is the corrosive form of vanadium.[26] However, reducing high temperature corrosion by using low excess combustion air is not always successful when applied to operating power plants.[27,28] The interplay between fuel chemistry, combustion conditions and boiler design complicate the use of low excess air to lower oil ash corrosion.

Inhibitors and Additives

Inhibitors and fuel additives have been used with varying success to prevent oil ash corrosion. There are a number of inhibitors commercially available which are intended to reduce the severity of oil ash corrosion.[21] Because of its effectiveness and relatively low cost, the most common fuel additives are based upon MgO.[10,11,19,29-32] Mg reacts with V in the fuel oil and produces a compound with a melting point above most metal surface temperatures in a boiler.[30] Figure 5 compares Mg with some other compounds in its ability to raise the melting point of a typical residual oil ash. However, Mg based inhibitors are not always totally effective.[28,33] Other fuel constituents, such as sulfur, can react with the Mg and reduce the efficiency of the inhibitor.[31]

A few Mn-based additives are also effective in preventing oil ash corrosion.[34,35] Mn reacts with Na in the fuel and thereby prevents it from reacting with the V to produce corrosive sodium vanadates. Other inhibitors,

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such as rare earth compounds, BaO, $Ba(OH)_2$, CaO, $Ca(OH)_2$, $CaCO_3$, Al_2O_3, SiO_2, as well as oil soluble Ni, Al, Fe and other compounds have been tried with some success.[33,36-40] However, in commercial practice these inhibitors have not proven to be as effective as Magnesium or Manganese-based inhibitors.[36,37]

FUEL EFFECTS ON OIL ASH CORROSION

The oil which is used as fuel in boilers is derived from crude oil. As the crude oil is refined gasoline, lube oil fraction, jet fuel, kerosene, and distillates are removed and what is left is called residual oil or bunker "C" oil. This residual oil, or blends thereof, is used for fuel in power plants. During the distillation process virtually all the metallic compounds and a large part of the sulfur are concentrated in the residual fuel oil.[41] Sometimes this residual fuel oil is blended with other petroleum products to lower the concentration of undesirable constituents, producing higher grades of fuel oil.

The fuel oil constituents which are reported to have the largest effect on oil ash corrosion are vanadium, sodium, sulfur, and chlorine. These constituents become concentrated in the fuel oil as a result of the refining process, or can also become introduced into the oil during transport and handling. The influence of each of these constituents is summarized below.

Vanadium

Vanadium is the major ingredient needed to cause oil ash corrosion.[2-4, 29, 34-36, 42-45] While other constituents aggravate tube wastage, the root cause of oil ash corrosion is vanadium. Vanadium, when mixed with other constituents, results in low melting point compounds, as shown in Figure 6.[46] When vanadium compounds become molten they act as a flux to remove protective oxide scales from tube surfaces, producing accelerated corrosion rates.

It is possible to have sodium vanadate compounds melt as low as 534°C (1000°F). Superheater and reheater tubes of modern power plants operate with tube metal temperatures well above the temperature at which oil ash corrosion is possible. Furthermore as tube metal temperatures are raised a greater number of molten phases can occur, which makes oil ash corrosion more likely.

Although the concentration of vanadium in the fuel is relatively low, typically less than 300 ppm, vanadium concentrates in the ash and can constitute 80% of the tube deposit. Because of this concentration effect, it is difficult to recommend a "safe level" of vanadium which can be allowed in the fuel. Deposition and concentration is influenced by other fuel constituents as well as by boiler operation and design.

Sodium

Sodium is generally regarded as the primary element that reacts with vanadium to produce low melting point compounds[2-4, 33-35, 42,43,45], as shown in Figure 6. Corrosion has been decreased in boilers by the addition of sodium specific fuel additives, which tie up sodium and prevent it from reacting with vanadium.[34]

The degree to which sodium contributes to oil ash corrosion varies from case to case. In one study sodium had no effect upon corrosion.[27] In other cases sodium is implicated as the major cause for accelerated wastage.[47] Such discrepancies serve to underline the complex nature of reactions occurring in a combustion environment and the need to consider each application on its own merits.

Sulfur

Oil ash corrosion is generally accelerated by sulfur.[2,3,29,33,35,44,45] Sulfur typically occurs in the form of sodium sulfate in tube deposits. Both sodium and sulfur increases the corrosivity of the resulting melt. Figure 7 shows that sodium increases corrosion in vanadium containing ash deposits and that sulfur causes a further large increase in corrosion rates.[48]

The exact role of sulfur in oil ash corrosion is not clear. Sulfur typically is analyzed as sodium sulfate in corrosive oil ash deposits. Sodium Sulfate in the ash will be in equilibrium with reaction products according to the equation:

$$Na_2SO_4 \rightarrow Na_2O + SO_3$$
$$\text{Salt} \rightarrow \text{Base} + \text{Acid}$$

When a simple salt dissociates it forms a base (Na_2O) and acid (SO_3). These reaction products will alter the bacisity of the molten ash deposits, which in turn controls the corrosivity of those deposits. Figure 8 shows an example of how the solubility of protective tube oxides are influenced by ash chemistry.[49] The melt chemistry in Figure 8 is characterized using Na_2O concentration, also known as the melt bacisity. Higher oxide solubilities in the melt will result in higher corrosion rates. Sulfur reacts with sodium in the melt, altering the concentration of Na_2O and thereby changing corrosion rates.

Sulfur can also induce other corrosion mechanisms and cause accelerated vastage, particularly for uncooled components in the boiler. uncooled tube supports operate at higher temperatures where sulfate induced hot corrosion becomes a concern. Austenitic stainless steels and other nickel containing alloys are particularly sensitive to attack by sulfidation.[44,50]

Chlorine

Chlorides can occur in fuel oil at concentrations up to 100 ppm[4,33,51], making corrosion by chlorides a concern. Chloride in the fuel can accelerate tube wastage in boiler systems.[1,36,37,50,51] As with sulfur the exact mechanism by which chlorides accelerate corrosion in boiler systems is not well understood. Chlorides are commonly found in ash deposits as NaCl. Adding NaCl to V_2O_5 causes corrosion rates to increase sharply. NaCl probably acts in a manner similar to Na_2SO_4 and alters the corrosivity of the oil ash deposit. Surprisingly, HCL in the flue gas has no effect on oil ash corrosion.[33] This fact points to NaCl in the deposit as controlling corrosion of superheater and reheater tubes.

Balancing the Bad Actors

Many investigators have considered fuel corrosivity indexes which include vanadium, sodium, and sulfur in order to account for some aberrations in general trends.[15,19,34,36,42,43,44,51,52] These corrosivity indexes and their application are summarized in Table 1. There is obviously some interplay between vanadium, sodium, sulfur, and other contaminants in residual oil fired boilers. There have been several attempts to arrive at a corrosivity index either for the fuel or for the resultant ash.

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Table 1 reveals discrepancies and contradictions when characterizing corrosive fuel oils. Most corrosivity indexes were developed for a particular source of oil (i.e., Eastern oils, Venezualean oils, etc.) and are therefore limited in their application. Certain oils can best be described by one method, while other oils may be better characterized by another corrosivity index. There is no general agreement on how to appraise the corrosivity of residual fuel oils.

MATERIALS FOR RESISTING OIL ASH CORROSION - FIELD TESTS AND PROBE STUDIES

Corrosion data from boiler field tests and probe studies were reviewed to determine the relative resistance of various materials to oil ash corrosion. Only field studies were included, since this data was felt to best represent the oil ash corrosion environment. Corrosion rates were calculated by taking the kinetics of oil ash corrosion to be essentially linear with time.[4,15] Although the corrosion data covered a wide temperature range only the data above 538°C (1000°F) were used in this analysis, since this is near the lower temperature limit where oil ash corrosion can occur. Corrosion data was considered for the materials shown in Table 2.

The temperature dependence of corrosion was calculated using an Arrhenius type relationship. This makes the assumption that oil ash corrosion is thermally activated. All of the available data above 538°C (1000°F) were used for this analysis. Corrosion rates are predicted using the relationship:

$$\mathrm{Log}(CR) = \mathrm{Log}(A) + Q/2.303RT$$

where CR = Corrosion rate (mpy)
A = Pre-exponential factor
Q = Activation energy (calorie/mole)
R = Gas constant (1.987 calorie/mole/°K)
T = Temperature (°K)

The results of this analysis are summarized in Table 3.

Since the data used for this analysis were from diverse sources, a test was made to see if a single corrosion process was operating, and to determine if statistics could be used on the data.[53] Figure 9 shows a probability plot of the SA213 Type 347 stainless steel corrosion data obtained from probe studies, steam cooled test loops, and some superheater and reheater tubes in several oil-fired utility and industrial boilers. In order to construct this plot the data had to be normalized with respect to temperature. The corrosion data were normalized using the formula:

$$\mathrm{Log}\ (CR_{1100}) = [\mathrm{Log}\ (CR_m) - Q/2.303RT_m] + Q/2.303R\ 866°K$$

where CR_m = Measured corrosion rate (mpy)
T_m = Temperature at which corrosion was measured (°K)
CR_{1100} = Normalized corrosion rate at 593°C (1100°F)
Q = Activation energy (calorie/mole)
R = Gas constant (1.987 calorie/mole/°K)

The data for the SA213 Type 347 stainless steel material appears to follow a standard normal distribution. Most materials show this same type of behavior. However, some of the stainless steel data sets, which contain higher temperature data, have a slight tendency towards a bi-modal distribution. This is felt to be due to a different mechanism, probably sulfidation, competing with oil ash corrosion at the higher temperatures. Although the corrosion process in boilers is quite complex, wastage was taken as being solely oil ash corrosion for this analysis.

There appears to be an advantage of using higher chromium alloys. Furthermore, ferritic steels are generally more resistant than nickel containing austenitic alloys.[54] The SA213-T9 and SA268-TP410 materials appear to be the tubing materials most resistant to oil ash corrosion. However, at higher temperatures, such as those seen by uncooled tube supports, it may be necessary to use an even higher chromium material, such as 50%Cr-50%Ni materials.[42,43]

Coatings have been used with some success in field applications. Most of the high chromium coatings offer some resistance to oil ash corrosion. Other coating systems, such as silicon[55], may also be helpful. However, in may instances porosity and defects in the coating allow the substrate to be attacked. Also, the coating may spall off in some cases.[1] Studies in Japan[2] and in the soviet Union[7], with exposure periods up to 6500 hours, have demonstrated the resistance of chromium diffusion coatings in field applications. Spray coatings of 50%Cr-50%Ni have also been applied with success to local areas of superheater tubes and have survived 20,000 hours with only minimal attack.[36] Therefore, coatings can be effective in controlling oil ash corrosion.

LONG TERM OPERATING EXPERIENCE IN OIL FIRED BOILERS

The value of field tests and probe studies in predicting long term corrosion behavior of superheater and reheater tubes was assessed by reviewing the operating experience of oil-fired boilers.

Corrosion data for SA213-T22 material were obtained from tube sections removed from 34 oil-fired superheater and reheater sections of utility and industrial boilers. The tubes removed for inspection had been in service for many years, with operation times ranging from 33,000 hours to over 290,000 hours. The wall thickness loss of the tube was divided by the operating time to arrive at an average corrosion rate. The average metal temperature of each tube was estimated from the steam-side oxide thickness using established oxide growth equations for SA213-T22.[56] This long term operating experience is also shown in Table 3. The predicted corrosion rates based upon long term operating experience are considerably lower than those predicted by field tests and probe studies.

Figure 10 compares field study and corrosion probe data to long term operating experience of superheater and reheater tube data from utility and industrial boilers. At lower temperatures, the field test and corrosion probe data predicts much higher corrosion rates than does the long term boiler operating experience. This is because most probe and field tests were performed in boilers suffering from severe oil ash corrosion; the long term operating experience represents all boilers, irrespective of the severity of oil ash corrosion. Corrosion rates predicted from these two different data bases tend to converge at higher temperatures because severe oil ash corrosion becomes more likely as the temperature is raised.

The field test and probe data will give a better estimate of oil ash corrosion for cases when severe oil ash corrosion is expected. The field survey data is representative of average corrosion rates experienced by oil-fired utility boilers in service today. Figure 11 summarizes the field data by giving the statistical probability of a given corrosion rate occurring in service.[1,2,5,7,19,36,56]

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CONCLUSIONS AND RECOMMENDATIONS

Based upon this review the following conclusions are drawn:

- Oil ash corrosion behaves as a statistical process and can be modeled accurately, provided the data base is representative and large enough.
- Higher chromium alloys are more resistant to oil ash corrosion.
- Ferritic materials are more resistant to oil ash corrosion than nickel containing austenitic materials for tubing applications.
- High chromium coatings can be used to lower oil ash corrosion rates, although care must be taken to assure a good coating bond.
- Chemistry of the fuel oil influences tubing corrosion rates; however, there is no current corrosivity index which models corrosion by either fuel or ash chemistry.
- Vanadium, sodium, chlorine, and sulfur all accelerate corrosion and should be limited in the fuel oil to be as low as practical.
- Operating a boiler on low excess combustion air can be effective in limiting oil ash corrosion, but proper air mixing and distribution are necessary.
- Limiting the metal temperature of tubing materials has been the traditional way to effectively avoid oil ash corrosion.

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TABLE 1
CORROSIVITY INDICES USED TO RANK FUELS WITH RESPECT TO THEIR POTENTIAL TO CAUSE OIL ASH CORROSION

Index Reference	Application	Evaluation	
Na/V	Fuel & Ash (weight ratio)	High Values Corrosive	15,34
Na+V	Fuel (ppm by weight)	High Values Corrosive Suggest <30 ppm total	42,43
Na+S/V	Ash (atomic ratio)	Low Values Corrosive >20 to avoid attack	19,36
Na_2O/SO_3	Ash (molecular ratio)	High Values Corrosive <1 to avoid attack	44
V/Na+V	Fuel (weight ratio)	High Values Corrosive <0.2 Use Stainless Steel >0.2 Use Nickel Base Alloy	52
V	Fuel (ppm by weight)	Higher Values More Corrosive	51

TABLE 2
MATERIALS SELECTED FOR ANALYSIS OF CORROSION DATA

	C	Mn	P	S	Si	Cr	Mo	Ni	Ti	Cb/Ta
SA213-T22 (UNS K21590)	0.15 max	0.30-0.60	0.03 max	0.03 max	0.50 max	1.90-2.60	0.87-1.13	...	...	...
SA213-T9 (UNS K81590)	0.15 max	0.30-0.60	0.03 max	0.03 max	0.25-1.00	8.00-10.00	0.90-1.10	...	...	...
SA268-TP410 (UNS S41000)	0.15 max	1.00 max	0.040 max	0.030 max	0.75 max	11.5-13.5	...	0.50 max	...	...
SA213-TP321 (UNS S32100)	0.08 max	2.00 max	0.040 max	0.030 max	0.75 max	17.0-20.0	...	9.0-13.0	4xC-0.60	
SA213-TP347 (UNS S34700)	0.08 max	2.00 max	0.040 max	0.030 max	0.75 max	17.0-20.0	...	9.0 13.0	...	8xC-1.0
SA213-TP316 (UNS S31600)	0.08 max	2.00 max	0.040 max	0.030 max	0.75 max	16.0-18.0	2.0-3.0	11.0-14.0	...	...
SA213-TP310 (UNS S31000)	0.15 max	2.00 max	0.040 max	0.030 max	0.75 max	24.0 26.0	...	19.0 22.0	...	...

TABLE 3
THE PREDICTED CORROSION RESPONSE OF SEVERAL ALLOYS IN BOILERS EXPERIENCING OIL ASH CORROSION

Alloy	Pre-exponential Factor, A	Activation Energy, Q (Cal/Mole)	Number of Data Points	Corrosion at 593°C (1100°F) (mpy)	References	Correlation Coefficient R	Temperature Range of Data
SA213-T22 (UNS K21590)	5.252	-14,030	10	51.6 +/-6.3	9,21,32 54,55	-0.772	538- 849°C (1000-1560°F)
SA213-T9 (UNS K81590)	2.989	-6,602	11	21.0 +/-3.6	21,38	-0.309	543- 691°C (1010-1275°F)
SA268-TP410 (UNS S41000)	7.126	-33,554	21	9.3 +/-4.7	13,25,38	-0.805	577- 849°C (1070-1560°F)
SA213-TP321 (UNS S32100)	7.126	-21,943	33	39.0 +/-6.4	7,8,9,13,25 B&W Data	-0.695	577- 849°C (1070-1560°F)
SA213-TP347 (UNS S34700)	3.933	-9,680	39	31.0 +/-4.6	7,13,15 50,25	-0.448	571- 850°C (1060-1562°F)
SA213-TP316 (UNS S31600)	6.800	-19,905	37	60.1 +/-3.5	13,25,38 B&W Data	-0.729	558- 788°C (1037-1450°F)
SA213-TP310 (UNS S31000)	4.344	-11,463	34	28.3 +/-12.5	8,15,52 B&W Data	-0.300	571- 850°C (1060-1562°F)
SA213-T22 (UNS K21590)	8.636	-30,295	47	9.8 +/-3.9	Long Term Operating Experience B&W Data	-0.622	539- 629°C (1002-1164°F)

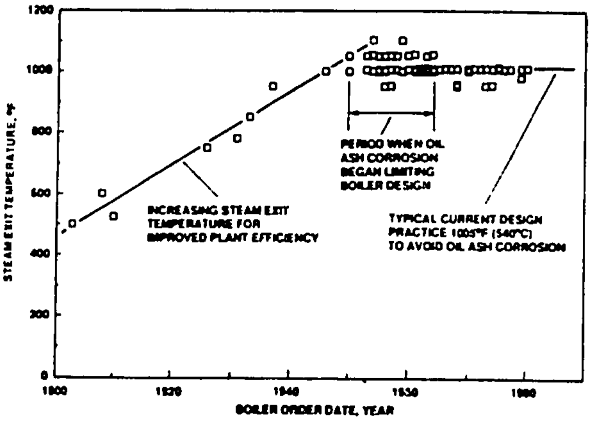

Figure 1. Design steam exit temperature for boilers during the twentieth century.

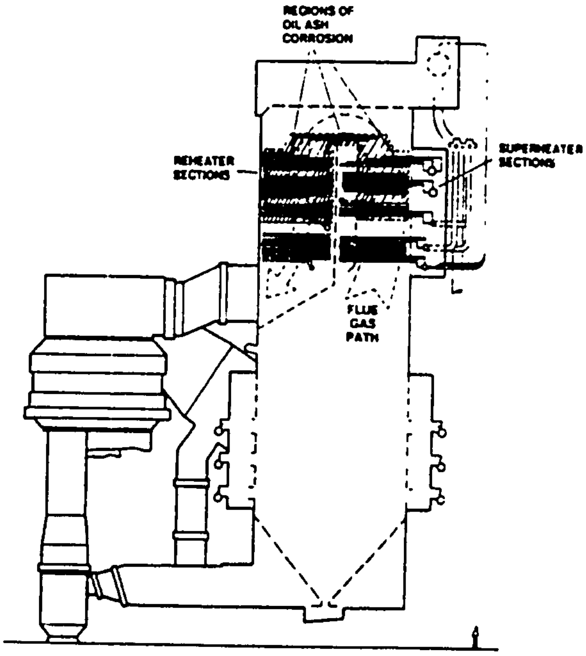

Figure 2. Modern day oil fired utility boiler, showing regions where oil ash corrosion is typically found.

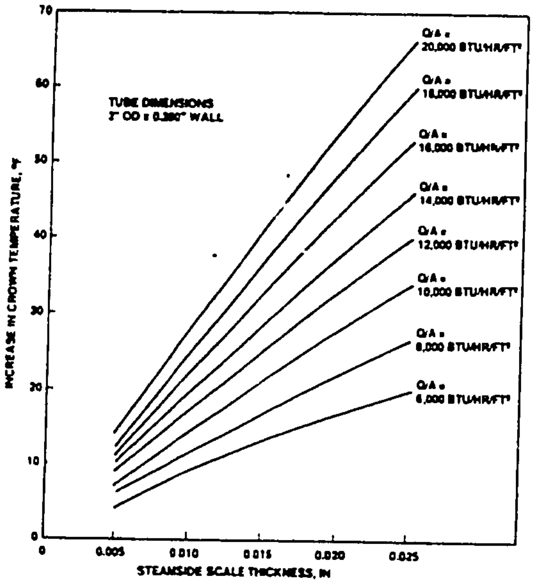

Figure 3. Increase in tube metal crown temperature as a function of steam-side scale thickness and heat flux into the tube. (After Reference 17.)

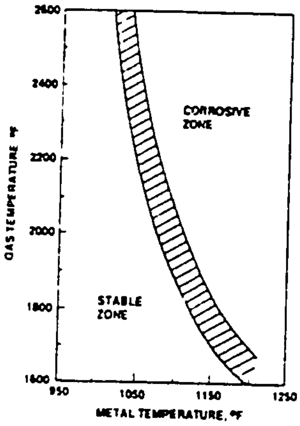

Figure 4. Regions where oil ash corrosion can be expected to occur as a function of tube metal and flue gas temperature. (After References 5 and 51.)

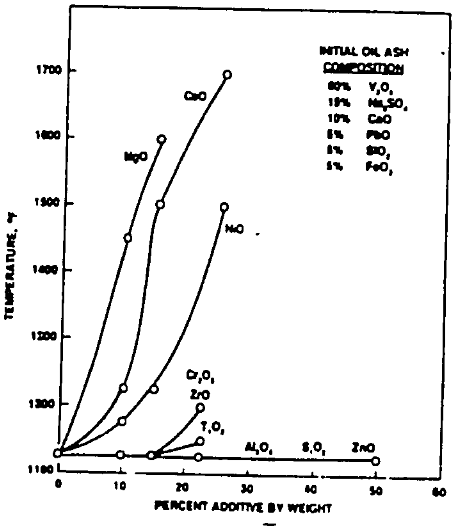

Figure 5. The effect of various additives upon raising the melting point of typical residual oil ash. (After Reference 23.)

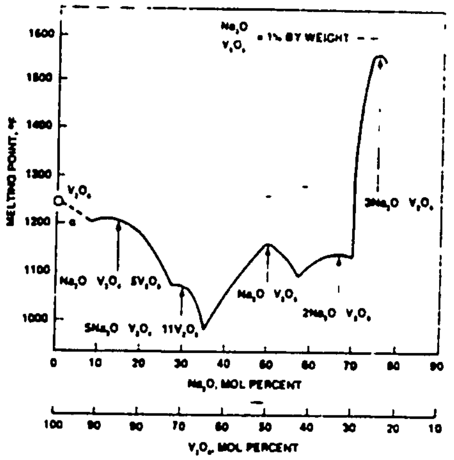

Figure 6. Melting points of vanadium-sodium oxygen compounds. (After Reference 46.)

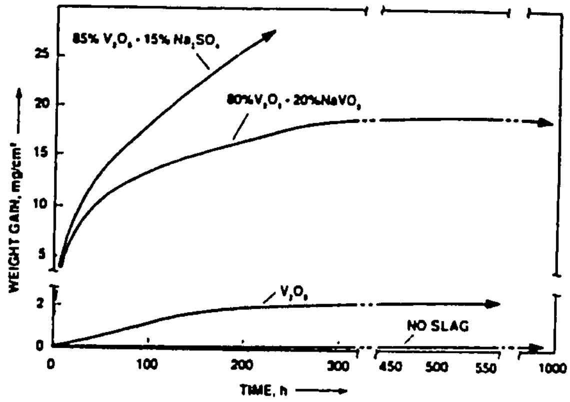

Figure 7. Corrosion (weight gain) of Fe 23 Cr material as a function of time in several synthetic ash mixtures under dry air at 750°C (1382°F). All of the mixtures are molten at this temperature. Corrosion increases when combining sodium with Vanadium but increases still further when sulfur is added. (After Reference 48.)

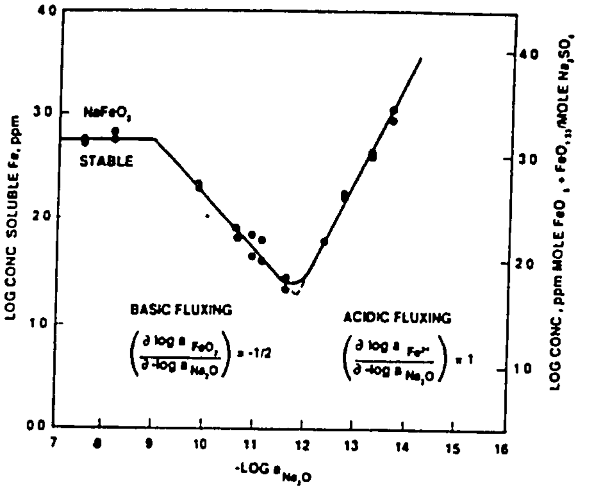

Figure 8. Solubility of a Fe_2O_3 and Fe_3O_4 in fused Na_2SO_4 at 927°C (1700°F) as a function of fused salt basicity (expressed as -LOG a_{Na_2O}). Higher solubility of Fe corresponds to higher corrosion rates. (After Reference 49.)

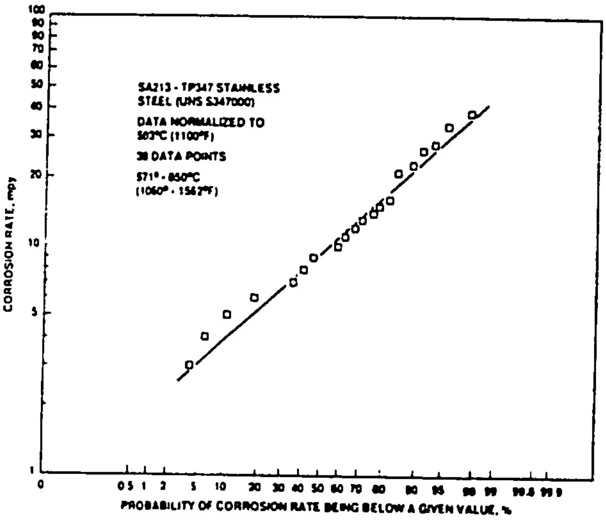

Figure 9. Probability plot of test probe and field study corrosion data for SA213-TP347 stainless steel (UNS S347000). Linear trend of data suggest that the data are statistically distributed. The data have been normalized to show the probability of corrosion rates at 593°C (1100°F) being below a given value.

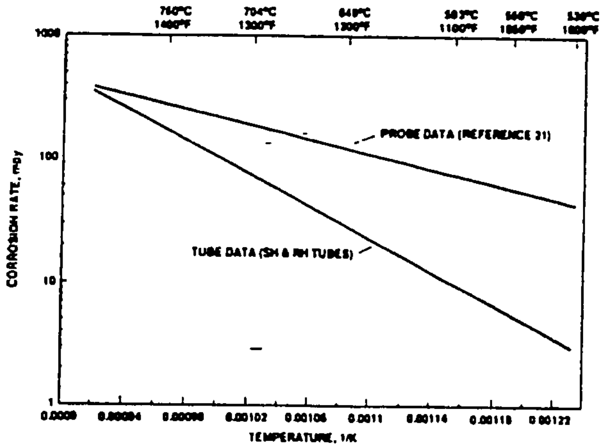

Figure 10. Comparison of SA213-T22 corrosion data from field tests and probe studies to long term operating experience of superheater and reheater tubes in oil fired boilers.

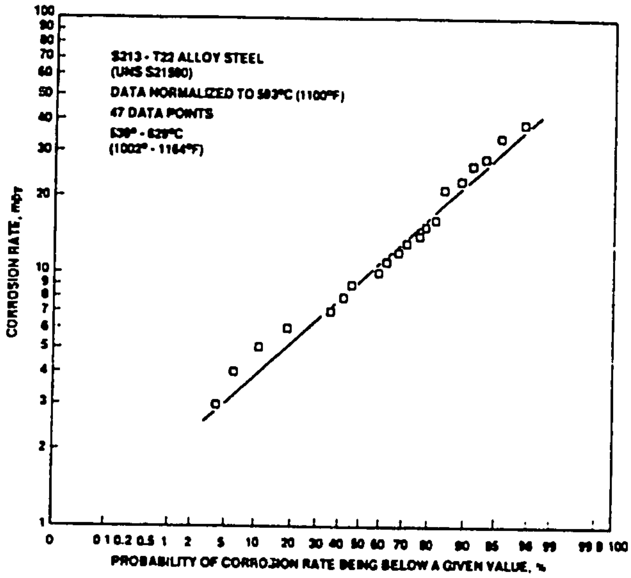

Figure 11. Probability plot long term operating experience of SA213-T22 tubes from 34 commercial boilers. linear trend suggest the data are normally distributed. The data have been normalized to 593°C (1100°F) and show the probability of the corrosion rate falling below a given value.

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APPENDIX C.2

Carbon Particulate Reduction Evaluation for Oil-Fired Utility Boilers

by

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Carbon Particulate Reduction Evaluation for Oil-Fired Utility Boilers

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ABSTRACT

An extensive program was undertaken to identify potential sources of and solutions to high emission levels of large (> 50 micrometer) carbon particles from San Diego Gas and Electric (SDG&E) oil-fired boilers. Carbon itself is neither corrosive nor staining, and total particulate emission rates are well below regulatory limits, but carbon has been shown to function as a vehicle typically transporting sulfuric acid that has condensed on the air preheater to ground level.

Carbon formation in an oil-fired furnace is controlled by a number of interacting factors, which fall into four general categories: (1) fuel oil properties, (2) fuel oil atomization quality, (3) boiler operation, and (4) boiler design. The impact of these four areas was studied by a combination of pilot-scale combustor tests, atomization spray facility tests, full-scale boiler tests, and design and operation evaluation. In addition, combustion-modifying additives were evaluated in a 320 MW boiler and in a laboratory combustor.

Atomization quality and fuel oil properties were identified as potentially the prime contributors to carbon emissions. One combustion-modifying additive was successful at reducing carbon emissions during a full scale boiler trial, and another was successful in combustion tunnel tests. A continuing program is planned to implement solutions developed on several SDG&E boilers.

INTRODUCTION

SDG&E has experienced problems in recent years with emissions of large carbonaceous particles from their oil-fired boilers. These particles are formed by incomplete combustion of fuel oil droplets, and are large enough to settle to ground level in the vicinity of the power plant after they are emitted. Although carbon is neither staining nor corrosive by itself, the particles can act as a vehicle to transport condensed sulfuric acid from air preheaters to ground level. These particles can then act as a nuisance to residents and businesses surrounding power plants.

SDG&E has an ongoing Carbon Reduction Program administered by its Emission Reduction Task Force Project Team. In 1983 and 1984, the Task Force intensified its efforts to address carbon emissions. A program was initiated to improve understanding of the cause(s) of carbon emissions, and to identify potential solutions.

TECHNICAL BACKGROUND AND PROGRAM APPROACH

The particles of concern for this program are large (50 to 250 micrometers in diameter) cenospheres, which are porous, hollow carbon particles formed as a result of incomplete combustion of oil droplets. Cenosphere formation occurs as fuel contained in large oil drops cracks through a fractional distillation process and carbonizes. These cenospheres pass through the combustion zone and exit the boiler. For a given droplet size, fuel oil properties (such as viscosity and the concentration of high molecular weight compounds), excess air levels, and furnace design parameters (such as residence time and flame temperature), can also impact the ability of the droplet to burn completely before exiting the furnace.

Soot, which consists of submicron particles normally formed when excess oxygen levels are too low, was not a primary concern in this program because soot particles are not large enough to fall to ground level. Soot is important in the overall applicability of the results of the program, though, because reductions in soot formation would have a beneficial effect on boiler efficiency and NOx emissions by allowing operation at reduced excess oxygen levels.

Factors that affect carbon emissions can be grouped into four general categories: (1) fuel oil properties, (2) atomization, (3) boiler operation, and (4) boiler design.

The program described in this paper was designed to evaluate the impact on carbon formation of each of the four categories listed above. In addition to these four areas, combustion-modifying additives were evaluated in a 320 MW boiler and in a laboratory combustor. The approach taken to investigate each of these five areas is described below.

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Fuel Oil Properties

Fuel Analyses. The first step in evaluating the effect of fuel oil properties on carbon formation was to obtain and analyze several fuel oil samples. Twenty-four oil samples were obtained from SDG&E's Encina and South Bay Power Plants, as well as from the three other major California utilities, Southern California Edison (SCE), Los Angeles Department of Water and Power (LADWP), and Pacific Gas and Electric (PGandE). These other utilities, unlike SDG&E, do not have carbon emissions problems on a systemwide basis. Therefore, analyses of the fuel samples were performed to determine if there existed any differences in the oils that might account for the differing carbon emissions from SDG&E boilers.

Combustion Tunnel Tests. A small-scale combustor (20.5 kW, 70,000 Btu/hr) was used to evaluate the relative tendencies of six fuel oils to form carbon particles. Use of the combustor allowed all of the oils to be fired under identical conditions (firing rate, viscosity, excess air, etc.). The oils were evaluated under staged and unstaged conditions, and their tendencies to form both cenospheres and soot were measured.

Additives

Two combustion-modifying additives were evaluated in full-scale tests on SDG&E's Encina Boiler 5 in November 1983. One of the additives (a water-based calcium nitrate solution) provided large carbon particulate reductions of up to 86% and smoke point reductions of up to 1.0% excess oxygen. As a result of those tests, use of the additive was implemented on a long-term trial basis on Encina 5 and South Bay 4.

To evaluate additional additives at minimal expense, six additives were tested on a small-scale combustor to determine if any of them merited a full-scale boiler trial.

Atomization

SDG&E is unique in that steam atomization is used on the majority of SDG&E boilers (Encina Units 4 and 5 and South Bay Units 1 through 4), rather than mechanical return flow atomization used on the other major California utility boilers. Although steam atomization is normally considered to be superior to mechanical atomization, the performance of steam atomizers is highly dependent on the steam-to-fuel mass ratios used. In the interest of fuel economy, the SDG&E atomizers have been designed for very low atomizing steam flow rates (or steam-to-fuel mass ratio).

In order to quantify atomizer performance, full-scale atomizer flow tests were performed on atomizers from four units: Encina 5, South Bay 4 (SDG&E), Pittsburg 6 (PGandE), and Alamitos 3 (SCE). The tests were performed at full load atomizer flow rates using a fluid which simulated typical oil properties. Droplet size distributions in the spray field were measured using state-of-the-art laser techniques. An alternate atomizer for Encina 5 was also evaluated to determine if a simple change in atomizer design could provide improved atomization.

Boiler Operation

The objective of the boiler operation investigation was to determine if there were any operational procedures that might impact carbon formation. Specific areas of investigation included NOx port operation, flue gas recirculation flow rate, overall unit balance of air/fuel ratio and carbon emissions, and specific procedures used by unit operators to control the boiler. Boiler operating procedures were reviewed and a series of baseline tests were performed simultaneously during December 1983.

Boiler Design

In this investigation, the overall design of Encina 5 was compared to similarly sized and designed oil-fired boilers at SCE, LADWP, and PGandE. The other utility boilers selected for comparison do not exhibit carbon particulate emissions. The design variables investigated that could potentially impact carbon emissions were:

- o Furnace volume
- o Burner zone radiant area
- o Furnace exit temperature
- o Burner size, number, and spacing
- o Burner design
- o Atomizer design and specifications
- o Overfire air port design and utilization
- o Windbox cross sections and arrangements
- o Air preheat
- o Flue gas recirculation rate and injection location

By evaluating design data for all four boilers, a determination was made as to whether design features of Encina 5 contribute to the carbon particulate emissions.

RESULTS

This section presents the results of the five separate investigations, along with more detailed discussions of the solution approach taken in each task.

Fuel Oil Quality

The objectives of the fuel oil quality task were:

1. Determine which oil properties influence carbon formation, and
2. Determine if SDG&E fuel oils tend to form more carbon than fuel oils from three other California utilities.

These objectives were met by performing detailed fuel analyses on 24 oil samples from the four utilities, and by performing small-scale combustion tunnel tests on six of the oils. Results are presented here only for the six oils tested ~~on~~ WITH the combustor.

Fuel Analyses. The analyses performed on the oils included a standard battery of tests (ultimate analysis, viscosity, heating value, sediment and water, Conradson carbon, and asphaltenes), plus a relatively new procedure, thermogravimetric analysis (TGA). TGA is a procedure in which a mass of oil is heated in either an inert or oxidizing atmosphere, and the percentage of sample remaining is plotted as a function of temperature. Differential thermogravimetic analysis (DTGA) is the derivative of the TGA curve. TGA and DTGA provide some information similar to a distillation curve, but they are simpler to perform and provide much more detailed data.

Since the tests here were performed in an oxidizing atmosphere, DTGA represents the "burning profile" for a specific fuel oil. DTGA curves show distinct peaks that identify specific fractions of an oil used in blending. If a fuel oil is a blend of a light oil used to cut a very heavy pitch, it would be expected to burn differently than an unblended oil of the same viscosity.

Analyses of the six fuel oils tested ~~on~~ with the combustor are presented in Table 1. DTGA data listed as the 10%, 50%, and 95% points represent the temperatures below which the stated percentage of oil burned. The data presented for peaks represent the percentage of oil contained in identifiable peaks on the DTGA curves, and the temperature of the peak. The curves for all of the oils tested contained either three or four peaks in the same approximate temperature ranges; the percentage of oil in the various peaks and the shapes of the peaks varied from oil to oil.

TABLE 1.
ANALYSES OF SIX COMBUSTOR TEST OILS

	Encina 4	LADWP	SCE	PGandE	Encina 5	South Bay 3
Ultimate Analysis (Wt %)						
Carbon	86.48	87.15	86.84	87.41	86.8	87.0
Hydrogen	12.21	12.27	12.38	11.60	12.2	12.3
Nitrogen	0.28	0.26	0.24	0.34	0.31	0.34
Sulfur	0.43	0.25	0.20	0.48	0.48	0.42
Ash	0.033	<0.001	0.044	0.026	0.025	0.015
Oxygen (by Difference)	0.57	0.07	0.50	0.14	0.19	
C/H Ratio	7.08	7.10	7.01	7.54	7.11	7.07
Viscosity, SSU						
at 99 °C	133.4	51.9	59.5	86.0	113.6	70.6
at 50 °C	1,475	191	719	876	1,065	452
Temp. at 135 SSU, °C	99	58	72	85	93	78
Asphaltenes, %	1.4	0.8	1.1	1.8	2.0	2.1
Conradson Carbon, %	6.49	2.87	3.50	5.62	7.09	4.90
Sediment by Extraction, %		<0.001	0.007	<0.001		<0.001
Higher Htg Value, Btu/lb	19,048	19,189	19,240	18,877	18,997	18,659
HHV, J/g	44,260	44,580	44,700	43,800	49,140	43,350
API Gravity	19.4	22.9	23.2	17.1	15.0	19.1
Specific Gravity at 16 °C	0.9377	0.9165	0.9147	0.9522	0.9659	0.9396
DTGA Data*:						
10% Point, °C	216	173	177	194	205	209
50% Point, °C	352	270	283	305	305	306
95% Point, °C	507	501	495	516	509	520
Peak 1, %/T, °C	50.6/311	83.3/290	74.0/305	63.5/325	54.0/302	66.0/320
Peak 2, %/T, °C	2.7/361	---	2.0/375	---	4.0/370	---
Peak 3, %/T, °C	25.7/440	7.1/440	12.0/445	22.5/445	22.7/430	15.3/376
Peak 4, %/T, °C	20.0/502	9.5/513	11.2/505	13.3/517	17.3/510	14.6/515

*See text for explanation.

Combustion Tunnel Tests

The combustion tunnel used for these tests was owned and operated by Energy and Environmental Research (EER), under subcontract to ESA. The tunnel has a firing rate of 70,000 Btu/hr (20.5 kW), and uses an air-atomized Delavan burner tip. Oil temperature was controlled to maintain a constant firing viscosity of 135 SSU for all oils. The following measurements were taken on each oil under both unstaged and staged (85% primary air) firing:

1. Bacharach smoke number (BSN) vs. O_2; smoke point defined as the O_2 level at which BSN=1.
2. Greased impaction plate - an aluminum sheet coated with high-temperature grease which is inserted into the gas stream for a fixed period of time to collect large (>30 micrometer) particles by inertial impaction. The "impaction plate rating" is determined by counting the density of particles collected on the plate.
3. Total particulate by whole-stream filtration - these samples were comprised mostly of ash rather than carbon, so the results are not presented here.
4. CO, O_2, NOx.

Table 2 presents the results of the tests. A review of these results leads to the following conclusions:

1. SDG&E's Encina 4 oil resulted in significantly higher impaction plate ratings (50 to 70) than any of the other oils. The PGandE oil resulted in plate ratings of 8 to 10, while all of the other oils (including the other two SDG&E oils) resulted in plate ratings of 3 or less.
2. The Encina 4 oil had the highest smoke point of any of the oils in the unstaged firing mode, and the second highest smoke point during staged firing. The LADWP and SCE oils had significantly lower smoke points than the other four oils.

TABLE 2.
RESULTS OF FUEL OIL EVALUATION COMBUSTOR TESTS

Oil	Unstaged Data Smoke Point % O_2	 Impaction Plate Rating*	Staged Data Smoke Point % O_2	 Impaction Plate Rating*
Encina 4	1.1	70	2.7	50
LADWP	0.3	0.5	1.4	1.6
SCE	0.6	3.0	1.3	2.2
PGandE	0.9	10.0	2.5	8.0
Encina 5	0.9	0.5	2.7	0.2
South Bay 3	0.7	0.1	2.9	2.0

*Plate rating is based the number of particles per 0.002 sq.in.

To determine which oil properties correlate with carbon emissions, linear regression analyses were peformed to determine the correlation coefficients between smoke point, impaction plate rating, and various oil properties. The correlations are discussed below.

Smoke point correlated well with Conradson carbon, viscosity, TGA 10% and 50% temperatures, and the percentage of oil in the high-temperature DTGA peak. There was a strong negative correlation between smoke point and the percentage of oil in the low-temperature DTGA peak.

Impaction plate rating correlated strongly with only one property evaluated: the midpoint TGA temperature cut-off. There were weak correlations with viscosity, Conradson carbon, and other TGA parameters. There was no correlation with asphaltene content.

A more detailed look at TGA/DTGA data provides additional insight into the effect of fuel properties on cenosphere emissions. Figures 1, 2, and 3 show the TGA/DTGA curves for the Encina 4, Encina 5, and LADWP oils. Encina 4 was the oil which produced the most cenospheres, Encina 5 was a similar SDG&E oil to Encina 4 which produced very low quantities of cenospheres, and the LADWP oil is a much lighter oil which produced low quantities of cenospheres.

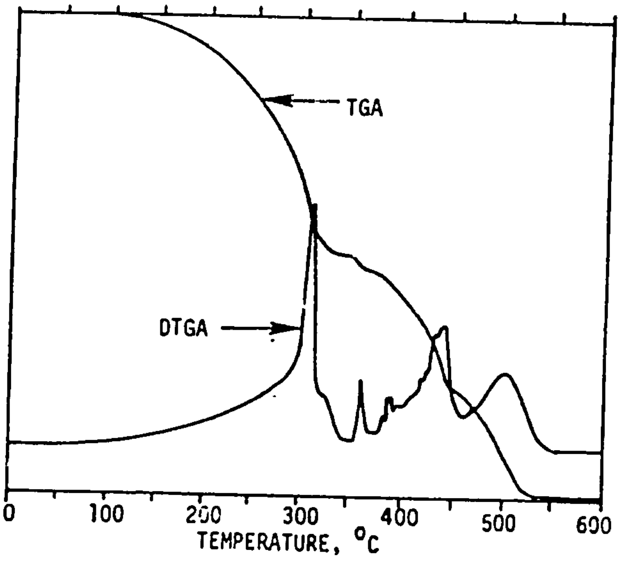

Figure 1. TGA and DTGA curves for Encina 4 oil.

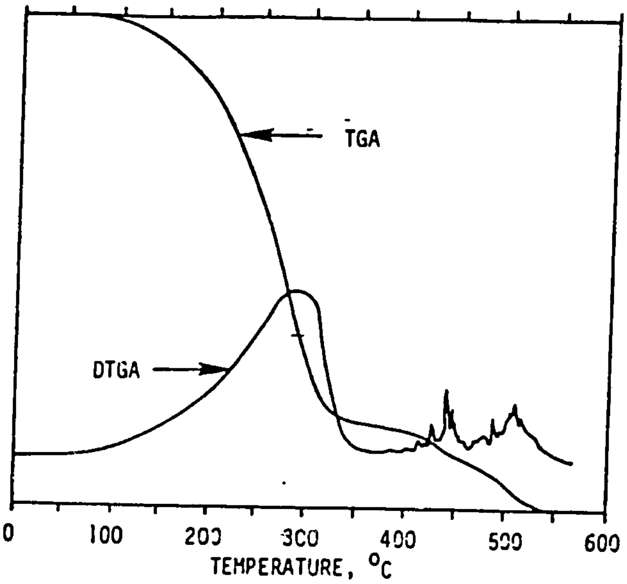

Figure 2. TGA and DTGA curves for LADWP oil.

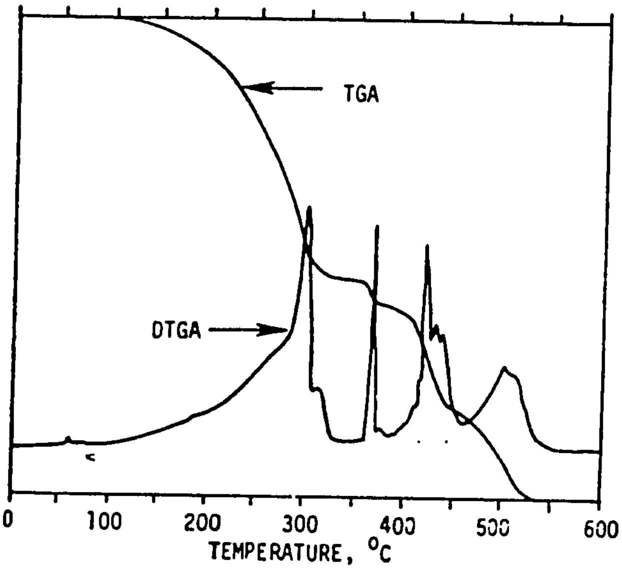

Figure 3. TGA and DTGA curves for Encina 5 oil.

The curves show that the LADWP oil has a very broad low temperature peak indicative of a straight run residual oil. The two SDG&E oils, on the other hand, show very steep low and mid-temperature peaks indicative of narrow light-end distillate fractions added to a heavy oil to meet purchaser requirements such as viscosity or pour point.

A comparison of the DTGA curves for the Encina 5 and Encina 4 oils indicates that the oils are virtually identical, with one exception: the Encina 5 oil (which had very low cenosphere emissions) has two very sharp and narrow peaks at 370 °C and 420 °C, while the Encina 4 oil (which produced the highest cenosphere emissions of any oil) has only a small peak at 370 °C and no peak at all at 420 °C. These two peaks contain 16% of the Encina 5 oil and, more importantly, are in the mid-temperature range between the light and heavy oil fractions. It is believed that these mid-temperature peaks provide a continuous burning rate/time/temperature profile to inhibit cenosphere formation. For the Encina 4 oil, the droplet flame might be extinguished in the temperature regime where the peaks are missing, since there would be little or no oil vapor evolving to sustain the flame.

These data indicate that the addition of a middle fraction to the oil or blending of oils with middle fractions with oils without middle fractions might be an effective means of reducing cenosphere production.

Fuel Oil Conclusions. Based on the fuel oil analyses and the results of the combustor tests, the following conclusions were drawn:

1. SDG&E oils tended to be heavier and have higher smoke points than the other California utilities' oils, but only one of the three SDG&E oils tested produced more cenospheres than the other utilities' oils.
2. DTGA data provide useful information in evaluating the tendency of an oil to form cenospheres.
3. The presence of two middle-cut fractions in the Encina 5 oil apparently reduced the quantity of cenospheres produced below the level measured on the almost identical Encina 4 oil.
4. Conradson carbon and viscosity can be used to predict the tendency of an oil to form soot and, with a lower degree of confidence, to form cenospheres.
5. Asphaltenes, over the narrow and low range encountered, did not correlate with either cenospheres or soot emissions.

Combustion-Modifying Additive Tests

Additive evaluations were performed in two separate test series: (1) full-scale boiler tests of two additives on Encina 5, a 320 MW Babcock & Wilcox opposed-fired boiler, and (2) combustor tests of six additives. The objectives of the tests were to determine if additives might offer a viable solution for reducing large carbon particulate emissions. Use of the combustor allowed screening a large number of additives at minimal cost.

Table 3 presents a summary of the results from both the boiler and the combustor. In the original boiler tests, the calcium-based additive showed reductions of up to 86% in large carbon particulate, and a reduction in smoke point of 1% O_2. Based on these results, long-term trials of this additive were initiated on Encina 5 and South Bay 4.

The combustor tests confirmed the results obtained on the calcium additive, with similar reductions in both plate density and smoke point. An iron-based additive gave a plate density reduction of 68% and a marginal smoke point reduction of 0.3% O_2. A full-scale trial of the iron additive is currently being considered.

A copper-based additive was tested on the boiler, and provided no reduction in large particulates. Other additives tested on the combustor that did not show enough promise for further consideration included zirconium, cerium, magnesium oxide with magnesium nitrate, and magnesium oxide with platinum.

Atomization Tests

The objectives of the atomization phase of the program were:

1. Compare the performance of two SDG&E steam atomizers to typical mechanical atomizers from a similar unit which does not have a carbon problem, and from a unit which has an intermittent carbon problem.
2. Quantify the effect of load and atomizing steam-to-fuel ratio on droplet size for the Encina 5 and South Bay 4 atomizers.
3. Select and evaluate an alternate atomizer for Encina 5 to determine if a simple design change can provide improved atomization.

Full scale atomizer spray tests were performed on the atomization facility at the Babcock & Wilcox (B&W) Alliance Research Center. A water/propylene glycol mixture blended to a viscosity of 135 SSU (29 centistokes) was used as a fuel oil substitute. For the dual-fluid atomizers, air was used as the atomizing fluid. The dual-fluid atomizers were tested over a nine-point matrix of three fuel rates by three air-to-fuel ratios each. The mechanical atomizers were tested at full load only.

The Encina 5 atomizer is a standard B&W Racer Y-jet, while the South Bay 4 atomizer is a custom-designed dual-fluid atomizer intended for low atomizing steam consumption. Both Pittsburg 6 (B&W) and Alamitos 3 (Combustion Engineering) are mechanical return flow atomizers.

Table 4 presents the particle size data at nominal full load conditions for the four atomizers, and Figure 4 shows mass median diameter vs. air/fuel ratio for the Encina 5, South Bay 4, and modified Encina 5 atomizers.

Table 4 shows that at full load, the two mechanical atomizers produced mass median diameters (MMD) of 114 microns, while the MMD for Encina 5 was 191 microns and the MMD for South Bay 4 was 156 microns. Additional insight into the performance of the SDG&E atomizers is gained from the data shown in Figures 4a through 4c.

Figure 4a shows that for Encina 5, atomizer performance degrades at high loads, where atomizing air-to-fuel ratio decreases. Above an air/fuel ratio of 0.03, droplet size is not significantly reduced by additional atomizing air. Below an air/fuel ratio of 0.02, atomization starts to become unstable, and droplet size increases dramatically as the air/fuel ratio decreases. This regime of instability corresponds with full load operation.

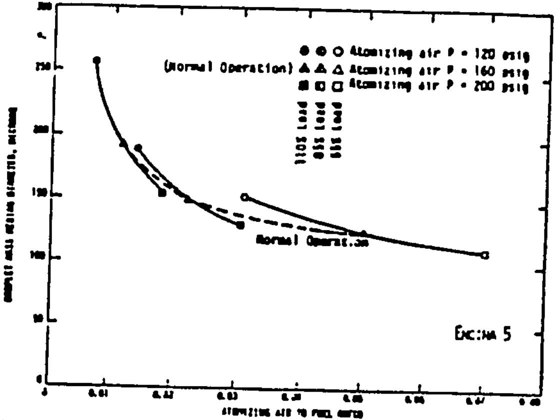

Figure 4a. Droplet mass median diameter versus air/fuel ratio for three dual-fluid atomizers.

Droplet size behavior on the South Bay 4 atomizer is significantly different than on Encina 5. Droplet size is affected more by fuel pressure than by atomizing air rate, with droplet size being higher at low load (where fuel pressures are lower) than at full load. This indicates that this atomizer behaves more like a mechanical atomizer than a steam atomizer, and that it uses atomizing steam ineffectively. At 50% load, it uses more atomizing air than the Encina 5 tip, yet produces a coarser spray.

TABLE 3.
SUMMARY OF COMBUSTION-MODIFYING ADDITIVE TESTS, UNSTAGED COMBUSTION

Active Ingredient	Form	Boiler/ Combustor	Concentration of Metal, ppm*	% Reduction in Impaction Plate Density at Constant Excess O_2	Reduction in Smoke Point, % O_2
$Cu(NO_3)_2$	Water solution	Boiler	100	0	0.1
$Ca(NO_3)_2$	Water solution	Boiler	90	86	1.0
$Ca(NO_3)_2$	Water solution	Combustor	98	−92	1.1
Zirconium	Oil solution	Combustor	780	29	0.2
Cerium	Oil solution	Combustor	75	8	1.0
Iron picrate	Oil solution	Combustor	2	68	0.3
$MgO/Mg(NO_3)_2$	Oil slurry	Combustor	280	9	0
MgO/Pt	Oil slurry	Combustor	57 ppm MgO 0.02 ppm Pt	0	No data

*Data are shown for the highest feed rate tested for each additive.

TABLE 4.
SUMMARY OF PARTICLE SIZE DATA AT NOMINAL FULL LOAD CONDITIONS

Atomizer	Encina 5	South Bay 4	PGandE	SCE	Oversized Encina 5
Fuel Flow Rate, lb/hr					
Design	6,900	11,000	6,800	6,900	6,900
Measured	7,700	11,200	6,880	7,300	7,700
Fuel Supply Pressure, psig					
Design	275	400	1,000	1,075	unknown
Measured	275	385	1,000	980	245
Atomizing or Return Fluid Pressure, psig					
Design	160	250	800	300	160
Measured	160	220	870	470	160
Atomizing or Return Fluid Flow, lb/hr					
Design	120	unknown	0	unknown	unknown
Measured	95	210	1,330	1,030	140
Mass Median Diameter, microns	191	156	114	114	158
Sauter Mean Diameter, microns	132	103	76	79	111

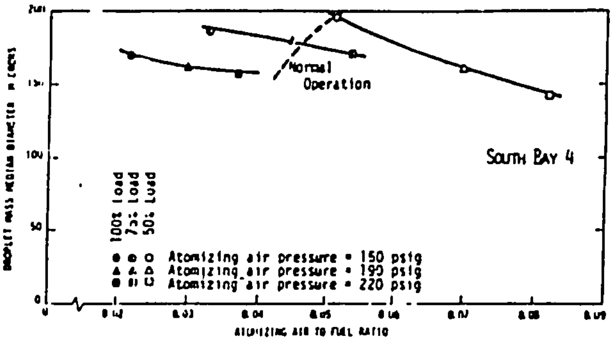

Figure 4b. Flow test facility determination of spray droplet mass median diameter versus air/fuel ratio.

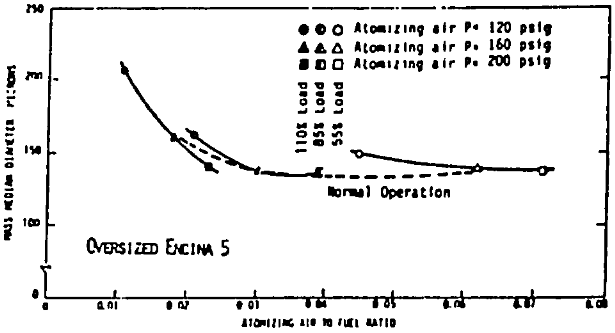

Figure 4c. Mass median diameter versus air/fuel ratio.

Based on the Encina 5 results that showed high droplet sizes at full load, it was decided to test a modified version of the Encina 5 tip. This modified version was basically the same design, but with larger orifices corresponding to a 10% increase in tip capacity. This tip was selected to determine if operation at a lower percent of atomizer load would avoid the steep part of the size vs. air/fuel ratio curve.

The data show that the oversize atomizer reduced the MMD at full load from 191 to 158 microns with a 0.006 increase in air/fuel ratio, but there was a slight increase in particle size at low loads. Figures 4a and 4c show that in terms of droplet size vs. air/fuel ratio, the standard and modified Encina 5 atomizer performed almost identically. The advantage of the oversized tip is that, at a given atomizing air pressure, it allows operation at increased air/fuel ratios.

Boiler Operation

Boiler operation on Encina 5 was investigated to determine if certain aspects of boiler operation contributed to carbon emissions. The investigation included two distinct tasks. First, a series of baseline tests were conducted in which carbon emissions were quantified and the effects of a limited number of operational variables (unit load, excess O_2, overfire air port operation, and spatial distribution of O_2, CO, and carbon in the boiler exhaust) were determined. Second, boiler operating manuals and operational procedures were reviewed along with conversations with boiler operating personnel.

The major results of the boiler operation phase are listed below:

1. Low excess air operation tends to aggravate the carbon emission problem, but increasing excess O_2 is not viable because it reduces unit efficiency and increases NOx emissions. Further, operation at increased O_2 levels would not completely solve the carbon problem.
2. Opening the NOx ports resulted in significant increases in both cenosphere emissions and opacity. Since it is already standard procedure to open the NOx ports only when necessary, there is not much room for improvement in operation.
3. There were no areas in which boiler operation was identified as the major source of carbon emissions. In particular, burner gun cleaning was adequate and there were no air or fuel imbalances on the boiler that would account for high carbon emissions during normal operation.

Boiler Design

Since overall boiler design can affect carbon formation and burnout, the design of Encina 5 was compared with that of three similar boilers at the other California utilities, which as presently operated are considered relatively carbon free. Items considered were burner zone heat release rate, volumetric heat release rate, furnace combustion gas velocity, combustion air duct and windbox velocities, burner throat velocities, minimum furnace residence time, and burner spacing and positioning.

The units compared to Encina 5 are all B&W units of modern vintage with ratings of 350 MW, 480 MW, and 325 MW. However, all of these units were constructed during the period when high power density (i.e., compactness, reduced material cost) was a competitive goal. When Encina 5 was designed, more recognition was given to NOx control parameters as well as the greater longevity of more generously proportioned units. For these reasons, Encina 5 has a larger furnace than the other boilers.

The large furnace incorporated into Encina 5 for NOx control tends to make the control of large carbon particulate emissions more difficult. However, the design review found that each of the other units has individual features which are "worse" than Encina 5, so the boiler design as such does not create an unsolvable problem.

Based on the boiler design study, no changes in boiler design were recommended to solve the carbon problem.

CONCLUSIONS AND SUMMARY

Table 5 presents a summary of the problem areas, potential solutions and their estimated effectiveness and cost, and whether or not each area is being investigated further. The two major conclusions drawn from the study are:

- Fuel oil quality and atomization are the major contributors to carbon emissions. They

TABLE 5.
SUMMARY OF CAUSES AND POTENTIAL SOLUTIONS TO CARBON PROBLEM

Area of Investigation	Problem Areas	Potential Solutions	Estimated Potential Effectiveness	Estimated Cost	Possible Negative Side Effects	Further Investigation
Fuel Oil Properties	Heavy fuels	Tighten fuel specs	Moderate-High	$0.20-$1.00/bbl	Reduced oil purchase options	Yes
	TGA properties	Screen/blend	Moderate	Undetermined	Compatability problems	Yes
	Fuel nitrogen	Tighten fuel spec	Low-Moderate	$1.50/bbl	Reduced oil purchase options	No
Additives	Cenospheres/soot	Calcium	High	9.8¢/bbl*	Boiler deposits	Yes
		Iron	Moderate-High	10.6¢/bbl	Staining particulate	Yes
Atomization	SB4-large droplet size at all loads	Redesigned atomizer	Moderate-High	Poten. cost svgs to 10¢/bbl	Higher NOx	Yes
	FAS-low steam/fuel ratio at high load	Larger atomizer or increase no. of jets	Moderate-High	2.6¢-9.0¢/bbl	Higher NOx; reduced turndown	Yes
Boiler Operation	Low O_2 operation	Increase O_2 and reduce fuel N to control NOx	Low	+$1.50/bbl	High NOx and lower efficiency	No
	NOx port operation	Tighten fuel N spec	Moderate	+$1.50/bbl	Reduce oil purchase options	No
	NOx port operation	Use additive to reduce O_2 and NOx	Moderate	9.8¢/bbl*	---	Yes
Boiler Design	High furnace volume, low furnace temps.	Insulate furnace 1. Make hotter 2. Increase residence time 3. Provide additional oxygen	Low	High	High NOx, temperature control problems	No

*Cost would be reduced by almost 8¢/bbl due to a reduction of 1% in excess O_2 and the resulting estimated 0.25% efficiency improvement.

are also the areas in which cost effective solutions are most likely to be found.

- Combustion-modifying additives can provide significant reductions in large carbon particulate emissions.

Now that the problem areas have been identified, continuing efforts to solve the carbon emission problem are focused in three main areas:

1. Fuel oil quality--efforts are underway to quantify carbon-formation thresholds for TGA properties, to provide fuel purchasing personnel at SGD&E with the additional information necessary to purchase the highest quality fuels at the lowest total cost, and to develop identification, burning and/or blending procedures for problem oils.
2. Atomization--continuing efforts include spray facility and limited full-scale testing of alternate atomizer designs for Encina 5 and South Bay 4, and baseline spray facility tests of atomizers on three additional SDG&E boilers.
3. Additives--long-term evaluation of the calcium-based additive is continuing, and evaluation is continuing on whether to perform full-scale tests on the iron-based additive.

Acknowledgements - The authors would like to thank Southern California Edison, Pacific Gas & Electric, and the Los Angeles Department of Water and Power for providing fuel oil samples, atomizers, and boiler design information as well as support funding for the program.

APPENDIX C.3

The Fundamentals of Atomization with Application to Heavy Fuel Oil Atomizer Design

by

Roger V. Jones

The Fundamentals of Atomization with Application to Heavy Fuel Oil Atomizer Design

A Presentation Made To The

1987 Electric Power Research Institute
Fuel Oil Workshop

Atomization Fundamentals and Applications Session

October 21-22, 1987

Boston, Massachusetts

Roger V. Jones

Parker Hannifin Corporation
Gas Turbine Fuel Systems Division
Cleveland, Ohio

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AP-5937
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ABSTRACT

A workshop to consider current problems related to fuel oil utilization was held in Boston, Massachusetts, on October 21-22, 1987. The 64 participants included fuels, engineering, and operating representatives of 21 U.S._utilities, one Canadian utility, the Instituto de Investigaciones Electricas (Mexico), the Energy and Mining Research/Service Organization (Taiwan), the Electric Power Research Institute, and several contractors engaged in related EPRI fuel oil projects.

The primary objective of the two-day meeting was the interchange of information related to fuel oil projects conducted by some of the utilities, EPRI, EPRI contractors, and others. Through the interactions, EPRI gained useful insight into directions for continuing and future studies and utility support efforts.

The presentations and discussions during the first day addressed fuels and combustion related problems encountered in utility boiler systems burning residual fuel oils as the primary fuel. Included were the results of fundamental studies, plant tests and demonstrations, and operating experiences. Among the major presentation topics covered were combustion and spray characteristics of residual oils, utility boiler emulsion economics, combustion tests using both low gravity API and high asphaltene residual oils, results of an actual fuel oil evaluation study in Florida, stability and compatibility predictions of residual fuel oils, ASTM activities related to heavy fuel oils, the relationship of fuel quality to particulate emissions from residual oil-fired boilers, and a status report on the EPRI Residual Fuel Handbook.

Introduced at the 1987 Workshop was a series of discussion groups which afforded attendees the opportunity to interact with others on topics of mutual interest. Four discussion group meetings were held on the second morning; the subjects including technology development, operating problems and methods, fuel supply, and atomization. The respective chairs of each discussion group presented a summary to the reassembled workshop attendees in the afternoon session.

ATOMIZATION FUNDAMENTALS AND APPLICATIONS

Moderator: Jim Nylander, San Diego Gas & Electric

The discussion group was lead off by a presentation by Roger Jones of Parker Hannifin, on atomization. A copy of the material presented is enclosed as Appendix B-2. Mean fuel droplet diameter of 50-100 microns are recommended for proper atomization. The use of emulsions can be justified based on savings due to a cleaner furnace, avoiding load curtailments, capacity to burn cheaper, lower quality fuel oil, reducing ignition compliance and nuisance problems, and reducing boiler excess oxygen levels. It was reported that emulsions reduce the particulate in the 3-50 micron diameter size range. No change in particulates was seen in the less than 3 micron size range. The optimum conditions appear to occur when the emulsions contains 5% water in oil. Water droplets in the oil are from 4-6 microns in diameter.

New England Power will conduct a test to determine the accuracy of their Dynatrol viscometers using high and low API gravity oil. Consultants indicated that inaccuracies can occur with this instrument, when gravities vary over a large range.

Concerning the question how do you know when an atomizer is worn out, Boston Edison commented that when they flow test their atomizers they check for wear they use a 2% variation. If the flow is greater than 2%, then they will discard them.

With respect to the method of measurement for droplet size evaluating of atomizer performance, most people use the Sotter-mean diameter standard for comparison.

1987 EPRI FUEL OIL WORKSHOP

OCTOBER 21-22, 1987 BOSTON, MASS.

GROUP DISCUSSION: ATOMIZATION FUNDAMENTALS AND APPLICATIONS

The Fundamentals of Atomization with Application to Heavy Fuel Oil Atomizer Design

Roger V. Jones

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A. INTRODUCTION

1. GTFSD of PH is a major manufacturer of many types of spray nozzles.
2. Our business is the design and manufacture of fuel nozzles and valves for gas turbine engines which we have been doing since the early 1950's.
3. We produce and test thousands of spray nozzles each week at our five manufacturing facilities.
4. Over the past five years we have been transferring our atomization technology into new product areas.
    a. First coal water slurry nozzles were developed.
    b. This led to heavy fuel oil applications (tip retrofits to existing burner guns).
    c. A test facility was established for testing of hi-flow HFO atomizers using water/glycol simulant.

B. FUNDAMENTAL ATOMIZATION CONCEPTS

1. Why Atomize?

It's important to keep in mind just what it is we are trying to accomplish when we spray a liquid. A basic definition :

"Atomization is the process whereby a volume of liquid is converted into a large number of small drops. Its principal aim is to to produce a high ratio of surface to mass in the liquid phase so as to best prepare the fuel for subsequent evaporization and combustion."

2. Jet Breakup

a. First consider how a liquid behaves. All changes in the shape of a body of liquid are resisted by the property of surface tension. Consider this as a force acting at the surface of the liquid in such a way as to maintain the lowest possible surface energy. This minimum energy state is exhibited in liquids by a spherical shape. In general terms, the larger the body of liquid, the less stable it is, so there is always a tendency for large drops to break into smaller ones.

b. The simplest mode of breakup is that of a plain circular jet. This jet is not stable and the mechanism first stated by Lord Rayleigh in 1878 predicts what oscillation will form in the jet. As soon as the surface of the jet becomes distorted surface tension comes into play and the jet necks and forms drops as shown. The large drops are approximately twice the diameter of the initial jet.

3. Flat Sheets

a. Since the objective is to produce the smallest drops possible, very thin jets are necessary. The simplest way to get these thin jets or ligaments is to spread the liquid into a very thin sheet or film. If we were to do this with a slit orifice we would produce a sheet as shown. This is much more effective than a jet, as the sheet "tears" and breaks up easily into ligaments of varying diameters. These then breakup into drops of various sizes.

b. The concept of forming fuel into thin sheets is the first fundamental concept of atomization and is the basis of Parker Hannifin's design philosophy. All of our atomizers in one way or another "prefilm" the fuel into as thin a sheet as possible before they interact with the ambient or atomizing gas.

4. Drop Interaction With Air

a. Up to this point we have been talking mostly about the breakup of liquids due solely to hydrodynamic forces. This is only the beginning of the story, as a liquid which is sprayed will immediately contact some gas which is moving at a different velocity. This interaction involves aerodynamic forces which actually accomplish the bulk of the liquid breakup. As a drop moves relative to the air there is a tendency for the liquid to break up into smaller drops. This is the second fundamental concept of atomization, to establish as high a relative velocity as possible between the fuel and the surrounding air. This creates high shear and velocity gradients across the liquid to gas interfaces which effectively atomizes the liquid.

b. Illustrated is a typical breakup mechanism for a drop which has a high relative velocity to the air. The large drop forms a bubble which then bursts, forming many more smaller drops of various sizes. The process of atomization will continue as long as there is a relative velocity between the liquid and the surrounding air.

5. Drop Size Distributions

a. It is of course impossible to produce a truly monodisperse spray. Each spray is composed of many drops of many different sizes as this diagram illustrates. Drop sizes are measured in microns. There are 25 microns to one thousandth of an inch. The drops are typically classed into size groups as shown here. In a good spray there are relatively few large drops but thousands of small ones.

b. A single "mean" drop diameter is usually used to describe a given spray. For combustion sprays the standard is the Sauter Mean Diameter, or SMD. This is the diameter of a hypothetical drop which has the same surface to volume ratio as the entire spray sample. This is an appropriate mean since we are interested in maximizing the surface area for a given volume of fuel. For this example the SMD is 100. This diameter can be obtained through the use of various particle-sizing instrumentation such as the Malvern laser diffraction device.

c. Another popular mean diameter is the Mass Mean Diameter (MMD) also known as the Volume Mean Diameter. This is that diameter for which 50% of the volume consists of larger diameter drops and 50% of smaller diameter. For this example the MMD is 120.

d. Although in a good spray there are usually not many large drops, it is still critical to limit their size and number as much as possible. These large drops take too long to evaporate and burn properly, resulting in inefficient combustion and possible soot and carbon production.

6. Spray Profile and Pattern

a. It is very important that the fuel not only be atomized into a spray of very fine droplets but that this spray be shaped such that the fuel is placed properly for complete and stable combustion in the burner/combustor system. This means matching the spray profile to the aerodynamics of the burner air flow to produce a strong, recirculating flame.

b. Spray profiles are measured using the level of obscuration of a laser beam passing through the periphery of a spray to establish the spray boundary. Plots are then made from this data as shown.

C. TYPICAL NOZZLE TYPES

1. Pressure Operated Simplex Nozzles

a. Fuel is made to swirl into a swirl chamber so that the fuel leaves the discharge orifice in the form of a thin conical sheet surrounding a core of air.

b. Usually tangential holes or slots are used to swirl the fuel as shown.

c. The liquid flowing in the swirl chamber is actually a free vortex, which means that the entire pressure drop across the nozzle is converted efficiently into high velocity at the discharge.

d. Conical inlet slots are used in some designs. We use a variety of exit lips to change the natural spray angle and place the fuel in the proper place.

e. The main drawback of simplex nozzles is their limited turndown. They must rely on very high pressures in order to get decent atomization at low fuel flows.

2. <u>Twin-Fluid Atomizers</u>

a. Improved atomization and much larger turndowns can be achieved when the liquid fuel is atomized using high pressure air or steam. When directed at the fuel sheet this atomizing gas creates the high relative velocities which are so important to effective atomization.

b. A number of schemes are used for allowing the air or steam to interact with the fuel. These can be broken up into two groups: internal and external mixing.

c. External mix atomizers consist of a simplex-type atomizer with high velocity air striking the fuel sheet as it is leaving the exit lip. We have made a number of tips like this for heavy fuel oil atomization, and typical configurations are shown.

d. Internal mix atomizers work on the principal of first mixing the high velocity air with the fuel internally before it exits to the surrounding air. Two schemes are shown, but the most common application of this technique to oil firing is the Y-Jet and T-Jet.

e. The Y-Jet admits the fuel to the gas passage at an angle as shown. The primary mechanism of atomization is the formation of an annular sheet of fuel which is accelerated and expelled by the air or steam. Breakup into drops then occurs in a manner similar to a pressure jet. Because of the small diameter of the mixing passage this fuel sheet is much thicker than would be formed by a large diameter prefilming atomizer.

f. A cross between the internal and external mixing types is our pintle nozzle. The oil enters a swirl chamber and is prefilmed as in an external mix nozzle, but is then struck by high velocity steam, accelerated and atomized within a confined space before exiting at an angle defined by the pintle.

3. Spill-Return Atomizers

A variation on the simplex pressure nozzle which is in use in some applications for oil combustion is the spill nozzle. It has tangential inlets and a normal discharge orifice but also has an opening in the rear wall of the swirl chamber of diameter greater than the exit orifice which allows fuel to "spill" back to the pump inlet. Since the strength of the spin chamber vortex is determined by the inlet flow good atomization can be obtained down to very low output flows. However the drawback of this nozzle is that the spray angle varies as the flowrate is turned down.

D. APPLICATION OF FUNDAMENTALS TO DESIGN

1. Simplex Atomizer

a. A single Forney-Verloop type TTL burner atomizer tip was replaced for tests at New England Power's Salem Harbor Station.

b. The liquid P at the tip was increased to take advantage of pump capacity for increased swirl in the spin chamber.

c. Spin chamber geometry was improved for better prefilming of fuel.

d. The exit orifice was designed to guide the thin fuel sheet directly to the high velocity air stream.

2. Pintle Steam Atomizer

a. This design was successfully tested at Encina and South Bay Stations of SDG&E as well as the Sabine plant of GSU.

b. The slots and spin chamber provide a thin fuel film at the exit lip.

c. The steam exit annulus and pintle direct the steam at this fuel sheet for efficient use of the steam energy in sheet breakup and fuel acceleration.

d. The pintle directs the spray, defining the spray angle.

e. Easily replaceable components allow multiple spray angles for matching with individual burners.

f. These new tips resulted in significant reductions in particulate emissions.

3. External Mix Atomizer

a. This design currently is in use at SDG&E's South Bay Station.

b. Fuel in the center is spun in a swirl chamber to create a thin sheet of fuel at the exit orifice.

c. The steam swirls through tangential slots, aimed at the exit lip of the fuel orifice to promote high velocity shearing of the fuel sheet into drops.

d. This design has also resulted in significant particulate emissions reductions.

E. CONCLUSIONS

1. More attention needs to be paid to atomization quality when dealing with heavy fuel oil combustion problems.

2. The examination and understanding of these fundamental concepts of atomization are the key to improving atomization quality.

   a. Form the fuel into as thin a sheet as possible.

   b. Establish as high a relative velocity as possible between the fuel and the surrounding air.

3. The application of these fundamentals to atomizer design will lead to new and perhaps radically different atomizer designs which will produce finer sprays with fewer large drops without an increase in atomizing steam consumption.

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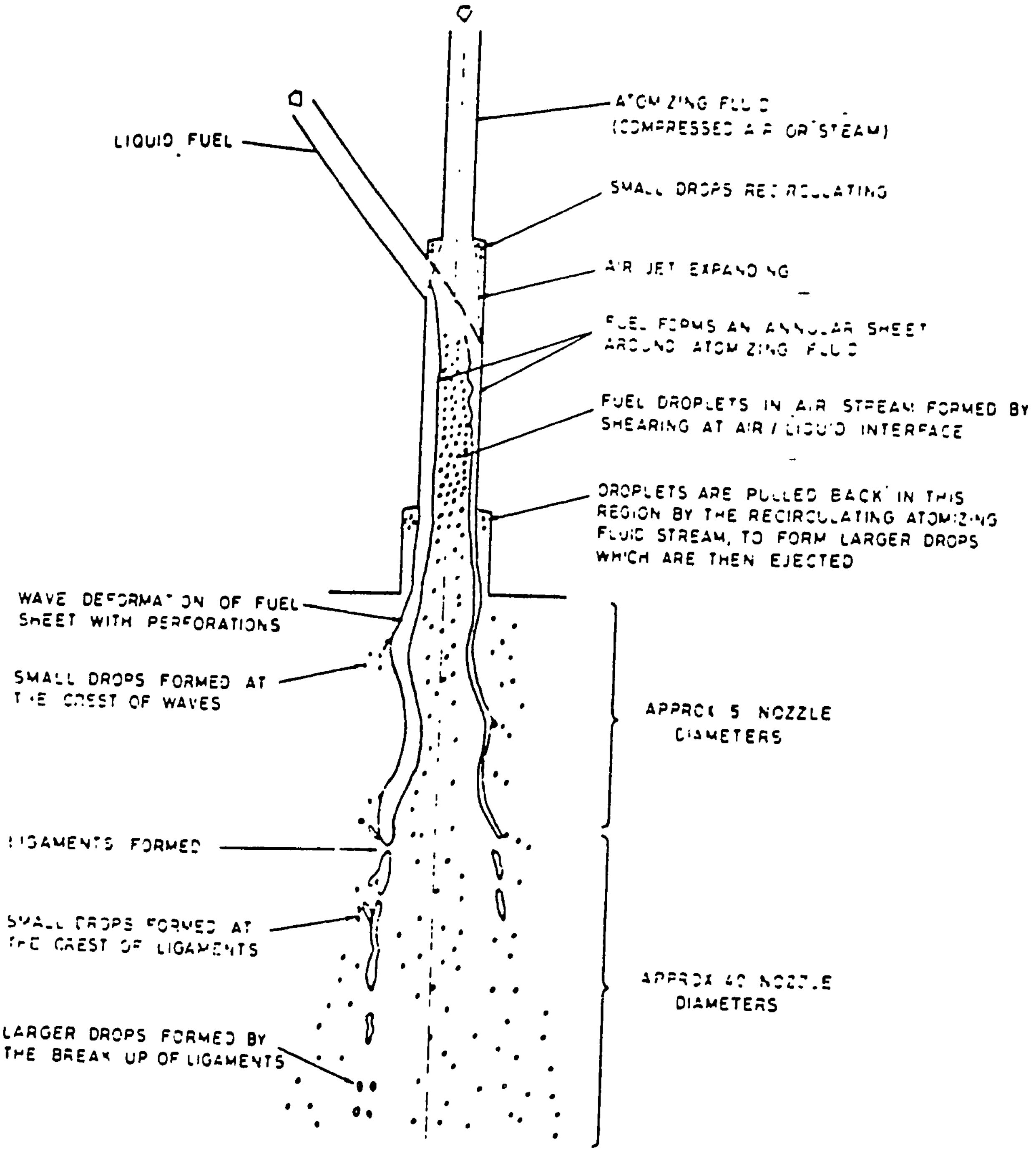
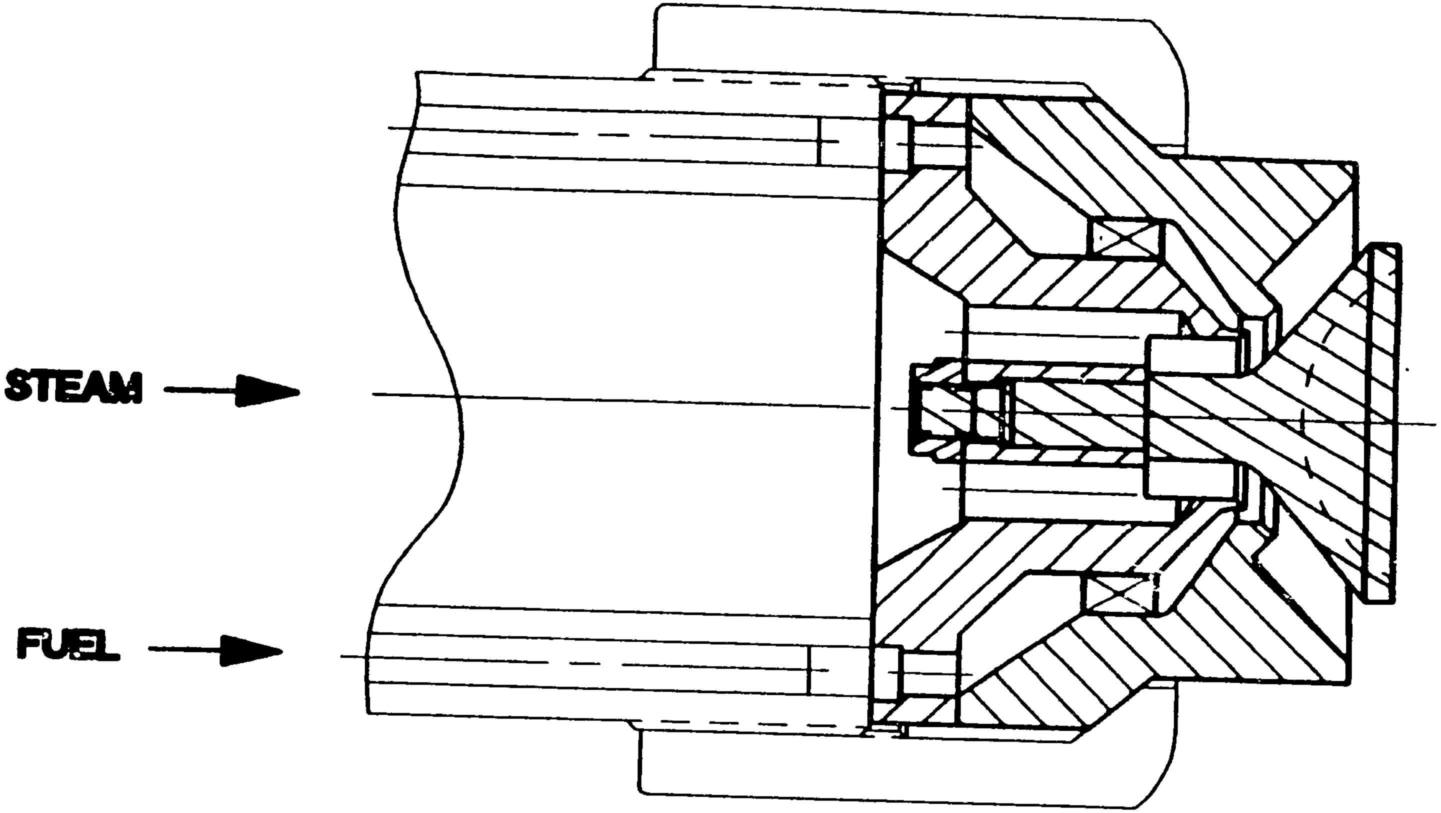


Figure 7.2 Liquid atomization in an internal mixing twin-fluid atomizer. (*Mullinger and Chigier, 1974*)



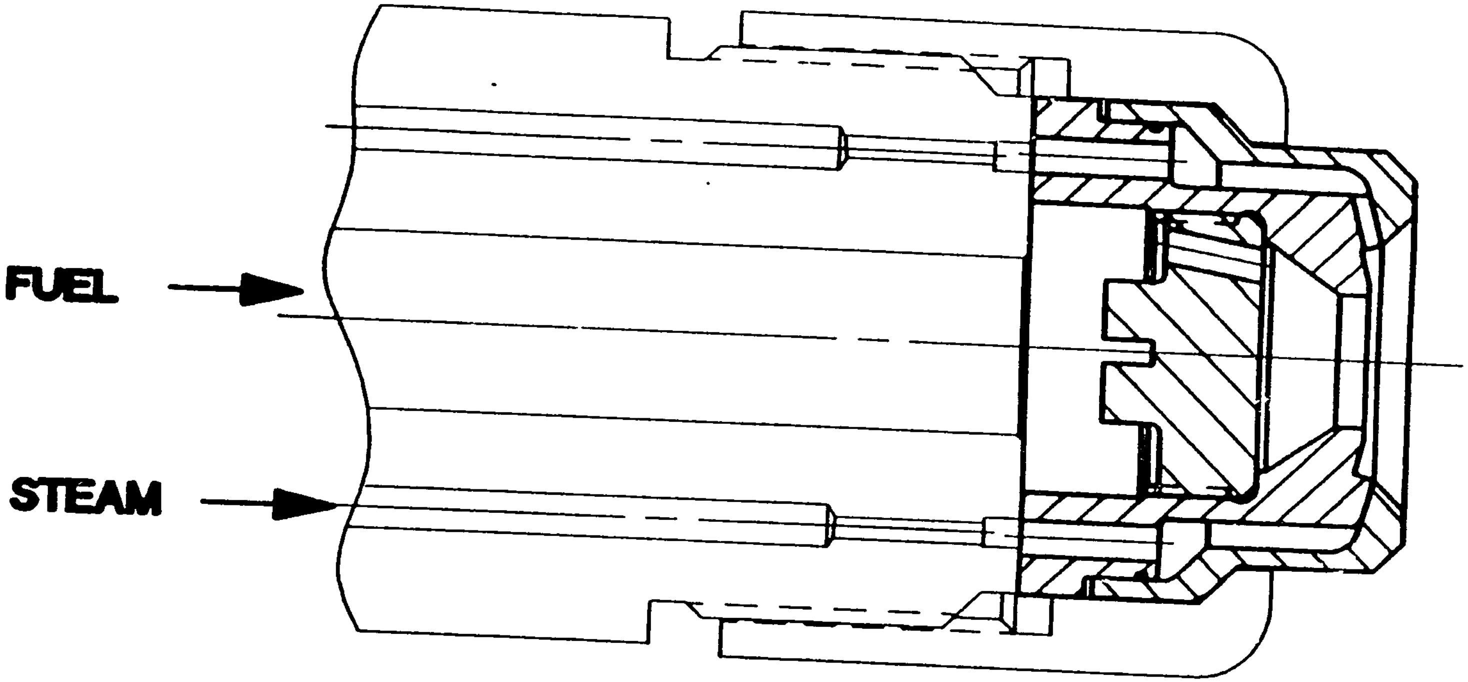
HEAVY FUEL OIL ATOMIZER

GULF STATES UTILITIES

SABINE UNIT 5

FUEL FLOW 12750 LB/HR

Parker

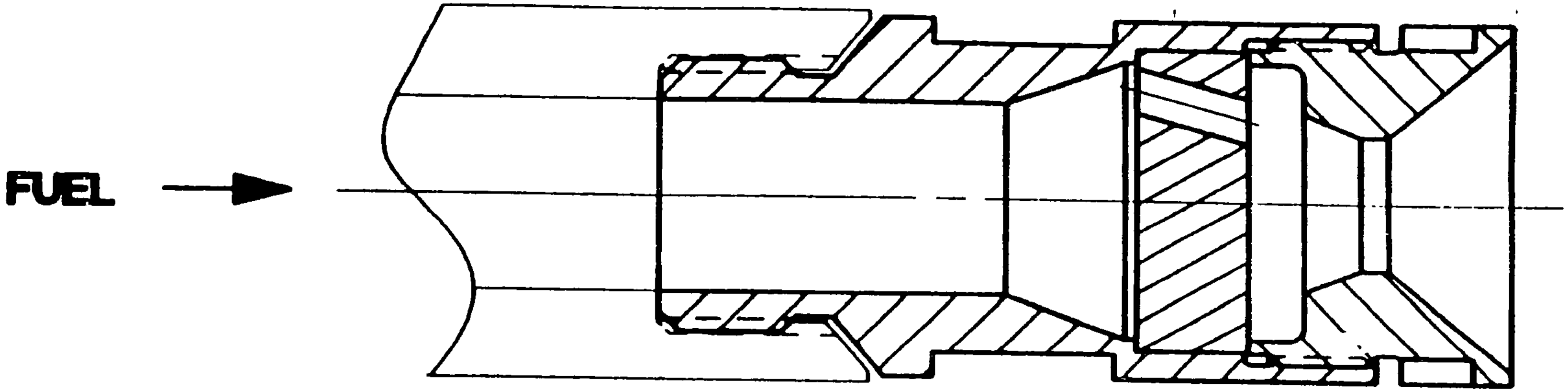


HEAVY FUEL OIL ATOMIZER

SAN DIEGO GAS & ELECTRIC
SOUTH BAY UNIT 1

FUEL FLOW 9000 LB/HR

Parker



HEAVY FUEL OIL ATOMIZER

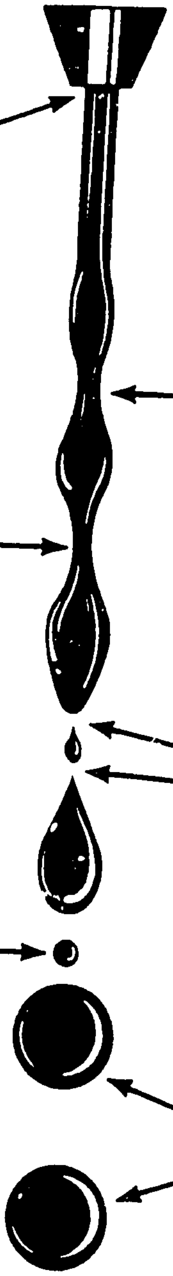
NEW ENGLAND POWER COMPANY
SALEM HARBOR UNIT 4

FUEL FLOW 10000 LB/HR

Parker

THE ATOMIZATION OF LIQUIDS

BREAKUP OF A PLAIN CIRCULAR JET



JET ISSUES FROM ORIFICE

OSCILLATION OF JET CAUSES FORMATION OF NECK

NECK THINS

NECK BREAKS DUE TO SURFACE TENSION

"SATELLITE" DROP (NOT ALWAYS PRESENT)

DROP BECOMES SPHERICAL

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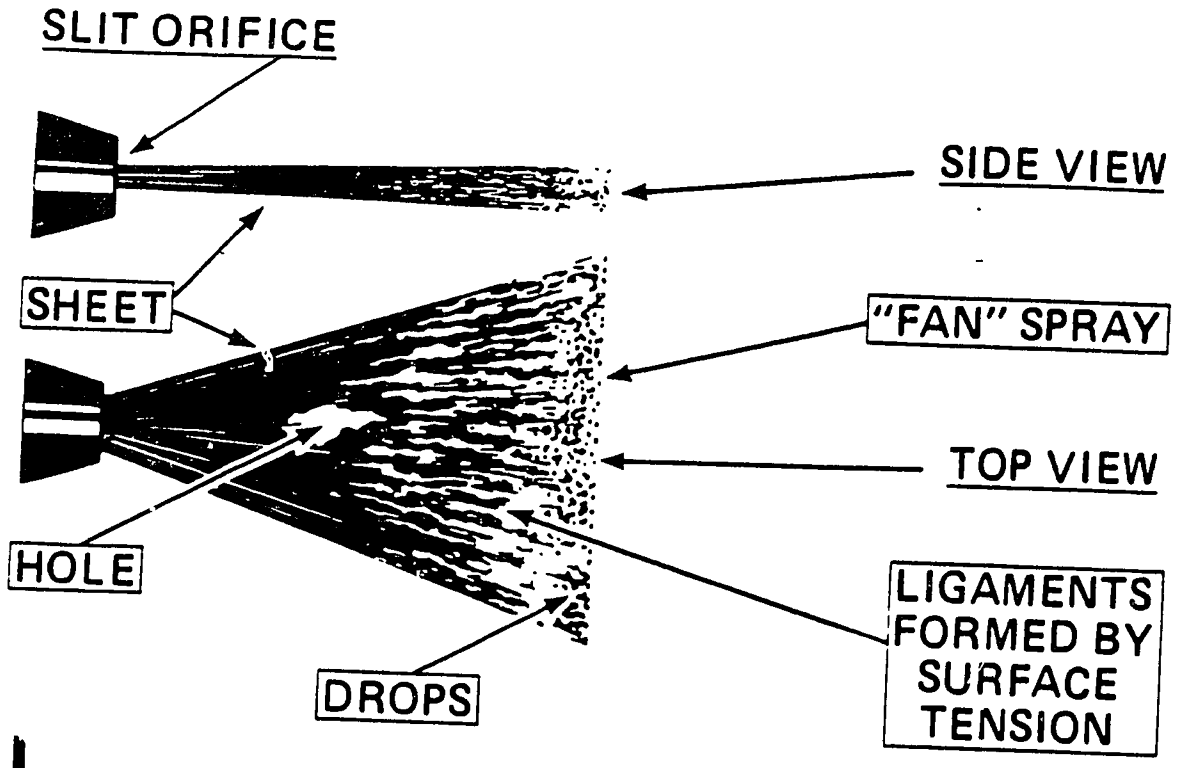
Cleveland, OH 44112 USA
1979

THE ATOMIZATION OF LIQUIDS

BREAKUP OF A FLAT SHEET INTO LIGAMENTS



BREAK-UP OF AN IRREGULAR LIGAMENT INTO SPHERICAL DROPS OF VARIOUS SIZES

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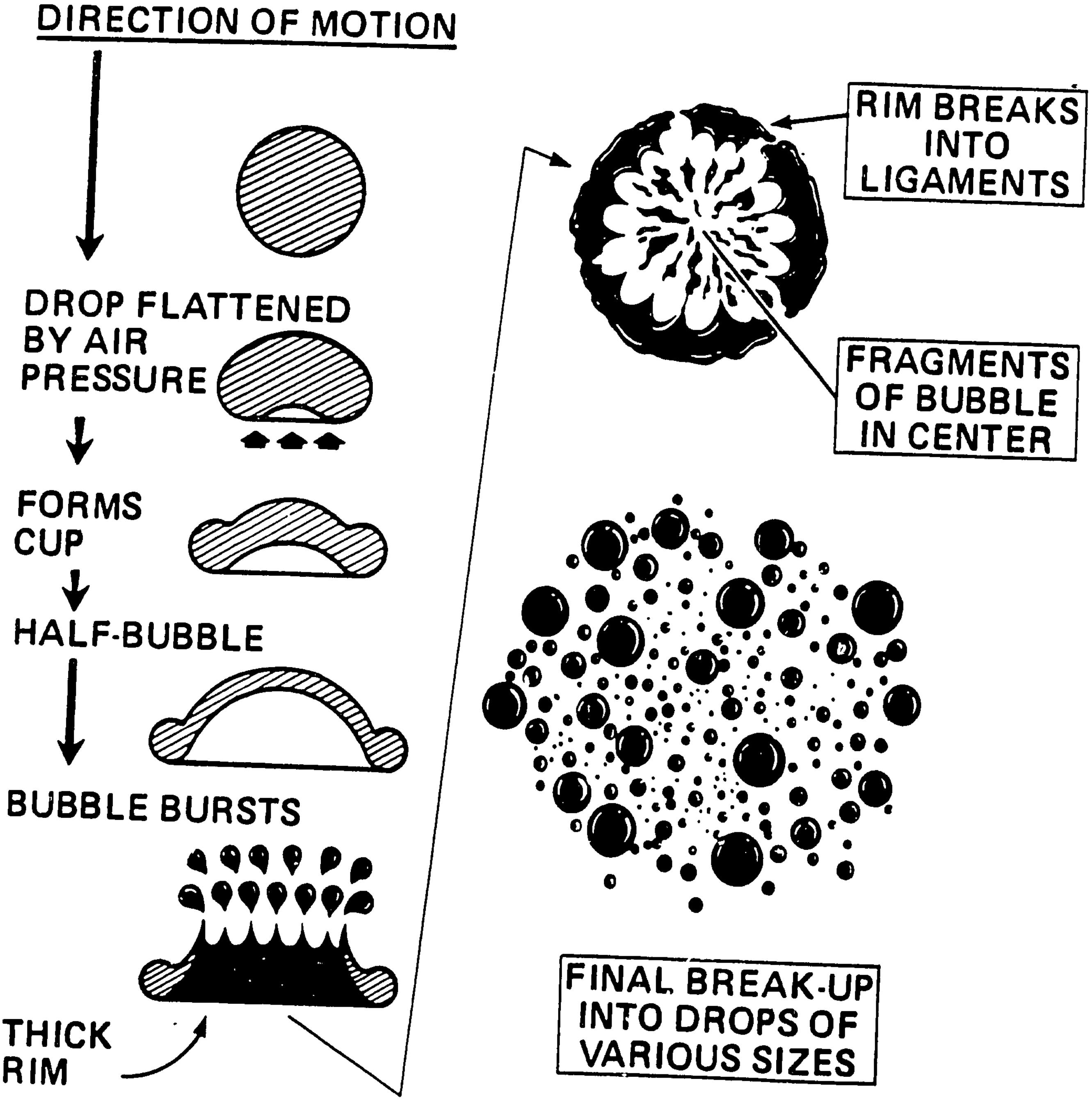
THE ATOMIZATION OF LIQUIDS

BREAKUP OF A SPHERICAL DROP BY INTERACTION WITH AMBIENT AIR



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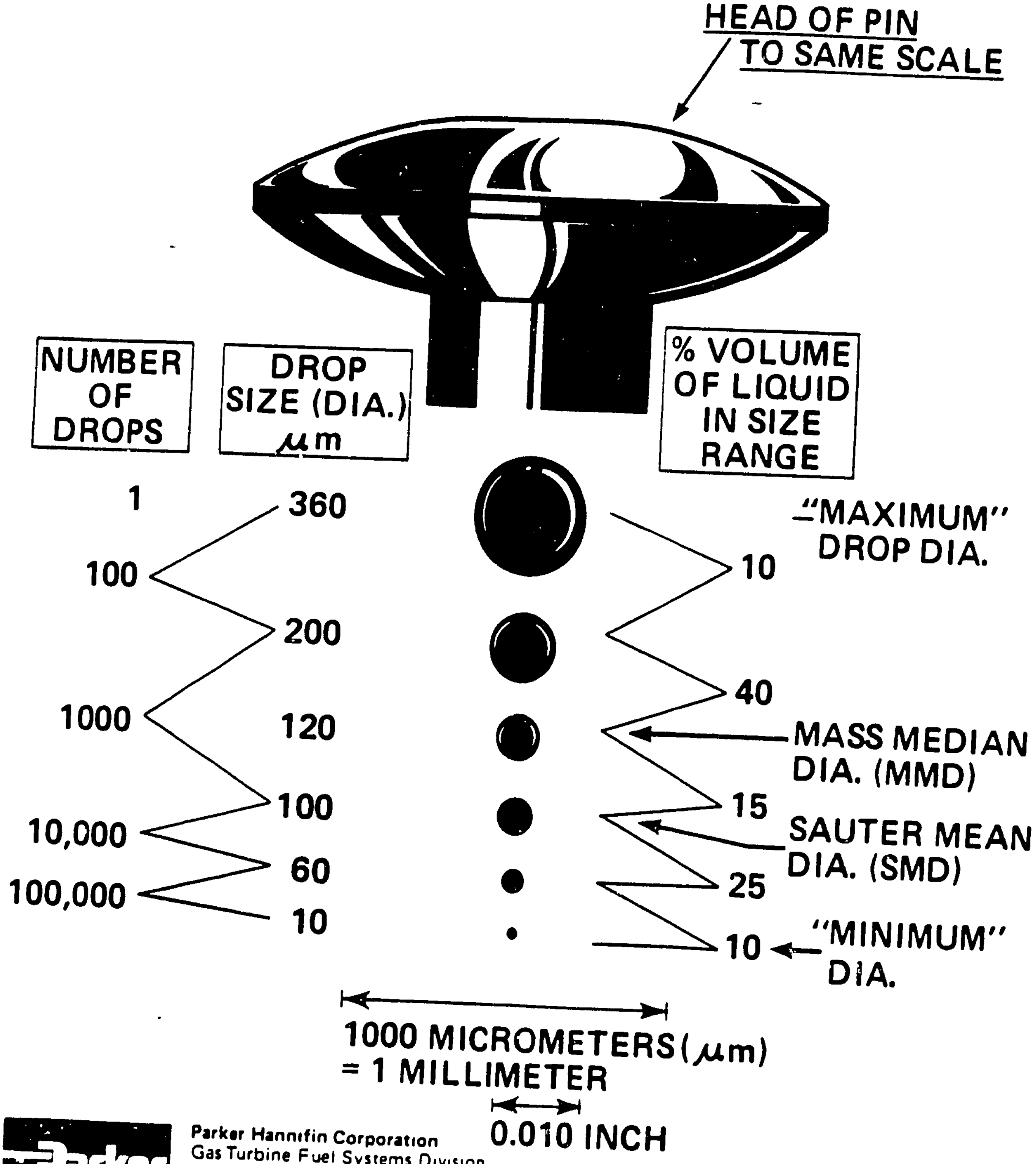
THE ATOMIZATION OF LIQUIDS

RANGE OF DROP SIZES IN A TYPICAL SPRAY



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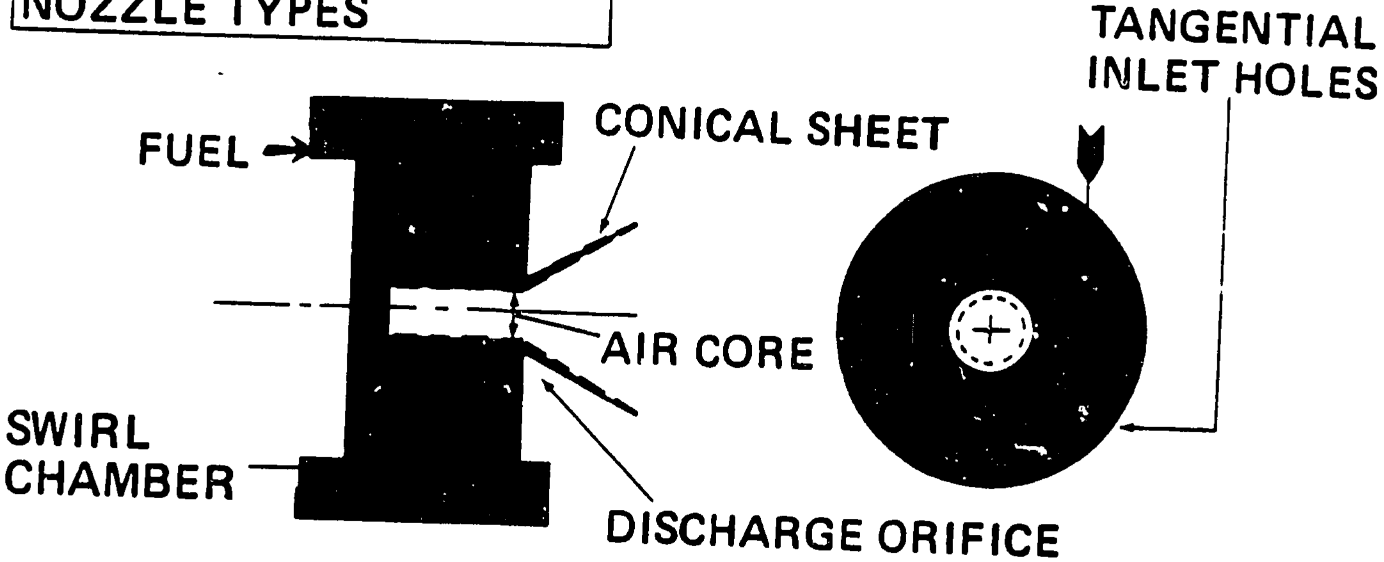
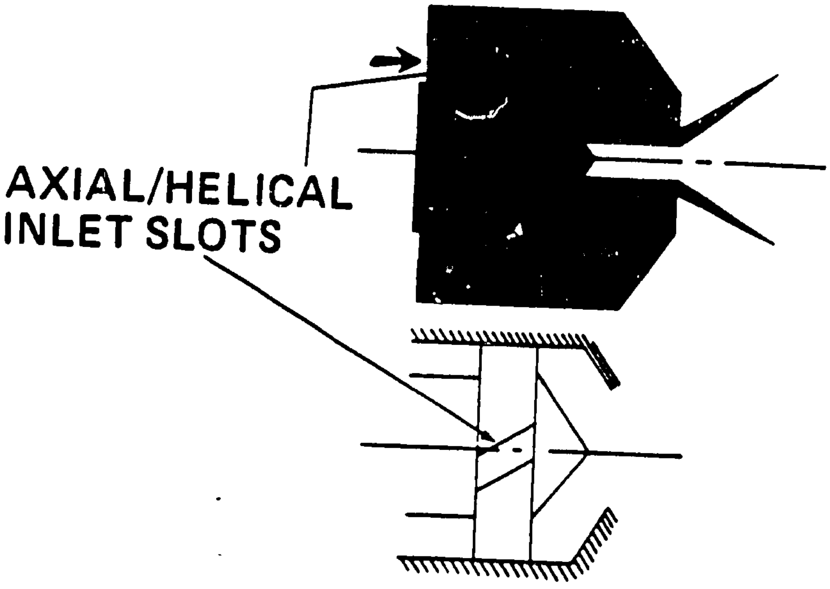
METHODS OF ATOMIZATION

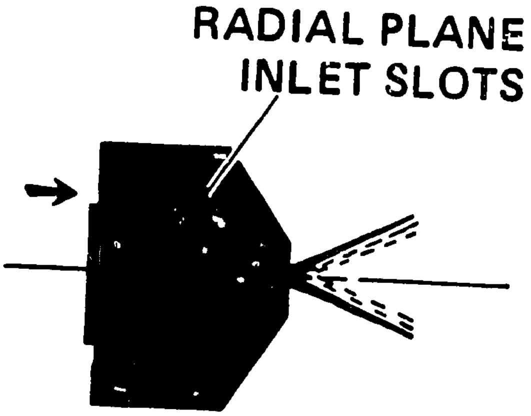
B. FIXED-ORIFICE, PRESSURE-OPERATED

HOLLOW-CONE SPRAYS

B.3.
SIMPLEX SWIRL-CHAMBER NOZZLE TYPES







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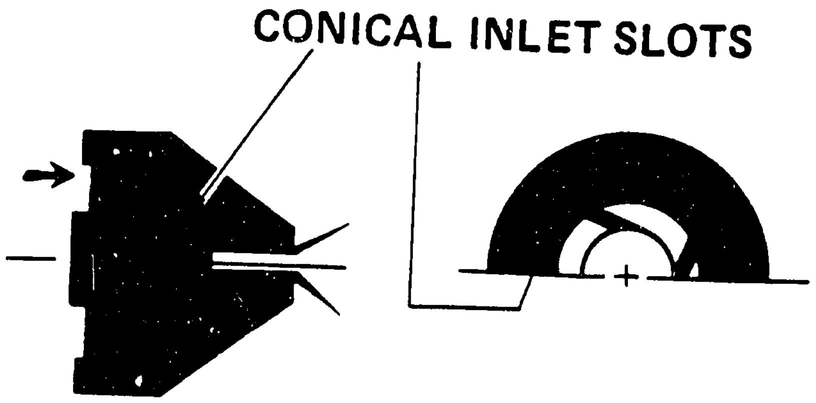
METHODS OF ATOMIZATION

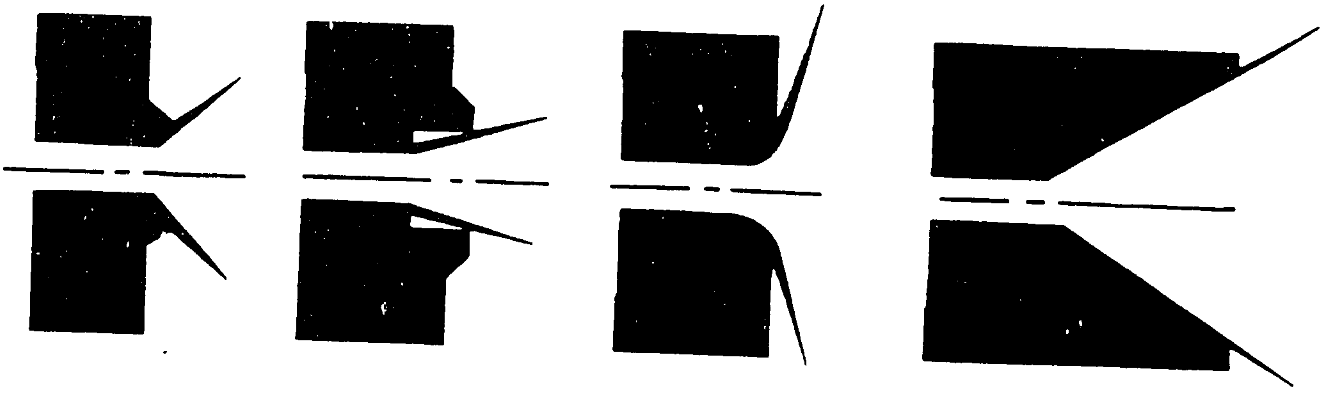
B. FIXED-ORIFICE, PRESSURE-OPERATED

HOLLOW-CONE SPRAYS

B.3.
SIMPLEX SWIRL-CHAMBER NOZZLE TYPES



VARIOUS ORIFICE LIPS TO MODIFY SPRAY ANGLE



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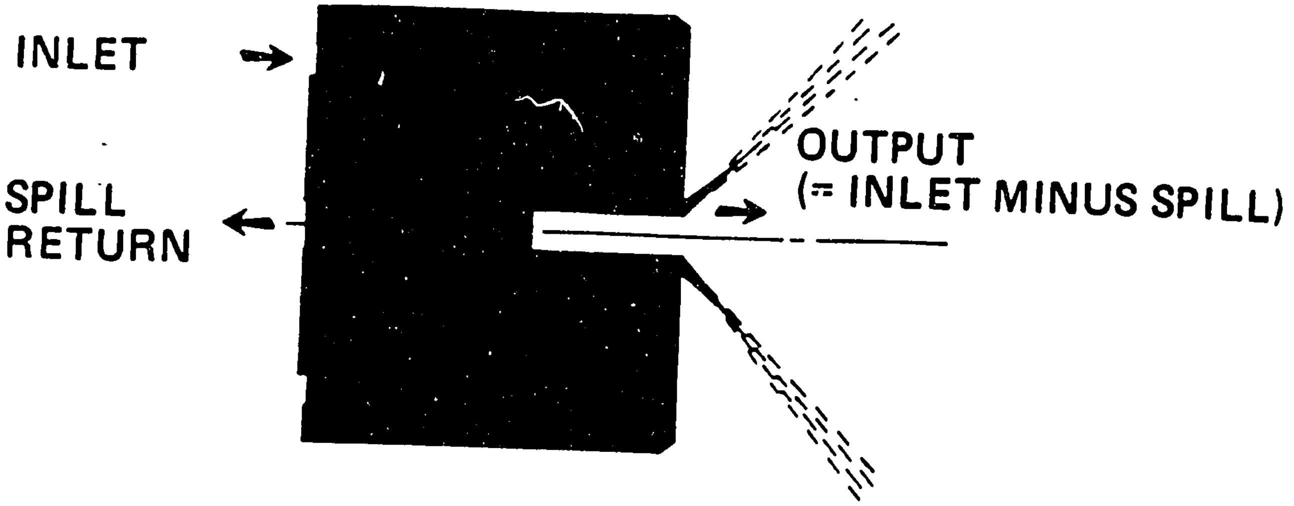
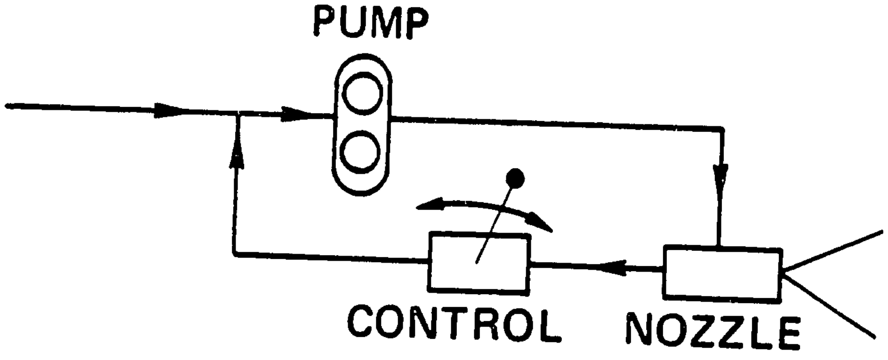
METHODS OF ATOMIZATION

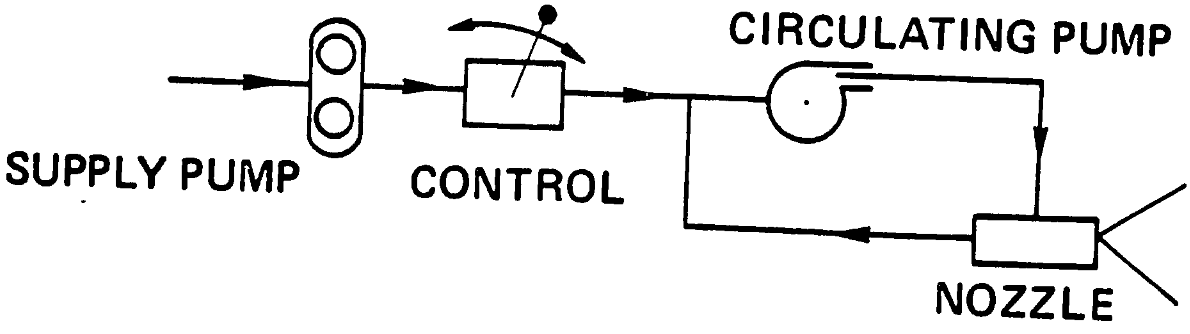
B. FIXED-ORIFICE, PRESSURE-OPERATED

B.7.
SPILL OR RETURN-FLOW NOZZLE



ALTERNATIVE CIRCUITS





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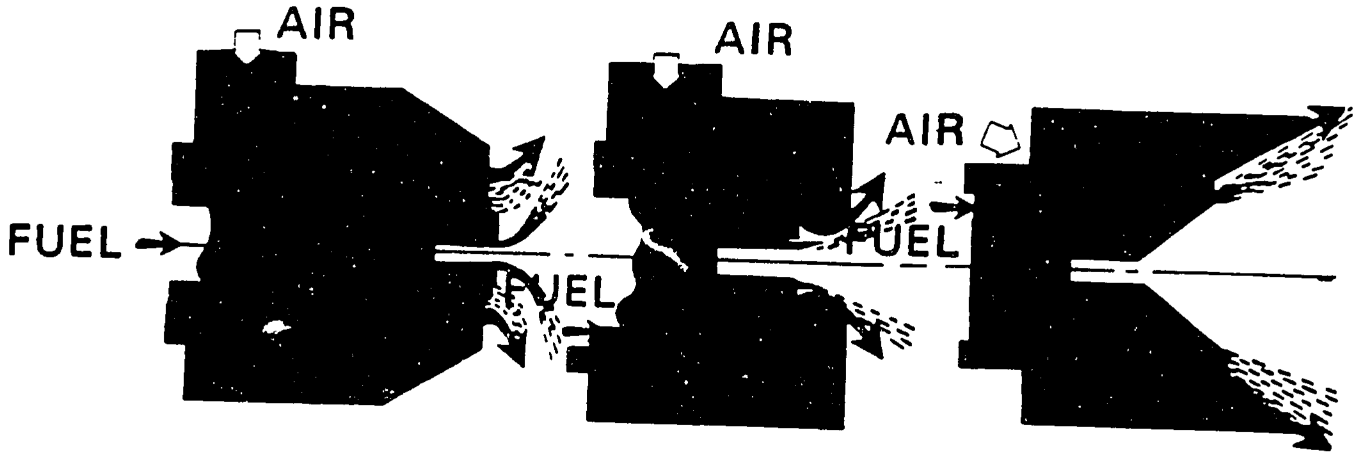
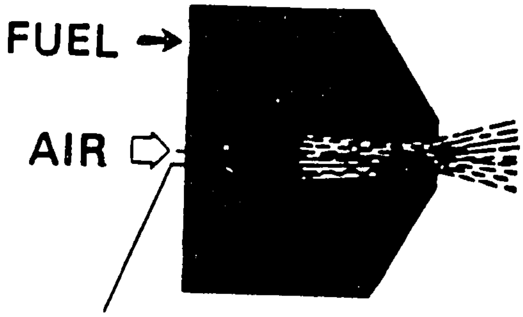
METHODS OF ATOMIZATION

D. AIR-ATOMIZERS

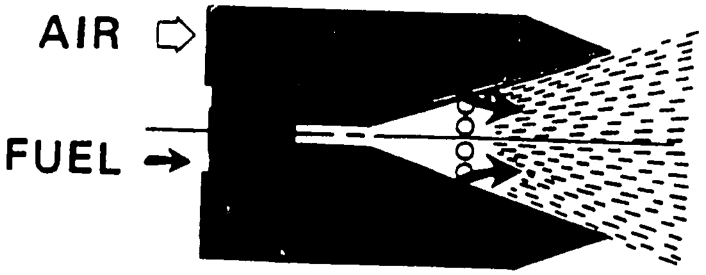
D.3. "EXTERNAL-MIXING" (AIR-ASSISTED SIMPLEX) TYPES



D.4. & D.5. "INTERNAL MIXING" TYPES



MIXING SWIRL CHAMBER



PERFORATED TRUMPET MULTI-AIR-JETS

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APPENDIX C.4

Fuel Oil – Its Impact on Air Pollution and Effects of Additives

by

J. MacLeod

FUEL OIL
—its Impact on Air Pollution and Effects of Additives

by J. **MacLeod**, power consultant, Chessco Industries, Connecticut, USA

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99

FUEL OIL

—its Impact on Air Pollution and Effects of Additives

by **J. MacLeod**, power consultant, Chessco Industries, Connecticut, USA

The power manager has always had the responsibility of providing continuous, economical power, and with the help of knowledgeable designers, alert operation, and skilled maintenance he has done a good job over the years. With the cost of fuel amounting to 50 to 75% of direct production cost of thermal electric power, emphasis has necessarily been on purchase of available fuels resulting in minimal annual costs. Factors of these annual costs are: delivered fuel; fuel storage and handling; labour; replacement material; deposits and corrosion; capability and cycle requirements of units; incremental efficiency of units.

Increase in fuel oil use for power generation from 118 million barrels in 1965 to 324 million barrels in 1970 with projection of usage in 1971 to 388 million barrels (Fig. 1) requires a new look at deposits and corrosion. Even with low excess air boiler operation and low sulphur fuel, the potential formation of 102,000 lb or more of sulphuric acid a day highlights the possibility of extensive corrosion.

Scope of Fuel Oil Use Problem

Assume a single unit with nameplate rating of 45,000 MW operating at 54% plant factor, or 24,000 MW production at 10,400 B.t.u./kWh net.

A material balance shows weight of gas and solids involved using the following data:

- Fuel oil consumed—one million barrels per day—42 million gallons.
- Fuel oil analysis 1.0% sulphur, 0.04% ash, 100 p.p.m. vanadium, 30 Na p.p.m.
- Operation data 6.0% E.A, 300°F Gas Temperature, 150 F Air. 1% SO_3/SO_2.

TABLE 1

Total sulphur burned per day	3.36 million pounds
SO_2 produced per day	6.72 million pounds
SO_3 produced per day (at 1% of SO_2)	84,000 pounds
H_2SO_4 produced per day	102,816 pounds
NO_x produced per day	2.1 to 2.6 million pounds
Ash produced per day	134,400 pounds
Carbon (0.4%) produced per day	1,344,000 pounds
Total products combustion per day	5,140 million pounds
Total solids	1,480,000 pounds
Total allowable emissions	(0.15 lb/million B.t.u) 930,000 lb

Total solids would be increased to 1.7 million lbs per day assuming 50% dropout and deposits. The 850,000 lbs remaining would be below the 930,000 lbs per day maximum recommended emissions ASME Standard APS-1 1968.

Combustion—Burner Development

Stoichiometric combustion with exactly enough oxygen to burn carbon to CO_2, hydrogen to H_2O, and sulphur to SO_2 would result in no atomic oxygen formation to generate SO_3 in the flame area and no excess O_2 to form SO_3 over catalytic tube surfaces. Any low melting components in the ash could be reduced in the normal reversible processes going on in a flame so that no sticky deposits would be present in the gas passes and no corrosion from acid deposition would take place.

Operation at stoichiometric condition would permit operation at 200°F or thereabouts stack gas temperature which would increase average efficiency by 3% or

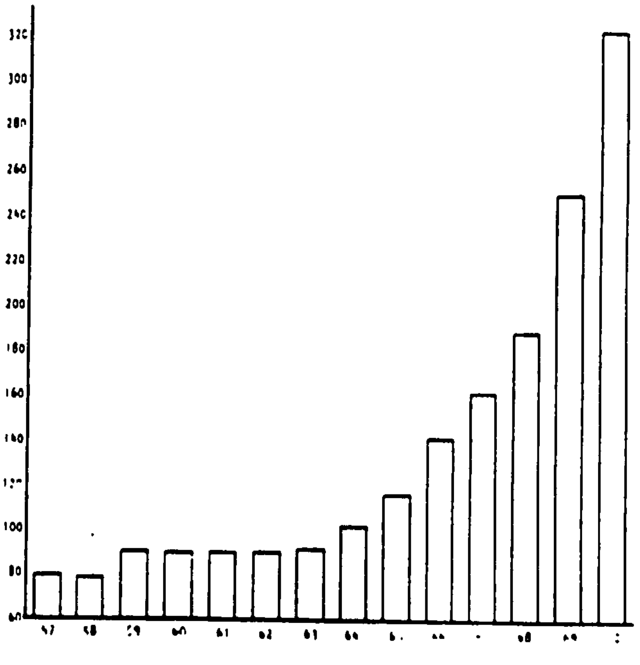

Fig. 1 Fuel oil used by utilities in USA and possessions, shown in millions of barrels per year. Source—Federal Power Commission

more and would result in a comfortable saving both in fuel cost and maintenance cost of cleaning deposits and replacing corroded material.

Present technology does not permit this ideal operation and even if material research, precision control, and flame research should result in improvement, it is unlikely that average excess O_2 would drop below 0.2% for new oil burning units. The majority of oil burning units will operate at 2% to 3% oxygen for some time with deposit and corrosion problems even with low sulphur oil, reduced ash and addition of SO_2 stripping plants.

Most promising efforts to improve performance is a new oil burner which is the result of work done at the Central Electricity Generating Board, England. Its axial flow design results in a smaller assembly; the individual burner can be adapted easily to old installations, can operate at near stoichiometric values, and can contribute to a considerable reduction in stack emissions and air pollution ordinances can be satisfied. This improved burner has been licensed for production in the USA and several hundred have now been installed in power stations in the UK.

Additive Development

With recognition that SO_3 formation was primarily from atomic oxygen produced in the flame by temperature and excess air there were many attempts to inject metals or other material into the air stream to combine preferentially with atomic oxygen. Some of these were zinc and magnesium with magnesium proving more reactive and having the advantage of oxidizing to MgO which would adhere to tube surfaces and increase furnace temperature somewhat, so that unburnt carbon would be reduced and superheat temperature increased. In many boilers this superheat increase was highly desirable and residual MgO could react with SO_3 formed over catalytic surfaces and also neutralize H_2SO_4 vapour condensed in the cold end area.

Modern additive treatment is designed to keep dry ash deposits throughout the hot end, so that slag build-up will be eliminated, superheated steam temperature will be increased, unburnt carbon will be reduced. In the intermediate section, deposits will stay powdery or crumbly and SO_3 formation will be reduced. SO_3 will react with MgO to form $MgSO_4$. In the cold end the airheater will be kept clean, condensing H_2SO_4 vapour will be neutralized and resistivity of solids will permit the precipitator to operate at maximum efficiency. Acid smuts will be eliminated and stack emissions will be low in solids and opacity. One of the few materials which admirably satisfies these requirements is MgO supplemented with Al_2O_3.

SO_3 Formation and Reduction and Additive Effects

Most of the SO_3 formed is a result of flame temperature and excess oxygen, although higher concentrations can exist in the flame since the reaction of SO_2 and O to SO_3 is reversible. The final SO_3 is uniformly 1% to 2% of total SO_2, with the higher amount due to burner performances. Generally 1% can be used for calculations with exact amount obtained by tests.

Since there is little or no SO_3 formed from sulphate reduction, the balance of SO_3 appearing in gas before or after the air heater as usually tested is formed catalytically from iron oxide or vanadium oxide surfaces in the 1,200°F to 600°F range with actual amount probably below 25% of total in all cases since this area is also the area where ash deposits generally form. It may be as well to point out here that various tests with metals, magnesium, zinc, carbon, ammonia and water to react rapidly with atomic oxygen did not always reduce SO_3 formation probably because of insufficient time or mixing. Massive doses which probably would have decreased SO_3 formation were not tried since they would not be economically attractive.

MgO and Al_2O_3 form a spinel, $MgAl_2O_4$, in the flame which is evenly dispersed throughout the hot end area. The micron size spinel is a major factor in the continuous removal characteristics of deposits in the hot end. This inert 3,880°F melting point material provides friability to deposited ash and any low melting point material such as V_2O_5, which is in vapour form or liquid, will be dried by absorption, the deposited mass will become dry and will be interspersed with low bonding strength spinel so that agglomerated particles will break loose from minor thermal changes, gas pressure fluctuations, gas turbulence impingement, soot blower high velocity impingement, or from high velocity air lancing during shutdown.

The remainder of the oxides, about 80%, also disperses evenly through the flame. The material forms a thin coating on all furnace tubes so that radiant heat transfer is decreased in the furnace and furnace temperature increases so that superheated steam temperature also increases and unburnt carbon decreases somewhat.

Some MgO dusts the furnace wall tube surfaces where together with $MgO{\cdot}Al_2O_3$ or $MgAl_2O_4$, it absorbs any gaseous, liquid or plastic low melting point compounds. The low strength bonded mass breaks off and has an MgO $MgO{\cdot}Al_2O_3$ coating restored from the gas stream. The porous MgO coating on the furnace walls adsorbs some SO_3 gas and with 650°F to 450°F tube metal temperatures there is some slight formation of $MgSO_4$. Residual MgO continues through the boiler passes with some formation of unstable $MgSO_4$ in the gas stream until gas temperature reaches 1,200°F when $MgSO_4$ reaction is a maximum.

Some absorbed SO_3 will form $MgSO_4$ wherever MgO has deposited on colder surfaces down to about 600°F. It is advantageous to have a dry inert material such as Al_2O_3 or $MgAl_2O_4$ interspersed through any sulphate deposit since in general the sulphate bonds firmly and requires high energy to be dislodged. It is for this reason that primary superheater section requires complete coverage by soothblowers.

It is important that enough MgO be retained in the gas stream entering the air heater, this means not deposited or dropped out in a hopper, so that there

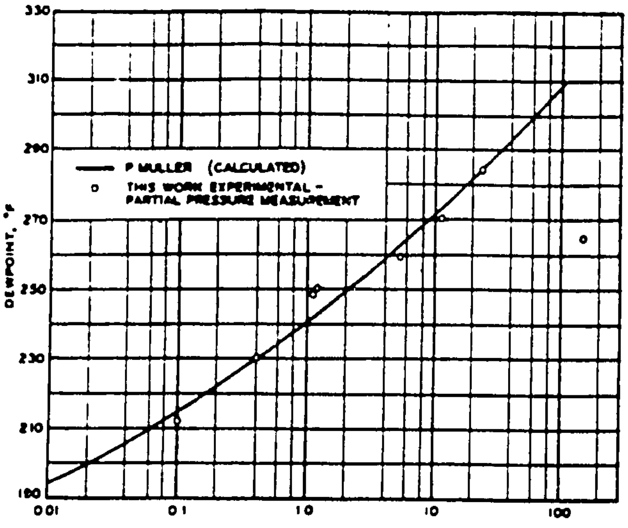

Fig. 2 SO_3 (H_2SO_4) in flue gas, p.p.m.

is a stoichiometric balance of SO_3 and MgO at this point. Since SO_3 and H_2O form sulphuric acid vapour at 640°F it is necessary to have MgO dispersed evenly through the gas stream so that any area chilled below the acid dewpoint will have sufficient MgO available to neutralize and dry the deposit. These chill points or areas can come from: observation or access doors; gaskets; bolts missing; holes in ducts; cracks in brickwork, or insulation if not steel jacketed; seals on hoppers; ID fan rotor seals; air heater seals; air heater tube holes; low load cycles when air inlet to air heater is not heated; when minimum metal temperature of air heater too low because of stratification or leakage; leakage in ash collector, ash precipitator seals, hoppers, valves, gaskets or elsewhere.

These factors contributing to metal areas chilled below the acid dewpoint as measured by Mueller's curve of p.p.m. SO_3 versus temperature °F (see Fig. 2) can result in acid saturation of deposits even if MgO is present and can result in a build-up of sticky material which can increase pressure drop in air heaters to lose capacity and have extensive corrosion.

Emissions History

Emissions from stacks have always been a nuisance. Starting in the thirteenth century when exhaustion of wood as a fuel occurred in Europe which resulted in introduction of coal as a fuel. A Royal Proclamation was issued in the year 1330 prohibiting the use of coal in London. Although smoke was a general nuisance, not much was done about it. By 1600 the irritating effects of sulphur were known. Not until 1850 did studies and documents start appearing on smoke. By 1900 the requirements of good combustion were known and Maximilian Ringelmann had issued his famous chart (1898), identifying smoke density by numbers, which is still used although more accurate photometer methods measuring plume opacity by light transmission are now in use instead of the blackness comparison of incomplete combustion.

Scientific knowledge of air pollution as extended beyond smoke and sulphur emissions had expanded considerably by 1930 and major cities initiated anti-smoke laws which by 1945 had cleared up smoke nuisances in Pittsburgh, St Louis, Chicago and other cities partly as a result of the smoke ordinances, partly as a result of efficiency gains from improved combustion in major industries, and partly as a result of increased use of gas and oils as these fuels became available and competitive in price.

Ripples of uneasiness had spread through the medical community when 60 people were killed by air pollution in 1930 in the Meuse Valley in Belgium. Again in 1948 when fifteen people were killed in Donora, Pennsylvania, by air pollution in that valley, active scientific interest was stirred up and instrumentation development increased for measurement of pollutants and effects. The 1952 London fog which resulted in the death of about 4,000 people probably triggered the action which is continuing into the worldwide revolution against man-made atmosphere pollution by gases and solids.

In 1957 a meeting of the World Health Organization Expert Committee on Environmental Sanitation composed of international authorities was held on all aspects of air pollution, not only from conventional fuels and industrial emissions, but also residential, transportation and nuclear facility emissions. The papers covered air pollution effects on man, plants, and animals and clearly indicated the direction all nations should take for survival.

In 1957, Great Britain passed the Clean Air Act and the United States passed the Air Quality Control Act in 1967, so that control of the atmosphere was well underway by 1971, even though problems of recycling are extensive as indicated by the Stanford Research Institute report on Sources, Abundance and Fate of Gaseous Atmospheric Pollutants, 1968 and 1969.

Although actual fuel oil prices have increased in many cases because of demand exceeding current supply and continued pressure from oil producing countries to increase their revenues, it is expected that these cost differentials will continue although the higher price of the desulphurization oil compared to high sulphur No 6 oil may be reduced by improved desulphurization methods. Actual cost of a 717 MW station operating at 73% plant factor and burning 6.746 million barrels of oil a year would be $2.9 million a year more for 1.0% sulphur oil and $5.26 million a year more for 0.3% sulphur oil compared to the $12.1 million per year cost of the 2.0 to 2.5% sulphur oil burned during the period when no sulphur restrictions on fuel or stack emissions were imposed.

There are advantages in use of low sulphur fuel oil since deposits and corrosion through the gas pass area will be reduced which will increase availability of the generating unit and will reduce maintenance costs. The most significant change is in the emission of sulphur dioxide gas from the stack and amount of ash in oil.

Assuming a 250 MW unit with a 1 675 million lb/hour boiler burning 3 million lb of oil a day with 3.5%

excess air the comparison between 2.5% and 0.3% sulphur in oil would be as in Table 2.

TABLE 2—MATERIAL BALANCE

Based on 100% load	0.3% S	2.5% S
Pounds fuel oil per day	3,000,000	3,000,000
Pounds of sulphur per day	9,000	75,000
Pounds of sulphur dioxide per day	18,000	150,000
Pounds of combustion products, million	44.4	44.4
p.p.m. SO_2 assuming 100% conversion	405	3,378
Possible p.p.m. SO_3	5 to 10	42.2 to 84.4
Dew point of gas °F (Mueller)	260 to 270	295 to 305
Pounds of ash (Siegmond-Esso)	300 to 600	(.1) 3,000

A unit like this operating at under 9,375 B.t.u./kWh net would be in service continuously at more than 50% load factor and would have regenerative air heaters with steam coil or hot water coil air preheaters in operation so that an average metal temperature of 225°F or so can be maintained to limit condensation of sulphuric acid in the regenerative air heater. Ash deposits would be removed by sootblowing and periodic shutdown for cleaning. Low melting point compounds formed which could bond firmly to gas pass surfaces would be removed periodically, or could have properties changed by a suitable additive so that gas passes would stay open without impairing the availability of a unit. It is significant that with high sulphur oil (3.0%) and low excess air (3.0%) (Fig. 3) there will be several parts per million SO_3 in the flue gas, so that addition of an additive is indicated to scavenge and neutralize the SO_3 and H_2SO_4 formed. This is especially important for units which cycle below 50% load and are subject to local low minimum metal through the airheater, ducts, ash precipitator and stacks; and ID fan if the unit is balanced draft.

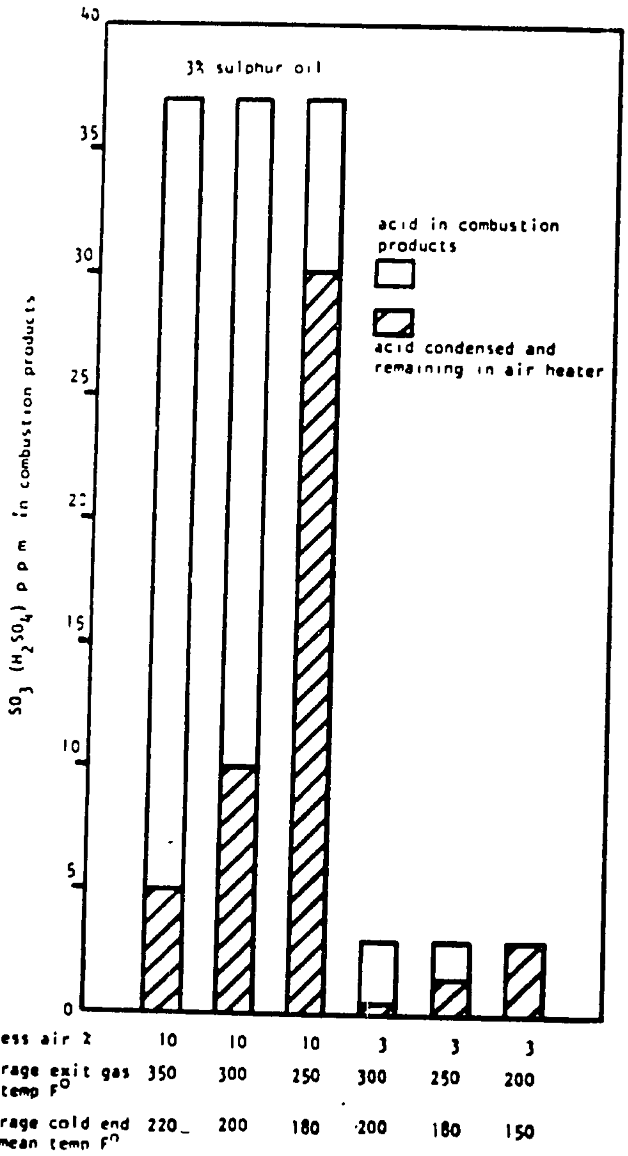

Fig. 3 Predicted corrosion potential in Ljungstrom air preheater based on high and low excess air operation

Burning low and high sulphur fuel oil in a 500,000 lb per hour boiler (60 MW unit) presents a similar operation except that excess air is more commonly 10% or more and since the 60 MW unit would have a heat rate of over 10,000 B.t.u./kWh net, the unit would be cycling down to 20% or so nights and weekends with probable shutdowns at weekends and nights in the future, as the larger units and particularly the nuclear units, with their inherent need to operate at high load factors, come into service.

In considering the many variables which affect the annual cost of operation of a fuel oil fired steam generating unit, there are two separate categories:

Legal

- Fuel oil limitation of sulphur to as low as 0.3%;
- Limit colour of plume;
- Limit particulate matter;
- Limit SO_2;
- Limit NO_x;
- Eliminate acid smuts;

Operational

- Minimum cost of steam per year;
- Maximum availability of steam generator;
- Minimum manual cleaning of deposits;
- Minimum replacement of corroded metal;
- Minimum dustfall from stack.
- No acid smuts emission.

Although there may be as much as 45,000 MW of steam electric generating units burning 42 million or so gallons of fuel oil a day in 400 or more units, it is unlikely that 0.3% sulphur in oil will be required in every state and locality; 0.5% to 1.0% will be more commonly used so that the higher sulphur oils with high vanadium could be mixed to meet the 1% sulphur requirements where gas stripping plants cannot be economically installed.

Help from Additives

Throughout the review of old and new equipment, high and low sulphur fuels and cycling operation, it is apparent that use of a suitable additive is a low cost means of complying with some of the Air Pollution Laws as far as plume colour and particulate matter are concerned and is necessary to maintain high availability and reduce maintenance cost in units burning high vanadium oil, and is also a necessity in all units burning high or low sulphur oil where metal temperatures are below the dew point during any hours of operation. In general this applies to units with steam temperature above 750°F and flue gas heat exchanger equipment with flue gas temperature below 350°F.

A factual review of additives will show that the most economical means of eliminating hot end and cold end corrosion and increasing availability of a steam generator burning fuel oil is to feed a magnesium oxide to the main oil stream into the burners. The additive feed should be continuous with enough overfeed to ensure dusting of furnace walls and screen tubes so that any low melting point vanadium oxides formed will deposit on a high melting point powder so that adherence will be low. To further reduce bonding of the deposits, aluminium oxide is necessary in the additive mix. The resultant deposit will be an agglomeration of oxides, sulphates, and vanadates interspersed with a spinel of magnesium aluminium with a low bonding strength. The normal pressure fluctuations and temperature changes as well as periodic sootblower cleaning of areas will then keep gas lanes open so that no draft loss or gas pressure loss will occur across the boiler passes. In many cases a boiler can operate a full year or more without necessity of shutdown for cleaning; with operating records of 600 MW utility units down to 300 m lb per hour industrial units we know that these one year operating records can be generally achieved.

To do this requires a review of total factors:

- Fuel oil analysis including ash constituents and sulphur;
- Type of burners and excess air operation;
- Heat recovery equipment predicted data, average and minimum temperatures;
- Correct application of additive;
- A reasonably tight air and gas system;
- Correct sootblowing procedures for unit operation;
- Recorded data through load cycles;
- Analysis of gas and solid components versus load, determine decrease of MgO through system;
- Recommendation for unit operation.

Since most data is recorded for plant records and accounting, the supplementary testing for confirmation of correct additive application or recommendations which will better the application are:

1. SO_3 tests—these tests should be ahead of air heater and after precipitator through load ranges. (ASME PTC-19-10 1968);
2. Dustfall—standard test to determine quantity and properties of dustfall as measured by ASTM Standard D1739-70 Collection and Analysis of Dustfall. Also USDHEW test for acid and alkaline fallout;
3. pH of last pass hopper ash before stack—this should be comprehensive with samples from hopper quadrants taken to coincide with SO_3 tests and plant data;
4. Determination of dust concentration in gas streams—these tests together with determination of properties of particulate matter are exacting, require a great deal of equipment and should be done by men with experience in testing. (ASME PTC 27-1957, TPC 28-1965. Western Precipiation Bulletin WP-50);
5. Cold end gas and air temperatures.

Emissions Control

Various tests on boilers burning fuel oil have indicated that a substantial reduction in solids emission is obtained by injection of a magnesium hydroxide into the flame.

A typical example is shown in Table 3:

TABLE 3—ANALYTICAL RESULTS

$Mg(OH)_2$	O_2 %	Dust Mg m_3	Composition of Dust V_2O_5; NiO; Fe_2O_3; Mg m_3	MgO Mg m_3	Unburnt Carbon Mg m_3
Injected	0.46	75	16	19	33
Not injected	0.44	143	17	0	124

This 48% reduction in total dust emission and 74% reduction in unburnt carbon is characteristic of a magnesium oxide additive injection since attachment of MgO to furnace walls traps any low melting compounds and raises furnace temperature to reduce unburnt carbon. Reduction of SO_3 generation over

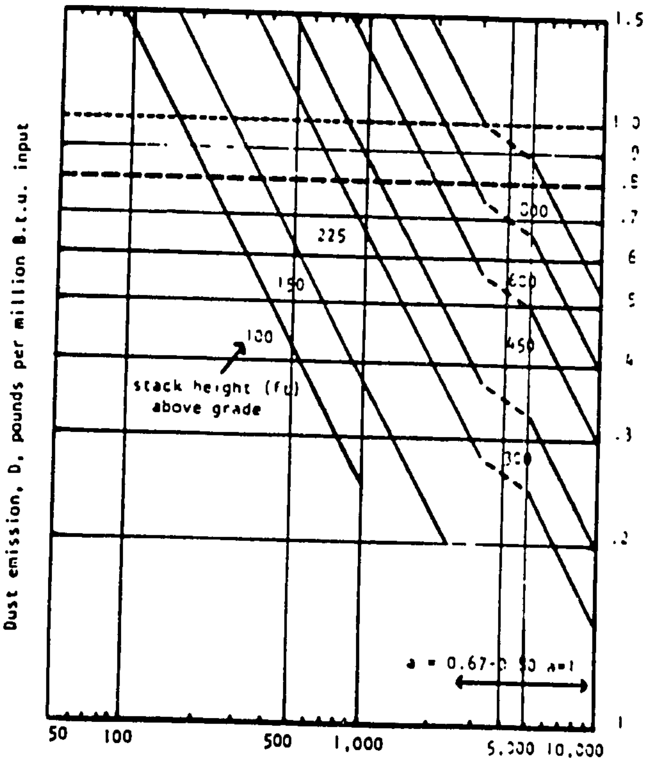

Fig. 4 Combustion for indirect heat exchangers, approximate steam generation, thousands of pounds per hour. Taken from ASME Standard—Guide for control of dust emissions

Line at 1.0—example sections for a smoke regulation ordinance (0.85 lb per 1,000 lb of gases). Line at 0.8—maximum recommended emission irrespective of stack height.

Maximum ground level dust concentration 100 micrograms/cu metre for 3-15 minutes; 50 micrograms/cu metre for 30 min to 1 hour; 17 micrograms/cu metre for 24 hours

TABLE 4—SOLIDS BALANCE IN BOILER

	Without Additives	With Additives
Ash	134,400	134,400
Unburned carbon	1,344,000 (0.4%)	336,000 (0.1%) (see Table 3)
Sulphates	100,800	100,800
Additives	0	126,000*
TOTAL FOUNDS	1,580,000	700,000 (*Could be less after evaluation)

catalytic surface is reduced and MgO reacts with SO_3 to precipitate $MgSO_4$.

Dust emission restrictions are correctly based on pounds per million B.t.u. input of fuel with reduced factor for equipment capacity rating and increased factor for height of stack to obtain ground level dust concentration considered satisfactory for design purposes. ASME APS-I Standard Guide for Control of Dust Emission from Stacks—recommends maximum limitation of 0.15 lb per million B.t.u. of heat for a 225 foot stack (see Fig. 4) and 0.55 lb per million B.t.u. for an 800 ft stack for a 1,000 MW plant with heat input of 10,000 million B.t.u. per hour.

Since ground level dust concentrations and ground level gas concentrations are similar problems it seems apparent that high stacks will be required in the future until the gas removal plants have been proved in practice.

Abatement of Sulphur Oxide Emissions

Many boilers designed for coal firing when converted to oil firing have been unable to use their electrostatic precipitators because of the low resistivity of dust due to SO_3 and H_2SO_4 vapour absorption. In reviewing electrostatic precipitation the most important characteristic of a dust is its electrical conductivity. The dust conductivity must be between that of a good conductor such as solid metal and that of a good electrical insulator and not too near either extreme. The reciprocal of conductivity, electrical resistivity, is used to define this property. For most effective operation of a precipitator, the dust resistivity should be between 10^4 and 10^{10} ohm-cm. Particles with a very low electrical resistivity lose their charge on the collecting electrode only to be re-entrained. Materials with high electrical resistivity coat and insulate the collecting electrode, thereby reducing potential across the gas stream. This may lead to a spark discharge that reverses ionization and causes re-entrainment. Conditioning agents such as moisture, acid mist and ammonia will reduce resistivity. We have found that use of an $MgO\text{-}Al_2O_3$ additive will maintain resistivity of dust in a good range so that electrostatic precipitator can be in continuous service. This is very important in coal fired boilers converted to oil which could have precipitators drop from 90% to 70% efficiency due to the difference in average size of particles.

Although precipitators can operate at 99.9% efficiency, the price comparison has to be considered. According to ASME figures of installed cost in 1968 this varies with efficiency with unity at 90% to 1.3 at 95%; 1.5 at 97%; 1.7 at 98%; 2 at 99%; 2.6 at 99.75% and 4.7 at 99.9%.

A unit burning 1 million barrels per day of fuel oil is assumed (according to ASME APS-I 1968. Recommended Guide-Control of Dust Emission) to contain: 1% sulphur; .04% ash; 100 p.p.m. vanadium; 0.4% unburnt carbon; pounds of oil 336 million with 6.2 x 10^{12} B.t.u.; average 6% excess air; products of combustion 5,107 x 10^6 pounds; allowable emission 124,000 pounds per day.

Assume 10% dropout through furnace and gas pass hoppers plus tube deposits. The 600,000 pounds per day left could be further reduced by 70% in a precipitator so that actual emissions could be 180,000 pounds per day or less than the 15% recommended.

Particle size of emissions from fuel oil burning are usually below 50 microns as tested by filters. An electrostatic precipitator designed for operation on pulverized coal at 95% efficiency and operating 70% efficiency on smaller particle size fuel oil firing emissions would easily meet emission laws and could meet the no visible emission requirements when using an additive. If a 90% efficiency electrostatic precipitator were installed the emission of particulate matter would meet the most stringent standard.

Use of a single steam generating unit to represent the 45,000 MW of electrical generation predicted to be in operation in 1971 with fuel oil fired boilers oversimplifies the problem of particulate emissions, however, it serves to indicate the value of a properly applied additive to reduce both solid and gaseous pollutants as well as to reduce cost of boiler maintenance, improve kW capability by superheat recovery and reduce cost of electrical generation.

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APPENDIX C.5

TUBEMOD™ Methodology

Assuring Increased Reliability of Superheater and Reheater Tubing and Headers by Optimization of Steam Side and Gas Side Temperatures

by

Aptech Engineering Services, Inc.

ASSURING INCREASED RELIABILITY OF SUPERHEATER AND REHEATER TUBING AND HEADERS BY OPTIMIZATION OF STEAM SIDE AND GAS SIDE TEMPERATURES

ABSTRACT

This paper presents a methodology called TUBEMOD™[1] for extending the life of superheaters and reheaters and reducing tube failure rates due to high temperature creep. The TUBEMOD™ methodology is based on the fact that almost all tube banks have regions where the tubes are running too hot, and consequently, tube creep life is expended in these regions much faster than in the remaining tubing. The TUBEMOD™ methodology uses steam flow redistribution to eliminate these local hot areas. The steam flow redistribution is accomplished by inserting tube segments with varying inner diameters into the tubing to adjust individual tube fluid flow pressure losses. The exact redistribution is dictated by targeting life increases and eliminating future failures.

The cost of this retrofit approach is a small fraction of the cost of replacement of a superheater or reheater. When required, a gas side optimization is included to obtain further benefits. A demonstration project is currently being conducted at a utility boiler under sponsorship from the Electric Power Research Institute. Economic analyses of the cost savings provided by the TUBEMOD™ methodology are also included in this project.

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[1] Patent Pending

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ASSURING INCREASED RELIABILITY OF SUPERHEATER AND REHEATER TUBING AND HEADERS BY OPTIMIZATION OF STEAM SIDE AND GAS SIDE TEMPERATURES

INTRODUCTION

Tube outlet steam temperatures and tube metal temperatures are not uniform through the superheaters and reheaters of most fossil-fired boilers. While the bulk steam temperature at the superheat or reheat outlet header may typically be 1005°F, the local steam temperatures in some of the tubes can be as much as 150°F higher or lower than the bulk temperature. These temperature variations typically occur both across the superheater or reheater tube bank from left to right and through each tube assembly in the direction of the gas flow. The cause of these variations is typically a combination of nonuniform gas velocity and temperature distributions, steam flow imbalance, burner firing imbalance, and intrinsic characteristics of convection pass heat transfer surface arrangements and header designs. In general, boiler manufacturers attempt to account for these temperature variations by specifying tube and header materials and thicknesses based upon worst case design conditions.

Under actual operating conditions, a nonuniform tube metal temperature distribution can often lead to metal temperatures in excess of the worst case design in localized areas of the superheater or reheater tube bank. This is generally due to off-design operating conditions, changes from design fuel, and errors in design. These elevated metal temperatures cause tube failures due to high temperature creep and header degradation due to thermal stress distortion and fatigue.
Failures of superheater tubes due to high temperature creep are a leading cause of forced outages in fossil fueled boilers in the United States. Often these failures are confined to very localized regions of the superheater tube bank for the reasons cited above. Furthermore, when the tube failure frequency or forced outage costs become unacceptably high for the utility, the entire superheater is often replaced when, in fact, only a small region of the tube bank has significant creep damage and the remainder of the tube bank has substantial remaining life.

To address this problem, Aptech Engineering Services, Inc. (APTECH) has developed a retrofit design procedure for reducing the nonuniformity in steam and tube metal temperatures through a superheater or reheater by redistributing the tube-to-tube steam flow. The steam flow redistribution is achieved by modifying the individual fluid flow pressure losses from tube to tube. Done properly, this will increase the steam flowrate through hot tubes and decrease the flowrate through cold tubes in a precise manner. In general, the fluid flow pressure loss is altered in a given tube by either decreasing or increasing the tube inner diameter over a specified length. This either accelerates or decelerates the bulk steam flow velocity in the region of the tube modification, thereby increasing or decreasing the flow frictional and momentum losses. The replaced section of the tube with the new inner diameter required to achieve the desired flow and increased life is called a steam flow controller (SFC).

The retrofit design procedure developed by APTECH determines the dimensions of the SFCs required throughout the superheater or reheater to achieve more uniform tube metal and steam temperature distributions. The procedure also provides estimates of the improved creep life that can be achieved in a local hot area by reduction of tube metal temperatures. The steamside oxide scale analysis technique developed by APTECH (Tube Alert™) is used to relate tube creep life expended to date and remaining in the future to metal temperatures in the past, present, and future. The design procedure has been computerized so that different combinations of SFC patterns and resulting superheater or reheater life extension can be evaluated and the tradeoff between retrofit cost and tube and header life increase can be optimized. This overall design package is termed TUBEMOD™.

The concept of superheater steam flow redistribution is not new. Typically, the SFC has taken the form of a sharp edged orifice. These orifices are then installed in the cold tubes, usually located near the walls of the boiler where gas temperature and velocity and consequently heat transfer are lower, in order to raise the outlet steam temperature in those tubes. This is usually done for the purpose of raising the superheater outlet bulk steam temperature which is too low. It is also sometimes used to bring temperatures out of alarm. With TUBEMOD™, the steam flow redistribution concept is exploited further for the purpose of increasing availability by reducing forced outages due to tube failures and postponing or eliminating superheater replacement by increasing tube lives.

The TUBEMOD™ design procedure has been under development at APTECH for two years. A validation of the technical performance of a TUBEMOD™ retrofit design and the associated economic impact is now underway to show that the technique is ready for commercialization. In early 1989, a project was put together to demonstrate the TUBEMOD™ concept. This project is financially supported by APTECH, the Electric Power Research Institute (EPRI), and San Diego Gas & Electric Company (SDG&E).

The specific boiler involved is SDG&E's South Bay, Unit 1. Phase I of this project is scheduled for completion in March of 1990. The remainder of this paper provides more details on the project and description of the progress and results to date. The boiler testing results were very recently obtained and the TUBEMOD™ design study has been completed. A complete EPRI report will be available upon completion of the project.

TUBEMOD™ THEORY

Tube Temperatures and Creep Damage Accumulation Rates

Figure 1 shows a typical profile of the steam temperature at the tube outlet legs of a superheater situated in a wall-fired fossil fueled boiler. These temperatures were obtained from thermocouples welded to the outside of the tubes in the penthouse just upstream of the outlet header. Since there is negligible heat flux in this region, this measured temperature is indicative of both metal temperature and steam temperature at the tube outlet. Note that in the center of the superheater, steam temperatures are substantially higher than the design bulk steam temperature of 1005°F, while at either side of the superheater, the steam temperature is substantially below this value.

Clearly, in the example of Figure 1, the center tubes are running hotter than the outside tubes. If this is typical of the unit operation from the beginning, then the center tubes will have substantially less remaining creep life than the outside tubes. Also, it is pointed out that tube metal temperatures in the furnace where a heat flux is imposed on the tube will be even higher than the outlet steam temperatures in Figure 1.

Figure 2 shows the creep damage accumulation rate of a typical tube throughout its life. In this particular case, the top curve shows that at an operating time of 200,000 hours slightly over 0.8 of the creep life has been consumed. If the tube continues to operate under the same temperature conditions, it will fail due to creep at approximately 225,000 hours. However, the lower curve indicates that if the temperature of this tube can be lowered at the 200,000 hour point, its remaining life can be significantly extended. For instance, by lowering the temperature 30°F, the remaining life is extended from 25,000 hours to 75,000 hours. This is an example of a specific tube. Each tube will have its own unique life gain depending on when and how much its temperature is reduced, how fast creep damage is accumulating, how much original life remains, and the wall thinning rate due to fireside erosion.

Figure 3 shows the overall impact of tube life extension. It shows the typical bathtub curve forced outage rate for a superheater over time. Toward end of life, local tube failure rates will increase until they reach an economically unacceptable level at which time the replacement of the entire superheater occurs. By using the TUBEMOD™ approach to achieve tube life extension in the localized hot spots in the superheater, the forced outage rate is held down for a longer period of time and the overall replacement date is pushed out into the future. In some cases, utilities utilize the TUBEMOD™ technique as a maintenance item and a replacement can be avoided during the life of the unit.

TUBEMOD™ Design Procedure

Figure 4 presents a flowchart which illustrates the TUBEMOD™ design procedure. This procedure requires 11 steps involving detailed inspection, testing, and engineering analysis. A number of these steps use special computer codes developed by APTECH. The procedure is not rigid, so the order in which the steps are taken can change from case to case and in some situations not all the steps are required. Figure 4 shows a typical order for the steps used in the TUBEMOD™ design procedure for a superheater. Due to space limitations, only a brief description of the procedure is provided here.

As indicated, the first step is to obtain operating data for the boiler and design information for the superheater. Operating data include number of hours of operation, bulk steam outlet temperature and pressure, and steam flowrate at different loads. Superheater design information includes all tube dimensions (lengths, outer diameter, and wall thicknesses), tube material specifications, and tubing assembly and row configurations.

The second step in the procedure is to perform a Tube Alert™ examination. This involves conducting a survey of the superheater tube bank during an outage in which the steamside oxide scale is measured at numerous points via ultrasonic testing (UT) (typically, several hundred points both in the furnace and the penthouse). In addition, a few tube samples are recommended at locations selected based upon the results of the UT survey. A computer code is used to compute the creep damage accumulation based upon the measured steamside oxide scale thickness and other data including boiler operating conditions, oxidation kinetics, and tube material properties. An effective time integrated tube metal temperature is also calculated at each UT measurement location by this computer code. The limited number of tube samples are subjected to complete chemical and destructive metallographic analyses and these data are then used to confirm the much more extensive nondestructive UT data.

The third step is to install thermocouples in selected tube inlet and outlet legs of the superheater, typically during the same outage as when the Tube Alert™ examination was performed. Most of the thermocouples are installed on tube outlet legs, with only a few thermocouples installed on inlet legs.

The fourth step requires that fireside conditions in the boiler be optimized. This means that fuel combustion, wall blowing, sootblowing, and any other pertinent fireside parameters must be "tuned" as appropriate for future boiler operation. Occasionally the boiler will already be optimized with respect to these parameters. However, most often a few burners, sootblowers, etc., will be malfunctioning or not performing acceptably. It is very important to perform this optimization before the remaining steps in the design procedure are taken. In this way, the future heating environment for the superheater is baselined and nonuniformities in combustion gas temperature profiles are minimized. Once steam flow redistribution is implemented, every effort should be made to maintain these fireside characteristics. In some cases, the utility may be planning to change fireside conditions coincident with a TUBEMOD™ retrofit (e.g., change in fuel, change in load profile, etc.). This presents no problems to the TUBEMOD™ concept, however, such changes must be quantified. Generally, more tube thermocouples are required if the utility is planning a change in fireside operating conditions.

The process of optimizing the fireside conditions is shown in Figure 5 , and it begins with documenting the burner characteristics in the as-found state, and reviewing the fuel properties. Fuel analysis and burning profiles are valuable information to begin with. Testing in the as-found state is a necessity and a way to become familiar with the burners and their limitations, and to gain the operator's confidence. Testing begins at the maximum design heat input rating with measurements of both air and fuel distribution and observation of burner shape. These measurements and observations have been simplified by use of new high resolution infrared cameras. Measurement of start-up metal temperatures and of the furnace outlet gas temperatures has been improved with the use of a system using infrared sensors and ceramic targets (APTECH's Smart-Start™ System, shown in Figure 6), acoustic temperature measuring devices[2], and thermocouples located on tubes in the superheater or reheater.

The fireside emissions including CO, CO_2, 0_2, NO_x, SO_x, and particulate should be measured and monitored at different locations (e.g., in the furnace and stack) during the testing. While all of these parameters may not be available, it is important to document those that are measured and expand capability to make all the measurements during future tests.

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[2] Muzio, L.J., D. Eskinozi, and S. Green, "Acoustic Pyrometry: New Boiler Diagnostic Tool", Power Engineering, November 1989, pp. 49-52.

The optimization process has many goals, some of which are typically as-follows:

1. Meet emission standards or reduce emissions.
2. Reduce peak temperatures and obtain a flame shape in the furnace that does not direct a high heat flux to specific areas of the furnace or tubes.
3. Obtain a temperature profile in the superheater and reheater which is as uniform from side to side as possible and meets the required bulk steam temperature specification.
4. Reduce temperatures and heat loss due to excess air and unburned combustibles while monitoring complete combustion.
5. Reduce slagging, fouling, and sootblowing requirements.
6. Minimize unit heat rate.
7. Maximize reliability and unit service life.

While the goals seem straightforward, some are directly opposed. A good example is the fact that high superheater and reheater temperatures are good for low heat rates, but may cause higher emissions, reduced service life, and loss of unit reliability. Therefore, these concerns must be balanced and an optimum condition achieved.

Returning to Figure 4, the fifth step is to obtain superheater test data, including tube inlet and outlet leg thermocouple data and bulk steam flowrate, pressure, and temperature data. Generally, a long test period is not required. However, several steady-state conditions covering the range of loads of interest are necessary.

The sixth step requires that the "as-is" temperature for each tube outlet leg be established. Both the thermocouple measured temperatures and the time integrated temperatures obtained from the penthouse steamside oxide scale thickness measurements are used. If the future boiler operating conditions are to be the same as those for the past, then these separately determined profiles should be similar. In this case the oxide-scale-deduced temperatures can be used to interpolate between the thermocouple measured temperatures. If future operating conditions will be different from the past, then the thermocouple temperature data will be significantly different from the oxide scale temperature data. In this case, the thermocouple data are taken as representative of the "as-is" tube outlet leg temperature distribution prior to the TUBEMOD™ retrofit.

At this point, the seventh step has been reached. This step and the following three steps are performed iteratively. The seventh step requires use of the TUBETEMP™ computer code. This code takes the inlet and outlet leg temperature distributions and individual tube steam flowrates as input and then calculates the average heat flux along each tube. The code then calculates the steam temperature at each tube material change, accounting for the constantly changing steam thermophysical properties from inlet to outlet. Finally, the temperatures at the scale/steam interface are calculated at each tube material change location using calculated values of the steam heat transfer coefficient.

The eighth step involves use of the LFRAC™ computer code. This code calculates the remaining creep life at each tube material change from inlet to outlet, for every tube in the superheater. This remaining life is a function of the scale/steam interface temperatures, heat flux, and steam pressure provided by TUBETEMP™, the tube dimensions and material properties, steamside oxidation rate, and fireside oxidation rate at each location. The scale/steam interface temperatures are used to calculate the metal/scale interface temperatures and metal temperatures of each tube. This calculation requires data on the oxide scale thickness, tube dimensions, and thermal conductivity for the tube metal and oxide scale. Once the distribution of remaining useful life is computed by LFRAC™, those regions of the superheater with the shortest and longest remaining lives can be determined. This provides a crucial input for determining steam flow redistribution. The steam flow redistribution is determined by specifying a tube metal temperature reduction in the regions with shortest remaining life and a tube metal temperature increase in the regions with longest remaining life.

The ninth step utilizes the SFC code. This code models the steam flow distribution in the entire superheater. A one-time input is the complete matrix of tube dimensions, including all lengths, outer diameters, and wall thicknesses. An iterative input is the desired change in tube outlet steam temperatures as determined from the tube metal temperatures specified by the LFRAC code. The SFC code redistributes the tube-to-tube steam flow, while maintaining total steam flow constant, to achieve the desired changes in each tube outlet temperature. The steam flow is redistributed by inserting SFCs of specified length and inner diameter at the inlet end of selected tubes. Usually, these SFCs consist of short portions of tube, typically one foot long with a reduced inside diameter. The SFC code also determines the magnitude of the slight increase in pressure drop across the superheater due to the presence of the SFCs. The slight increase in pressure drop potentially has as small impact on the unit heat rate.

The tenth step in the process involves an economic analysis of the steam flow redistribution. The economic benefits are associated with the reduction in forced outages due to tube failures and the postponement of superheater replacement. The economic penalties are associated with the cost of fabrication and installation of the SFCs and the potential small impact on plant heat rate due to the slight increase in superheater pressure drop associated with steam flow redistribution. Depending upon the results of this economic analysis, additional steam flow redistribution patterns can be considered by repeating Steps 7 through 10. This would be done, for instance, if it was desired to install fewer SFCs with smaller inner diameters to achieve the same life extension in the hottest tubes.

The eleventh and final step is to establish the superheater retrofit specifications. These specifications are based upon the desired economic benefits as determined in the previous steps. The specifications include the dimensions and locations of all SFCs and any other changes in tube materials and/or design that may be desired during the superheater retrofit.

It should be noted that this design procedure just described can be applied either to existing superheaters or reheaters or new replacements. In either case, life can be extended through the application of steam flow redistribution because heat transfer nonuniformities will always exist on the fireside.

Steam Flow Controller Design

The SFC is made as long as practical (e.g., approximately one foot so that the diameter restriction can be minimized). A three-to-one taper is used at the entrance and exit to comply with ASME codes and also to minimize flow separation and the formation of eddies as well as eliminate any propensity for plugging. This design does not have the drawbacks of a sharp edged orifice design which include steam erosion of the orifice inner diameter with subsequent change in flow characteristics, a tendency to cause buildup of deposits upstream and downstream of the orifice, and possibly even pluggage.

PROJECT OVERVIEW

As mentioned in the introduction to this paper, an EPRI-supported project is underway to demonstrate the application of the TUBEMOD™ concept to a specific boiler, SDG&E South Bay Unit 1. This unit is a Babcock & Wilcox oil and gas fired boiler rated at 980,000 pounds steam per hour with superheater outlet conditions of 1005°F and 2150 psig. It went into service in 1960 and has accumulated 227,327 service hours and 271 start-ups as of February 1989.

The demonstration project is divided into two phases. In Phase I, which is nearly completed at this writing, detailed operating data have been obtained for the unit with emphasis on conditions in the superheater. These data will be used in a TUBEMOD™ retrofit design for life extension. Several design iterations have been considered and the associated economic benefit quantified for each design. An analysis will be conducted to determine the sensitivity of SFC design parameters on superheater and boiler performance and resulting economics. Two SFCs have been installed in cold tubes for which metal thermocouple temperature data before and after installation are available. This will assist in verification of the SFC computer code and will provide experience in design and construction issues associated with the SFCs.

The culmination of the Phase I project is a complete site-specific TUBEMOD™ retrofit design for SDG&E's South Bay Unit 1 with associated installation cost estimates. In Phase II (planned), the actual retrofit will be implemented and boiler and superheater performance will be monitored in order to confirm the performance and economic projections established in Phase I. The Phase I project was started in March of 1989 and is currently scheduled for completion in March 1990.

SUPERHEATER DESCRIPTION

Figure 7 shows the SDG&E South Bay Unit 1 secondary superheater tube arrangement. The inlet branch consists of a four-flow, four-pass pendant configuration with 42 elements across the unit. This inlet branch tubing is constructed of ASME SA-213-T11 low alloy steel material. The outlet bank consists of a two-flow, four-pass pendant configuration with 83 elements across the unit. The outlet bank tubing is constructed of ASME SA-213-T22 low alloy steel material.

PROGRESS AND RESULTS TO DATE

Installation of Additional Instrumentation and Steam Flow Controllers

During the Spring 1989 outage for SDG&E South Bay Unit 1, a condition assessment of the superheater was performed and 14 tube samples were extracted. The oxide scale thickness measurements were performed in six locations labelled A through F in Figure 7. These areas were selected based upon operating conditions, accessibility, and tube material. A total of 804 measurements were taken. The tube sample locations were selected based upon this Tube Alert™ analysis. These samples were used to verify the field UT measurements and to perform additional analyses including metallography, chemical composition, and dimensional analysis.

Fifty additional tube inlet and outlet leg thermocouples were installed. Six of these thermocouples were installed on inlet legs in Tube Rows 9 and 12 and Elements 3, 9, 19, 25, 33, and 40 which span the entire width of the superheater. The remaining 44 thermocouples were installed in tube outlet legs in Tube Rows 19 and 20 and Elements 4, 7, 10, 17, 20, 23, 26, 31, 34, 37, 40, 45, 48, 51, 54, 59, 62, 65, 68, 73, 76, and 79 which again span the total superheater width.

Two SFCs were installed in tubes known to be relatively cold. The SFCs were fabricated according to the design previously described. They were installed in Tube Row 9 in Elements 1 and 42 just downstream of the inlet header as indicated in Figure 7.

Finally, during the Spring outage pressure taps were prepared in the two inlet header tees and the single outlet header tee. Pressure transducers were then procured and installed in October 1989. This instrumentation provides an accurate measurement of the secondary superheater pressure drop at all loads.

Test Data

Performance tests were conducted on the unit over the normal operating range. The outlet leg tube metal temperature data from thermocouples (Figure 8) were obtained along with other data critical to the project. Figure 8 shows that the temperature profile is relatively insensitive to the load. Note that the temperature variation from maximum to minimum across the unit is approximately 130°F. From this it becomes obvious that the life differences between hot and cold tubes will be enormous.

Tube Alert™ data were taken and analyzed at more than 800 locations in the furnace and in the penthouse. These data included wall thickness, oxide thickness, temperature, stresses, and remaining useful life. A typical tube scale thickness map for row 20 in the penthouse is shown in Figure 9. Analysis and integration of all the results showed that the TUBEMOD™ analysis could proceed under the assumption that past and current boiler operation will be consistent with future operation.

The data collected on the two tubes where SFCs were installed indicated an outlet steam temperature rise of 20°F to 40°F. The preliminary TUBEMOD™ calculations had predicted a rise of approximately 50°F to 70°F. This conservatism is partly due to the conservative assumptions built into the model.

Preliminary TUBEMOD™ Design

Using the performance test data, the TUBEMOD™ methodology was implemented to produce a retrofit design. The methodology allows a great deal of flexibility in the different maintenance philosophies used by utilities. APTECH selected several approaches. The design presented here for illustration is the most basic approach. This approach requires the installation of 59 SFCs (approximately 35% of the available tube circuits). Two tube circuit repairs were also required. Three SFC diameters were sized and located by the methodology. The TUBEMOD™ analyses indicate that with this configuration the temperatures of the hottest tube locations are reduced by approximately 20°F.

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Figure 10 shows the before and after TUBEMOD™ temperature profiles. Note that the lowest temperatures still remain quite low. These low temperatures can be increased further by decreasing the SFC diameters, but in this case it was not required. After TUBEMOD™, the drum pressure will increase approximately 6 psi at 70% load and 13 psi at 100% load.

By reducing the temperatures of the hot tubes using the steam flow redistribution selected for this design, the expected time to failure can be significantly altered.

Figure 11 shows the before and after TUBEMOD™ failure rate curves. As can be seen from this graph, the TUBEMOD™ analyses will extend the time to first failure from approximately 12,000 hours to 80,000 hours. In addition, the total number of failures is reduced for the same time period. After 140,000 additional hours, 25 failures are expected with the as-is superheater. The number of failures has been reduced to four in this same time period using TUBEMOD™. It should be noted that the life gain and availability improvement can be enhanced even further depending on the requirements of the utility.

Economic Analysis

As a part of the demonstration project, APTECH developed a number of economic models to determine the financial impact of implementing the TUBEMOD™ retrofit. For purposes of illustration, one economic model is presented. Using the retrofit design presented earlier, a unit-specific economic model was developed. The major assumption of this model is that the South Bay unit will operate for a service life of approximately 50 years (i.e., for an additional 20 years of service from the present). In addition, the existing superheater will require replacement in 80,000 hours of operation. This is the optimum economic time to replacement based on a comparison of the present value cost of a new superheater and the present value cost of failures.

Utilizing the TUBEMOD™ redesign and the economic model, the replacement of the superheater can be avoided for the life of the unit. This results in a significant cost savings of $1,300,000 in a present value analysis. This savings would be greater if the retirement date were less than 20 years. As with all economic analyses, the results are highly dependent on the assumptions used in formulating the economic model. The savings presented here are for the economic model of South Bay Unit 1. The economic analysis can be performed before installation of the TUBEMOD™ retrofit. It can also be used to drive the TUBEMOD™ design procedure to achieve the required economic payback. It should be noted that no credit was given for the increase header life that is expected.

CONCLUSIONS

The use of steam flow redistribution and fireside burner optimization to eliminate hot spots in superheaters and thereby increase overall superheater/reheater reliability and longevity -- reduced failure rates and postponement of superheater replacement -- shows definite promise. The TUBEMOD™ design methodology described here offers an analytical procedure for determining the pattern of SFCs required to redistribute the steam flow to eliminate the local regions of high temperature in the tube bank.

The demonstration project now being conducted at SDG&E South Bay Unit 1 under EPRI sponsorship will provide a documented case study showing the TUBEMOD™ design methodology and the sensitivity of the overall economics to various design parameters. Specifically, this project will show on a site specific basis how the economic savings realized from reduced tube failure rates and postponement of superheater or reheater replacement depend upon the number of SFCs used and their inner diameters. All results and conclusions of this demonstration project will be presented in a final report to be issued at the conclusion of this project.

Although this demonstration has focused on superheaters, the general TUBEMOD™ methodology can also be applied to reheaters. It is also emphasized that the TUBEMOD™ methodology can be used to increase the longevity of new superheaters as well as those already in service. The most practical use of the TUBEMOD™ methodology is to increase reliability and operating life of superheaters and reheaters, which results in postponement of the capital expenses associated with replacements of these tube sections.

ACKNOWLEDGEMENTS

The authors gratefully acknowledge the efforts of Richard Shoemaker of SDG&E in sponsoring the project at South Bay Unit 1, and managing the instrumentation and testing aspects of the work. In addition, we acknowledge the assistance of Dave Broske of the Electric Power Research Institute in providing extensive review of the project at its various stages. This demonstration project at SDG&E South Bay Unit 1 was financially supported by both EPRI and SDG&E.

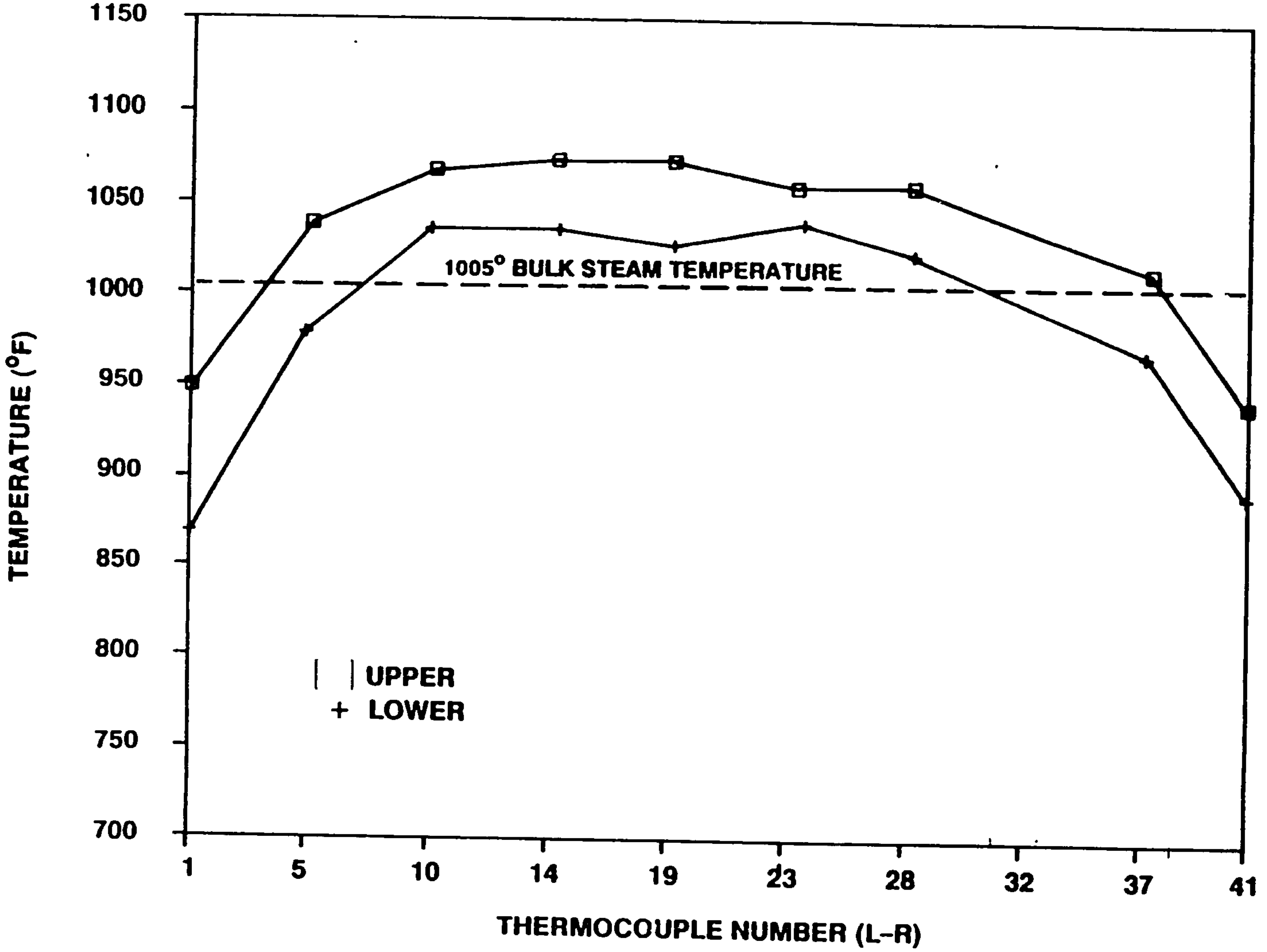

FIGURE 1 – TYPICAL TEMPERATURE PROFILE AT SUPERHEATER TUBE OUTLET LEGS.

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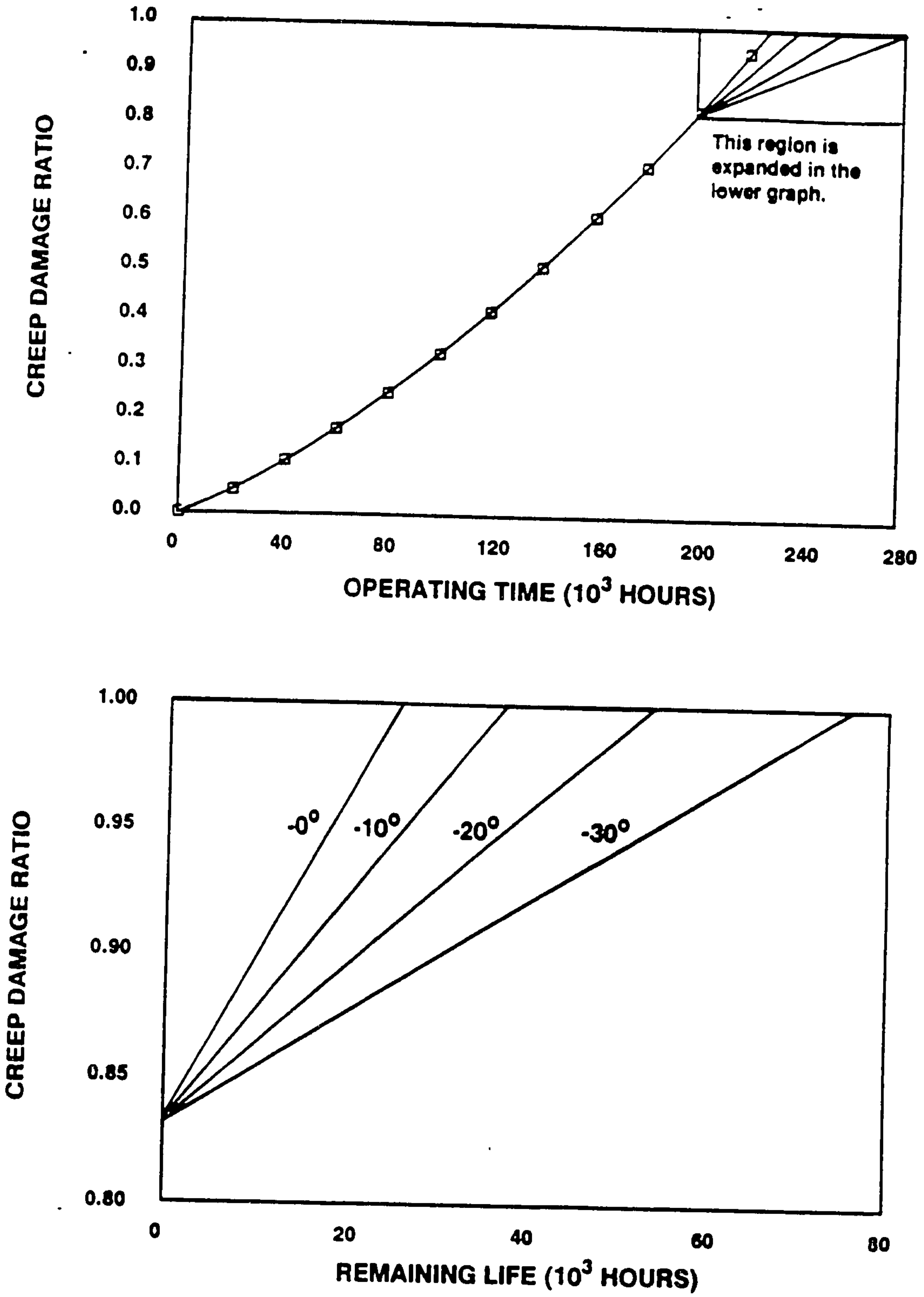

FIGURE 2 – CREEP DAMAGE ACCUMULATION SHOWING LIFE EXTENSION OBTAINED BY REDUCING METAL TEMPERATURE.

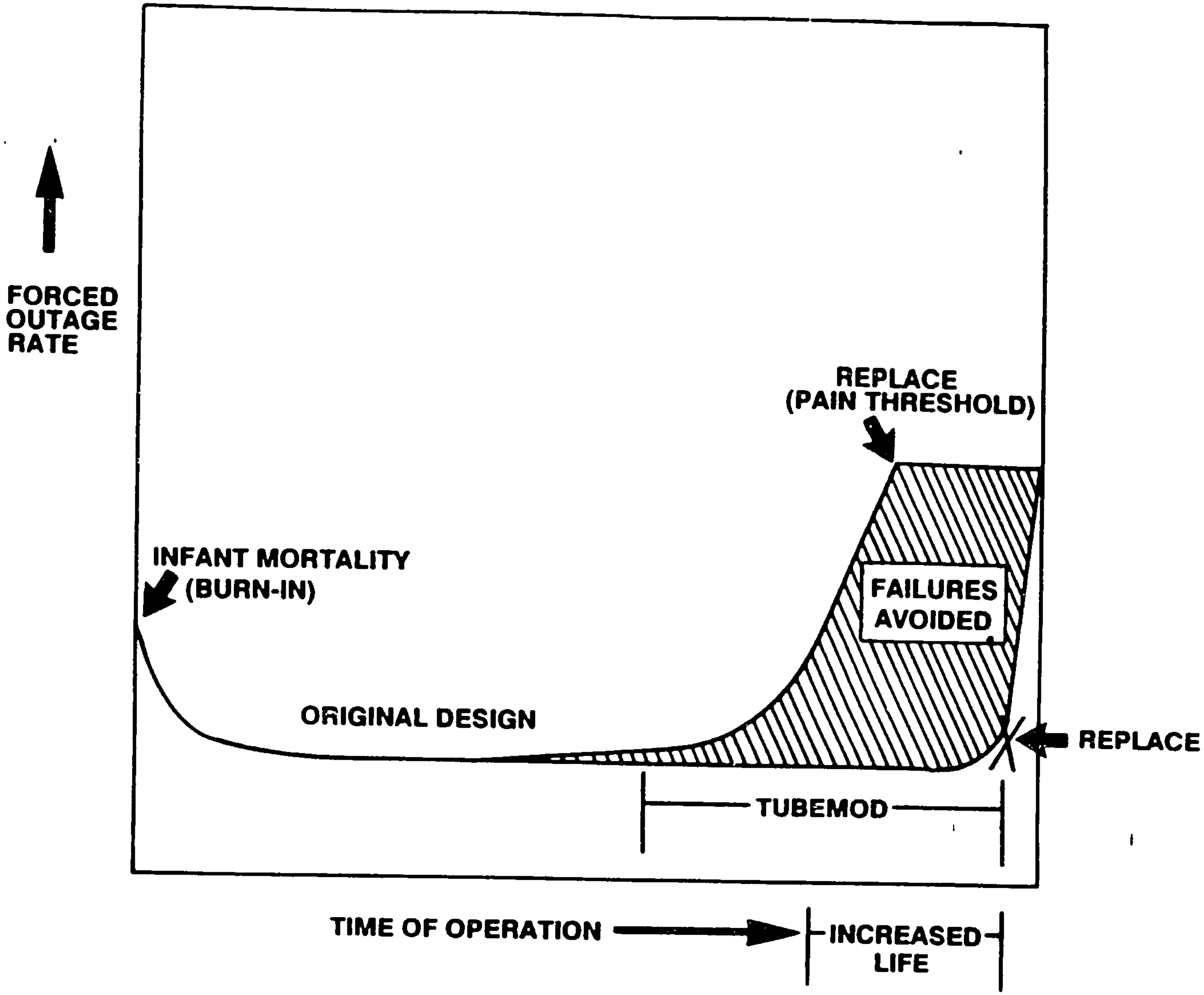

FIGURE 3 – DIAGRAM SHOWING THE REDUCED FORCED OUTAGE RATE AND LIFE EXTENSION OBTAINED USING TUBEMOD™.

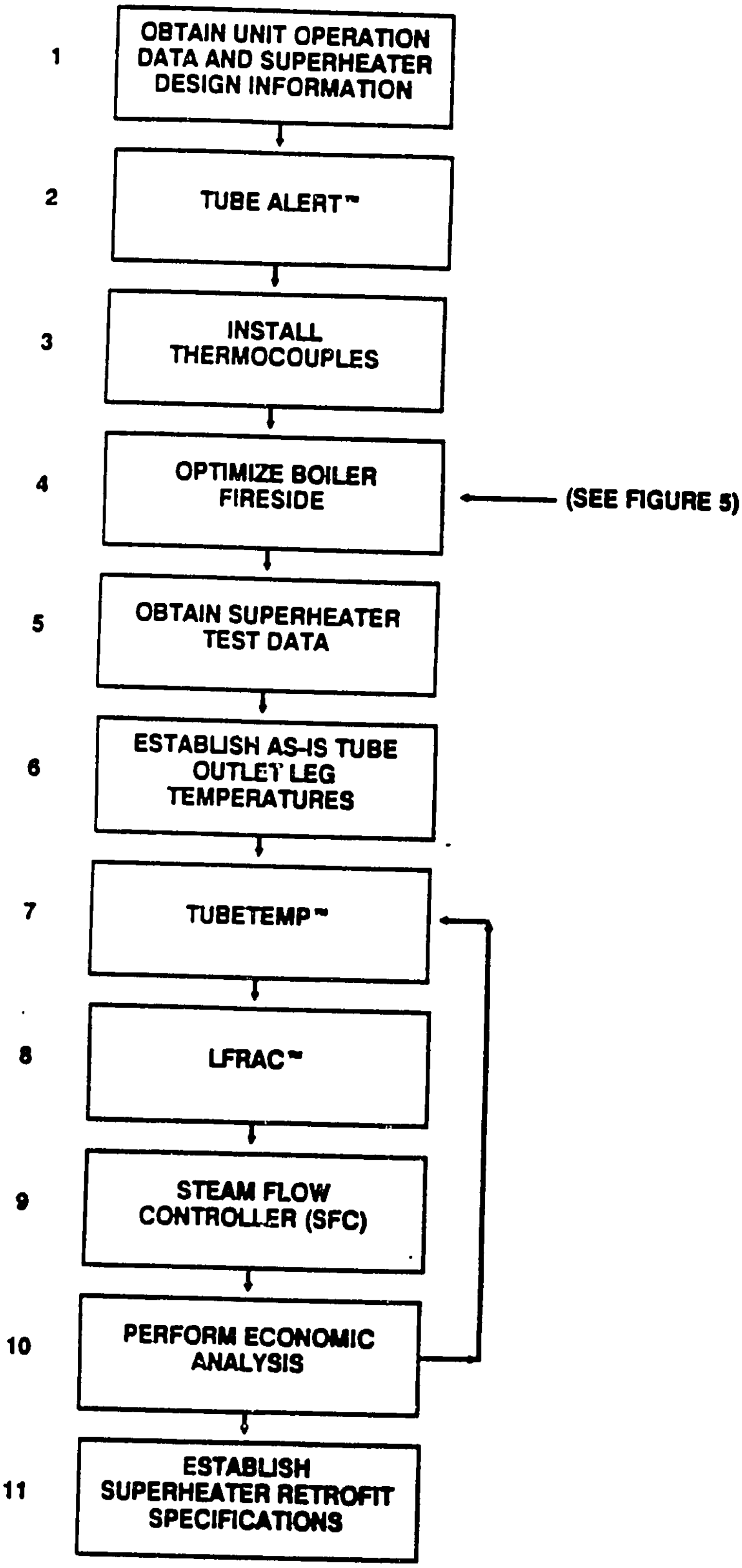

FIGURE 4 – TUBEMOD™ DESIGN PROCEDURE.

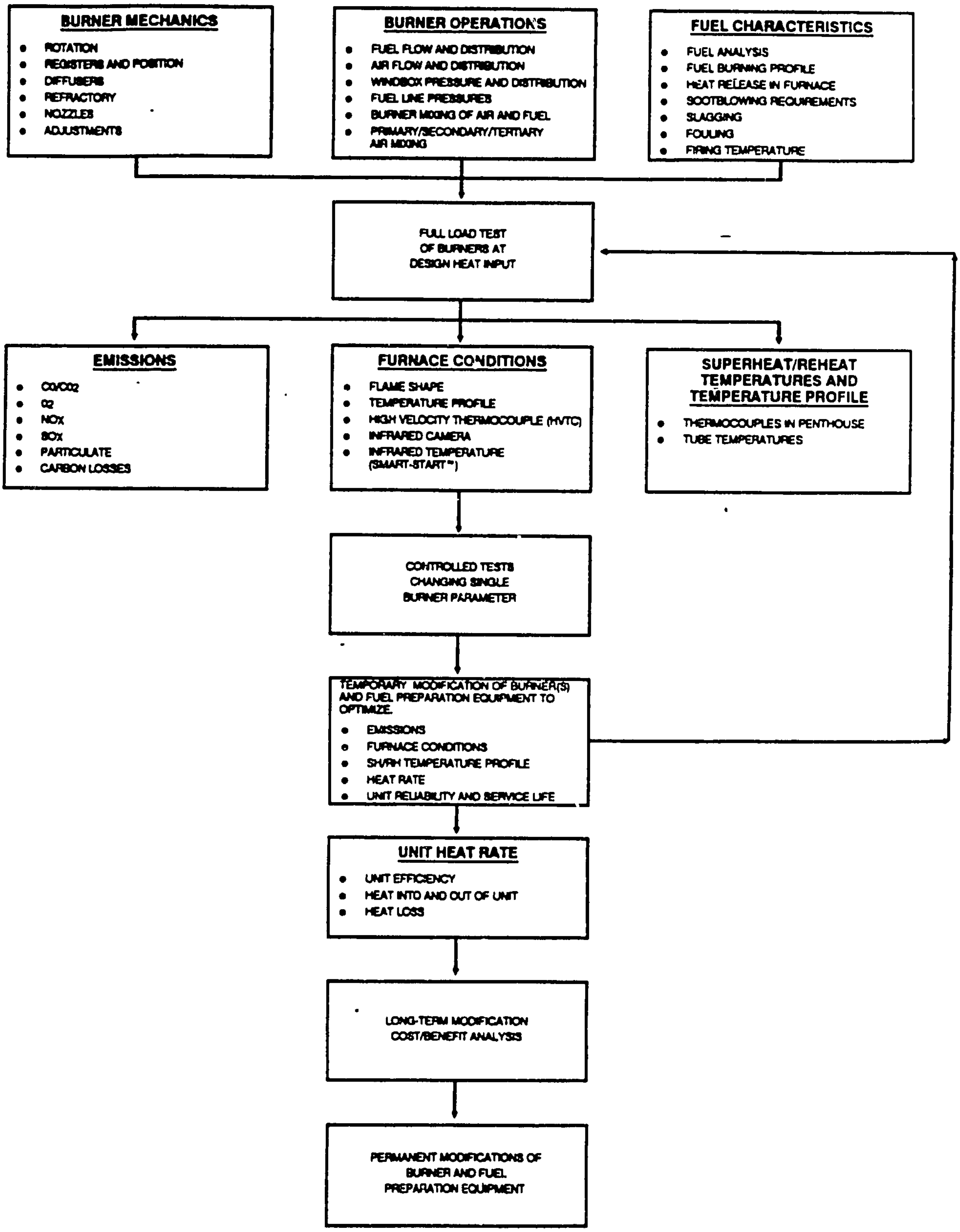

FIGURE 5 — BOILER FIRESIDE AND BURNER OPTIMIZATION.

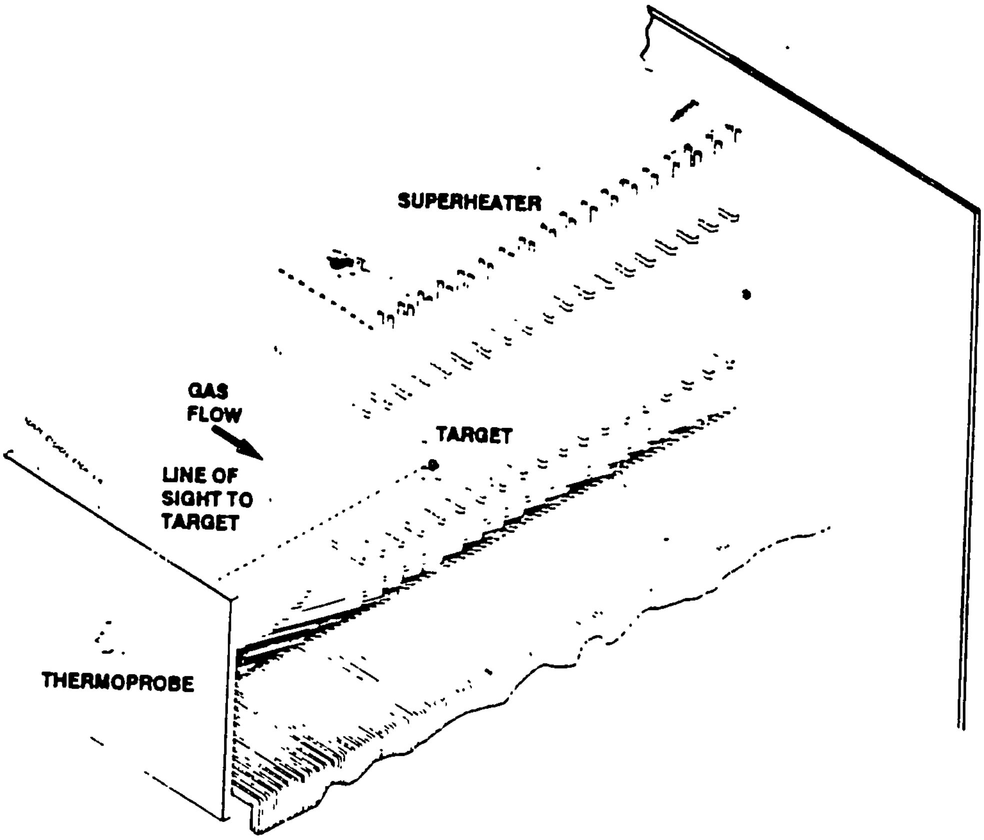

FIGURE 6 – THE SMART START™ INFRARED THERMOPROBE MEASURES THE HEAT FLUX FROM A CERAMIC TARGET. THE RESULTING REPRESENTATIVE GAS TEMPERATURE READING IS DISPLAYED IN THE CONTROL ROOM.

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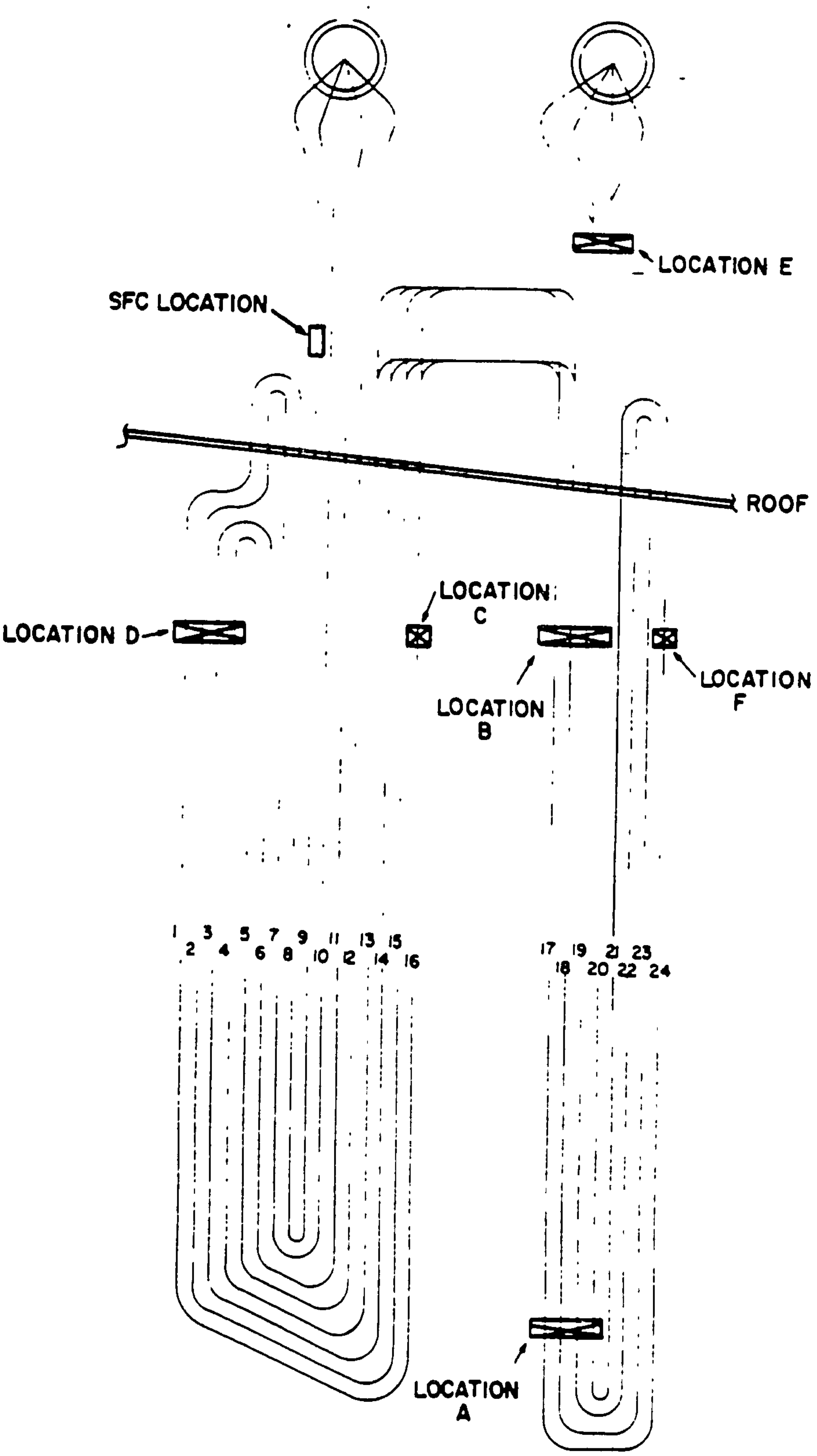

FIGURE 7 – SECONDARY SUPERHEATER TUBE ARRANGEMENT SHOWING NONDESTRUCTIVE EXAMINATION LOCATIONS (TUBE ALERT™).

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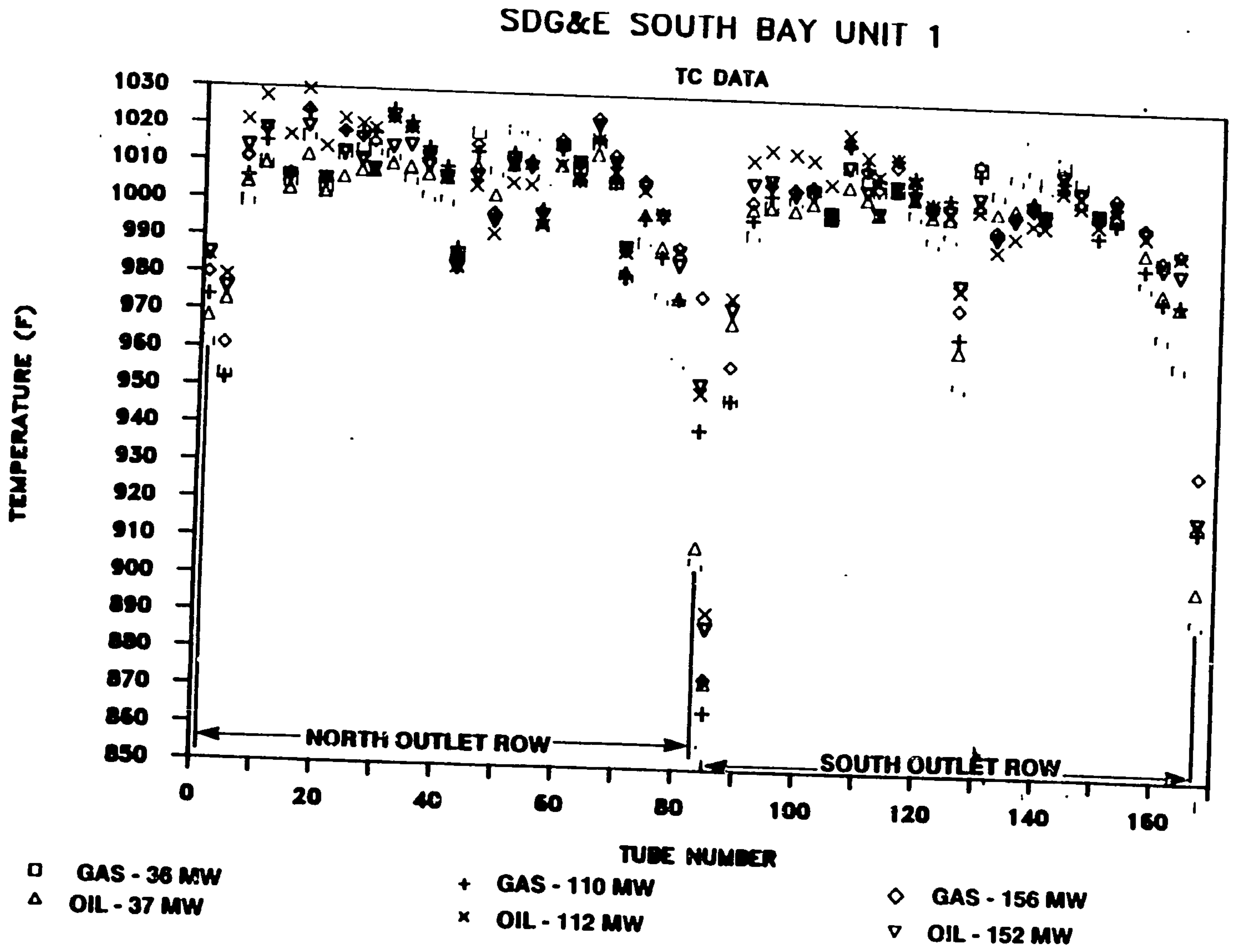


FIGURE 8 — SUPERHEATER OUTLET TEMPERATURE THERMOCOUPLE DATA AT VARIOUS LOCATIONS.

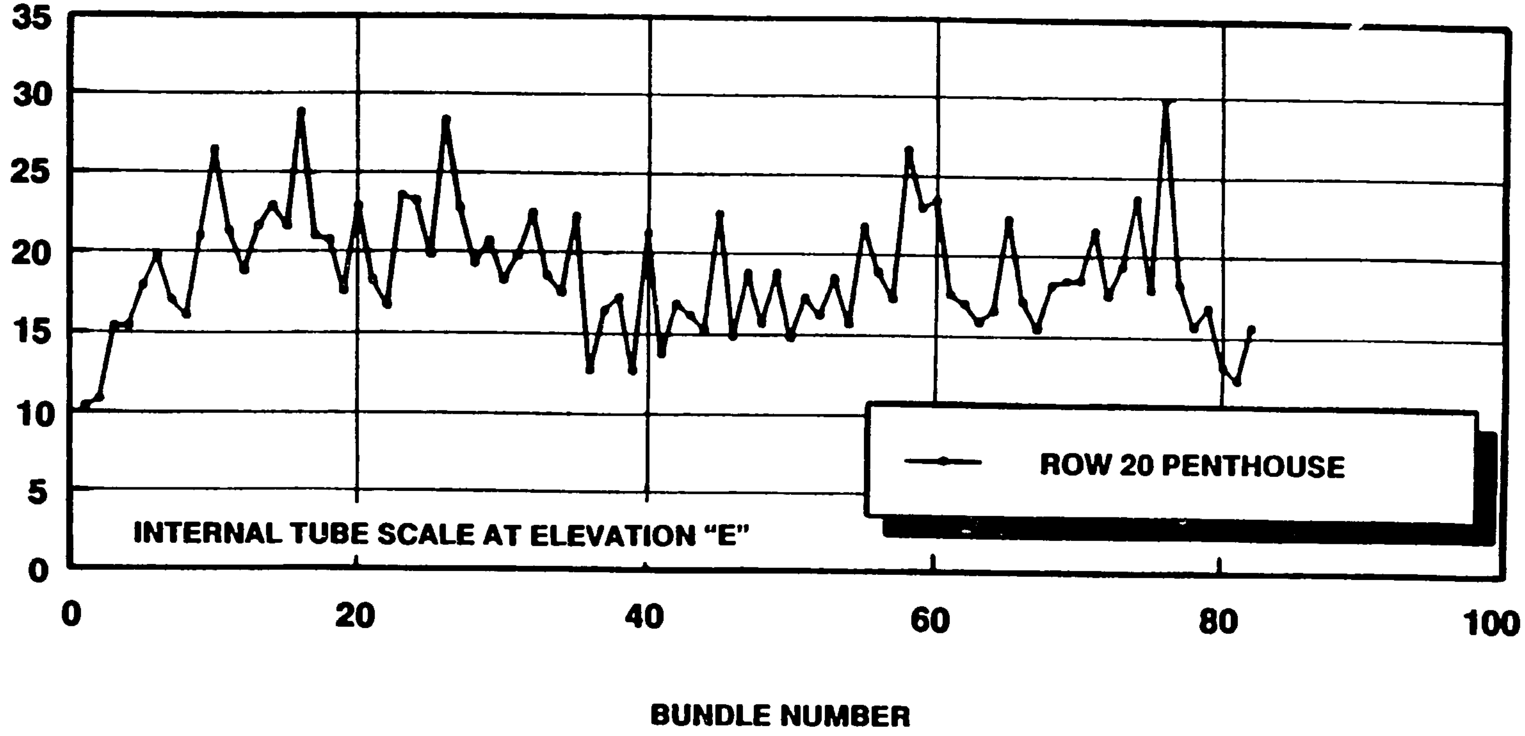


FIGURE 9 — STEAMSIDE OXIDE SCALE THICKNESS DATA.

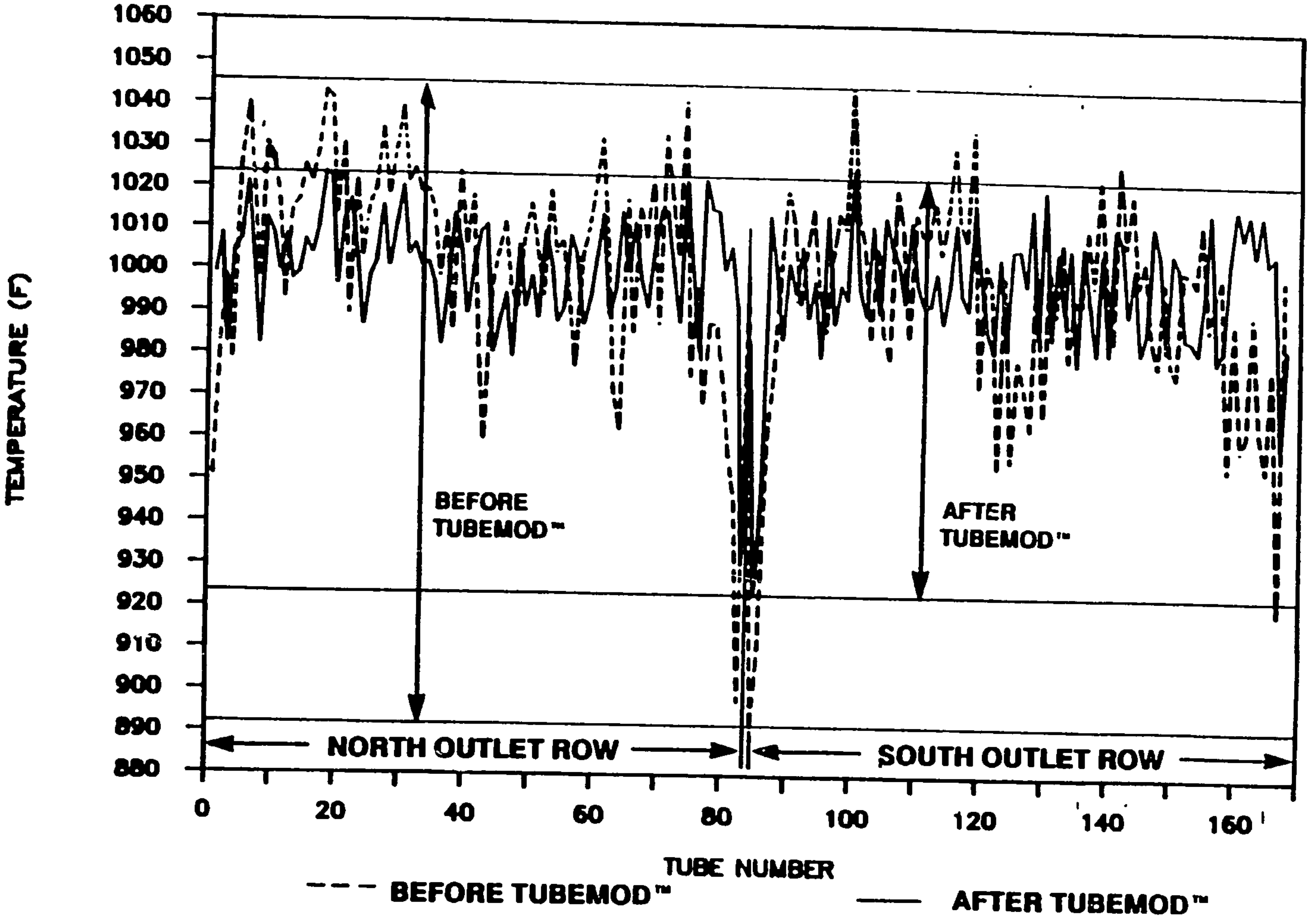


FIGURE 10 – OUTLET TEMPERATURE BEFORE AND AFTER TUBEMOD™.

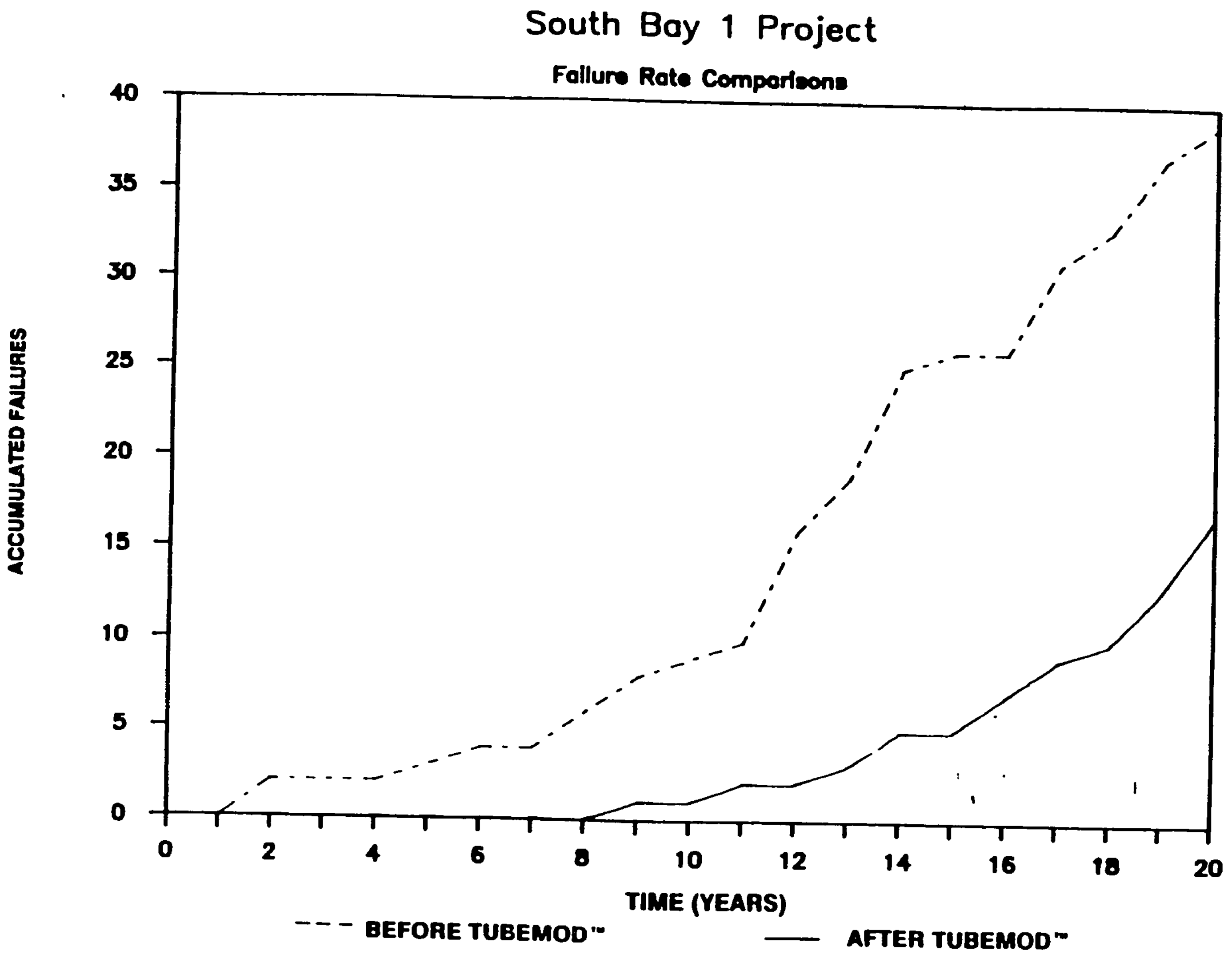


FIGURE 11 — NUMBER OF FAILURES BEFORE AND AFTER TUBEMOD™.

APPENDIX C.6

Residual Fuel Oil User's Guidebook
Volume 2: Residual Oil-Fired Boilers

Electric Power Research Institute
August 1988

1.2 ATOMIZATION

The atomization of a heavy residual oil is one of the most critical steps in the combustion processes since it can directly or indirectly affect:

- amount of air required to achieve complete combustion
- amount of unburned carbon in the fly ash
- boiler efficiency and fuel use to achieve a given load
- boiler particulate emissions
- burner flame stability, possible impingement, and boiler deposits
- boiler NO_x and SO_3 emissions at high excess oxygen levels
- performance and maintenance requirements of auxiliary equipment such as air heaters
- safety of plant personnel where an explosion or fire can occur due to accumulations of poorly atomized or incompletely burned oil

The objective of this section is to 1) review the various types of atomization equipment used in typical utility boiler systems, 2) identify critical parameters essential to achieving effective atomization, followed by 3) a discussion of specific problems and potential solutions for improving the atomization of heavy fuel oils.

1.2.1 Utility Boiler Atomization Equipment

Utility boilers burn fuel at very high rates which requires the oil to be finely atomized and dispersed in the combustion air. Vaporization of the fuel droplets is directly dependent on the surface area of the drop. Increasing the total droplet surface area of the spray by producing a larger number of small droplets increases the rate of fuel vaporization and subsequent combustion. Combustion experiments have shown that the lifetime of a fuel droplet is directly proportional to the square of the droplet diameter. Therefore, rapid combustion of a low volatility residual oil is directly dependent on minimizing the average drop size of the spray. However, the atomizer passages should not be so small that they frequently plug or cannot be easily serviced. Also, an extremely fine spray may lead to an increase in NO_x emissions in some cases.

Many utility boiler burners are designed for gas or oil operation where the atomizer tip is mounted at the end of the oil gun near the diffuser cone or swirler (Figure 1.2-1). Most oil-fired utility boilers use either mechanical or twin-fluid atomizers. Mechanical or pressure atomizers utilize the potential energy supplied by the fuel pumps (i.e., high pressure) to disperse the oil as it exits an orifice. Twin fluid atomizers rely upon gas (steam or air) pressure to assist in the atomization process.

A. <u>Mechanical Atomizers</u>. A typical mechanical atomizer is illustrated in Figure 1.2-2. The fuel enters the mixing chamber through tangential slots in the orifice or sprayer plate. The high rotational velocity imparted by the slots causes the fuel to spread into a thin film on the sidewall of the swirl chamber, forming a hollow conical sheet of fuel as it exits the orifice. This fuel sheet expands downstream of the atomizer leading to the formation of fuel ligaments, followed by eventual breakup into individual drops.

Although older low pressure mechanical atomizers operate efficiently at high flow rates, they suffer from poor turndown (3 or 4:1) as the result of the low oil velocities and pressure drops associated with reduced load operation. Modern mechanical atomizers operate at much higher pressures (up to 1000 psi) and with increased turndown since the development of the return flow or wide range mechanical atomizer. Enhanced atomization is achieved over a wide range of loads by delivering the full load flow rate to the atomizer under all operating conditions. High flow rates ensure high swirl velocities and efficient atomization across the load range. A return flow passage in the center of the atomizer tip allows the excess oil to be bled off at reduced loads without impairing the high swirl level. Turndown ratios of up to 10 to 1 have been achieved with wide range mechanical atomizers operating at 1000 psi fuel pressure and optimum combustion conditions (<u>4</u>).

A typical flow curve for a return flow atomizer is shown in Figure 1.2-3, although these will vary according to the nozzle size and manufacturer. Supply pressures range from 200 to 1200 psi for various designs with the return flow pressure maintained at a nearly constant differential to the supply. The constant differential results in a relatively fixed pressure drop across the tangential slots and swirler of the atomizer. In this manner, swirl levels remain fixed over an extended range of atomization.

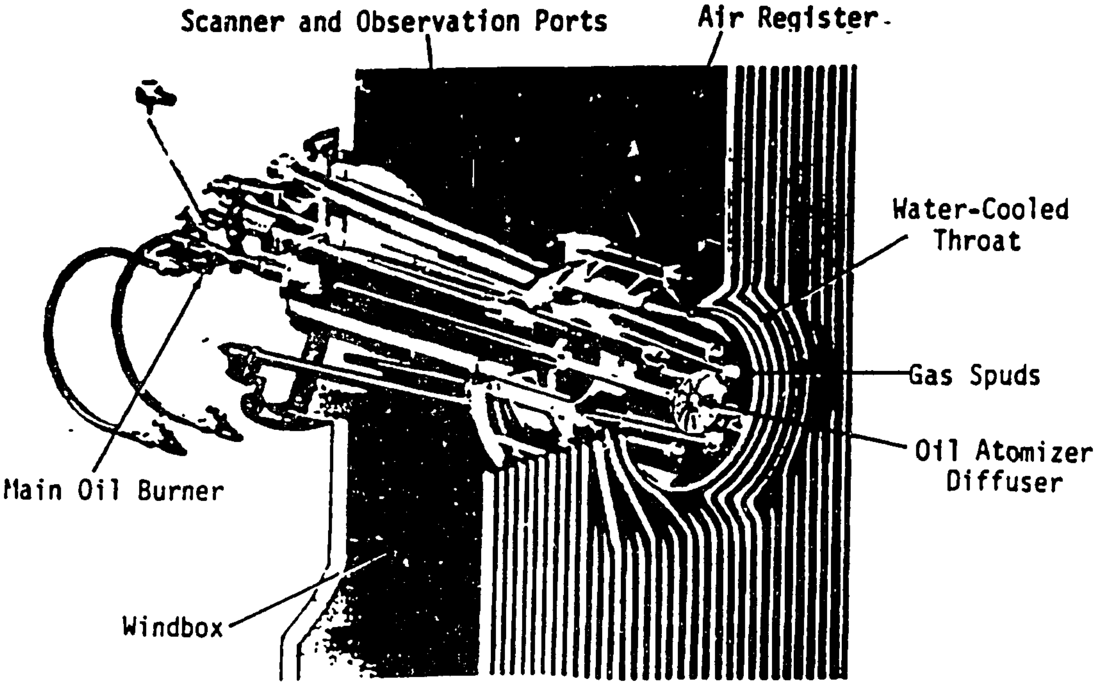
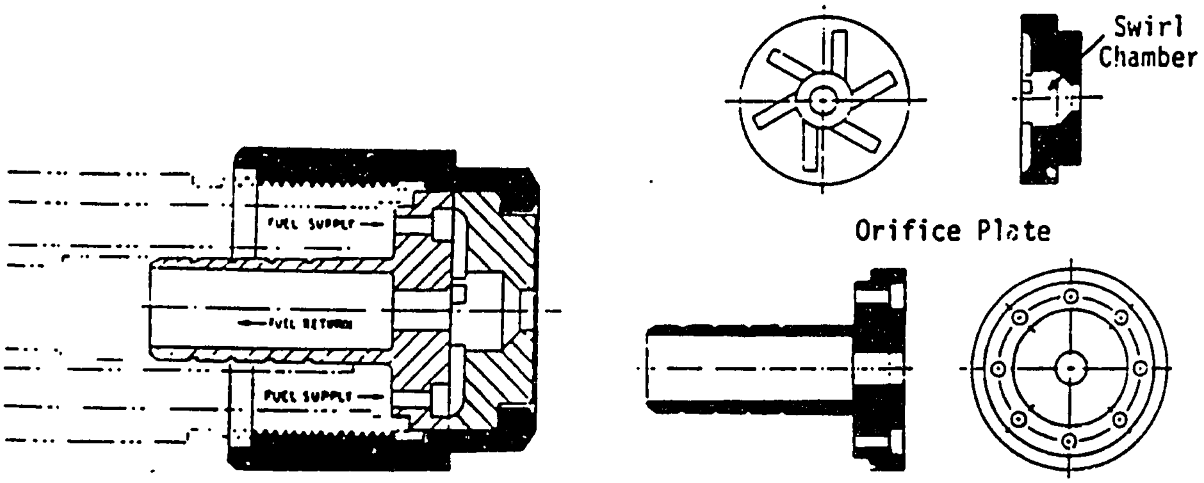


Figure 1.2-1. Circular Register Burner with Water-Cooled Throat for Oil and Gas Firing
Source: Reference 4



Orifice Plate

Atomizer Tip Assembly

Distributor Plate

Figure 1.2-2. Wide Range Mechanical Atomizer
Source: Reference 14

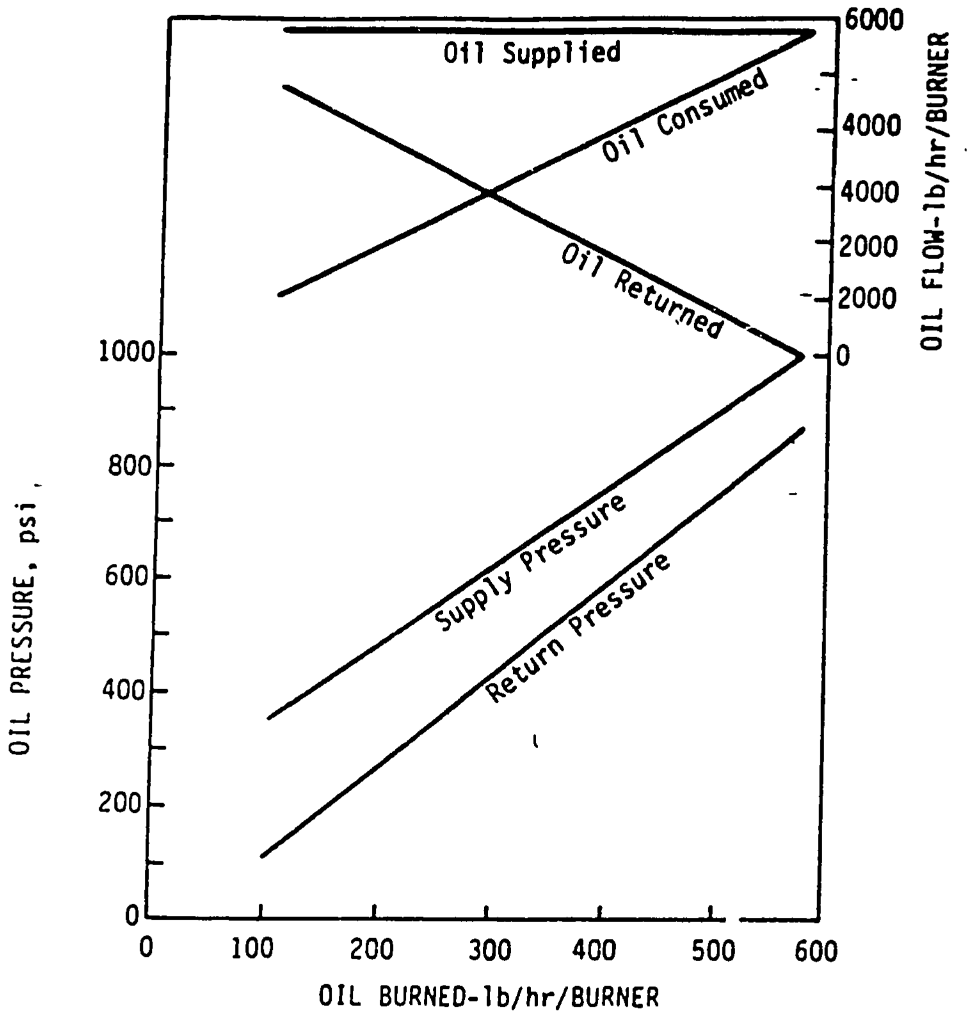


Figure 1.2-3. Typical Return Flow/Pressure Characteristics of a Wide Range-Return Flow Atomizer
Source: Reference 4

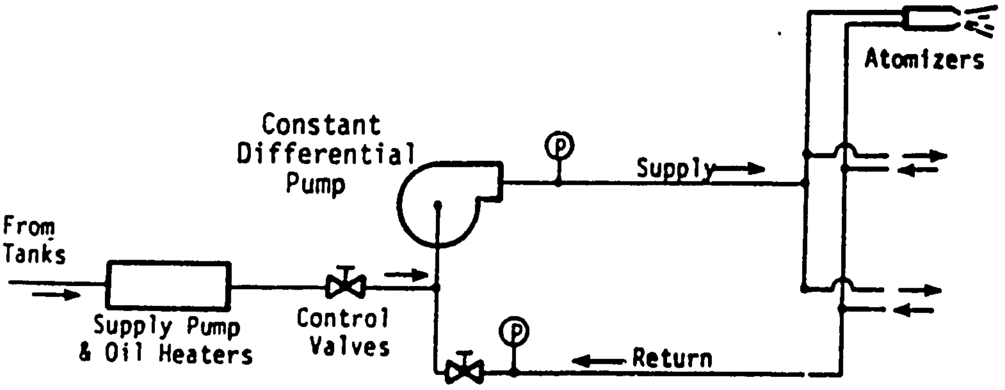


Figure 1.2-4. Simplified Return Flow Atomizer Fuel Flow Control System

Fuel flow through the orifice is controlled by directly or indirectly regulating the pressure or flow through the return flow circuit (Figure 1.2-4). The fuel oil, which is preheated for heavy fuel oils, is supplied to the boiler fuel control system. A control valve regulates the oil flow to each boiler pump and burner system. The high pressure pump (often called a constant differential or CD pump) is typically designed to provide a nearly constant pressure rise between inlet (return) and outlet (supply) flow lines at constant flow rate. As more flow is required by the boiler, less flow is allowed to return from the nozzle, and therefore, the flow through the atomizer nozzle is increased. At maximum capacity, no oil returns from the atomizer and the supply and return pressures are at their maximum.

It should be noted that the performance of mechanical atomizers is directly dependent upon the tolerances and finish of the flow passages and exit orifice in the distributor and sprayer plate. Therefore, minor changes to these dimensions due to erosion, deposits, or mechanical damage during cleaning and inspection can drastically degrade atomizer performance.

B. Twin Fluid Atomizers. Twin fluid atomizers rely upon a supply of steam or compressed air to atomize the liquid fuel, rather than oil pressure alone. Oil supply systems for twin fluid atomizers often have a lower capital cost by eliminating the need for high pressure pumps, but the operating cost can be substantial due to the steam or compressed air consumption. Twin fluid atomizers are generally categorized as either internal or external mix designs, as defined by the point at which the gas stream and fuel come in contact. Externally mixed atomizers are generally characterized by high steam or air consumption rates and therefore, are not commonly used in utility boiler applications.

Two of the most common types of internal mix atomizers are the "T"-jet and "Y"-jet designs. In either design, the atomization is dependent on an exchange of kinetic energy between the two fluids as they mix and exit the atomizer. Typical utility operation favors low pressure steam for atomization, rather than compressed air, due to cost considerations. In addition, utility burner designs have been optimized to provide adequate atomization with the smallest steam consumption in order to minimize operating costs.

T-jet atomizer designs vary with the manufacturer but the fuel and steam flow most often impinge at 90 degrees to one another. Figure 1.2-5 shows a typical T-

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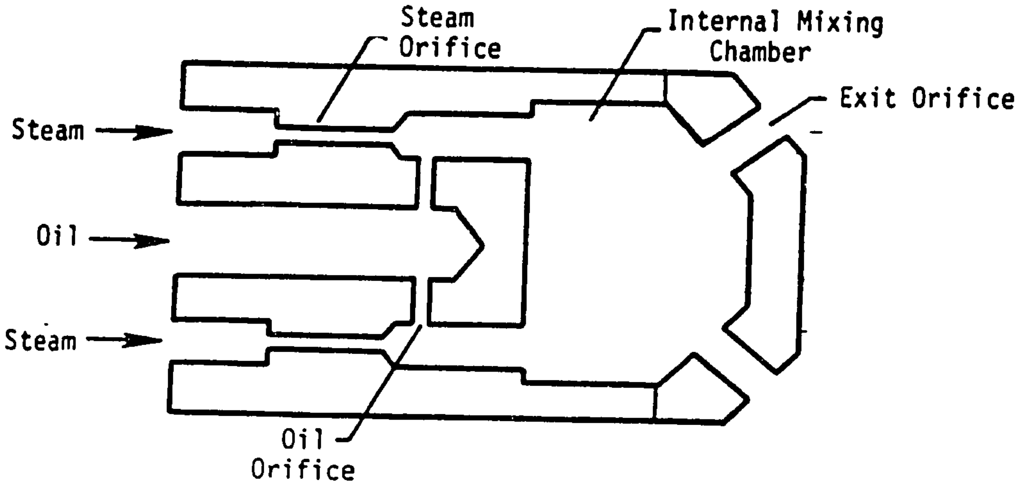

Figure 1.2-5. Generalized Configuration of a T-Jet Atomizer

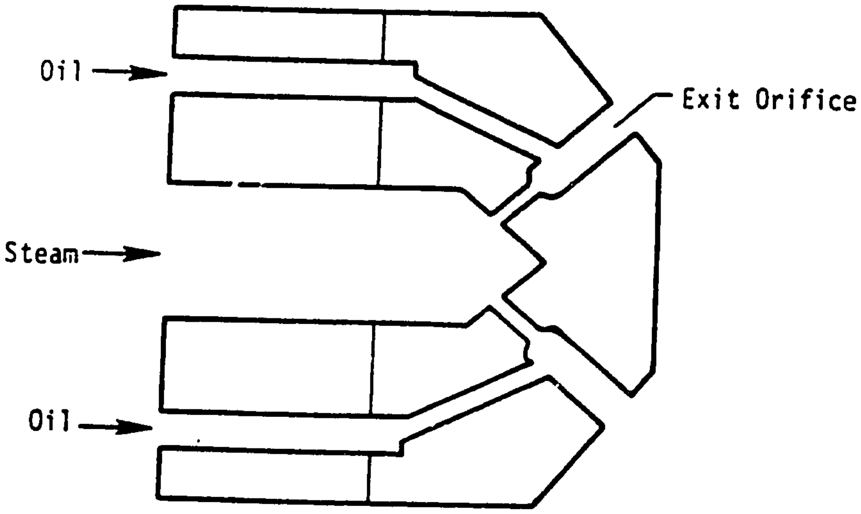

Figure 1.2-6. Generalized Configuration of a Y-Jet Atomizer

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jet atomizer. The steam is injected at a velocity which is typically an order of magnitude greater than the oil velocity. The resulting mix of oil and steam follow in the direction of the steam flow, thus forming a "T" and hence, its name. Utility boiler atomizers utilize a number of steam/oil orifice sets, arranged concentrically within the atomizer. Following the initial mixing, the oil and steam mixture flow into a common mixing chamber and exit through multiple orifices arranged concentrically around the nozzle centerline but angled away from one another. Similar to mechanical atomizers, these nozzles may consist of multiple sprayer plates or plugs, which are attached and sealed to the end of the oil gun.

The steam and oil pressure characteristics of individual burners will vary but typical oil pressures are of the order of 100-150 psi. Recommended steam pressures are typically 10 to 40 psi above the oil pressure, depending on the manufacturer. As the oil flow increases, the steam pressure and flow is adjusted relative to that of the fuel. A typical ratio of steam to oil flow is 0.10 to 0.20 lb/lb under normal operation. The relative steam flow requirement is lowest at high loads, and increases in relation to the oil flow at lower loads, even though the total flow of both fluids decreases.

A "Y"-jet atomizer operates on the same principle as the T-jet, however, its design geometry is different. Figure 1.2-6 shows a typical Y-jet atomizer where the steam and the fuel flow orifices are positioned to form an acute angle, hence the Y configuration. Unlike the typical T-jet, the Y-jet does not incorporate a large internal mixing chamber and only allows a brief time period within the nozzle prior to ejection from the tip. The exit orifices are arranged concentrically around the centerline of the atomizer and are angled away from one another, similar to the T-jet. Oil flow or load turndown ratios can be as high as 10 or 20:1 for Y-jet atomizers. However, a 20:1 turndown of a burner system is not likely, due to constraints of air flow control or flame stabilization requirements. A more practical turndown limit for utility operations is 5 or 7:1.

The fuel pressure versus load requirements of the Y-jet vary according to the specific design or manufacturer, with 100 to 300 psi required at maximum capacity. The oil flow controls are simple and entail only a valve to control the flow of preheated heavy oil through the fuel orifices of the atomizer; no extra pumps are required. Since the Y-jet atomizer has no large internal volume which can pressurize and upset the fuel flow, it is not necessary to maintain the steam pressure above the fuel supply pressure. In one mode of operation, the steam flow controls are set to follow the oil pressure at a fixed differential (similar to a T-jet) but in an alternate operating mode, the steam pressure is fixed at one operating pressure regardless of load. In the latter case, the fuel pressure may exceed the atomizing media pressure by up to 100 psig at full load. The relative pressures of the fuel and atomizing media are design specific and the manufacturer's specifications should be consulted in establishing operating practices.

Y-jet atomizers operate with low fuel pressures (100-150 psi) and typically require the steam pressure be maintained at a set differential, resulting in steam/fuel flow ratios of 0.1 lb/lb. However, Y-jet atomizers designed for constant steam pressure operation frequently require fuel supply pressures of 200 to 300 psi and can operate with low (150 psi) steam pressures. Steam consumption can be reduced to 0.02 to 0.03 lb/lb of fuel at the maximum fuel flow rate condition. These atomizers are specifically designed for minimum steam consumption and utilize energy from the fuel pressure as well as the steam flow to achieve atomization. At low load conditions, the fuel flow is reduced while the steam pressure is maintained constant, resulting in higher steam/fuel ratios, but extended atomization operation.

Besides the reduced steam consumption of Y-jets compared to T-jets, they offer the potential of simplified steam flow controls. The simple design configuration of the Y-jet may also offer maintenance advantages due to the absence of complicated or easily plugged flow passages and convenient tip cleaning operations.

C. Atomization Parameters. The objective of the previous discussion was to review common atomizer designs and operating conditions as background for subsequent discussions of critical atomization parameters important in achieving optimum boiler performance. As noted in the introductory paragraphs, complete combustion and minimum emissions are more likely to be achieved with a fine spray of small oil droplets. Therefore, it is appropriate to identify and discuss the critical atomization parameters that dominate the droplet formation process. The objective is to make the reader sensitive to the importance of controlling these parameters in heavy residual oil firing applications where atomization is more critical.

Listed below are several of the more important atomization process parameters that influence total fuel flow rate and drop size:

Fuel Properties	Atomizer Design	Operating Parameters
viscosity	orifice diameter	supply pressure
density	slot size, aspect ratio	flow rate/return pressure
surface tension	swirl cup diameter ratio	fuel preheat/temperature

It is not appropriate to present an involved discussion of atomizer design theory since this is not essential to establishing optimum atomizer performance. However, a brief review of how these parameters affect atomizer performance and their relative importance is very useful in practical power plant operations.

For a given nozzle design, several fuel and atomizer operating parameters will alter the process and efficiency of droplet formation. The droplet size "D", for a typical mechanical or pressure atomizer, is determined by the flow rate, pressure and kinematic viscosity according to the proportionality:

$$D \propto \frac{w^x \nu^y}{p^z}$$

where w = mass flow
p = pressure
ν = kinematic viscosity of oil
D = drop size

and x, y, and z are exponents in the range of 0.2 to 0.4. Thus, the drop size decreases with increasing pressure or a decrease in viscosity or flow rate.

Viscosity is one of the most critical parameters in the atomization of fuels and it varies widely with fuel type and firing temperature. Residual oil is the heaviest or most viscous fuel oil and has the widest range of viscosity of any fuel type. The optimum viscosity requirement for No. 6 oil atomizers will vary, but generally ranges from 130 to 150 Seconds Saybolt Universal (SSU) maximum for twin fluid atomizers compared to 100 SSU for some mechanical nozzles. Excessively high viscosity will require more energy to overcome frictional forces in the burner and piping systems, leaving less for the breakup of the fuel at the atomizer tip. Coarse sprays or a larger droplet size distribution will result, leading to less efficient combustion and poor flame conditions.

For a typical No. 6 fuel oil, 130-150 SSU will require raising the fuel oil temperature to approximately 200 to 220 F (4). All No. 6 fuel oils require heating for pumping purposes. The typical viscosity versus temperature plots for fuel oils are shown in Figure 1.2-7. A fuel properties analysis is required in order to adequately determine the proper pumping and atomization temperature of a new fuel oil shipment. Frequent sampling and testing of a fuel oil to determine the proper firing temperature is recommended as a minimum, with the use of on-line viscosity indicators or controls preferred.

Although poor atomization frequently results from failure to heat the oil adequately. Excessive fuel temperatures may result in sparklers in the flame and perhaps unstable flame operation. High fuel temperatures can also create problems resulting in coking and vaporization or flashing. Under these conditions, pump operation can be impaired (vapor lock) or flow interruptions to the burner may result. Interruptions of fuel flow to a burner can result in a flameout and create a hazardous situation. Up to this limit, however, a higher fuel temperature is often beneficial and will provide less pressure drop and generally better atomization. The point at which a fuel will flash depends upon its specific composition and the amount of light, easily vaporized hydrocarbons that it may contain. A heavy No. 6 fuel oil would not generally be expected to suffer from this problem.

Mechanical atomizers are more sensitive to a higher than specified viscosity because they are solely dependent upon the flow characteristics of the fuel. Twin fluid atomizers are less viscosity dependent because a majority of atomization energy is supplied by the gas stream. Atomizers designed for very low steam consumption rely upon a combination of pressure and gas assist for atomization, therefore would be expected to be influenced to a moderate degree by high viscosity.

Other fuel properties, in addition to viscosity, that play a factor in the atomization of a liquid are the density and the surface tension. However, these properties play only a minor role in the practical aspects of atomizing utility boiler fuels since these properties are relatively constant for residual oils and are taken into consideration in the design of the atomizer tip. Liquids with a high surface tension require higher energy levels to break a fuel drop into smaller droplets, but there currently are no practical options for significantly altering the density or surface tension of residual oils.

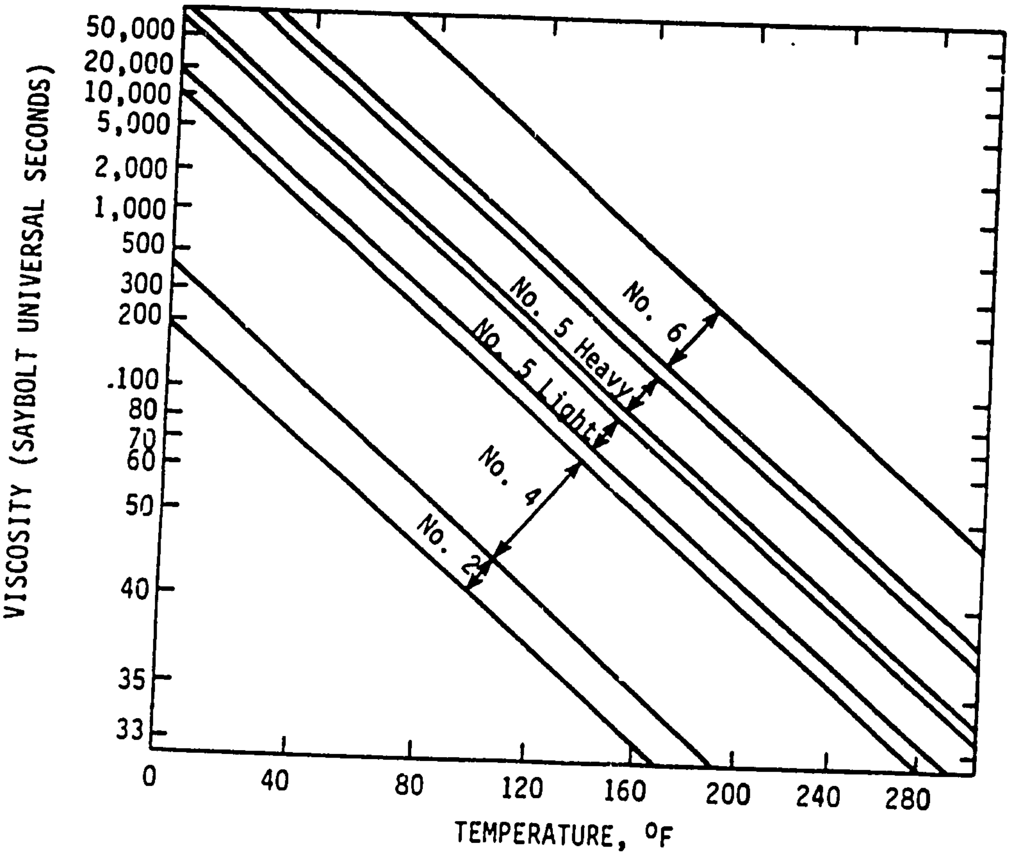

Figure 1.2-7. Viscosity versus Oil Temperature Characteristics for Various Fuel Oils
Source: Reference 4

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The primary atomization parameters under control of the utility engineer, are the process variables such as flow rate, supply and return pressure, and fuel preheat (which affects the viscosity). The impact of these parameters on atomization (i.e. drop size) is dependent upon the nozzle design. A mechanical or pressure atomizer supplies kinetic energy for atomization by converting a high supply pressure to fluid velocity. The atomizer flow versus pressure relationship is similar to an orifice and follows a characteristic square root relationship (Figure 1.2-8). A wide range mechanical or return flow atomizer decouples the orifice pressure versus flow characteristic by maintaining a constant pressure drop and total inlet flow at all load conditions. This allows optimum atomization over a much wider turndown range.

Twin fluid atomizers involve the use of an atomizing fluid (steam or air), and are not as dependent upon the fuel oil pressure drop for atomization. With exception of the interaction between steam and fuel pressure, the dependence of the fuel flow on pressure drop will be similar to a conventional orifice. The ratio of steam mass flow to that of the fuel is often utilized to characterize twin fluid atomizers. High steam to fuel flow ratios will result in improved atomization. High ratios may result from increased steam flow (or pressure) and reduced fuel flow (e.g. reduced loads). A typical droplet diameter versus steam to fuel mass flow ratio dependence is depicted in Figure 1.2-9. A family of curves will result from operation at various mass flow rates.

Since the design of the atomizer is usually fixed by the burner manufacturer for a given boiler, the utility engineer does not routinely become involved in changes in the atomizer design to improve atomization. However, there are some exceptions where actual atomizer tip modifications have become necessary. For example, the implementation of low-NO_x firing where a portion of the burners are operated fuel-rich, requiring a substantial increase in flow rate through selected burners. In other cases, the grade or quality of fuel has changed significantly or there are indications that the original atomizer design was marginal. Although it is beyond the scope of the current discussion to review and summarize atomizer design principles, it is appropriate to note some of the general correlations that have been developed to relate mechanical atomizer design parameters. The drop size "D", is proportional to the geometrical parameters as noted below:

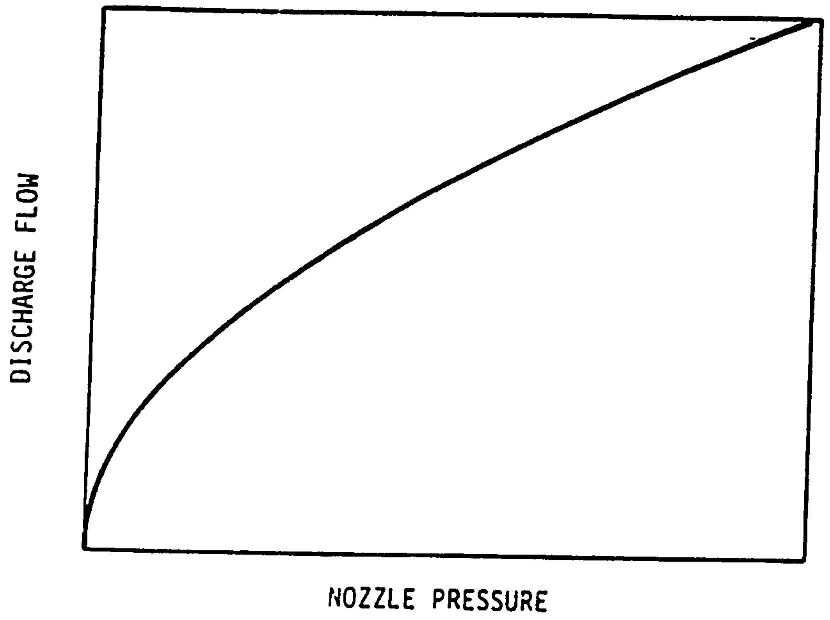


Figure 1.2-8. Typical Flow versus Pressure Characteristic of a Simplex Atomizer

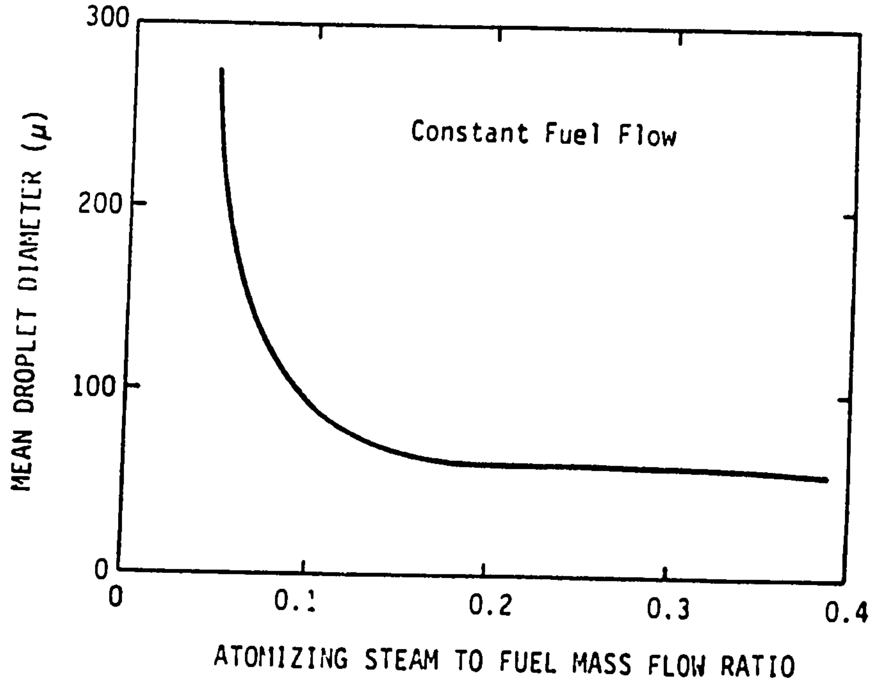
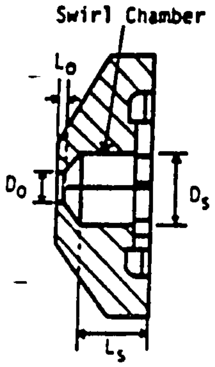


Figure 1.2-9. Typical Droplet Diameter versus Atomizing Fluid to Fuel Mass Flow Ratio Curve

$$D \propto \frac{L_o^{\,a} L_s^{\,b} D_s^{\,c}}{D_o (A_i / L_o D_s)^d}$$

where L_o = orifice length
L_s = swirl chamber length
D_s = swirl chamber diameter
D_o = orifice diameter
A_i = inlet area to tangential swirl slots
D = drop size



A correlation of this type has been used to optimize atomizer performance (5) and examples of modifications to atomizer design will be discussed in more detail in the next section.

1.2.2 Utility Operating Experience With Residual Oil Atomizers

The objective of this section is to summarize recent utility operating experience with residual oil atomizers so that utility engineers can take advantage of this experience in improving operations within their plant. Although the primary emphasis will be on operations and maintenance practices to achieve efficient atomization and combustion, a portion of the discussion will also address emission impacts and potential atomizer design modifications associated with trouble-shooting residual oil combustion problems. Many of these combustion problems are directly related to fuel property changes.

Heavy residual oils have changed in composition during the past decade to the extent that they may pose new operational problems when utilized in oil-fired boilers with no previous history of problems. To some degree, the unit has undergone a "fuel change" and the boiler may not operate in the manner normally expected. Residual fuel oils have generally become more difficult to burn, as discussed in previous sections. A change in atomizers or fuel firing practices may be required to burn these fuels in an acceptable manner.

Several options exist to improve the atomization and combustion of a residual oil or to maintain optimum performance in a fuel supply system that has been operating satisfactorily. Meetings that were held with utility engineers and boiler equipment manufacturers during guidebook preparation focused on the importance of fuel specification, fuel property measurement, and well defined operations and maintenance practices. The current discussion will focus on utility operations and maintenance practices since the fuel specification and characterization issues have been previously addressed.

A. Residual Oil Operating Practice.

1. Viscosity Control. Maintaining the design operating pressure and temperature/viscosity of the fuel for a specific flow rate is critical to achieving satisfactory atomization of residual oils. Since the dominant fuel property affecting atomization is viscosity, it is important to always maintain the fuel temperature high enough to meet the minimum viscosity requirements. These viscosity requirements vary with burner manufacturer and type of atomizer. An example of standard operating conditions for Forney Engineering burners is shown in Figure 1.2-10. Combustion Engineering recommends that the oil temperature be maintained high enough to keep the viscosity below 150 SSU. Babcock & Wilcox recommends that a Number 6 oil be heated to reduce its viscosity to 130-150 SSU for proper atomization (4). For a typical No. 6 residual oil, this corresponds to a firing temperature in the 200-220 F range. However, frequent sampling and analysis of each individual oil is recommended as a minimum to establish the viscosity vs. temperature relationship and the proper firing temperature. Since the viscosity varies rapidly with small changes in temperature, a significant shift in atomization characteristics can occur.

Some utilities prefer continuous on-line instrumentation to monitor fuel oil viscosity and control fuel oil temperature as the fuel properties change. Unfortunately, the utility experience with viscosity control instrumentation is not well documented. However, discussions with plant engineers acquainted with its use indicated that it can be a very effective means of controlling atomization and combustion conditions, particularly where the utility is subject to both NO_x and particulate emission regulations.

Many utilities customarily raise the operating excess air level when problems with high carbon content in the fly ash are encountered. Although this may successfully overcome viscosity related atomization problems, it can easily increase NO_x emissions on marginal units to the point that regulations are violated. High excess air also decreases boiler efficiency due to increased dry flue gas losses. A more attractive alternative is to implement fuel oil viscosity/temperature control which offers the potential

SPECIFICATIONS

STANDARD OPERATING CONDITIONS

Atomizer Type*	Oil Pressure, psig	Oil Viscosity, SSU	Atomizing Media Pressure, psig	Atomizing Media Flow, (lbs media/ lbs fuel)
WRMA	1000	100	none	none
Y-Jet (assist)	250	130-150	150	0.03
Y Jet	125	130-150	150	0.12
IM	125	130-150	150	0.18

*Wide Range Mechanical Atomizer (WRMA)	Return oil pressure controls firing rate
Y-Jet (assist)	Maintains constant atomizing media pressure
Y-Jet	Maintains constant differential pressure between fuel and atomizing media (typically 25 psig over oil)
IM	Maintains constant differential pressure between fuel and atomizing media (typically 25 psig over oil).

Figure 1.2-10. Recommended Standard Operating Conditions for Forney Engineering Burners
Source: Reference 15

of more consistent atomization at a lower excess air level and increased boiler efficiency. One East Coast utility segregates their oil by sulfur content but will blend fuels when necessary using on-line viscosity control to adjust firing conditions. A tank of light (one percent sulfur) oil is reserved for emergency use only when blending is required to burn an unusually high sulfur fuel. The boiler is fired out of a service tank where the fuel has been blended. The importance of fuel viscosity control instrumentation has been very evident to the utility where changes between fuel tanks during normal operations have required an increase in the fuel firing temperature from 140 F to 220 F to meet the boiler manufacturers recommended optimum viscosity specifications. However, it should be noted that very little data is available on the precision with which the continuous oil viscosity measurement instrumentation matches the measured viscosity obtained in the test laboratory. In theory, the benefits of viscosity control are great in terms of more consistent and improved atomization. However, in actual practice, some utilities have had mixed results overall, primarily because of operations and maintenance problems outlined in the next paragraph.

Although sufficient technical information and utility operating experience was not available to quantitatively define the effectiveness of viscosity control, several utilities did offer comments about the maintenance problems they have experienced. Most of the viscosity controls currently in use are made by A. O. Smith, CE/Bendix or Dynatrol. Many of the problems have been associated with leaks and fouling of the mechanism within the viscometer due to fine grit and other contaminants within the oil. Some designs also seem to be prone to a frequent drift or a shift in calibration requiring removal from service and return to the manufacturer for recalibration. Since most utilities had very few units in service, they were reluctant to offer details on these problems since they were not sure whether they were unusual problems associated with their fuels filtration and operating practices or characteristic of the viscometer. Although it may be coincidental, most of the utilities experiencing difficulty were located in Northeastern U.S. firing high API moderate to high sulfur fuels. One west coast utility with considerable viscosity control experience, essential to emissions compliance, has had no instrumentation problems with higher grade, low sulfur residual oils.

Since a number of utilities favored viscosity control but were just beginning to define its application in their system, other sources of information on viscosity control operating experience were considered. Two manufacturers of viscosity instrumentation (CE/Bendix and Dynatrol) were contacted twice for technical data on the performance of viscosity instrumentation for utility applications, but neither vendor responded to these requests. Consolidated Edison of New York and New England Power Service Corp. are in the process of installing viscosity control instrumentation and their experiences will be incorporated in possible future updates to the guidebook.

2. Benefits of Temperature/Viscosity Control. Several utilities that have experienced high carbon levels in the particulate and "smoky" fires have improved atomization and minimized these problems by raising the fuel temperature above normal recommended levels. This approach can sometimes be beneficial if a change in firing temperature is instituted cautiously in small steps. Changes in boiler operation should be carefully monitored and the process halted if any detrimental effects are noted. An improvement in atomization is usually indicated by a reduction in the ash carbon content, total particulate emissions or opacity, CO emissions and the minimum excess air level at which visible stack emissions are encountered (smoke point or threshold). A particulate size analysis may also confirm a shift to a finer size range for a majority of the emissions. A less reliable indicator is the direct observation of the flame length, shape, and burnout characteristics (although a significant improvement in atomization can occasionally be confirmed visually).

The operating temperature limits and capacities of the existing oil heaters, fuel pumps, piping, and controls should be reviewed before increasing oil temperatures to insure that the equipment is always maintained within safe operating limits. Excessively high fuel temperatures may result in coking or carbonaceous deposits in the fuel oil heaters or other burner operational problems. Flame stability may be adversely affected as evidenced by a tendency for the flame to lift off and blow away from the tip of the burner. A high fuel oil temperature can also result in the appearance of sparklers in the flame. A primary concern is the increased tendency for carbon buildup in the atomizer tip and the fuel oil heaters. With these caveats or precautions in mind, it is appropriate to review some of the benefits that have been observed by an increase or adjustment of the oil firing temperature.

Some of the most dramatic improvements in atomization, CO and particulate emissions have been demonstrated on large industrial boilers where the combustion intensities and residence times for carbon burnout are more restrictive than large utility boilers. However, the same principles apply. For example, a 20°C (36°F) increase in heavy fuel oil temperature from 87°C (189°F) to 107°C (225°F) on a 45,000 lb/hr water tube industrial boiler reduced particulate emissions by 50 percent (6). Although no direct measurement of improved atomization was made, it was evident by the reduced carbon content in the ash plus reduced CO and particulate emissions. The burner utilized a twin fluid steam atomizer with a full load fuel pressure of 60 psi and a 20 psi steam to fuel pressure differential. In addition to the fuel temperature increase, subsequent atomizer modifications were also made resulting in a final fly ash carbon content of less than two percent by weight.

The Central Electric Generating Board (CEGB) in England conducted a very extensive residual oil combustion improvement and emissions reduction program on large utility boilers in the late 1960's and 70's. Pilot-scale tests of viscosity reduction and control were followed by full-scale tests in a 500 MW utility boiler (7). A significant particulate emissions reduction benefit (10%) was demonstrated when the oil firing temperature was increased by 17°C (approx. 31°F) from 115°C to 132°C. However, this was less than the 50 percent reduction observed by CEGB in the 0.5 MW (thermal) pilot-scale tests with a 30 C (54°F) fuel temperature rise as shown in Figure 1.2-11. The much higher reduction in particulate emissions on smaller units is not surprising since industrial boilers have much cooler furnace sections and therefore, are more susceptible to carbon burnout problems and the potential improvement with better atomization.

There is also some evidence that the improvement in atomization with increased oil temperature may have a maximum after which the effects begin to degrade. In small scale atomizer tests with a heavy fuel oil, optimal fuel oil temperatures were found to correspond to approximately 92 SSU for a pressure atomizer and approximately 90 SSU for a medium pressure air atomizer (8). The optimum was determined by particulate emission

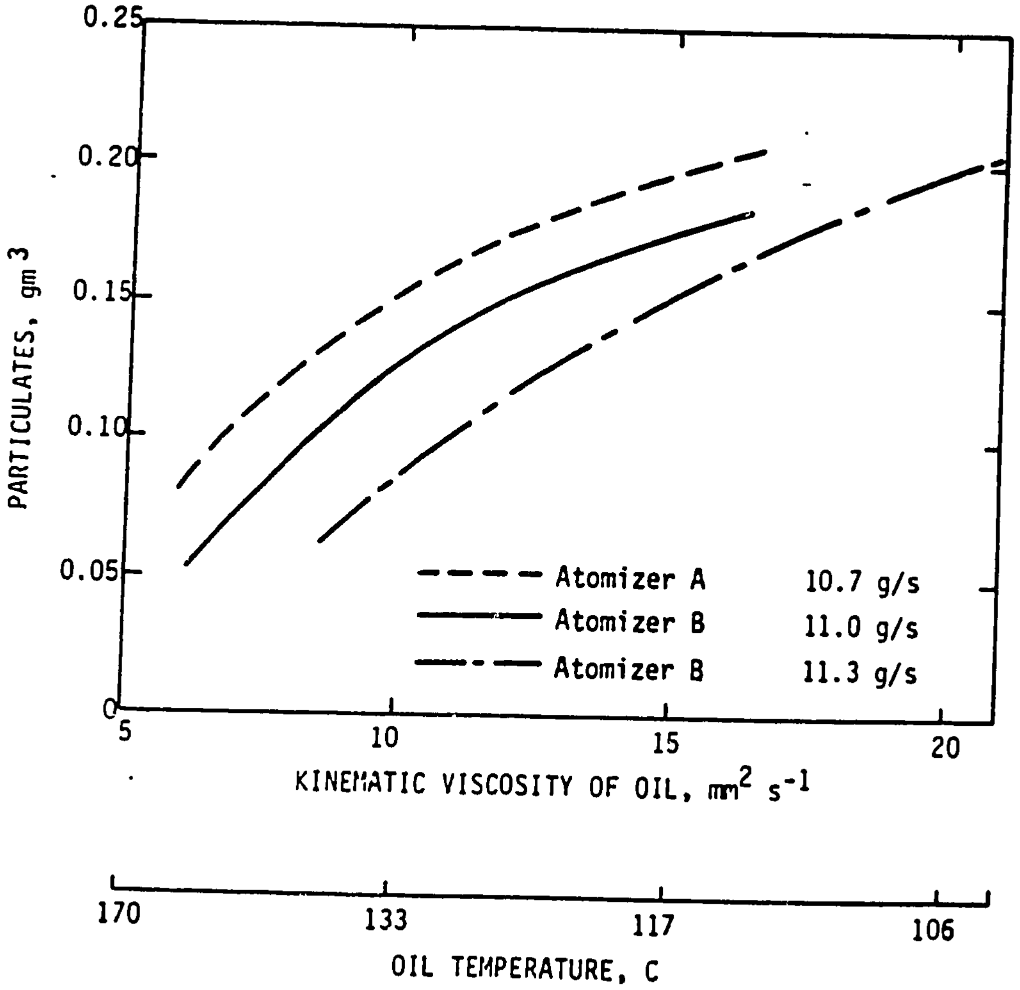


Figure 1.2-11. Variation in Particulate Emissions with Fuel Viscosity and Oil Temperature at 1% Excess Oxygen
Source: Reference 7

measurement. Although the increase in emissions at higher temperatures was less pronounced than at lower temperatures, an optimum was found. It is quite likely that results such as these will be highly fuel oil/atomizer design specific; therefore, an optimum may not occur at the same viscosity (temperature) as described here (if at all). The reason for an optimum temperature is probably related to combustion aerodynamic effects, rather than atomization degradation. Cold flow tests of atomizers show a continual improvement in atomization (smaller drop size) with lower viscosity liquids. One speculation concerning the increased particulate at reduced viscosities is the possibility that smaller drops may experience less aerodynamic drag and quickly reach the air steam velocity. The reduced differential velocity may affect the vaporization rate and carbon burnout.

Another important finding of studies of increased fuel oil temperature was the time dependence in achieving the full benefits of the implementation. An industrial boiler fuel temperature study by Laurendau (6) indicated that at least 48 hours of operation at the new fuel firing temperature was required before the associated particulate emissions stabilized. Utilizing the standard EPA particulate measurement techniques, a continuous reduction of particulate emissions was monitored for the two-day period. While atomization improvements resulted in immediate benefits (such as improved flame conditions, smoke point, and CO emissions) the full reduction of particulate emissions was not simultaneously evident. Particulate emissions involve a dynamic process of deposition upon and removal from heat transfer surfaces which may be the reason for the delay. In the current example, the particulate emissions continued to drift downward from approximately 0.11 lb/10^6 Btu immediately after the fuel temperature increase to approximately 0.08 lb/10^6 Btu 48 hours later. This change represented the difference between non-compliance and compliance with emission regulations. A similar time dependent effect on particulate emissions may occur for any operational, fuel or burner change.

The demonstration tests summarized above indicate that significant improvements in atomization have been attained by increasing the fuel firing temperature. Reduced viscosity results in smaller droplet size distribution, which improves fuel burnout with lower carbon content in the particulate. The degree of success appears to be dependent upon the severity of the carbon burnout problem, which may be influenced by boiler size.

3. Other Operational Methods. The preceding discussion has focused on fuel viscosity control because it is one of the most direct methods of improving atomization, but there are other operational methods that should also be considered. In some cases, it may be possible to increase the energy available for atomization by increasing fuel pressure differentials on mechanical atomizers or by increasing the steam pressure for twin fluid atomizers. These measures will result in higher operating costs through higher pump power or higher steam consumption. For mechanical nozzles, the potential for better atomization may be limited by the existing pump system or related controls. In some cases, adjustments may not be feasible. Raising the pressure differential may also result in limiting the maximum capacity of the nozzle due to a reduction in maximum flow imposed by the differential pumps.

An increase in steam or air pressure is likely to be more straightforward procedure, and requires a higher differential between fuel and steam or a higher fixed steam pressure, depending on the type of flow control utilized. Improved atomization will result from raising the steam flow, and thereby the steam to fuel mass flow ratio operating point (Figure 1.2-9). The exception to this will be the case where the steam to fuel flow ratios are already high, and little or no reduction of mean droplet diameters will result (see Figure 1.2-9, flat part of the curve). Reducing the mean droplet diameter of a fuel spray can only be determiend by flow tests of a nozzle and direct droplet size measurement techniques, or by implementing atomizing steam pressure modifications on a boiler and determining the impact on combustion performance as outlined in later sections. Since steam consumption is a primary concern to utility boiler operators, the most likely zone of operation is near the knee of the curve in Figure 1.2-9, where the steam consumption and droplet size are likely to be optimized. In the case where a particularly viscous or off-spec oil is encountered, current atomizer operation may be on the high slope region of the curve, allowing improvement by higher steam flow adjustments.

Higher atomizing steam or mechanical atomizer differential pressures will result in higher exit velocities from the burner tips. Besides higher operational costs, other potential problems may occur and should be monitored. Near burner flame characteristics may become more unstable as a result of unstable ignition or poor flame holding qualities. Higher velocities may produce a wider flame, and result in flame impingement or a buildup of carbonaceous deposits on the burner refractory (quarl). Flame detection and scanner adjustment may also be affected if the flame position or radiation characteristics have changed.

Many burner manufacturers recommend that dry steam be used for atomization to prevent slugs of condensate from upsetting the atomization and/or burning process. Therefore, steps should be taken to be sure that the steam has sufficient superheat at the takeoff point to remain dry by the time it reaches the individual oil guns on the burner front. However, it should be noted that the impact of steam quality on atomization has not been well documented. One study by the CEGB in England (9) compared the particulate emissions using 60 F superheated steam with that of 14 percent wet steam. The scatter in the data over a range of excess O_2 levels was approximately 20 percent, which was indicative of the uncertainty in the particulate measurement masking any potential difference due to the steam quality. Nonetheless, steam traps should be used to prevent slugs of water from reaching the atomizer in cases where condensation has inadvertently occurred.

B. *Maintenance and Inspection*. Discussions with a number of utilities who are heavy users of residual oil indicated that a very large fraction of the combustion performance and atomization problems are equipment maintenance related. This should not imply that operational, design or fuel property issues are less important because their impact or dominance vary with each individual situation. The difficult challenge for the utility engineer is to determine whether a residual oil atomization problem is caused by 1) a change in fuel properties, 2) operating practice, 3) equipment maintenance or 4) equipment design. Quite often a change in fuel properties will aggravate an existing operations or maintenance problem leading to unacceptable performance that is blamed on the fuel when the fundamental root cause is less evident. In some instances, there is no *single* cause of a residual oil combustion problem which may, in fact, result from an unfortunate "coincidence" of all four problem areas. The need for a diagnostic aid for troubleshooting residual oil combustion problems was recognized during the current study and subsequently led to the preparation of Section 9.0 of this report.

Two of the most critical maintenance and inspection issues concerns the condition of the atomizer tip or nozzles and the position of the oil gun tip in the burner throat (e.g. relative to the diffuser or stabilizer). Common atomizer tip problems include 1) oversize orifice diameters due to erosion, 2) carbonaceous deposits due to leaking fuel shut-off valves or poor purging practices, and 3) leaks due to damaged or poorly assembled components. However, even a well maintained atomizer will perform poorly if it is not properly positioned relative to the combustion air flow. Since these issues are so critical to overall boiler performance, they are discussed in more detail in the remainder of this report section.

One of the first steps in evaluating atomizer performance should be an inspection of the current condition of the atomizers to determine if they are still within tolerances specified by the original manufacturer and have not been damaged by improper handling. In general, the primary atomizer maintenance issue is nozzle wear and damage. Erosion will adversely affect the nozzle by enlarging the fuel passages. Heavy oils are among the "dirtiest" liquid fuels due to their high ash content. While not high in ash compared to coal, for example, the ash in the oil will erode the flow passages given sufficient time. An increase in flow area will geometrically reduce fluid velocities and impair the atomization process. This is obviously most critical for pressure atomizers, although twin fluid atomizers can be adversely affected as well. Since nozzles are not repairable, frequent gauging and eventual replacement of atomizer tips are required to maintain atomization quality. Wear tolerances recommended by burner manufacturer should be observed, and excessively worn atomizers discarded.

Poor atomizer performance can also result from undersize orifices or flow passages which become partially (or totally) plugged due to carbonaceous deposits. The condition of the exit orifice is particularly important for mechanical or pressure atomizers, since the shape and flow characteristics of the fuel passages are critical to the creation of the spray. Heavy fuel oils in particular, are troublesome since they possess a greater tendency to form carbonaceous deposits in a nozzle compared to lighter, more highly refined fuels. These deposits frequently form when fuel is allowed to remain within the nozzle and exposed to heat. Deposits can also form on the exterior of nozzle during routine operation. If allowed to grow, deposits of any type will affect the internal or external fuel flow and can adversely affect the spray. Multiple jet nozzles may become partially clogged and give an unbalanced spray, resulting in poor fuel distribution and impaired combustion. Two very common causes of plugged nozzles are 1) failure to properly purge an oil gun when it is removed from service and 2) improper gun retractor position when the oil gun is left in place, but temporarily out-of-service (due to a load reduction or use of another fuel). There is a natural tendency to hurry the oil gun purging process before all of the oil has been adequately flushed from the gun. However, traces of oil left in the gun can become hard deposits upon subsequent heating. A related problem is coke and deposit formation in the oil gun if the retractor position is improperly set or malfunctions, leaving the tip of the gun exposed to the high radiant heat load of the furnace.

Plugged orifices can also result from contaminants carried into the atomizer from other sources. The remainder of the fuel supply system should be periodically examined for plugged strainers or fuel filters where samples can be taken and analyzed for the source of the deposits.

Other common causes of poor atomizer performance are fuel or steam leaks due to damaged or poorly assembled atomizer components. Multiple part atomizers consisting of various sprayer plates are typically assembled with an end nut holding lapped surfaces together for sealing. Deposits or irregular surfaces will allow fuel or atomizing steam leakage, both of which will adversely affect atomization. Again, inspection and maintenance are required to insure fluid tight joints. These precision parts can be damaged by improper handling or other accidents. Nicks or deformations of the exit orifices, internal flow passages, or lapped joints must be avoided. Maintenance personnel should be continually reminded how important the surface finish is on some atomizer parts and the use of improper instruments to clean orifices and passageways should be strongly discouraged. Some utilities have instituted a comprehensive operator training program that covers detailed atomizer maintenance procedures. Maintenance is scheduled according to the time an oil gun has been in service since its last cleaning and inspection. Routine lapping of sprayer plate assemblies have also been instituted to ensure leak-free joints and proper atomizer operation. These procedures have led to a very noticeable decrease in atomizer related combustion problems. Two west coast utilities (Southern California Edison and San Diego Gas and Electric) with strict NO_x emission regulations have conducted very

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comprehensive reviews of their residual oil firing and maintenance practices at their plants with substantial benefits in performance.

Other maintenance related factors include the position of the atomizer in relation to the diffuser, or impeller. The purpose of the diffuser is to protect the base of the fuel spray from the combustion air being supplied by the burner and thereby, stabilize the flame. A diffuser is typically used with mechanically atomized sprays but may be absent from twin-fluid atomizers. A positional change of 1/2 to 1 inch can have a major effect upon the flame, since it affects the initiation of the combustion process. The position of a diffuser is recommended by the burner manufacturer at startup, although it can be modified for optimum performance (see Figure 1.2-12 for example). This may occur if the tip has been replaced with a new atomizer design. Maintenance is limited to inspection of the condition of the diffuser and insuring that its position remains at the optimum setting.

C. Atomizer Design Modifications. Operational adjustments to the atomizer or the fuel pumping system may not be practical, or perhaps insufficient to resolve a problem condition. Modified or new atomizers may be justified if the easily implemented operational changes cannot be performed, or if satisfactory results were not achieved for reasons not related to improved atomization (e.g. emissions). The original atomizers specified for a newly constructed boiler are designed for the specific fuel oils (or range of fuel oils) that were expected to be burned, the type of boiler operation, and preferences of the utility. However, since many oil-fired boilers are approximately 20 years old, the type of fuels available, as well as the operation of the boiler (i.e., cycling operation, etc.), may have significantly changed. The type or quality of residual fuel oils may have deteriorated and may no longer be optimum for the original atomizers or operating conditions.

Design modifications intended to improve atomization include varying the tip geometry, orifice diameters, resizing the nozzles, or perhaps entirely new atomizer tips. This modification process will require more engineering and planning than the trial and error approach sometimes used during a change in operational or firing practices. Atomization may be enhanced by increasing the nominal steam to fuel flow ratios for steam atomizers or by utilizing a design which is better matched to the current fuel. In addition, design modifications can be utilized to vary the combustion process or flame shape, by altering the

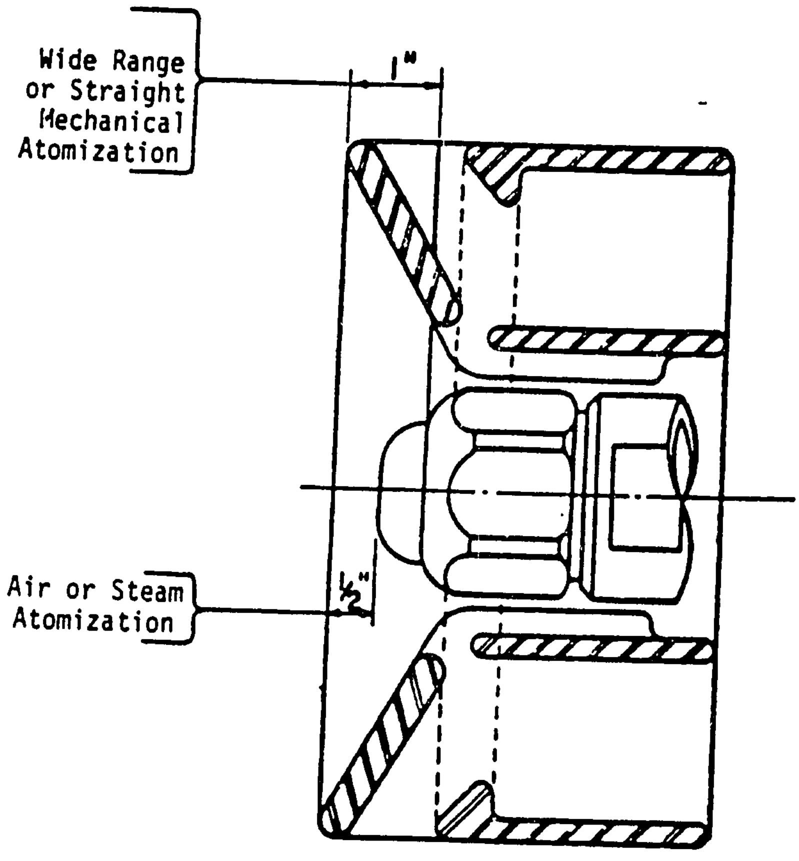

Figure 1.2-12. Example of Typical Relation of Oil Gun Tip to Diffuser Cone (Courtesy of Combustion Engineering)

shape of the fuel spray. Once the modified atomizer tips have been installed, their performance must be verified by observation or specific performance tests such as opacity, excess air reduction, particulate loading, modified flame shape, NO_x emissions, etc. Changes to an atomizer design can also be evaluated by cold flow testing of the original and modified designs in a droplet sizing test rig or "spray booth". A change in the mean droplet diameter or droplet size distribution can be used to evaluate atomizer design changes before they are tested in a boiler.

Design changes to mechanical atomizers must consider the maximum supply pressure and flow capacity characteristics of high pressure fuel pump system. The use of undersized or modified nozzles may limit the maximum flow capacity as the result of excessive pressure drops. Enhanced mechanical atomization often requires higher fuel velocities, smaller fuel flow passages and therefore higher pressure drops.

For twin fluid atomizers, increasing the steam flow is likely to be an effective method of improving atomization. This may be performed by machining larger steam flow orifices or by resizing the atomizer with the next larger size commonly offered by the manufacturer. When operating at the same steam pressure, a larger area orifice will permit higher flow rates, higher steam/fuel ratios, and will generally improve atomization. The fuel oil pressure drop should be within specifications of the atomizer; however, it will be expected to be lower. This design modification process will require more engineering and planning than the trial and error approach sometimes used during a change in operational or firing practices.

Design modifications may include improved atomization by increasing the nominal steam to fuel ratios for steam atomizers or by utilizing a design which is better matched to the current fuel. In addition, design modifications can be utilized to vary the combustion process or flame shape, by altering the shape of the fuel spray. One specific example is altering the orientation or angle of the exit orifices to broaden or narrow the spray and therefore, the flame.

In one heavy fuel oil atomizer improvement program, the utility was experiencing excessive carbonaceous particulate problems at high loads due to poor atomization of the fuel with the original Y-jet atomizer design. Full-scale cold flow testing of the atomizer indicated the large drop sizes produced at high flowrates were primarily caused by inadequate atomizing steam flow. The utility (San Diego Gas & Electric) solicited custom atomizer designs from two independent suppliers which were compared to an oversized nozzle (next larger standard size) of the original Y-jet atomizer design. Drop size data for two different boiler applications are shown in Figures 1.2-13, 14. Operation of the oversized nozzle reduced the drop size by 17 percent with a corresponding 50 percent increase in atomizing fluid use (10). Perhaps more important was the decrease in the fraction of fuel contained in the very large drop sizes (9.5 percent of the total mass was reduced to 2.9 percent). Although the oversized Y-jet did not produce drops as small as the two custom designed tips, the reduction in drop size was sufficient to reduce the particulate emissions to an acceptable level. (Extensive full-scale testing of one custom designed atomizer by Parker Hannifin gave a 64 to 74 percent reduction in the emissions of large carbon particles at full load.)

Although use of the oversized Y-jet nozzle did improve atomization at the highest load settings, the results at reduced load were not as beneficial. At approximately one-half load, the oversized nozzle gave slightly larger drop sizes than the standard nozzle, although the median droplet diameters were still lower than for higher flow rate cases (see Figure 1.2-13). This low load droplet diameter increase illustrates the problem of a potential reduced turndown ratio for an oversize nozzle. Since the oversized nozzle is designed for higher flows, its minimum flowrate will be a higher percentage (lower turndown ratio) of the standard atomizer tip design. Nonetheless, an acceptable solution to a particulate problem was achieved by simply substituting the next larger tip size to achieve increased steam flow. This approach is a relatively inexpensive option that should be considered where full load design atomizing steam flow appears to be inadequate.

An opposite approach, increasing the fuel pressure by resizing the burner tips can also be an effective solution. For example, smaller fuel orifice diameters can be selected to increase the fuel pressure drop and thereby increase fuel velocity to enhance atomization. One test with twin fluid atomizers in an industrial boiler has been documented. New burner tips were specified which produced higher fuel pressure drops at the same fuel flow rates (6). The type and size of these steam atomized nozzles were not documented in these tests, but a relative particulate mass emission reduction of approximately 30 to 40 percent was recorded, indicating enhanced carbon burnout. The steam atomizing tips were

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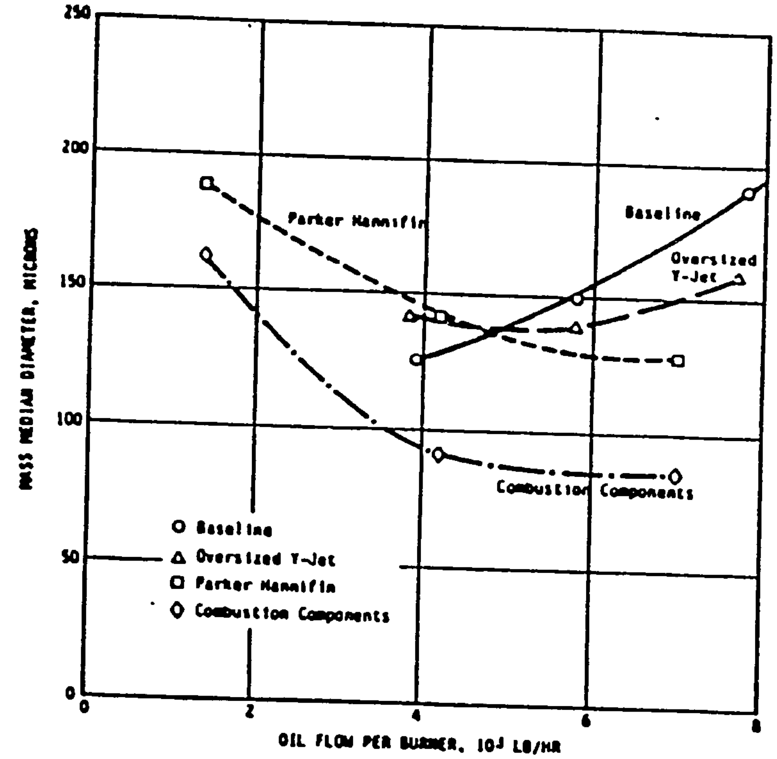

Figure 1.2-13. Droplet Size Data for Various Nozzles - Encina 5 Boiler, 160-180 psig Atomizing Air
Source: Reference 10

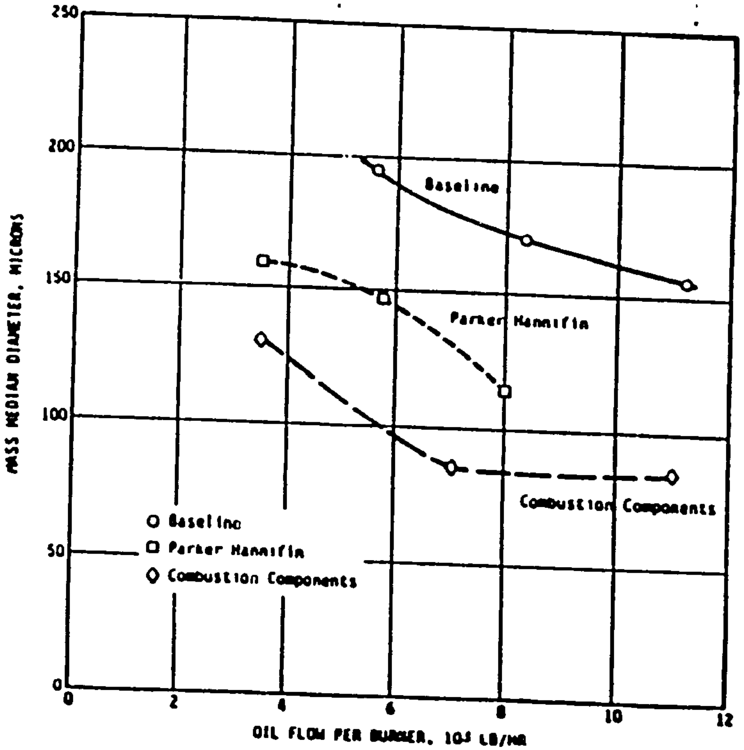

Figure 1.2-14. Droplet Size Data for Various Nozzles - South Bay 4 Boiler, approx. 220 psig Air Pressure
Source: Reference 10

specified to have a 20 psi differential between fuel and steam, so that the steam pressure may also have been raised to retain the differential. Data of steam to fuel mass flow ratios were not given. Despite the lack of evidence of direct flame impingement, one detrimental side effect of the higher fuel pressure was a carbonaceous deposit which formed on the burner throat. This problem was fixed by reducing the exit hole spray angles from 70 to 65 degrees (see below).

Modification of the spray cone angle may be useful in affecting fuel burnout. Increasing the fuel spray angle (the angle formed by the orifice centerlines of a multiple orifice nozzle, or the spray cone angle formed by the fuel film) in part increases the width of the flame. Other factors which affect the flame profile are the air swirl level as well as velocity. In general, a wider spray will broaden the flame, if all other parameters are fixed. The spray cone angle of a mechanically atomized nozzle is a property of the nozzle design, but generally can be altered with a new specification for the same nozzle. A wider flame may be beneficial to reduce the flame length (if currently too long) or as an aid in preventing excessive carbon emissions or flame impingement on the back walls. However, trade-offs may exist with emissions and/or potential impingement on the burner throat in extreme cases.

A wider spray angle was utilized in one heavy fuel oil industrial boiler test to improve carbon burnout and reduce particulate emissions. In these tests, the original steam atomized 55 degree nozzle was replaced with a 70 degree nozzle resulting in reduced particulate emissions (a 10 to 30% reduction) and shorter flame length (6). In addition, the minimum operating excess O_2 level was reduced by approximately 1-1/2 percent. An increase of NO_x emission (not specified) was said to accompany an improvement of the combustion process and carbon burnout. A decrease in particulate emission with increasing spray angle was also demonstrated on an industrial boiler mechanical atomizer system (11). An improvement in particulate emissions occurred with an increase in spray angle from 70 to 80 degrees, but a further increase to 100 degrees resulted in particulate emissions worse than for the 70 degree case. The 80 degree case was apparently optimum for this atomizer/burner/boiler system.

The type of atomizer in use on a boiler experiencing combustion problems will directly affect the options available for nozzle design modifications. The Y-jet is typically easy to modify due to its simple construction and minimal interaction between fuel and steam flow paths. A T-jet atomizer has greater

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internal mixing between steam and fuel and may be more difficult to modify. Mechanical atomizers are likely to be the most difficult to modify due to their internal design which dictates the pressure drop versus flow characteristics of the fuel system. If an older oil-fired boiler is operating with the original atomizers of antiquated design, complete nozzle replacement may be a worthwhile alternative to tip modifications. However, new atomizers may require a significant capital expense, compared to more cost effective operational modifications and the decision as to which approach to follow can only be made on a design specific basis. Additional limitations may be imposed by physical constraints of the fuel gun design type. More radical changes of the atomizer design may require new fuel guns and in the case of converting from mechanical to steam atomization, the installation of steam supply piping as well. The degree of change required will ultimately depend upon 1) the severity of an inadequate atomization problem, 2) the type and condition of the existing atomizers and auxiliary equipment and 3) the availability of replacement fuel nozzles. In addition, limitations imposed by the furnace geometry or heat transfer constraints (e.g., flame length or heat absorption pattern) must also be considered.

D. New Residual Oil Atomizers. The preceding section focused primarily on modifications to existing atomizers or specification of custom designed atomizers for a particular boiler encountering combustion or emissions problems. A related approach is to purchase completely new atomizers/burners to replace the existing units with a higher performance or "second generation" design. As part of the current EPRI study, a number of major boiler equipment manufacturers were contacted regarding new atomizer/burner developments or commercial offerings designed specifically for the more difficult to burn high asphaltene content residual oils. The remainder of this section summarizes these designs and options.

1. Forney Engineering Co. Forney Engineering Co. is offering a retrofit axial-flow, wide flame burner that they claim is ideally suited for combustion of low-grade residual oils without exceeding the EPA particulate limits (Figure 1.2-15). A Vero Beach (Fla.) municipal utility retrofit a 33 MW Combustion Engineering wall-fired unit with four of the new burners that met the 0.10 lb/MBtu particulate emission standard at very low excess air levels (12). The burner was designed to meet the EPA requirement with a No. 6 fuel oil specification summarized below:

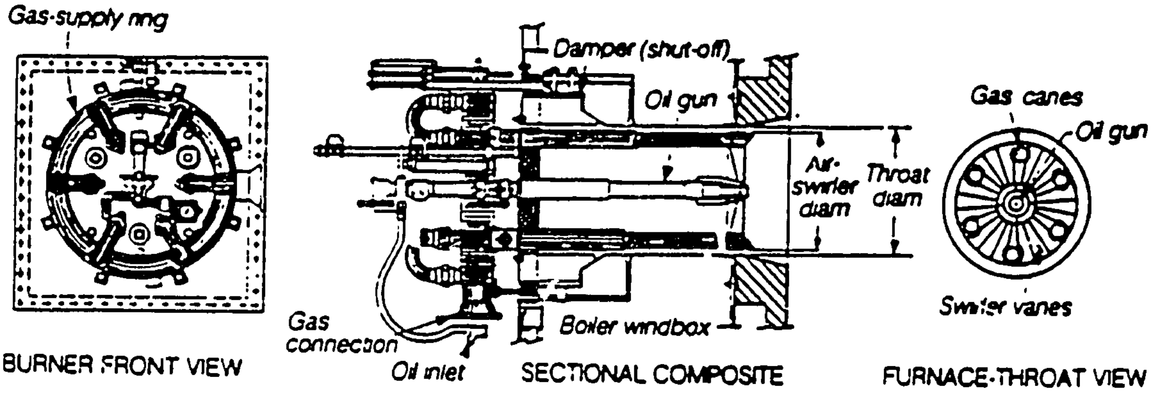

Figure 1.2-15. Retrofit Low Excess Air Burner for High Asphaltene Oils
Source: Reference 12

Sulfur	2.5 percent
Asphaltenes	6 percent
Vanadium	250 ppm
Ash	0.05 percent

The axial-flow, wide-flame burner was appropriate for the Vero Beach Unit 3 retrofit because of the limited furnace depth and the relatively short distance (17.5 ft) from the top burner row to the pendant superheater. This required uniform fine atomization, a wide flame shape, and rapid mixing of the fuel and air. (NO_x emissions were not mentioned as a consideration.) Equipment modifications included a large diameter air swirler, a small windbox baffle, reduced throat diameter and an internal mix steam atomizer including associated plumbing.

Although initial tests were conducted with a 4.1 percent asphaltene, 1.4 percent sulfur content fuel, the utility was anxious to burn up a 16 percent asphaltene, 2.3 percent sulfur fuel stored at the plant. Forney Engineering claims that particulate and opacity emissions regulations were met at an average excess O_2 level of 0.8 percent while the overall unit heat rate was improved by 0.7 percent using the high asphaltene fuel. These test results were very encouraging, but also surprising considering the heavy grade oil (370 ppm vanadium). Forney Engineering has also recommended the axial-flow, wide-flame burner as a replacement for the low atomizing air pressure, Forney Type TTL-5 Verloop burners in applications where high asphaltene oils have led to particulate emissions concerns.

2. B&W, CE, and Riley Stoker. Babcock and Wilcox, Combustion Engineering and Riley Stoker were contacted with regard to recent atomizer/burner developments, specifically for difficult to burn residual oils. All three indicated that they provide technical support to utilities considering retrofit installation of new burners or atomizers to reduce emissions or improve performance, but have not developed any special equipment designed specifically to address heavy residual oil combustion problems. They indicated their latest liquid fuel burners had the capability of burning a wide range of fuels and still meet NO_x and particulate emission standards. For example, the problem of high particulate emissions with some low steam

consumption atomizer tips has been resolved in some applications by simply recommending the next larger tip size (to increase the steam flow).

3. Foreign Atomizer Designs. A substantial amount of atomizer/burner development with heavy residual oils has occurred outside the United States, particularly in Europe and Japan. A major contributor to these developments has been the Marchwood Engineering Laboratories of the Central Electric Generating Board, where a number of atomizer optimization projects have been conducted for both the swirl-type pressure jet atomizers and twin fluid (steam) atomizers. Several of these designs have subsequently been licensed to British firms such as Hamworthy Engineering, Airoil-Flaregas, CEA Combustion Ltd., etc. For more information, contact: Mr. Alan Jones, CEGB, Marchwood Engineering Laboratories, Marchwood, Southampton (SO4 4ZB), England.

Prior studies by CEGB indicated that a 10 percent reduction in mean drop size (from approx. 150 microns) would yield a 25 percent, or greater decrease in particulate emissions. A drop size correlation relating the mass median diameter to the atomizer design parameters was used to optimize the atomizer geometry for heavy residual oil applications. The optimized atomizer design and associated drop size distribution data are shown in Figure 1.2-16 and 1.2-17 (5). The new atomizer produced a finer spray that decreased the mean drop size by about 12 percent. A prototype atomizer was installed in a 500 MW oil-fired unit producing an excellent well defined stable flame with a brightly luminous root. After 1800 hours of operational experience with the prototype atomizer, a full set of 32 tips were installed and extensive particulate characterization tests were conducted at low excess O_2 levels. The new optimized atomizers produced a 26 percent reduction in total particulate which corresponded to a 30 percent decrease in unburned carbon (after adjusting for the ash contribution).

Similar atomizer development work has been conducted by CEGB on twin fluid atomizers (10). They found that the fuel oil must be injected symmetrically about the exit port axis (see Figure 1.2-18) in order to achieve a fine droplet spray. The radial oil jets are directly opposed with no swirl and are designed to meet at a point so that the air (or steam) could not pass down the center axis without shearing the oil flow. In the final design, an air to oil mass ratio of 5.8 percent provided the best atomization

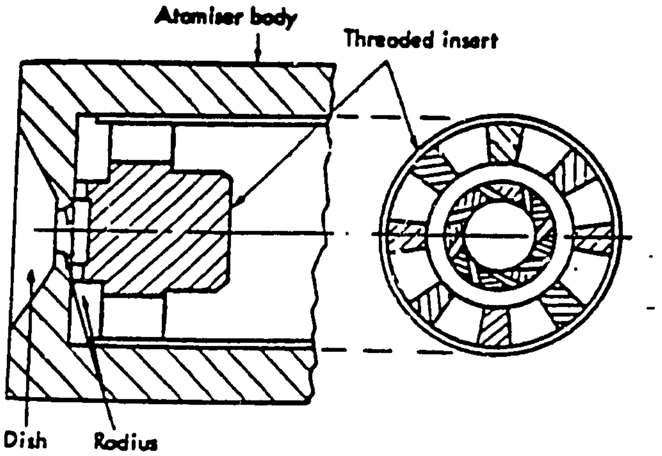

Figure 1.2-16. The optimized pressure jet atomizer.
Source: Reference 5

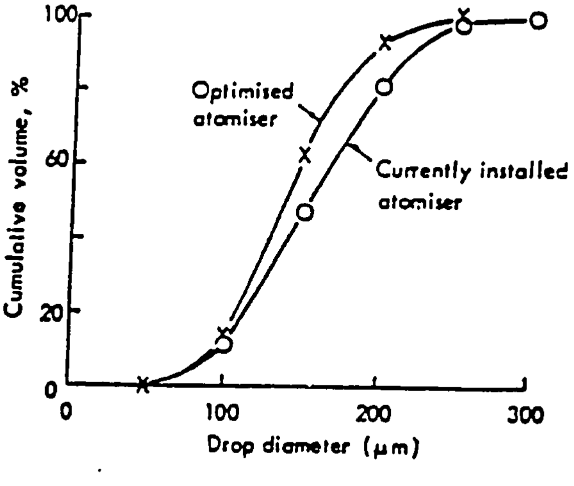

Figure 1.2-17. Comparison of drop size distributions for a currently installed large pressure jet atomizer and the optimized design (both at MCR).
Source: Reference 5

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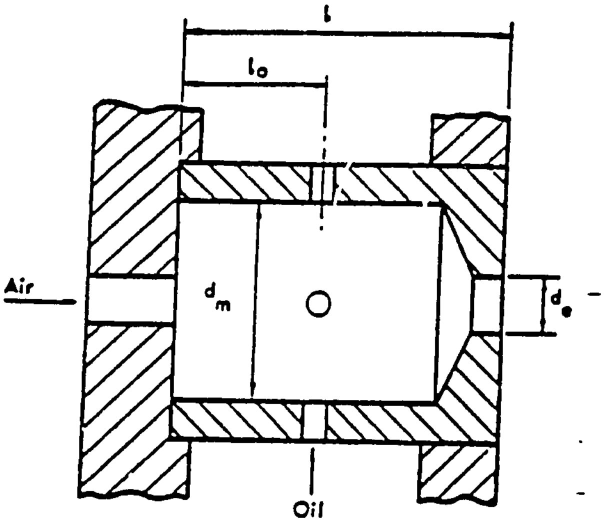

Figure 1.2-18. Symmetric Two Fluid Atomizer
Source: Reference 13

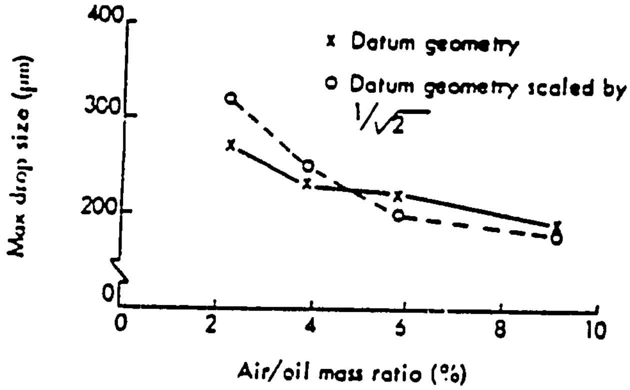

Figure 1.2-19. Dependence of Drop Size on Mass Ratio for STFA
Source: Reference 13

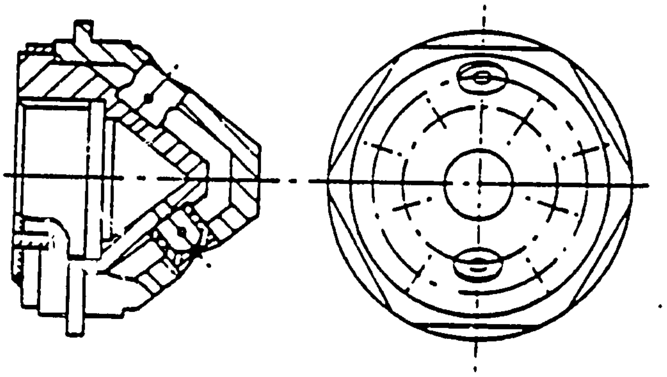

Figure 1.2-20. Multi-ported STFA
Source: Reference 13

consistent with other supply pressure constraints. The drop size vs. air/oil mass flow ratio for the optimum design is shown in Figure 1.2-19. In the final commercial configuration, CEGB used two rows of atomizer inserts in a staggered pattern to form a multi-ported atomizer tip (Figure 1.2-20). The new atomizers were unsusceptible to fouling and blockage when exposed to high furnace radiation fluxes at full load. Full-scale field tests at two CEGB power stations reduced particulate emissions by up to two-thirds with only minor flame detection problems.

Articles by the CEGB indicate that the pressure jet and twin fluid atomizer development programs have given the utility the ability to satisfactorily burn any residual fuel oil that can be pumped in their oil-fired power stations. These atomizer designs may eventually be licensed or imported to the U.S. In the interim, additional information concerning these atomizer designs can be obtained from References 2 and 10 or by contacting the Chemical Engineering Section of the CEGB at their Marchwood Engineering Laboratories, Marchwood, Southampton (SO4 4ZB), England.

1.3 EMULSIONS

The combustion of high asphaltene fuel oils in older boilers, subject to stringent NO_x and particulate regulations, has led to several problems that have been difficult (or costly) to solve with conventional methods. These problems include excess carbon carryover, high excess air requirements to avoid smoking, and degraded boiler efficiency. They are often encountered on small older units, formerly coal-fired, scheduled for retirement and not particularly well maintained.

In response to this, several utilities have recently conducted full scale test programs with emulsions of heavy residual oils and water to achieve more complete combustion with problem fuels. This approach is seen as a potentially quick and cost effective means of combating carbon burnout problems on oil-fired units. Adding water to the fuel decreases boiler efficency due to higher fuel moisture losses (i.e., the heat required to vaporize the liquid water to a gas). However, emulsions have been credited with improving the fuel burnout by aiding the atomization process. The conversion of the water in the fuel to steam helps break up the fuel droplet. Increased atomization of the liquid fuel enhances burnout by decreasing the mean fuel droplet size, thus reducing residence times required for complete combustion.

In general, emulsions have been evaluated by utilities in those cases where 1) acceptable burnout was not achieved through conventional means of improving atomization or 2) the cost of installing new burners or using higher quality fuels could not be justified. The substitution of an increased operating expense for the emulsion vs. the capital expense of reburnering a unit can be an attractive trade-off on older boilers scheduled for retirement. Although several utilities view emulsions as a short term solution to an emissions compliance and performance problem, some process developers contend that emulsions will also prove attractive on some larger units for long term applications.

1.3.1 Emulsified Fuel Use Methodology

Emulsified fuels generally aid in atomization, but only under certain circumstances and only when the emulsion is prepared in a specific manner. It should be noted that fuels which do not exhibit carbon burnout or atomization

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problems in a particular boiler will not likely benefit from the use of emulsions.

A. Theory of Operation. Most emulsions contain from 5 to 10 percent water by weight in the fuel oil. Typically, the water is finely dispersed as small droplets within the oil (2 to 15 microns mean droplet diameter). Dispersion of the water in the oil may be produced by specific emulsion equipment or, in some cases, by the normal flow of the oil-water mixture through high pressure pumping equipment. Dispersion and stability of the water in the oil can be aided by the addition of chemical surfactants. Other proprietary chemicals may also be utilized in some commercial emulsion products to aid in combustion or acid deposition problems. A brief review of the combustion and atomization of a conventional heavy fuel oil will aid in understanding the effects of fuel oil/water emulsions.

Heavy fuel oils are typically preheated and atomized at the proper viscosity to produce a fine spray of droplets that leave only a small particle of ash after complete combustion. However, large droplets will be formed if the fuel is not heated to the proper viscosity or is poorly atomized (e.g. because of a worn burner gun tip or inadequate atomizing steam flow). The larger drops may not be totally combusted as they exit the flame zone, leading to the formation of large porous cenospheres of unburned carbon and ash. This problem is most often encountered with heavy residual oils of high asphaltene content, but other fuel properties are a factor as outlined in Sections 1.1 and 1.2.

The normal utility operating practice should be to use all conventional means to bring the atomization process up to the original design operating condition, to produce the optimally sized fuel droplets, and thereby aid in carbon burnout. Many of these conventional means to improve atomization were discussed in detail in Section 1.2, but are briefly summarized below. They include inspection or replacement of worn or damaged fuel nozzles, increased atomizing steam or air flow, adjustment of burner or oil gun operating variables, balancing the distribution of fuel or combustion air to all operating burners, increasing the fuel temperature (reducing fuel viscosity), and raising the overall excess air operation of the boiler. However, these measures are not always sufficient to overcome the atomization problem due to limitations in adjusting the burner or oil gun operating parameters and constraints in the boiler dimensions or residence time that affect flame length and shape. Other constraints may be

limited temperature capability of the fuel heaters in some instances or coking at low **flow rates** at the other extreme.

Emulsions are typically prepared in one of two common ways: 1) using continuous on-line emulsion equipment at the plant site or 2) as a batch process where the emulsion is typically stored for subsequent use. In the latter case, the option exists to prepare the emulsion at a central preparation plant prior to shipment to the utility boiler as opposed to on-site preparation. After the emulsion is prepared by adding and dispersing water in the fuel, the mixture is atomized in the conventional manner using standard equipment. The water droplets in the fuel are typically much smaller than the emulsion droplets formed by the atomization process. The presence of liquid water droplets enveloped by the oil droplets in the hot flame zone leads to superheating of the water, at temperatures well under the vaporization point of the heavy fuel oil. The rapid expansion of the internal liquid water into vapor causes the larger fuel droplets to explode. The physical phenomenon has been called "micro explosions" and has been photographed and documented by various researchers; (<u>16</u>, <u>17</u>, <u>18</u>, <u>19</u>, <u>20</u>). The micro explosions break up the original large emulsion droplets into smaller diameter droplets and hence aid the atomization process

Emulsified fuel combustion mechanisms are not yet completely understood. Significant variability in test results from site to site may be experienced until most of the dominant process parameters are well understood and brought under close control. Nevertheless, initial utility boiler test results have shown promise, justifying continued investigation.

B. <u>Emulsified Fuel Trade-offs</u>. Before discussing the potential benefits and disadvantages of emulsified fuels, it should be stressed that these benefits are often dependent on the type of combustion system and fuel used. For example, it is largely recognized that emulsified fuels offer no advantage for easily atomized fuel oils or light hydrocarbons when burned in utility boilers. Similarly, when a typically hard-to-atomize fuel can be routinely burned in a furnace or boiler without excessive particulate or carbon carryover problems, then use of an emulsified fuel will offer few advantages.

The primary attraction of emulsions is the potential reduction in carbonaceous particulate for emission compliance purposes. The secondary gains in boiler efficiency due to the reduction in carbon loss are typically small. Figure 1.3-1

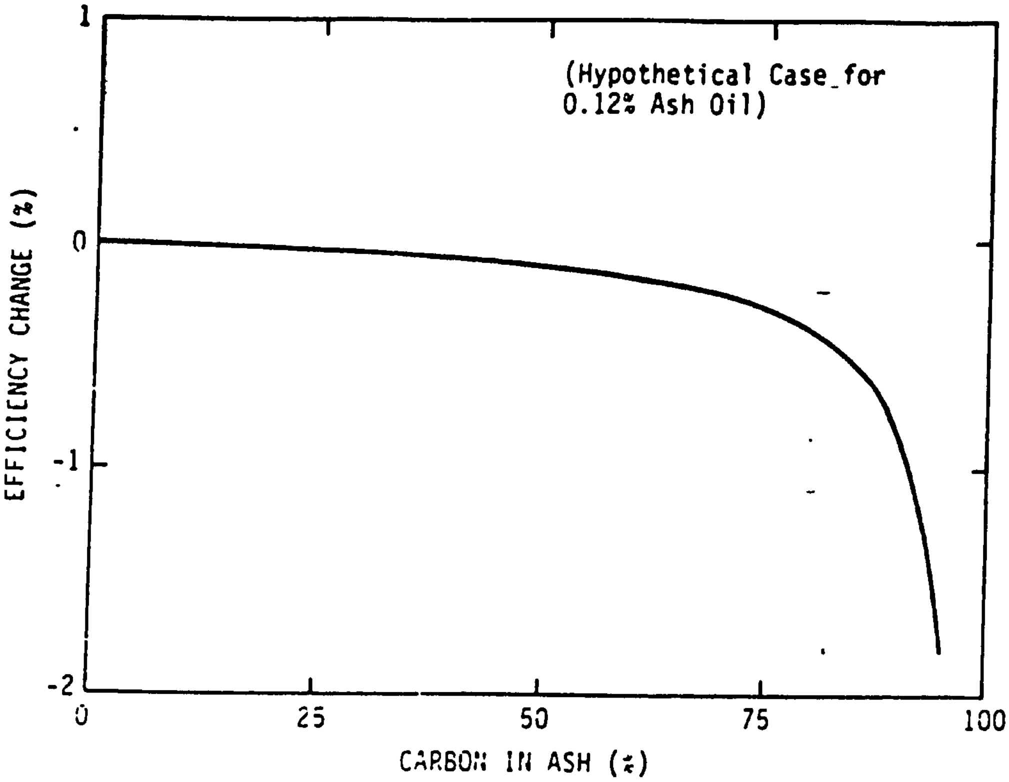

Figure 1.3-1. Effect of Carbon Carryover on Boiler Efficiency

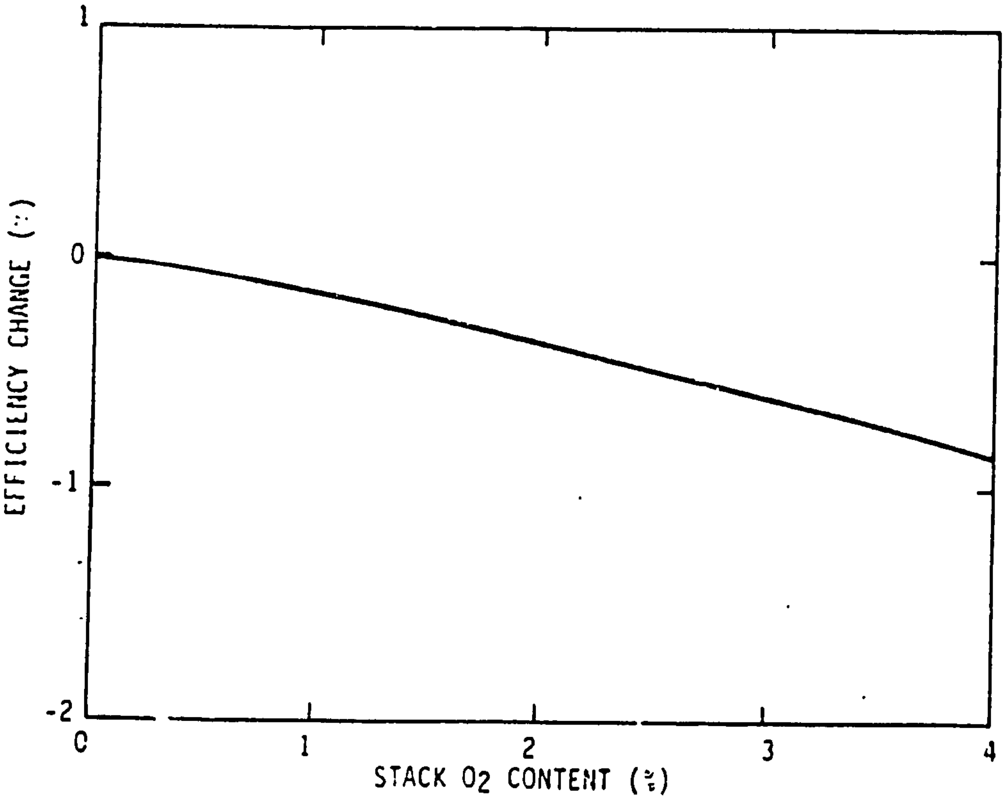

Figure 1.3-2. Effect of O_2 on Boiler Efficiency

shows the dependence of boiler efficiency on carbon content in the ash for a hypothetical high ash oil (0.12 percent ash by wt.). For ash carbon contents of less than 75 percent, the potential gains in boiler efficiency with emulsions will be limited to 0.3 percent and most often will be considerably less. Therefore, reductions from very high carbon levels would be necessary to produce sizable efficiency gains with emulsions.

A larger potential for boiler efficiency gain is possible through a reduction in the required excess air level or stack excess oxygen content. High excess air levels result directly in high flue gas losses from the boiler and reduced boiler efficiency. Therefore, improved carbon burnout with emulsions may permit operation at a lower excess air level without smoking and with improved boiler efficiency. Those potential efficiency gains are shown in Figure 1.3-2, which is arbitrarily referenced to 0 percent O_2. For example, if improved atomization resulting from the use of emulsions allows the boiler to be operated at 1 percent O_2 rather than 3 percent (with a comparable carbon carryover characteristic), then the boiler efficiency will increase by 0.44 percent, all other factors being equal. (A procedure for optimizing combustion performance by selecting the proper excess O_2 operating level is outlined in Section 4.1 of the guidebook.)

Reduction of excess air levels with emulsion use has been the primary basis for efficiency gains claimed by the various emulsion or equipment suppliers. An additional benefit is that reduced excess air operation will reduce the proportion of SO_2 which will be converted to SO_3, thereby leading to reduced corrosion of low temperature heat transfer equipment and ductwork. Low excess air firing has been widely recognized as one means of combating acid smut or low temperature corrosion, which are common problems with oil-fired boilers.

A significant disadvantage in the use of a water-in-oil emulsion is the efficiency penalty associated with the water content. The efficiency penalty (fuel moisture enthalpy) is the result of the energy loss associated with vaporizing the liquid water. Figure 1.3-3 shows the dependence of the efficency loss on the water content of a typical No. 6 fuel oil. For emulsions of 5 to 7 percent water in oil, the result is a 0.33 to 0.50 percent loss of boiler efficiency. This efficiency penalty must be evaluted against the potential gains of efficiency due to the combination of reduced carbon carryover and lower excess air. The advantages of reduced particulate emissions and potential operation within the emissions regulation with an inexpensive heavy fuel oil must also be

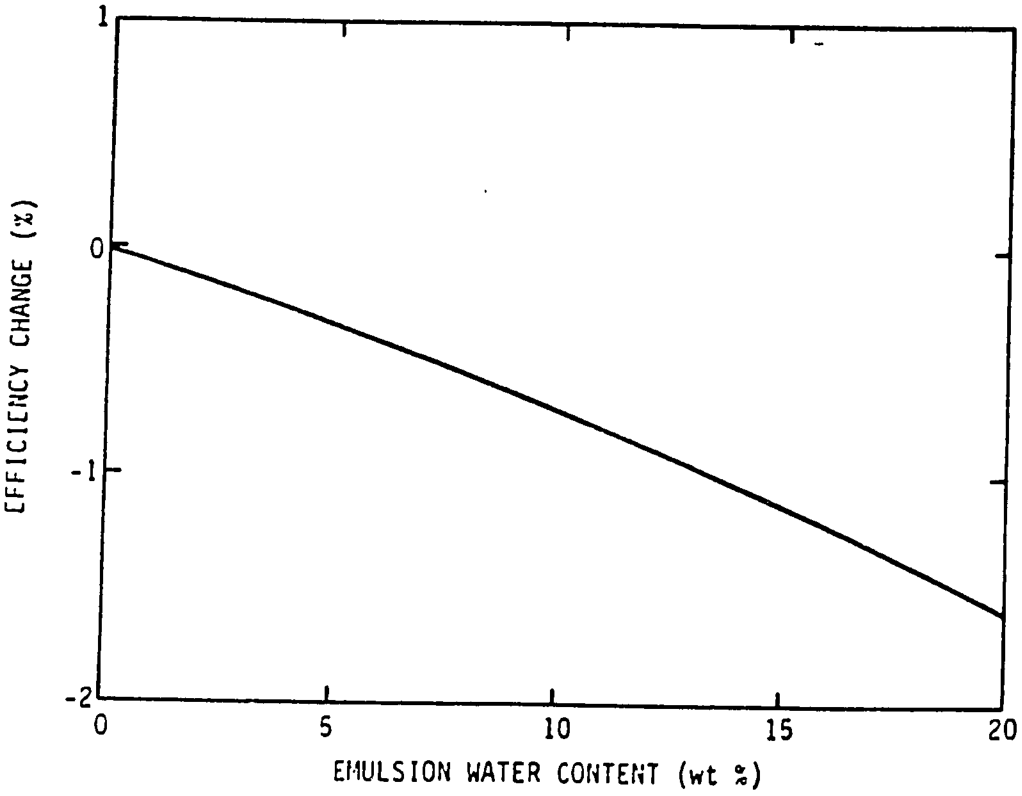

Figure 1.3-3. Effect of Emulsion Water Content on Boiler Efficiency

considered. A cost/benefit analysis should be made to evaluate efficiency trade-offs, the fuel cost savings of burning a heavy viscous fuel, and the cost of the emulsion. An alternative comparison is the cost of purchasing a higher quality premium fuel which does not exhibit operational problems or equipment modifications to accommodate the heavy oil.

C. Emulsion Preparation. A variety of methodologies have been developed for producing water-in-oil emulsions. Options range from pre-prepared fuels, in-line emulsification in the existing fuel handling system or retrofit mechanical emulsifiers added to the fuel system. Some proposed systems require specific emulsified fuel burners. Surfactants are sometimes used to help stabilize the water-in-oil mixture while additives such as combustion catalysts or acid neutralizers are also combined in the final mixture.

Most recent emulsion work has utilized emulsions with less than 10 percent water content. Common emulsion requirements appear to be water droplets of 2 to 15 microns in mean size which are thoroughly dispersed in the fuel oil. A range of 5 to 10 microns may be optimum for heavy residual fuel oils. Smaller or larger water droplet mean size may not optimize the micro explosion process, and therefore require more water content for the same effect. Too small a water droplet size may be ineffective in breaking apart the fuel droplet.

The need for surfactants for utility-sized emulsion applications is probably minimal, because storage of large quantities of emulsion is not generally required. All water-in-oil utility demonstrations have utilized emulsion preparation immediately prior to combustion in the boiler, thus storage and stability factors were not significant issues. Re-agglomeration of the stored emulsion in a tank to form larger water droplets requires time on the order of an hour. Therefore, the seconds of elapsed time prior to combustion in a boiler with an in-line emulsification system does not require the use of stablizers. In-line emulsification systems are generally installed in the low pressure portion of the fuel line between the oil storage tanks and the existing fuel pumps.

The type of emulsification equipment required to achieve uniform dispersion of the water is generally dependent upon the design of the boiler fuel supply system. For example, the existing fuel pumps, oil strainers and valves were effective in thoroughly dispersing the water in the heavy oil in one early emulsion test program (21). In a more recent full-scale boiler test, a static mixer was required upstream of the constant differential fuel pumps and downstream of the point of water addition (22).

Several utility test programs with emulsified fuels were conducted with emulsification systems provided either by Fuel Tech, Inc. of Stamford, Connecticut or the Columbia Chase Corp. of Holbrook, Massachusetts. In one Fuel Tech application, the existing fuel pumps were blamed for creating emulsion water droplets that were smaller than desired, while in the second application, satisfactory results were achieved with externally powered rotary atomizers. Both applications included the use of additives (surfactants, combustion catalysts and acid neutralizers) as part of the vendor recommended emulsification system package.

Very little has been written about the process control system requirements for emulsifier installations. In one case, the utility specified a non-load following system, and the emulsification system was turned on only at full load operating conditions. Many demonstrations have been temporary in nature, therefore, fully automatic commercial control systems were not installed.

1.3.2 Utility Operating Experience With Emulsified Fuels

Utility experience with emulsified fuels is limited to less than 10 full scale demonstration tests. Generally, these tests have addressed a specific problem concerning a difficult to burn fuel in a specific boiler design within the utility system. While the same fuel may burn acceptably in other boilers, some units may exhibit combustion problems due to specific burner, atomizer, or boiler design factors which constrain operation. Unacceptable opacity, particulate emissions or carbon burnout were the reasons for most emulsion trials.

A. Northeast Utilities. Northeast Utilities initially implemented emulsion firing at its Devon Station Unit 6 in Milford, Connecticut (22, 23) subsequently Units 3 through 5 were also outfitted with an emulsion system. Unit 6 is a 72 MW Combustion Engineering wall fired boiler constructed in 1951 to burn pulverized coal, but converted to oil in 1969. This unit was selected for the test because historically it was one of the most difficult units on which to achieve NO_x and particulate compliance. Unit 6 is fitted with Peabody wide range atomizers (in a 2 high by 4 wide burner arrangement) with a 300 psi constant differential fuel

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pump (450 psi at the atomizer). The unit is subject to cyclic operation and began experiencing difficulties in meeting a simultaneous NO_x (0.30 lb $NO_2/10^6$ Btu) and particulate (0.14 lb/10^6 Btu) emissions standard starting about 1982. Although originally installed for coal operation, its electrostatic precipitators were no longer operable. The emission difficulties were attributed to fuel quality changes (an increase in fuel oil ash content of 0.03 to 0.08 percent wt and delivery of incompatible fuel blends as indicated by the ASTM spot test). The result was an increase in the quantity of ash emission and slag buildup in the boiler, as well as higher visible emissions. Maintenance and operational practices were improved but did not rectify the problems. Attempts to improve fuel quality were considered, but apparently were either not successful or economical. Because of the age of the boilers, extensive modifications to install new burners or overfire air for NO_x control were not considered cost effective.

The non-load following emulsion preparation system, supplied by Fuel Tech, included provisions for chemical additives (a surfactant stabilizer, a platinum-based combustion improver and magnesium hydroxide SO_3 corrosion inhibitor). The utility did not consider the additive package necessary, since a magnesium-based additive was already in use for the base fuel. Early tests with combustion improvers showed little effect, and there was no need for long-term emulsified fuel storage. However, the additives were included as part of the emulsification system package since any potential advantage to gain emissions compliance was considered helpful. The emulsification system consisted of a water and additive feed system and a static emulsifier located upstream of the constant differential pump supplying fuel to the burners.

Downstream of the constant differential pump, the water was found to be emulsified to a size distribution of 50 percent less than 5 microns at 7 to 7.5 percent water in oil. The mean drop size was considered to be too small, resulting from exposure of the oil/water mixture to high shear in the conventional pumping system. Optimal water droplet diameters were considered to be in a range of 5 to 10 microns.

Combustion tests were performed at full load under steady state conditions. The magnesium additives were utilized for all tests with both the base fuel and the emulsion. The surfactant and combustion improvers were used for all emulsion tests. Additive feed rates were not varied for these tests. After the water feed was optimized to approximately 7 percent water in oil, boiler emission compliance tests showed NO_x emissions of 0.264 lb $NO_2/10^6$ Btu (approximately 215 ppm at 3% O_2,) particulate emissions of 0.092 lb/10^6 Btu and an opacity of 4 percent. Use of the emulsion resulted in a 26 to 28 percent particulate mass reduction and a 10 to 15 percent reduction of NO_x emissions. Almost all of the particulate reductions occured for particles greater than 13.8 microns. The reduction of NO_x emissions was attributed to a reduction in flame temperature due to the water content. Overall, the opacity increased slightly with the emulsion. This was attributed to a shift in particulate size to smaller particles, which are more effective in reflecting light. However, additional data was needed before definitive conclusions could be made. A reduction of excess O_2 occured with the emulsion, but was not quantified. Based on the results of the emulsion tests, Units 3 through 5 were also fitted with the emulsion system. The emulsification systems are only operated above 85 percent load in order to satisfy emissions limitations.

B. Long Island Lighting Co. Long Island Lighting Co. conducted emulsion tests at their Port Jefferson Unit No. 4 boiler (24, 25). The 185 MW Combustion Engineering tangentially-fired test boiler was converted from coal to oil firing during the 1960's. The unit was equipped with flue gas recirculation and electrostatic precipitators. The tests were conducted with a 2.5 percent sulfur residual oil with a 9.7 percent asphaltene, 460 ppm vanadium and 0.12 percent ash content. A magnesium-based fuel oil treatment is routinely used to limit high temperature corrosion and acid smut emissions.

Inefficient boiler operation caused unburned carbon to be collected in the electrostatic precipitator. Continuous operation resulted in buildup on the precipitator plates, diminished collection efficiency, and caused frequent derating when 20 percent opacity was reached or exceeded. Therefore, the emulsion program was initiated to maintain compliance with opacity limits without derating the unit.

The emulsification system supplied by Fuel Tech included an additive, water forwarding system and two parallel rotary emulsifiers with 50 hp motors. The emulsion water droplet size was reported to be 5 to 10 microns. The emulsion included a chemical package consisting of a surfactant, combustion catalyst and magnesium for acid control. Details concerning the existing fuel forwarding system or the type of original equipment burners were not provided.

Due to limitations in precipitator cleaning under normal full-load boiler operation, the opacity increased with time over the course of one day. Tests were conducted to determine the effect of various emulsion water concentrations on the rate of opacity increase. Figure 1.3-4 shows that the 7 percent water-in-oil emulsion gave the lowest rate of increase in opacity over time. Note that the higher water content from a 9 percent emulsion showed a higher rate of opacity increase, and that the 9 percent emulsion without the additive treatment package was higher yet. Dynamic tests showed that the rate of opacity increase under baseline operating conditions could be halted and perhaps reversed when emulsion operation was initiated.

Although the opacity benefits of emulsion use were apparent from the LILCo tests, it is important to also characterize the effect on particulate emissions. Since opacity readings are primarily concerned with emissions in the visible light range, the total particulate emissions on a mass basis may be affected, to a different degree. However, the particulate emission tests also indicated that a 7 percent water-in-oil emulsion was optimal at full load test conditions (Figure 1.3-5). A 56 percent reduction was obtained at 186 MW using a 7 percent emulsion, but the results were based on projections using EPA Method 17, rather than the high volume sampling method used for other data points. A 61 percent reduction in carbon was achieved with the same 7 percent water emulsion.

The particulate size distribution for the various emulsions is shown in Table 1.3-1. The 7 percent emulsion has a larger fraction in the small size range than the 5 and 9 percent emulsions. This data supports the postulated secondary atomization benefits of the emulsion and a reduction of the large particulate.

NO_x emissions are also presented in Figure 1.3-5. Only small changes of NO_x were recorded (approximately 10%) but the optimum also occurred with the 7 percent emulsion. A reduction in SO_3 emissions occurred with the emulsion (plus additive). However, it was not clear whether the baseline test followed the normal practice of using a magnesium based fuel additive. The results of a gross heat rate comparison at high load are summarized below:

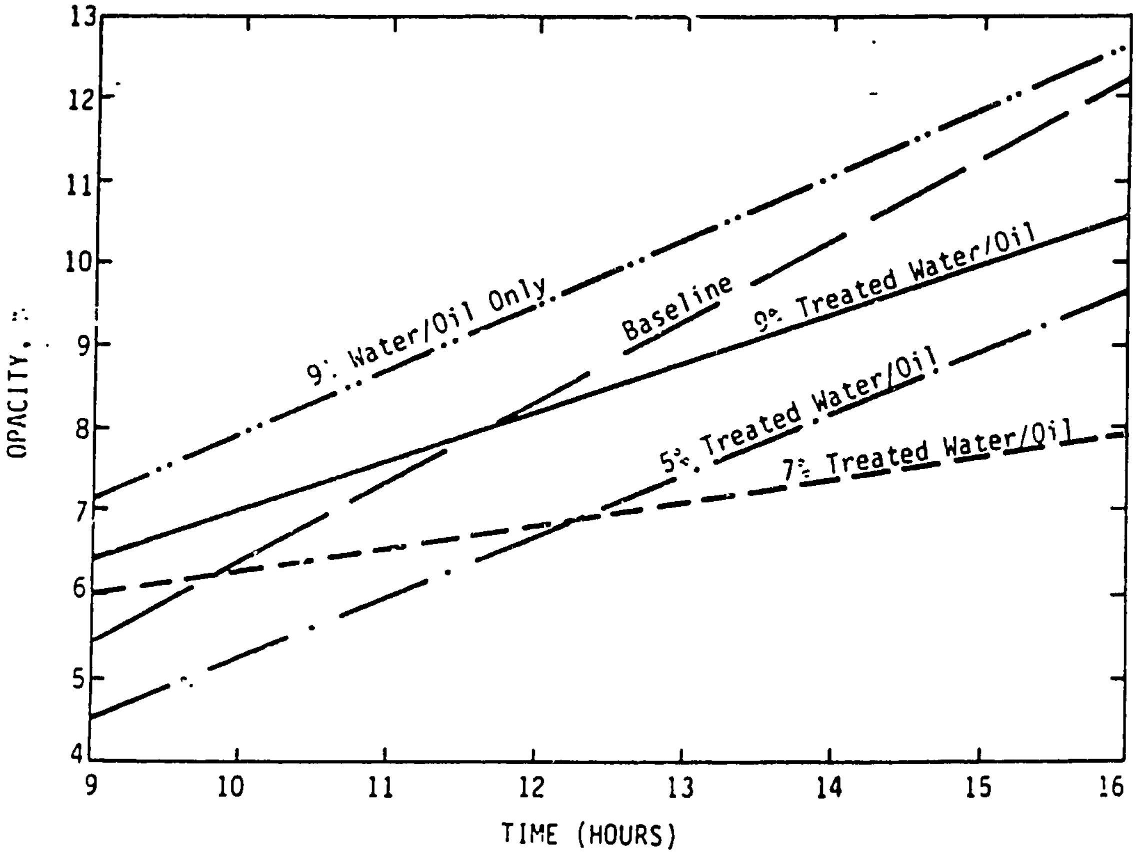

Figure 1.3-4. Rate of Opacity Change versus Emulsion Use, LILCO Tests
Source: Reference 24

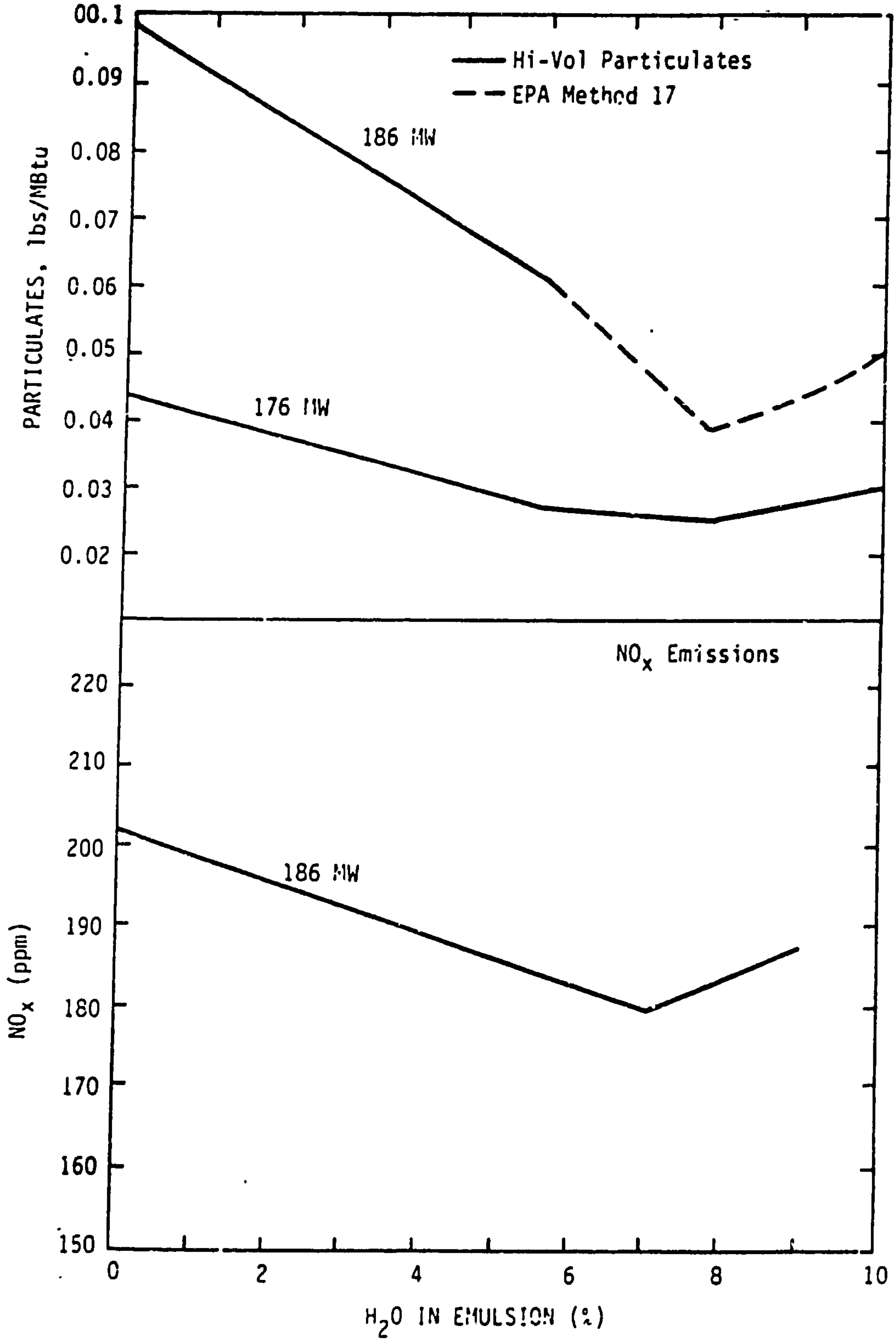

Figure 1.3-5. Particulate and NO_x Emissions with Emulsions
Source: Reference 25

Table 1.3-1

PARTICULATE SIZE DISTRIBUTION FOR EMULSION FIRING, LILCO TESTS

Source: Reference 24

Diameter Microns	Base	% In Size Range 5% Emul.	7% Emul.	9% Emul.
12.4	37.5	37.3	11.6	22.2
7.7 - 12.4	19.1	23	8.6	18.6
5.2 - 7.7	10.4	9.7	3.3	12.2
3.6 - 5.2	14.1	6.1	7.9	14
2.3 - 3.6	6.3	5.1	5.7	8.6
1.1 - 2.3	2.8	4.2	5.9	10.2
0.7 - 1.1	4.4	4.8	43.8	6.6
0.48- 0.7	2.7	2.9	2.2	4.1
0.48	2.7	6.9	6	3.5

Test	Average Heat Rate
Baseline	10,210 Btu/kWh
5% emulsion	10,165 Btu/kWh
7% emulsion	10,203 Btu/kWh
9% emulsion	10,231 Btu/kWh

Although an extensive heat balance or boiler efficiency test was not conducted, the data indicate no significant changes due to emulsion operation. A long-term evaluation of emulsified fuel operation was considered necessary to fully verify these results.

C. New England Power Service Company. The New England Power Service Company conducted an emulsion test firing in their Salem Harbor Unit 4 boiler. The unit is a 450 MW Riley wall-fired boiler equipped with 24 Forney Verloop TTC-5 liquid fueled burners (26). These burners operate with low fuel and atomizing air pressures, unlike more conventional twin fluid atomizers. Particulate emissions in excess of regulatory limits were experienced with lower quality residual oil (increased heavy hydrocarbon content). Emulsions were evaluated as an alternative to much more costly reburnering or major modifications to the boiler and burner management systems. The oil used for testing was a 1.83 percent sulfur, 14.1 percent asphalene fuel oil with a 130 degree API and a viscosity of 260 SSF at 122°F.

A Columbia Chase emulsification system was chosen, largely because no stabilizer or combustion catalyst was required to maintain the quality of the emulsion. The system consists of two stages: the first stage was a conditioner, a static mixer or "deagglomerator" located downstream of the water/oil injection point, and the second stage consisted of a recirculation pump and the emulsifier. The three conditioner units located next to the boiler service oil tank had a capacity that exceeded the 30,000 gph firing rate of the boiler.

Three basic operating modes were evaluated: 1) baseline operation with the original oil, 2) operation with the conditioner only (no water addition) and 3) operation of both the emulsifier and conditioner with approximately 6 percent water added. Boiler operating conditions were optimized for the baseline tests and held steady thereafter for the balance of the tests. The objective of the conditioned oil test was to evaluate the deagglomerating effect of the static mixer. The developer claimed it would break up or deagglomerate clumps of asphaltene and particulates in the oil (in addition to dispersing the water in oil when emulsification was used). The fuel properties for the three tests are shown in Table 1.3-2.

The conditioned oil test results showed a small (and perhaps uncertain) reduction in particulates relative to the baseline tests (Figure 1.3-6). This change was not accompanied by a reduction of unburned carbon in the ash. However, a large reduction in particulate (approximately 52%) was recorded with the conditioned and emulsified oil, as compared to the baseline (0.20 versus 0.095 lb/10^6 Btu). This reduction was largely due to the 82 percent reduction in ash carbon content. Particle size data showed a signifcant reduction in the number of particles larger than approximately 2 microns which accounted for the decrease in particulate emissions. The size data also supported the contention that a higher degree of atomization was caused by the emulsion of water with the oil.

One would not expect a change in the ash component of the total particulate for the conditioned or emulsified oil relative to the baseline. No explanation was given for the apparent change in ash fraction data in Figure 1.3-6.

Boiler efficiency decreased by 0.75 percent with the addition of water. Approximately half of the reduction was due to the added moisture loss caused by the 6.4 percent water. The balance of the efficiency degradation was caused by changes in exit gas temperatures and gas mass flow (sensible heat losses). As mentioned previously, boiler operation was not optimized with the emulsified fuels. It is possible that these losses could be reduced by minimizing the water injection rate, and perhaps by reducing excess air levels. Lower excess air levels were possible with the 6.4 percent water emulsion compared to baseline operation with the neat oil (1.46% vs. 1.74% O_2) and additional benefits may occur with optimum water injection.

NO_x emissions for the three tests showed no significant change (Figure 1.3-7). All data points lie within the scatter of the baseline tests.

D. Central Electricity Generating Board. The CEGB has been conducting laboratory and full-scale boiler tests with emulsified fuels during the last decade (21, 27, 28). Although most of the testing has been performed in laboratory combustors, a few test points confirming the data have been conducted in large boilers with very few details given.

Table 1.3-2

FUEL PROPERTIES FOR THE NEPSCo TESTS
Source: Reference 26

Properties	Neat Oil	Cond. Oil	Cond/Emul. Oil
Flash Pt. ^{o}F	200+	200+	200
Degrees API @ 60^{o}F	13.0	13.0	12.7
Moisture %	0.10	0.30	5.70
Sulfur %	1.83	1.83	1.68
Visc. @ 122^{o}F SSF	260.3	261	262
Btu/lb	18,328	18,363	17,304
Btu/gal	149,466	149,749	141,412
Sodium ppm	28.1	25.6	26.5
Vanadium ppm	166	284	262
Nitrogen %	0.41	0.42	0.40
% Asphaltene	14.17	14.08	12.41

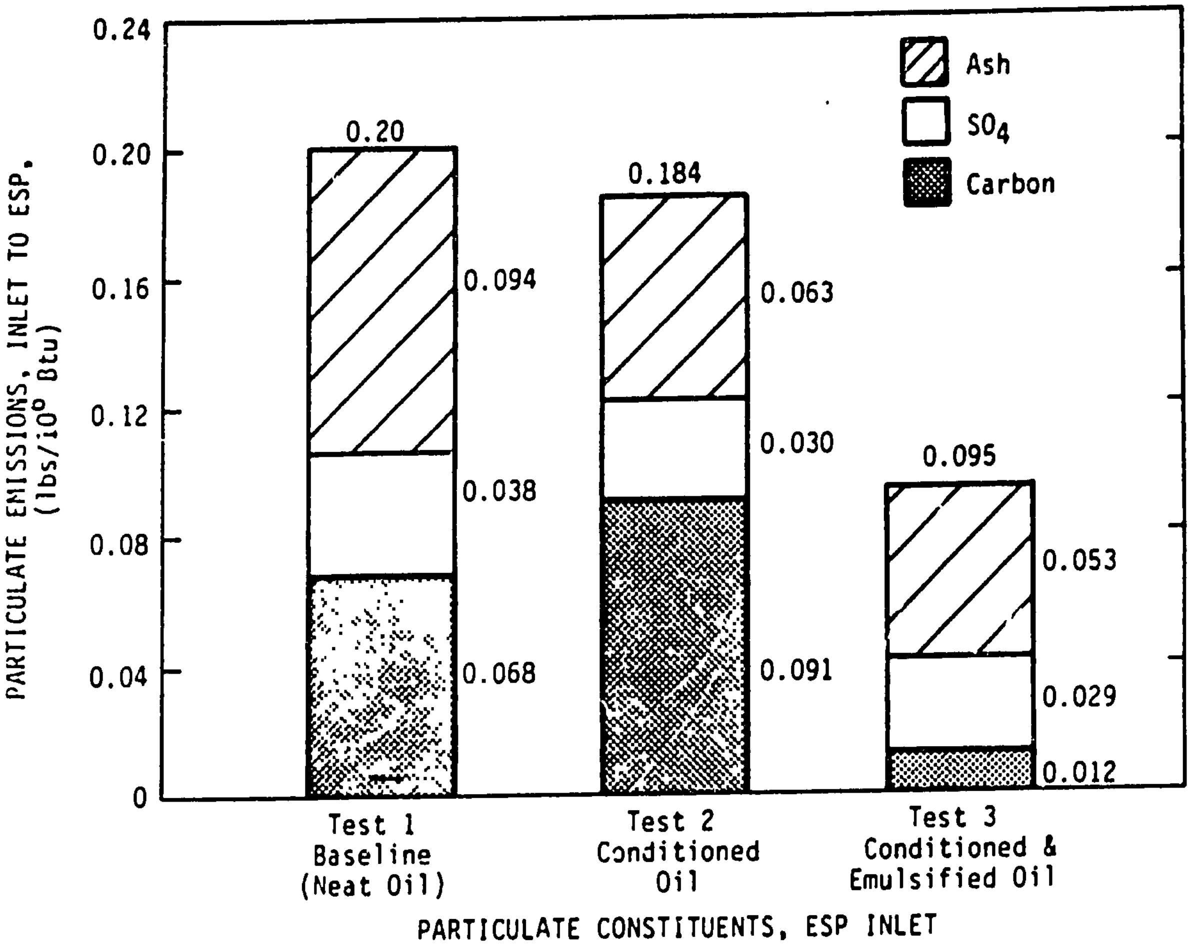

Figure 1.3-6. Particulate Emissions, NEPSCo Tests
Source: Reference 26

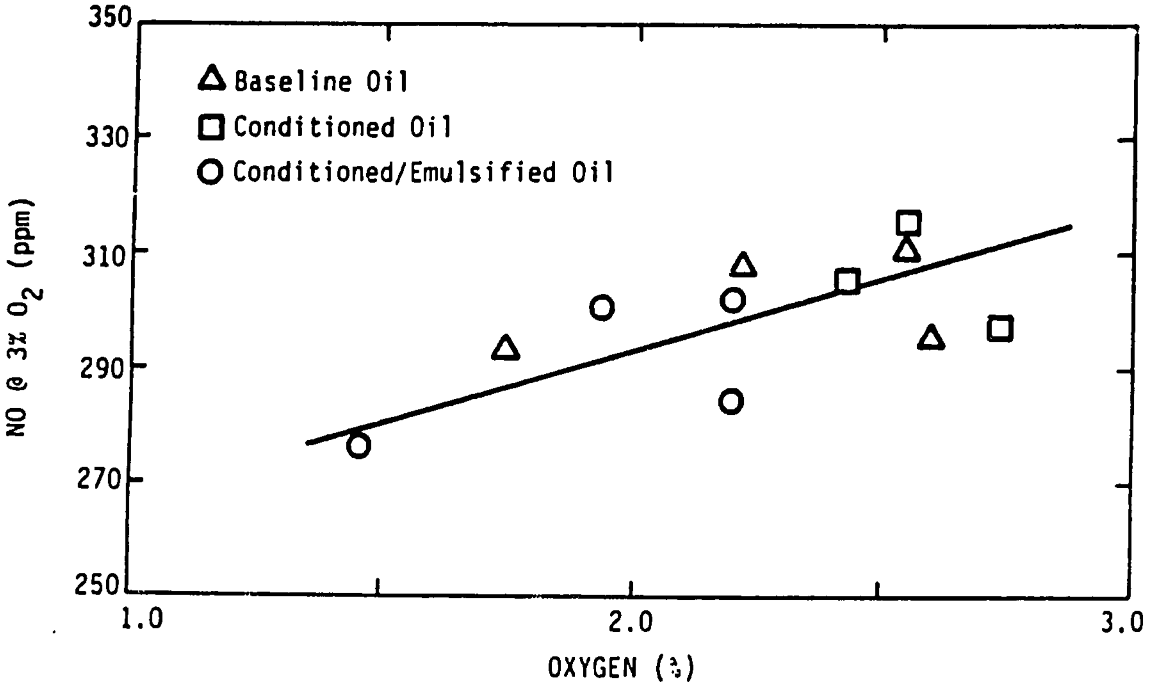

Figure 1.3-7. NO_x Emissions, NEPSCo Tests
Source: Reference 26

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In laboratory tests, the degree of emulsification produced by the existing fuel pumping system was found to be adequate. Gradual coalescence of the water in the 7 micron to 20 micron size range was noted when the warm emulsion was allowed to stand for several hours (21). Since the emulsion was prepared on line and not stored, coalescence was not considered to be a problem. An existing pumping system was used on a 500 MW boiler test to emulsify the fuel and the effectiveness was verified by the measurement of a mean water-droplet size of 5 microns.

Data from the laboratory combustor was obtained with both twin fluid and pressure atomizers as well as a variety of residual fuel oils. Limited full-scale boiler tests reconfirmed some of the laboratory data. Significant findings from the laboratory tests and the few full-scale boiler tests are summarized below: (21, 28)

- Reduction of carbon in the ash required a minimum of 2% water in oil, while significant reductions were found with 5% water. Optimum carbon reduction resulted from 5 to 10% water content by weight (see Figure 1.3-8, note full-scale data).
- The greatest carbon (particulate emission) reduction occurred when operating at the lowest excess air conditions (Figure 1.3-9). However, particulate emissions still increased slightly as excess O_2 was reduced.
- Emulsions offer an alternative to high excess air operation and may avoid high SO_2 to SO_3 conversion as well as reduced dry gas losses.
- Higher emulsion firing temperatures improved the carbon burnout (Figure 1.3-10). Optimum temperatures were approximately 150°C (302°F). Higher emulsion temperatures may require a higher fuel pressure to prevent water vaporization in the fuel system.
- The largest carbon reduction was achieved with the smallest water droplets (Figure 1.3-11). Water droplets of less than 15 microns diameter are required, but are easily achieved with existng pumping systems.
- Emulsions had no signifcant effect upon gas phase species such as NO_x, SO_3 and CO (i.e., none greater than ± 10%).
- UV flame scanners suffered from loss of signal, however, high frequency flicker detectors seemed to be satisfactory.
- CEGB researchers considered emulsions appropriate for firing very viscous oils (10,000 sec. Redwood; approximately 12,000 SSU). These oils would ordinarily require additional heater installation

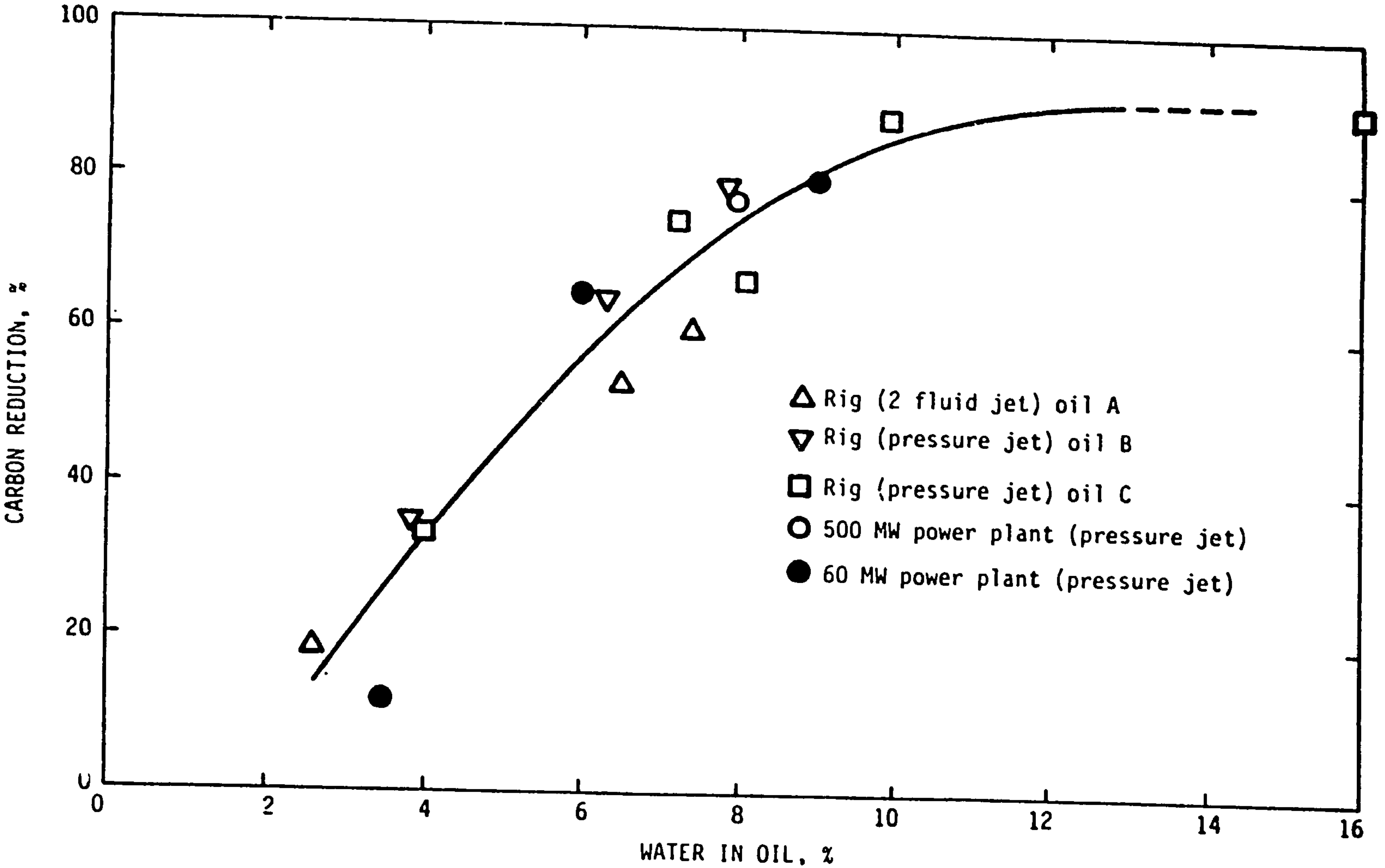

Figure 1.3-8. Carbon Reduction for CEGB Tests
Source: Reference 28

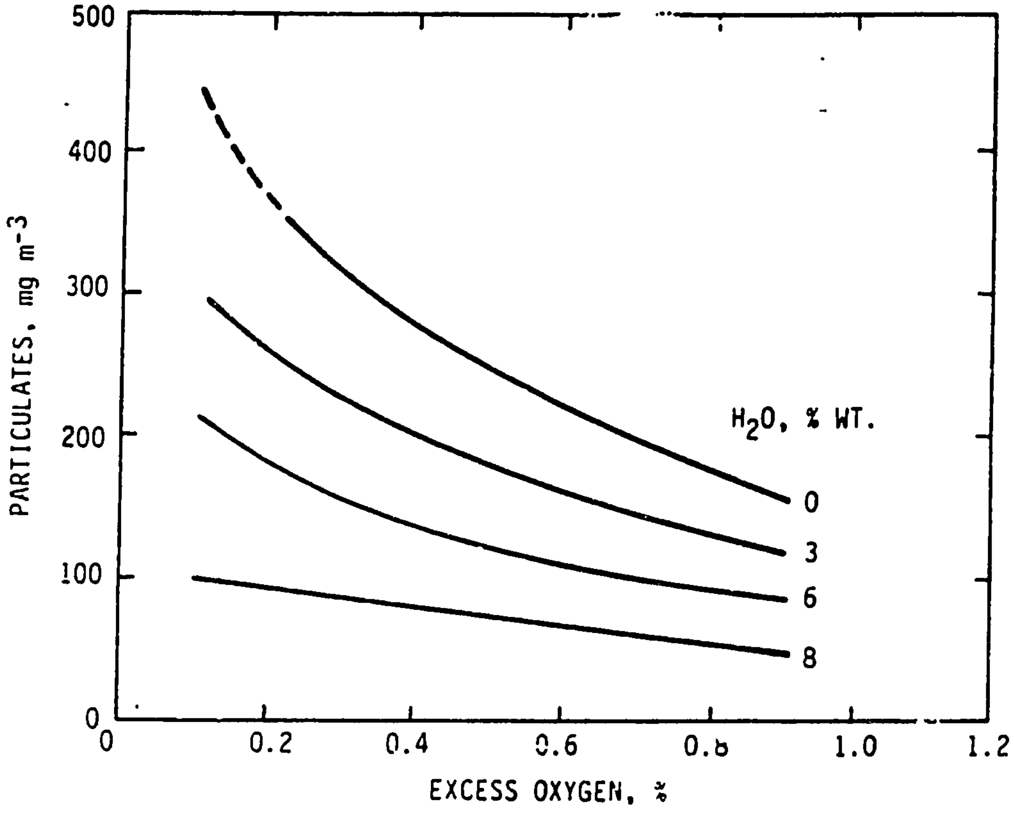

Figure 1.3-9. Effect of Water Concentration on Particulates (CEGB Tests)
Source: Reference 21

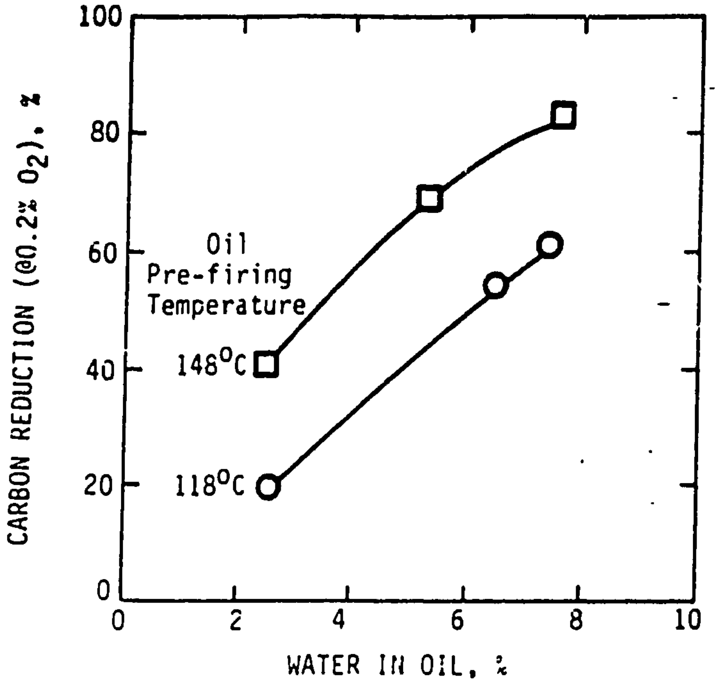

Figure 1.3-10. Carbon Reductions at Two Oil Firing Temperatures (CEGB Tests)
Source: Reference 28

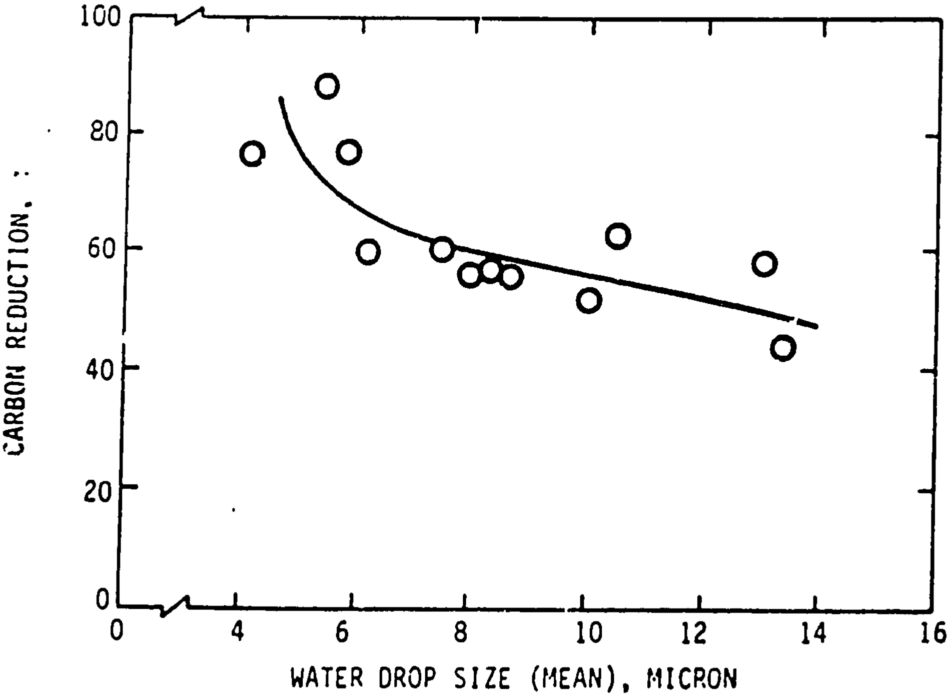

Figure 1.3-11. Effect of Water Drop Size (7% H_2O, Firing Temp. 125°C, 0.2% Excess O_2, CEGB Tests)
Source: Reference 28

to achieve fuel temperatures of greater than 150°C, but may result in deposit formation or coking due to the high temperature.

Since most of these results have been concluded in other studies, the observations listed above also serve as a summary of the overall status of the emulsion technology.

The information concerning the flame detector failure has not been reported elsewhere and was attributed to changes in the fuel spray characteristics. The emulsions were credited with creating a finer fuel spray which is more efficient at scattering light. Since the flame detector views the flame through the fuel spray, a fine spray attenuated the signal to the point it could not be detected. Apparently, high frequency flicker detectors were not similarly affected.

E. Compilation of Carbon Burnout Data. Since an improvement in carbon burnout is one of the primary benefits of using emulsions, data acquired during guidebook preparation were compiled and summarized in Figure 1.3-12. Carbon emissions are a better indicator of emulsion effectiveness because particulate emissions are affected by the ash content of the oil and thus will vary from test to test. Considering the variability in fuels and test conditions (i.e., ash content, oil composition, methodology of testing, method of emulsion preparation, burner/boiler type and operating parameters), the results are relatively consistent. Tests which do not include a baseline test, or which did not include ash carbon content or emissions were not included. The curve drawn through the data points represents the average from the CEGB rig and full-scale tests which may also be a reasonable average for all of the data presented. The data show that emulsion operation can result in a carbon emission reduction at low excess air levels of 60 to 80 percent with a water content in the range of 6 to 9 percent.

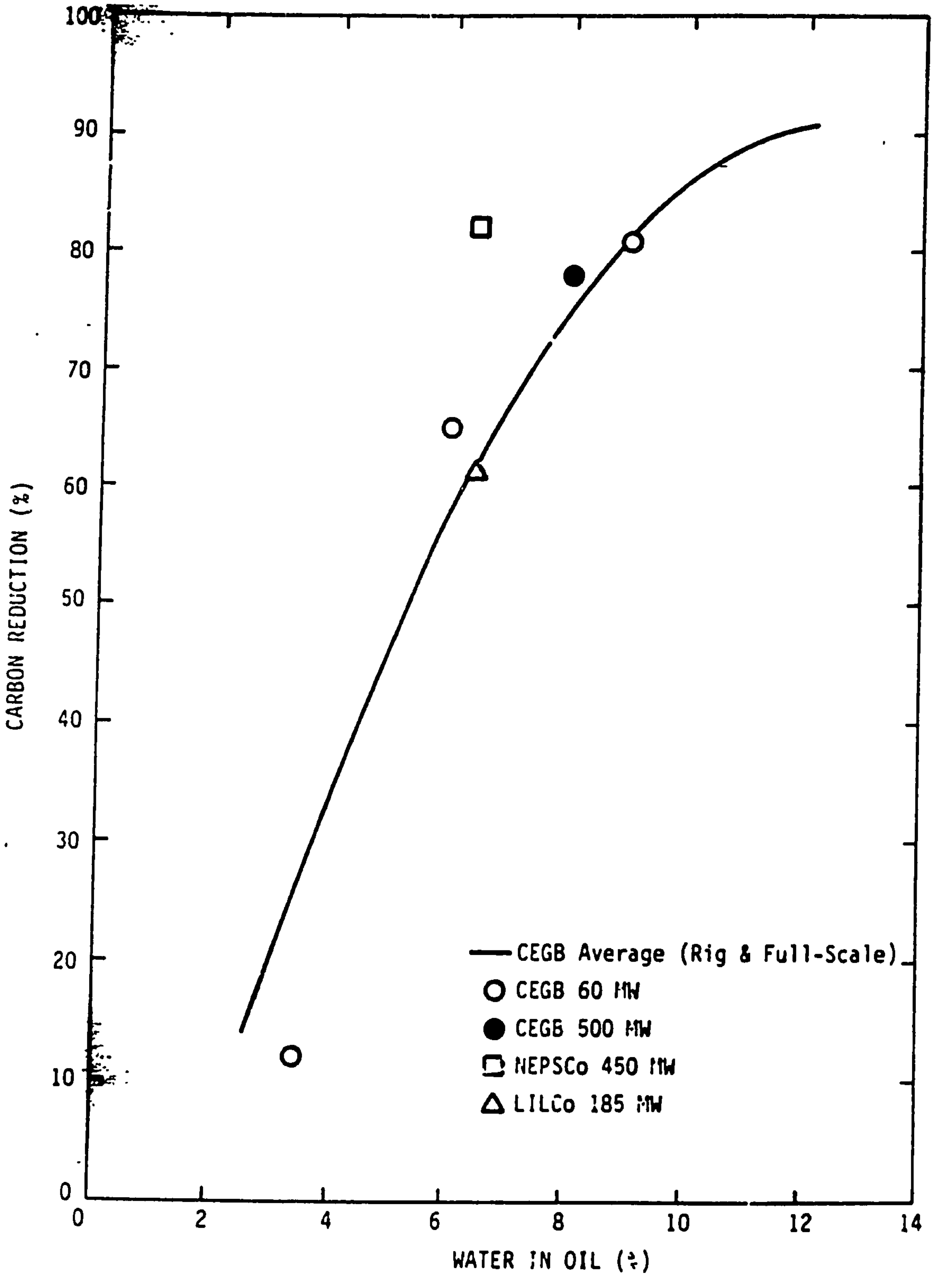

Figure 1.3-12. Utility Scale Water in Oil Emulsion Tests

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APPENDIX D

Air Preheater

Appendix D

Air Preheater

Air heaters play an important role in achieving efficient boiler operation with residual oil firing, because of their impact on combustion air flow and temperature. Deposits from oil firing can affect the resistance to air flow through the air beater and its heat transfer effectiveness. Since the air heater is generally the last heat recovery device in the flue gas stream, the mean metal temperatures in the heat exchanger are relatively low. When metal temperatures are at or near the acid dew point, sulfuric acid and other deposits can condense on the surface. Sulfuric acid is formed from the water and SO_3 in the flue gas. The SO_3 is generated by burner zone oxidation of SO_2 or by catalytic action at high gas temperature. The condensation of sulfuric acid results in corrosion of the metal air heater elements, and the formation of sticky deposits composed of ash and acid. Deposits can build up to create a high pressure drop across the air heater and result in a boiler load limitation if the forced draft fans are no longer able to supply sufficient combustion air.

The acid-related problems are a constraint specific to residual oil-fired boilers. Gas-fired boilers are not affected by these problems. On oil-fired units, air heater corrosion and deposition are a primary operational problem.

The low temperature corrosion characteristic of oil-fired boilers is reflected in the design of the air heaters, not only in the type and shape of the heat transfer materials, but also in terms of the minimum flue gas temperatures at which the unit should operate. The minimum design metal temperature for a residual oil-fired boiler can be 240° to 260°F, while for a comparable fuel sulfur, the minimum for a pulverized coal unit is 160° to 180°F. These minimum temperatures are not the exit flue gas temperature, but an average metal surface temperature to which the air and flue gases are exposed. There is a relationship between the metal and flue gas temperatures, depending on the specific design of the air heater. Lower metal temperatures allow lower exit flue gas temperatures to be achieved. Lower exit flue gas temperatures are desirable to achieve better boiler efficiency.

A large number of utility boilers built in the past 30 years have used regenerative air heaters, most frequently of the Ljungstrom design. A rotating cylinder of air heater baskets passes alternatively through the flue gas and combustion air flow paths. The baskets are made of leaves of metal which absorb heat from the flue gas and transfer it to the combustion air.

The second type of air heater is of the recuperative design, which conforms to a heat exchanger design with gas and air flow separated by tubes or flat plates. Although tubular air heaters are still quite common on utility boilers, recuperative air heaters have become less popular, as a result of the increasing size of utility boilers. Recuperative air heaters enjoy one important advantage because of the separation of the air and flue gas with less leakage of combustion air into the flue gas. Regenerative air heaters with a rotating seal design are much more subject to leakage.

Either type of air heater can be affected by corrosion and deposition problems. The result is the same; a reduction of the metal heat transfer material which will eventually require replacement. Partial pluggage of the gas flow area with increased pressure drop requires washing or other deposit removal means.

D.1 SO_3 GENERATION

The SO_3 present in combustion flue gas is responsible for low temperature boiler corrosion problems. Sulfuric acid (H_2SO_4) is formed when the flue gas or metal surface temperature falls below the acid dew point. Low dew point temperatures at the air heater outlet are desirable since they permit more efficient operation as long as condensation is not present. The acid dew point is not linear with the concentration of H_2SO_4, and above 5 ppm, only a moderate reduction in dew point is achieved by a reduction in SO_3 concentration. The water vapor concentration also influences the acid dew point, but is not a parameter that can be easily altered. Large variations in acid dew point with H_2SO_4 content occur only below approximately 3 ppm. Typical oil-fired boiler SO_3 levels at the air heater are of the order of 10 to 40 ppm.

Concentrations of SO_3 are approximately 1 to 4 percent of the SO_2 formed during the combustion of the fuel. SO_3 formation occurs during the combustion process and remains relatively stable after leaving the visible flame zone. Approximately 1 percent of the SO_2 is converted to SO_3 in the flame zone. The conversion depends upon the concentration of oxygen or excess air, with lower levels favoring reduced SO_3 formation. These reactions require the presence of atomic oxygen, which exists at very high flame zone temperatures. Formation of SO_3 at lower temperatures is relatively low, even though equilibrium calculations indicate almost all of the SO_2 should be converted to SO_3 for temperatures below approximately 1000°F and excess air levels common to boilers. However, the residence times available for the reaction and the rapid cooling process through the convective sections of the boiler preclude appreciable conversion to SO_3.

Catalytic SO_2 to SO_3 conversion can occur at rates well above formation rates in the combustion zone. Catalytic oxidation of SO_2 is considered a heterogeneous reaction by occurring on a solid surface as opposed to a gas phase reaction. Iron oxide (Fe_2O_3) is known to oxidize SO_2 in the temperature range of 800 of to 1200°F. By contrast, Fe_3O_4 is considered to be only moderately catalytic. Heat transfer tube materials,

V_2O_5 and Cr_2O_3, have shown catalytic SO_2 to SO_3 activity. A significant source of V_2O_5 is the residual oil, which typically contains trace levels of vanadium (50 to 500 ppm). Vanadium plays a major role in the corrosion and fouling of superheater heat transfer surfaces, and will promote the formation of SO_3 by contact with flue gas containing SO_2. Mixtures of V_2O_5 and Na_2SO_4 (i.e., ash deposits) can exhibit higher catalytic activity than V_2O_5 alone. Sodium plays a role in the formation of high temperature boiler deposits, which, in turn, may catalytically form SO_3.

The amount of catalytic oxidation of SO_2 to SO_3 depends upon the time and temperature history of the flue gas as it passes from the furnace through the heat transfer sections of the boiler. High surface to volume ratios, as well as large accumulations of ash deposits enhance the catalytic oxidation of SO_2. Smaller and older boilers (60 to 120 MW) tend to have lower SO_3 concentrations (5 to 10 ppm SO_3 at 0.5% O_2) because of convective section designs and operating temperatures that do not tend to promote catalytic formation. Larger, more modern boilers (500 to 600 MW) have longer residence times (15 to 20 sec) and higher levels of SO_3 (25 to 30 ppm at 0.5% O_2). Although only a small fraction of the SO_2 is converted to SO_3, these levels of SO_3 can cause problems as the acid dew point is approached in the air heater or other downstream equipment such as ID fans, ductwork and stacks.

The amount of SO_2 converted to SO_3 is not proportional to the sulfur content of the oil; reducing the fuel sulfur content is not an effective solution to an acid smut problem. For example, some U.S. utilities are limited to 0.25 or 0.50 percent sulfur fuel by local regulations, yet some of these boilers experience acid smut emission problems. Only very low sulfur content fuels (approx. 0.1% S) may reduce SO_3 levels to below 10 ppm, where significant reductions in acid dew point occur. The availability of oxygen is a factor in the amount of catalytic conversion of SO_2 to SO_3, similar to the burner zone SO_3 generation. The use of low excess air combustion is discussed in another section.

D.2 OPERATIONAL IMPACT OF ACID SMUT

Pluggage of the air heater with sulfate deposits is one of the primary operational impacts associated with SO_3 formation and acid smut deposition. Restricted flow through the air heater causes increased back pressure on the FD fans and higher operating costs. Excessive deposits may be difficult to remove on-line and continual buildup may eventually lead to a boiler load restriction. Although the ash content of residual oils is relatively low compared to coal, any unburned carbonaceous material in the oil ash due to incomplete combustion can lead to buildup of deposits. The acid and particulate material in the flue gas form a sticky matrix which can adhere to heat transfer surfaces. Besides the plugging problems associated with the deposits, acidic corrosion of metal can occur. Increased sootblowing frequency as well as more frequent water washing are used to counteract the pressure drop and deposit buildup, but do not reduce the corrosion problem. Water washing often can only be done with boiler shutdown which reduces unit availability.

Acid smut problems have been associated with high SO_3 formation or combustion of high vanadium content oils. A matrix of acid and oil particulate matter (including unburned carbon particulate) is characteristic of the composition of many acid smuts. Typically, 20 to 25 percent of acid smut material is acid, although a 40 percent acid content is possible. In addition, iron sulfate from the corrosion of boiler steel components may be included in the matrix. Large particles of acidic materials form and are carried aloft in the flue gas plume. As a result of their large size, the acidic particles can fall out of the plume and onto neighboring areas. Stains from the acid have discolored and corroded paint finishes on automobiles and other unprotected structures. In some cases, acid smut has been responsible for crop damage. The iron sulfate content in acid fallout causes brown stains on light colored surfaces, in addition to the acidic damage that occurs. Acid smut can create a public relations problem with nearby residential or industrial neighbors.

Acid smut is not a problem that is limited to the air heater zone and it may arise in cooler downstream ductwork and equipment. A study by the CEGB reported that approximately 40 percent of the smut particles were created near the top of the chimney (15 meters below the lip of the stack). The top of stacks were found to be significantly cooler than upstream sections of the gas flow system and are likely zones for acid condensation and smut formation. Acid smut has also been blamed for the formation of deposits or corrosion products which are later reentrained into the flow stream. It is likely that the largest acid fallout particles are formed in this matter, since agglomeration or large fallout particles might not be likely in a flowing gas system.

Creation of acid smut can be influenced by the cyclic loading operation of the boiler. Cyclic loads vary the velocity and temperature of the flue gases, which can dislodge deposits from the air heater or ductwork. Low loads can promote the formation of acidic particles, since low loads result in lower flue gas temperature. Accumulation of acidic material on steel and stainless steel surfaces was found to be at a maximum at 20°C to 30°C (36°F to 54°F) below the acid dew point. The accumulation of a deposit layer expanded, then peeled away leaving a clean surface. The peeling action could potentially be initiated by changes of boiler operation, wind speed and direction, and perhaps the humidity. Flue gas temperature may not be a good indicator of cooler metal temperature, due to poor or defective insulation or low ambient temperatures. Acid smut emissions have been associated with boiler startup, when cool metal surfaces exist.

The acid smut emission problem has also been related to the water content of the flue gas in at least one utility boiler. Acid smut production was characterized by large emissions at some times, then emissions would stop for no apparent reason. Water vapor content was suspected and a relation of smut occurrence with water content was established. In this case, it was found that the boiler would emit large quantities of smut when the flue gas water content was between 8.5 to 9.5 percent, while above or below this region, normal smut emissions occurred. Smut emission was induced on two occasions with the use of water injection into the furnace, to raise the water content within this humidity band. Smut emission decreased when water was added to raise the water content greater than 9.5 percent. The reason for this characteristic is not known.

A final factor in the generation of SO_3 and the creation of fouling deposits or acid smut is the boiler design. Problems have been experienced with boilers that were converted from firing pulverized coal to residual oil. One major design-related problem is low temperature corrosion and fouling resulting from SO_3 formation. Coal units can withstand lower back-end temperatures since SO_3 is either formed to a lesser degree or absorbed by the fly ash; therefore, the acid dew point is lower. Unless modified, the heat recovery equipment on a coal-designed unit converted to residual oil-firing will drop flue gas temperatures below the oil-fired acid dew point. This can result in a significant corrosion or deposition problem.

Units designed for oil-firing can experience SO_3 related problems since low temperature corrosion is a chronic problem associated with oil fuels. Changes in boiler firing practices or fuel quality may exacerbate a corrosion problem. The quality of residual oil being fired may be significantly different from the design fuel specifications. The fuel sulfur and vanadium content are the important properties. Boilers originally designed for base-loaded operation but operated in a cyclic mode may have increased acid smut formation or other corrosion-related problems.

D.3 ABATEMENT MEASURES

Abatement measures have been implemented to reduce low temperature emission and corrosion problems caused by SO_3 formation. These measures have emphasized reducing the operational symptoms caused by the SO_3 content, and reducing or eliminating the SO_3 entering the air heater. Measures to reduce the operational impact of SO_3 include the following:

- Increasing air heater sootblowing or water washing procedures
- Raising the air heater gas (or air) temperatures to raise the metal temperatures above the acid dew point
- Changing the design of the air heater elements to reduce the potential deposition and corrosion

Options for minimizing the SO_3 level include operating the boiler with very low excess air, as well as using additives to neutralize or impede the formation of SO_3. Often, both approaches are utilized in combination, since none of these measures alone has the ability to eliminate SO_3 problems without some type of operating cost or loss of boiler efficiency.

D.3.1 Air Heater Sootblowing and Water Washing

More frequent sootblowing and water washing procedures combat the effects of excessive pressure drop across the air heater caused by deposits, but do not prevent potential corrosion problems. Corrosion is a long-term process which will continue regardless of the cleaning frequency.

On regenerative air heaters, the sootblowing is usually performed on the flue gas side. However, the use of sootblowing on the combustion air side (called reverse lancing) has been used as one means to reduce an acid smut problem. The objective is to prevent the removed deposits from exiting through the stack by sootblowing them into the combustion air. Reverse lancing reduces the emission of particulates by returning the deposits to the furnace via the burner air flow.

Steam for sootblowing is not as good as the use of air as the cleaning medium. Steam is credited with more momentum than air at the same pressure, and therefore, better ability to clean deposits. However, the moisture in the steam can be detrimental to a deposition problem. One study indicated that small quantities of moisture contributed to increased fouling. Economizer or boiler tube leaks are a source of moisture as well as leaking steam sootblowers and water washing nozzles or valves. By contrast, dry air was considered the best cleaning medium, primarily due to the absence of moisture, not for its better cleaning ability.

Sootblowers may not be capable of removing all air heater deposits, and the eventual buildup of deposits will lead to high-pressure drops and/or load restrictions. At this point, water washing the air heater is warranted to fully remove deposits (which are typically water soluble). Water washing is generally done with the unit shut down, although some boilers have systems designed to allow washing at low loads. Washing an air heater on-line requires isolating one air heater and fans, while continuing to operate the boiler on the second air heater at reduced load.

Water washings are performed with alkaline materials such as sodium hydroxide and sodium carbonate (soda ash) dissolved in water to neutralize the acidic nature of the deposits.

Cleaning of downstream ductwork and stacks during outages tends to lessen the impact of an acid smut problem, removing deposits which may be emitted later, and helps to lessen acid smut during startup.

D.3.2 High Air Heater Exit Gas Temperature

One means to combat a low temperature corrosion and deposition problem is to modify the exit gas temperature to prevent reaching the acid dew point. A higher exit gas temperature will raise the operating temperature of the metal air heater components as well as help to maintain the temperature of downstream equipment. The disadvantage is the efficiency loss associated with a higher exit gas temperature. A 10°F increase in the exit air heater gas temperature corresponds to approximately 0.25 percent reduction in boiler efficiency for oil firing. Large temperature increases can result in significant energy penalties, and therefore are seldom utilized. A variety of means can be used to raise the exit flue gas temperature including: (1) bypassing air around the air heater; (2) heat exchanger steam coils; and (3) partial basket removal. The first two methods can be part of a normal boiler system to control the combustion air preheat temperatures.

Bypassing cold air around the air heater reduces the combustion air preheat, and allows less energy to be withdrawn from the flue gases. Alternatively, hot air can be recirculated from the air heater exit and back to the FD fan or air heater air inlet, which raises the mean inlet air temperature.

The use of low pressure/temperature steam coils at the air heater inlet also results in higher temperature operating conditions for an air heater. An increased air temperature results in a higher combustion air exit temperature and less energy extracted from the flue gas. Problems with the use of steam coils have included leaking of steam or water into the air heater. The additional moisture can result in fouling problems similar to that described for leaking steam sootblowers.

Another approach to raising air heater temperatures is partial removal of air heater baskets. This can be accomplished in regenerative air heaters by replacing or substituting basket elements which are shorter than the originally supplied baskets. Less metal area means less heat transfer, higher exit gas temperatures and higher air metal temperatures. The use of shorter baskets is one method that can compensate for oil firing in a coal-fired boiler designed for lower exit gas temperatures. There is a drawback with this technique. In addition to the efficiency losses, a lower combustion air temperature will result from the reduced heat transfer. Although lower combustion air temperatures could result in flame problems if major reductions are made, such large changes would likely be economically prohibited by the efficiency losses associated with the higher flue gas exit temperatures.

A fair amount of work has been concerned with the proper insulation of ducts and stacks downstream of the air heater to prevent low metal temperatures. The primary objective is the prevention of acid smut and corrosion in these components. If ductwork, fans, or the stack are poorly insulated, the metal temperatures can drop below the acid dew point at the walls and severe corrosion or acid smut generation will occur, even if the bulk flue gas temperature remains high. Very high rates of acidic material deposition have been attributed to metal temperatures roughly 40°F below the acid dew point. Ductwork or stacks, which may be poorly or inadequately insulated, can easily drop into this high attack temperature range. Acid smut emissions originating from acidic material condensing on cooler metal have also been attributed to deposits on downstream equipment.

Proper weatherproofing of the flue gas ductwork insulation is required to prevent low wall temperatures, particularly at expansion joints. If inadequate or damaged lagging allows water to soak the insulation, much lower metal temperatures will result. Minimizing air infiltration is considered mandatory in maintaining gas and metal temperatures. Maintaining desired exit gas temperatures during low load operation requires proper operation of steam coil heaters or bypass systems.

Similar considerations are required of stacks, although their construction makes sealing and insulating a more difficult task. Simple steel stacks can emit acid smuts containing a staining iron sulfate when metal temperatures drop below 250°F. Shielding the uninsulated stack to keep the gas temperatures above 240°F was found to eliminate the smut. Brick-lined stacks can also be susceptible to damage by acids if they are allowed to penetrate into coatings or mortar. Acid or moisture penetrating the stack liner can destroy the effectiveness of the fiber insulation or attack the steel or concrete structure.

Creation of acid smut near the top of a stack is reportedly a big problem. This problem is mostly the result of radiation and convective cooling, which creates substantial differences between the flue gas and stack temperature. This drop of stack temperatures has been shown to exist approximately one stack diameter below

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the lip, resulting in a differential between gas and stack temperature as high as 55°F. A hot air heating system at the top of a stack has been installed by the CEGB as a means to control an acid smut problem.

D.3.3 Air Heater Design

The regenerative rotary air heater design allows relatively easy access and removal of the basket elements, as compared to a tubular air heater. This design characteristic offers additional flexibility in combating plugging and air heater deposition problems. Some options include: 1) altering the heat transfer surface area to increase the average cold end temperature, 2) changing the element material for more corrosion resistance, and 3) modifying the basket element to permit more effective sootblowing.

Baskets removed from the hot or intermediate sections in one case resulted in a 30°F increase in average cold end temperature. In another trial, the removal of baskets was effective in raising the cold end temperature and reducing corrosion but the remedy was not considered cost-effective. The cold end temperature was increased by 30°F in the latter case, but the corrosion problems persisted.

In addition to basket removal, baskets can be made of materials, which offer better corrosion resistance than the originally designed materials. Typically, low alloy steels are substituted (such as Corten), but other more corrosion resistant materials, such as enameled steel, or 409 stainless steel have also been utilized. The success or failure of the replacement basket material depends upon which baskets have experienced the corrosion problems. For example, if hot or intermediate open hearth steel baskets have had excessive corrosion, they can be changed to low alloy (Corten materials). Cold-end baskets may be subject to high rates of corrosion due to their low operating temperatures, and therefore may require the use of the more exotic materials. In a trial with enameled steel baskets, the enamel coating was chipped by debris and the corrosion continued at the steel substrate. Mixed results with enameled coatings have also been reported by the CEGB with the conclusion that there is no obvious advantage or justification for the additional cost in terms of longer element life or low pressure drop. Cold-end baskets made of 409 stainless steel have apparently been successful in resisting corrosion (2 years) for plants that previously had used the Corten and enameled baskets.

The design shape of the basket elements is a factor in the sootblowing effectiveness. Notched flat element sheets offer smooth, parallel heat transfer surfaces which are considered the easiest to clean by sootblowing or water washing. Double undulated elements have traverse corrugations (approx. 30°) superimposed on the parallel

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sheets, which are intended to promote gas turbulence and aid heat transfer. Double undulated elements are considered more difficult to clean due to the undulated design. Most baskets of the double undulated design are used in the hotter sections of the air heater, while the notched flat design are often used in the cooler, more deposit prone sections of the air heater.

One variation of the basket design is a loose packing of the material sheets within a basket. The intent is to allow movement of the sheets (rattling) which would loosen cake deposit buildup (popcorn ash) and allow passage through the air heater. This technique may be specific to coal-fired applications, since an application to oil-fired deposits is not known and may not be effective on sticky, acidic, oil-fired deposits.

D.4 DUCT AIR HEATING SYSTEM

The duct air steam heating system heats the air entering the regenerative air preheaters from 27°C to the temperature required to maintain the air preheater recommended average cold-end temperature at all loads. This temperature is the average temperature of the air entering and the flue gas leaving the regenerative air preheater. Maintaining the average cold, end temperature protects the air preheaters against corrosion and fouling by preventing condensation on air preheater surfaces.

D.4.1 System Description

The system is designed to perform heating functions in a safe, reliable, and economical manner with minimal vibration and noise.

The duct air steam heating system is sized to use auxiliary steam to heat air with an inlet temperature of 27°C and to avoid vapor binding and entrapment of noncondensables in the equipment and lines. The system is capable of handling inlet air of -40°C without freezing the condensate in the system.

The duct air steam heating system has a design rating 300 psig at 370°C. The nominal operating conditions are 180 psig at 260°C. The system is designed to be cleaned initially by steam blowing and laid up with inert gas.

D.4.2 System Components

The duct air steam heating system consists of the following components:

- Two duct air steam heaters. Each heater is installed in the discharge duct of each air fan upstream of the regenerative vertical shaft air preheater.
- Two duct air steam heater drain tanks
- Piping, valves, and controls essential to the system operation.

Steam heaters are perpendicular to the floor and to the airflow in the fan ducts. Each steam heater assembly is made up of sections which are continuous from the top to the bottom of the duct. Each heater section consists of a single row of stainless steel tubes that terminate in a single steam inlet at the top and a single condensate outlet at the bottom. The width of each section is limited to 0.6m, and the heaters are sized for effective distribution of steam and condensate drainage. The individual heater sections can be removed without entering the duct.

Steam from the auxiliary steam system is supplied to the separate distribution header for each steam heater assembly. Separate lines from this header distribute steam to the inlet of each heater section. Condensate legs from each heater section outlet terminate in a single header, which is connected to the drain tank for the heater assemblies.

Isolation valves are provided in the inlet and outlet lines to each heater section. Each section is self-draining and self-venting. To permit the flow of noncondensable gases from the system to the condenser, flow orifices are installed in all vent lines connected to the condensate legs of the heater sections and in the vent lines of the drain tanks and steam headers.

Carbon steel drain tanks are sized for stable level control. Level control valves, in the drain lines from the tanks to the condenser and close to the condenser, regulate the drain tank level.

The difference in elevation between the drain tank and the condenser provides the static head required for drainage of the condensate to the condenser, even when the pressure in the condenser is atmospheric.

To prevent freezing of the coils in case of a heating system failure, an automatic valve located in a vent line to the condenser will open if the air temperature is low, to pass 10 percent of the maximum steam flow.

D.4.3 System Operation

The forced draft air fans draw air from the outside which is normally 27°C. These fans discharge through the fan ducts into the steam air heating system. In this system, the air is steam heated to the temperature required to maintain the recommended average cold-end temperature of the regenerative air preheaters. A temperature control system, compensated for steam header pressure, maintains the average cold-end temperature at the setpoint (desired temperature) by regulating a valve controlling the steam flow to the steam air heater. The steam pressure downstream of the control valve will be above the minimum pressure required for venting the steam heater assembly to the condenser under all load conditions. Steam supplied from the auxiliary steam system will also be regulated to this requirement.

The rate of steam flow, and therefore the pressure losses, through each section of the air steam heater, depends upon the plant load and the relative location of the section with respect to the air duct. The condensate levels in the individual condensate legs of each section will vary accordingly. By providing enough difference in the elevations of the air steam heaters and the drain tanks, the possibility of having a dead leg of condensate in a heater tube which subsequently might freeze is eliminated.

An equalizer line connecting the drain tank to the steam inlet header stabilizes the system pressure against transients. The stainless steel tubing provides a degree of corrosion resistance and the unrestricted gravity flow prevents freezing in cold winter weather.

To provide the maximum protection from acid corrosion, the cold-end temperature should be kept as high above the acid dewpoint temperature as is necessary to provide a safety margin. At the same time, a high cold-end temperature, and hence, a high exit gas temperature, produces a loss of boiler efficiency and is undesirable from a fuel usage standpoint.

To exit gas temperatures high enough to prevent corrosion but low enough to achieve maximum boiler efficiency, numerous Western boilers have been equipped with acid dewpoint monitors. These monitors detect incipient acid formation and can either provide an alarm to the operator or they can be incorporated directly into the control system to raise or lower the cold end temperature control setpoint.

APPENDIX E

Burner Test Plan

Appendix E

Burner Test Plan

E.1 INTRODUCTION

Preceding sections of this report have described the potential benefits of using steam or air atomizer burners and additives to improve combustion performance and reduce gas-side corrosion in boilers fueled with low grade residual oils. Before making large capital investments to retrofit the existing RENEL boilers with burners of improved atomization, it is advisable to carry out a test program. The purpose of this program is to confirm that these types of burners can indeed alleviate the severe corrosion problem. This Appendix outlines the method of selecting a representative boiler for tests, the necessary hardware for valid testing and the specific tests that need to be carried out to establish the optimal operating parameters for the retrofitted boilers.

E.2 PREPARATORY STEPS

E.2.1 Test Site Selection

In the ideal test installation, all the burners of the selected boiler need to be replaced with test burners. For economic reasons, a moderate size unit should be selected. The steam side conditions (particularly the temperatures) should be representative of those prevailing in oil burning units. The boiler should have convenient access provisions for installation and removal of test coupons or tube sections. The tests will require some peripheral hardware; there needs to be sufficient floor area available for these.

Retrofitting operations and the actual test program is expected to require months, during which the boiler needs to be shut down or must be operated at various load levels. To avoid interruption of the program, it is desirable to have sufficient spare capacity available at the station to minimize the impact on meeting electric power or district heating demand. Finally, the site should be readily accessible for transportation and have sufficient technical staff available to carry out the program.

E.2.2 Test Program Planning

The overall test program may be subdivided into the following phases:

- Define program objectives and scope
- Develop technical specifications for test equipment
- Procure, install, and start up test equipment
- Develop test plan

- Conduct test runs and revise test plans, as necessary
- Reduce and analyze test data
- Develop recommendations for retrofitting the remaining oil-fired boilers

The burner test plan will be presented in this sequence.

Burner Test Program Objectives and Scope

The objectives of the test program are to verify the effectiveness of improved atomization and suitable additives to:

- Increase boiler efficiency
- Eliminate furnace wall coking from incomplete combustion
- Reduce vanadate deposits (vanadium oxides and complex vanadium/sodium oxides) in the superheater sections of the boilers
- Reduce conversion of SO_2 to SO_3 in the back end of passages of the boiler (the air preheater, ID fans, flue gas ducting, and chimney liners)
- Decrease the amount of NO_x produced in the combustion process
- Establish optimal combustion parameters to minimize hot and cold-end corrosion

The program scope includes:

- Base line measurements to record the current conditions
- Design and installation of test burners, fuel oil conditioning equipment, data acquisition and control system, and any required modification of existing equipment
- Planning and execution of burner test runs at various operating parameter settings
- Analysis of test data and definition of optimal parameter settings
- Recommendations for actions regarding changes at other RENEL oil-fired plans

Test Equipment Technical Specifications

Details of the test equipment specifications must take into consideration the following:

- Configuration of the burner and its auxiliaries

- Configuration of the boiler where the burners will be installed and tested
- Services available at the test site
- Data acquisition and control system needs
- Requirements of the planned test program

In general, the following equipment should be specified:

- **Burner.** Including steam atomized guns, ignitors, castable refractories,
- **Burner management system.** Including flame scanners, safety shutoff valves, limit switches, pressure switches, and control logic software to be incorporated in the distributed control system (DCS)
- **Oil conditioning equipment.** Including positive displacement pumps, shell-and-tube heat exchangers with relief valves, inlet and discharge strainers, oil pressure regulating valves, steam regulating valves, and mass flow and viscosity sensors/transmitters
- **Distributed control system.** Configured for both control and data acquisition/analysis to perform all control functions during the tests and burner efficiency calculations
- **Sensor/transmitters.** Including air and oil mass flow meters, oil viscosity meters, insitu oxygen analyzers, flue gas analyzers, in-line sampling devices, pressure, temperature, and flow elements for measuring furnace and auxiliary parameters, and laboratory analysis equipment to fully characterize the composition of oil and the flue gas (including trace elements)
- **Removable test coupons.** Measure and analyze deposits in the hot and cold section of the flue gas path
- **Modifications to the test bed boiler.** Including provisions for installing the new burners, fast responding controls for combustion air supply, insertion provisions for additives and oil storage tank for testing specific oil batches.

Manufacturers of steam atomized boilers normally provide sufficient technical details and technical support to allow development of design details for the test installation.

Test Planning

Three types of tests are to be performed:

- Baseline tests to determine boiler efficiencies achievable at 100% and 50% boiler load with the existing burners,
- Parametric tests to determine the optimal operating parameters with steam atomized burners at 100% and 50% boiler load,
- Long-term tests to evaluate the benefits of additives to reduce gas-side corrosion

Baseline Testing. Two steady-state tests are to be performed (at 100% and 50% power) before installation of the steam atomized boilers to provide a basis for comparison with future tests. Data accumulated should provide necessary input to define boiler efficiency, air/fuel ratio, representative gas path temperatures, flue gas composition, and chemical analysis of fuel oil. It is desirable to perform these tests after the new sensors and DCS system are performed to ensure realistic comparisons with future tests. In preparation for baseline testing, all the instrumentation should be calibrated.

Parametric Tests. After installation of the new steam atomized burners and other modifications to the boiler have been completed, a series of exploratory runs are to be made. The purpose of these runs will be to explore responses to burner controls and to determine the time required to reach steady-state operations after changes in the control settings.

Once these exploratory runs are completed and the results are analyzed, a matrix of test runs is to be conducted to determine the combustion efficiency, boiler efficiency, and flue gas composition at a range of boiler loads, air/fuel ratios, and fuel composition. For every set of parameter combinations at least three points of the independent variable should be tested to allow drawing of a valid curve. To minimize measurement and analysis uncertainties, the tests should last about 24 hours. Boiler characteristic data, flue gas composition, and fuels samples are to be taken at 4-hour intervals. The test instrumentation should be periodically recalibrated to ensure data validity.

It would be desirable to install new hot- and cold-end test coupons at each test run and to examine them for indications of deposits and corrosive damage. If the early coupons show no detectable deposits, due to the short exposure time, this step may be deferred until the long-term testing phase.

Long-Term Testing. As noted in Section 3.5.5, magnesium compound additives have been successfully used in Western residual oil-fired boilers for reducing vanadium-caused corrosion. The third group of tests is designed to establish the optimal additives injection rates for various vanadium concentrations and vanadium/sodium molar ratios in the fuel oils.

The long-term tests should be conducted after the boiler and air heater surfaces have been cleaned from accumulated deposits. This will ensure that the results are not biased by the additives being used up in reactions with existing deposits. During the tests, the boiler should be operated at optimal parameter settings, as determined during the parametric tests.

Tests at a given Mg/V ratio should be run until noticeable deposit layers are formed. Hot and cold end test coupons should be examined once a week during the tests to track the deposit formation. If no deposits can be observed over a 3-week period, the test may be terminated and a new test with lower Mg/V ratio may be started. Conversely, if the deposit buildup is significant, a new test may be started with Mg/V ratio.

Data Reduction and Analysis. It is desirable that the DCS be made capable to perform the boiler performance calculations automatically, using the data stored during the tests. It will be necessary to manually enter such data as the fuel oil composition, coupon examination results, and possibly the flue gas analysis. The test results should be analyzed at the earliest possible time after the tests, to be able to modify the test plan in case of anomalous results.

Laboratory Support. During the test program, periodic fuel oil and flue gas samples are collected. Laboratory support will have to be obtained to determine the physical properties and chemical composition of these samples, particularly those related to corrosive damage (vanadium, sodium, asphaltene, sulfur, etc.) In addition, examination of coupon samples will require the availability of metallurgical and metallographic facilities.

Test Schedule. Depending on local conditions, the actual testing may require at least 6 months. A detailed schedule should be established after the preliminary parametric tests when the time to steady state is determined, and the time required for test preparation can be realistically estimated. A nominal schedule for the program is shown in Figure E-1.

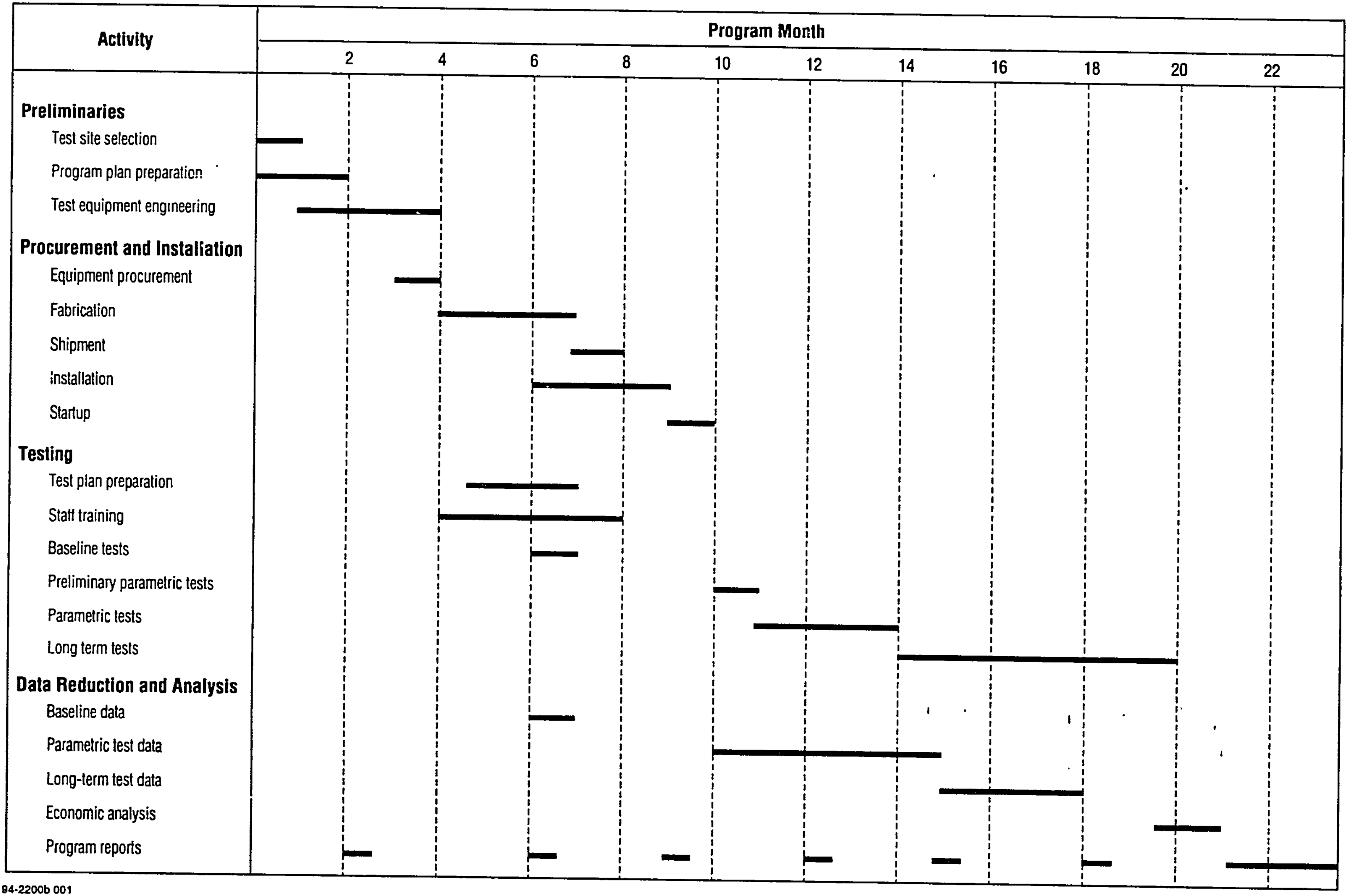

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Figure E-1 Nominal Test Program Schedule

Test Program Staffing. Assuming that the test site is able to supply the operating and maintenance staff, including instrument technicians, the test team would initially consist of a test director, a secretary, 4 to 6 test engineers, 6 to 8 technicians, and 2 analysts. The test engineers would be charged with detailed test planning, supervision of test preparations by the plant staff, and collection of data and chemical analysis samples performed by the technicians. During the tests, one test engineer is stationed in the control room and one engineer works with the DCS and the test data analysts. During long-term testing, after completion of the parametric tests, the staffing requirement may be significantly reduced.

It is often beneficial to establish a test program overview committee to oversee the progress and provide technical guidance to the test team. This committee should include representatives from the operations organization, upper level RENEL management, and recognized technical experts in combustion technology, corrosion chemistry, and metallurgy.

E.3 TEST PROGRAM IMPLEMENTATION

E.3.1 Test Runs

For each specific test run, detailed instructions should be prepared – listing all the data taking and sample collection requirements. The instructions should also specify any special observations that need to be made during the runs and any precautions needed for personnel safety and equipment integrity. Requirements for laboratory tests and analyses should also be specified.

Depending on the qualifications of the staff assigned to the test program, it may be necessary to allocate time at the beginning for staff training and trial runs for certain tasks (e.g., sample collection and handling).

To facilitate data reduction and interpretation, it will be necessary to maintain a test log. In this log, the test engineers note any unusual occurrences and observations. This log is kept together with printouts of all data.

E.3.2 Data Reduction and Analysis

As soon as all the test data are available, a review is to be held to confirm the validity and consistency of the test run. If there is some question about the validity a decision needs to be made about repeating the run, or even modifying the program.

After completion of the parametric test phase of the program, the results should be compared with data from the baseline tests to determine how much improvement in boiler performance is achievable with the new burners and additives. The following items should be considered.

- Combustion efficiency, especially carbon burnup
- Boiler efficiency
- Amount and composition of superheater tube deposit
- Indications of cold and sulfuric acid deposits/corrosion
- NOx concentration in the flue gas
- Mg/V ratio and excess air required for optimal boiler operation (this may vary with oil types and grade)

If the results are sufficiently promising, the program should proceed into the long-term testing phase.

Concurrent with this phase, an economic analysis should be performed to determine the savings that may be achieved by retrofitting the remaining RENEL plants with the new burners. This analysis should determine if, over the remaining life of the plants, the cost of retrofitting could be offset by reduced fuel costs, maintenance costs, and reduced hot standby reserve requirements. The results of this analysis form the basis for recommendation to RENEL's management.

In case of favorable results, RENEL may consider using the test installation as a training site for selected operations personnel from other plants.

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