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UNIFIED FACILITIES CRITERIA (UFC)

CENTRAL HEATING PLANTS OPERATION AND MAINTENANCE

APPROVED FOR PUBLIC RELEASE; DISTRIBUTION UNLIMITED

UNIFIED FACILITIES CRITERIA (UFC)

CENTRAL HEATING PLANTS
OPERATION AND MAINTENANCE

U.S. ARMY CORPS OF ENGINEERS

NAVAL FACILITIES ENGINEERING COMMAND (Preparing Activity)

AIR FORCE CIVIL ENGINEER SUPPORT AGENCY

Record of Changes (changes are indicated by **1**\ ... /**1**/)

Change No.	Date	Location
1	Dec 2005	FOREWORD

This UFC supersedes Military Handbook 1125/1, dated October 1995.

FOREWORD

\1\
The Unified Facilities Criteria (UFC) system is prescribed by MIL-STD 3007 and provides planning, design, construction, sustainment, restoration, and modernization criteria, and applies to the Military Departments, the Defense Agencies, and the DoD Field Activities in accordance with USD(AT&L) Memorandum dated 29 May 2002. UFC will be used for all DoD projects and work for other customers where appropriate. All construction outside of the United States is also governed by Status of forces Agreements (SOFA), Host Nation Funded Construction Agreements (HNFA), and in some instances, Bilateral Infrastructure Agreements (BIA.) Therefore, the acquisition team must ensure compliance with the more stringent of the UFC, the SOFA, the HNFA, and the BIA, as applicable.

UFC are living documents and will be periodically reviewed, updated, and made available to users as part of the Services' responsibility for providing technical criteria for military construction. Headquarters, U.S. Army Corps of Engineers (HQUSACE), Naval Facilities Engineering Command (NAVFAC), and Air Force Civil Engineer Support Agency (AFCESA) are responsible for administration of the UFC system. Defense agencies should contact the preparing service for document interpretation and improvements. Technical content of UFC is the responsibility of the cognizant DoD working group. Recommended changes with supporting rationale should be sent to the respective service proponent office by the following electronic form: Criteria Change Request (CCR). The form is also accessible from the Internet sites listed below.

UFC are effective upon issuance and are distributed only in electronic media from the following source:

- Whole Building Design Guide web site http://dod.wbdg.org/.

Hard copies of UFC printed from electronic media should be checked against the current electronic version prior to use to ensure that they are current. /1/

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CHAPTER 1

INTRODUCTION

1-1 **PURPOSE AND SCOPE**. This UFC is comprised of two sections. Chapter 1 introduces this UFC. Appendix A contains the full text copy of the previously released Military Handbook (MIL-HDBK) on this subject. This UFC serves as criteria until such time as the full text UFC is developed from the MIL-HDBK and other sources.

This UFC provides general criteria for operating and maintaining heating systems.

Note that this document does not constitute a detailed technical design, and is issued as a general guide to the considerations associated with operating and maintaining heating systems.

1-2 **APPLICABILITY**. This UFC applies to all Navy service elements and Navy contractors; Army service elements should use the references cited in paragraph 1-3 below; all other DoD agencies may use either document unless explicitly directed otherwise.

1-2 **APPLICABILITY**. This UFC applies to all DoD agencies and contractors preparing designs of maintenance facilities for ammunition, explosives and toxins.

1-2.1 **GENERAL BUILDING REQUIREMENTS**. All DoD facilities must comply with UFC 1-200-01, *Design: General Building Requirements*. If any conflict occurs between this UFC and UFC 1-200-01, the requirements of UFC 1-200-01 take precedence.

1-2.2 **SAFETY**. All DoD facilities must comply with DODINST 6055.1 and applicable Occupational Safety and Health Administration (OSHA) safety and health standards.

NOTE: All **NAVY** projects, must comply with OPNAVINST 5100.23 (series), *Navy Occupational Safety and Health Program Manual*. The most recent publication in this series can be accessed at the NAVFAC Safety web site: www.navfac.navy.mil/safety/pub.htm. If any conflict occurs between this UFC and OPNAVINST 5100.23, the requirements of OPNAVINST 5100.23 take precedence.

1-2.3 **FIRE PROTECTION**. All DoD facilities must comply with UFC 3-600-01, *Design: Fire Protection Engineering for Facilities*. If any conflict occurs between this UFC and UFC 3-600-01, the requirements of UFC 3-600-01 take precedence.

1-2.4 **ANTITERRORISM/FORCE PROTECTION**. All DoD facilities must comply with UFC 4-010-01, *Design: DoD Minimum Antiterrorism Standards for Buildings*. If any conflict occurs between this UFC and UFC 4-010-01, the requirements of UFC 4-010-01 take precedence.

APPENDIX A

MIL-HDBK 1125/1
OPERATION AND MAINTENANCE: CENTRAL HEATING PLANTS

INCH-POUND

MIL-HDBK-1125/1
15 OCTOBER 1995

MILITARY HANDBOOK
MAINTENANCE AND OPERATION OF CENTRAL HEATING PLANTS

DEPARTMENT OF DEFENSE
UNITED STATES OF AMERICA

AMSC N/A

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DISTRIBUTION STATEMENT A: APPROVED FOR PUBLIC RELEASE; DISTRIBUTION IS UNLIMITED.

ABSTRACT

A modern power plant requires that a very diverse mixture of technology and hardware combine to form unique systems. These systems must then be integrated and developed into a complete power plant. By understanding these individual systems, plant personnel are better able to perform the correct operation and maintenance procedures needed to run a plant efficiently and safely.

This handbook was developed for personnel who work in the field performing operation and maintenance work on equipment. It should be used along with manufacturers' literature to gain a better understanding of the different types of equipment available within the power plant.

FOREWORD

This military handbook is approved for use by all departments and agencies of the Department of Defense.

Beneficial comments (recommendations, additions, deletions) and any pertinent data which may be of use in improving this document should be addressed to: Commander, Atlantic Division, Naval Facilities Engineering Command, Code 161B, 1510 Gilbert Street, Norfolk, VA, 23511-2699, telephone commercial (804) 322-4625, by using the self-addressed Standardization Document Improvement Proposal (DD Form 1426) appearing at the end of this document or by letter or by e-mail to harperww@efdlant.navfac.navy.mil.

The purpose of this publication is to provide practical information on the equipment operation and maintenance of central heating and power plant facilities. It is primarily directed to the personnel in the field who actually supervise and perform the operations and the maintenance work.

Although the general subject of steam and power is highly technical, this publication has been written in nontechnical language, brief and direct, so that the reader will have the basic information required for the intelligent handling of field situations.

This publication has been written, not only to be read, but more important, to be used. To obtain maximum benefit, it should be consulted together with the equipment manufacturers' instruction manuals, parts lists, and drawings. Much of the data contained herein has originated at activity level and represents the actual experiences of field personnel. In addition, the latest information operation and maintenance procedures have been collected and included.

THIS HANDBOOK SHALL NOT BE USED AS A REFERENCE DOCUMENT FOR PROCUREMENT OF FACILITIES CONSTRUCTION. IT IS TO BE USED IN THE PURCHASE OF FACILITIES ENGINEERING STUDIES AND DESIGN (FINAL PLANS, SPECIFICATIONS, AND COST ESTIMATES). DO NOT REFERENCE IT IN MILITARY OR FEDERAL SPECIFICATIONS OR OTHER PROCUREMENT DOCUMENTS.

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MAINTENANCE AND OPERATION OF CENTRAL HEATING PLANTS

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Section 1: INTRODUCTION

1.1 Scope. The purpose of this handbook is to provide information and guidance on installation, operation, and maintenance of U.S. Navy central boiler plant equipment. Efficient plant operation becomes more important with each increase in cost of fuel and equipment. The central plant operator has an important job in achieving and maintaining maximum efficiency of plant operation. Information and guidance in this handbook should be reviewed as a first step toward achieving efficient plant operation. Consult manufacturers' literature to obtain information specifically related to your plant.

1.2 Application. The primary purpose of a central boiler plant is to economically produce energy for distribution. This energy may be in the form of steam, hot water, or occasionally, compressed air or electric power. A distribution system is necessary to carry this energy to buildings, hospitals, kitchens, and laundries where it is used for heating, cooling, process, sterilization, and production of domestic hot water. Condensate or hot water is returned to the central boiler plant where it is reheated in a boiler and returned to the distribution system to be recycled.

Section 2: CENTRAL BOILER PLANTS

2.1 Introduction. The purpose of this handbook is to provide information and guidance on installation, operation, and maintenance of U.S. Navy central boiler plant equipment. This handbook is generic in nature because it is intended for use in Navy shore steam/heating plants. It is limited to basic theory and concepts, typical equipment, generally accepted operating procedures, proven maintenance principles, and practices common to most installations.

2.2 General Considerations. The primary purpose of this manual is to inform and guide the plant staff in operation and maintenance of the overall plant and associated equipment; ranging from small sensitive instruments to rugged pumps and boilers. This manual meets the needs of both plant operators and maintenance staff by providing a better understanding of the inner workings and purpose of every piece of equipment. With a common understanding, each discipline can communicate well and assist each other to achieve efficient and reliable plant operations.

It is essential that each plant have in place all material from manufacturers pertinent to specific items of equipment. Identical plants do not exist, consequently one manual cannot be written to meet the complete needs of all plants. Most major manufacturers publish informative books, booklets, bulletins, or pamphlets dealing with their products. They are in a wide range of physical sizes from small pocket books to encyclopedias. In addition, there are several thermal plant oriented books, pamphlets, and periodicals available. These publications can provide viable, up-to-date information on central heating plant equipment and should be available to the plant staff.

2.2.1 Types of Central Boiler Plants. Energy for heating or process use is generally produced in one of three forms:

a) Low temperature water (LTW) (up to 250 degrees F and less than 160 psig)

b) High temperature water (HTW) (pressure exceeding 160 psig and/or temperature exceeding 250 degrees F)

c) Medium temperature water (MTW) (200 to 300 degrees F and 150 psig to 300 psig), i.e., overlaps ASME ranges for LTW and HTW generators

The type of central boiler plant depends upon requirements of the specific installation. For applications involving only space heating and domestic water, a LTW plant is generally sufficient. If steam is required for large process loads or electric generation, a steam plant must be constructed. For most other installations, an economic evaluation must be performed to compare the costs of a HTW system to those of a steam system. Such an evaluation usually shows the HTW plant to be more economical. The following paragraphs provide a brief comparison of the major types of central heating plant systems.

2.2.2 Comparison of High Temperature Water and Steam. Major advantages of HTW and MTW systems result from the closed-loop distribution system. The closed-loop system recycles unused energy in the water which results in very small system water losses. By comparison, steam distribution systems include condensate return systems with potentially significant energy and water losses due to steam flashing, defective traps, defective pressure reducing valves, pipe leaks, and unreturned process steam. Advantages of HTW and MTW systems are further discussed in the following paragraphs.

2.2.2.1 Energy Losses From a Steam System. Figures 1 and 2 illustrate the heat balance at a heat exchanger for a 100-psig and 15-psig steam/condensate system, respectively. When 100-psig steam is supplied to a heat exchanger, condensed water is at a temperature of 338 degrees F and contains 26 percent of the energy originally supplied in the steam. When condensate discharges from the trap, 13 percent of the water flashes to steam and the remaining condensate is at a temperature of 212 degrees F. When 15-psig steam is supplied, condensed water contains 19 percent of the original energy at a temperature of 250 degrees F. When condensate discharges from the trap, 4 percent of the water flashes to steam. Energy losses and makeup water requirements of the low pressure system are thus lower, making the low pressure system preferable if a steam system is used.

2.2.2.2 Pressure Reducing Valves and Vent Condensers. The pressure reducing valve supplies the heat exchanger with low pressure steam, thus minimizing flash losses. If a vent condenser is not supplied, flash-off steam is lost. If a portion of condensate is not returned to the central boiler plant for any reason, the portion of energy remaining in the condensate is lost. For example, if a 100-psig system has 20 percent condensate loss, 5.2 percent (0.20 x 0.26 = 0.052) of total energy produced is wasted. In addition, 20 percent treated makeup water is needed to keep the system operating.

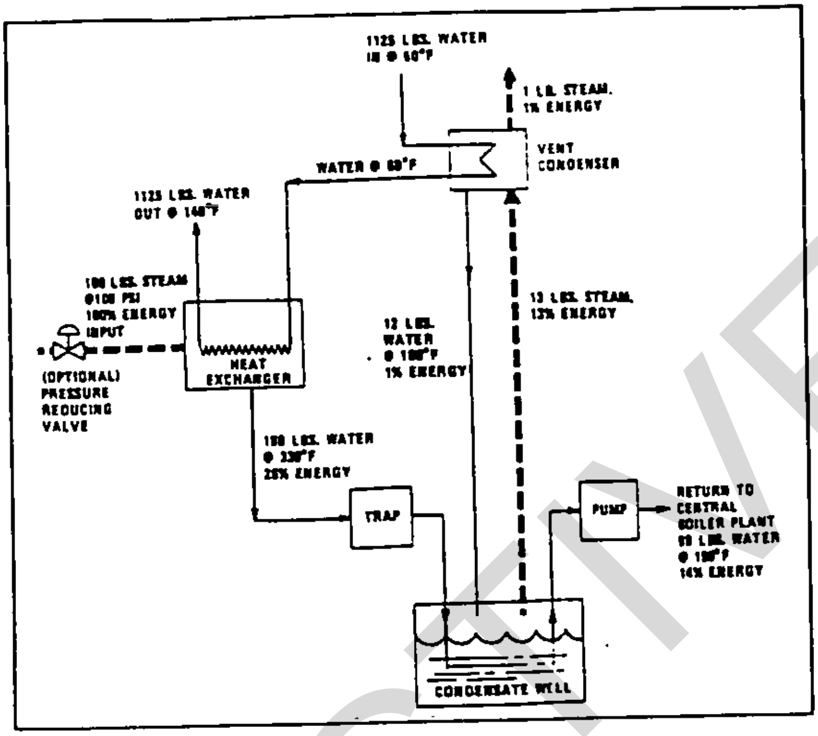


Figure 1
100-psi Steam Heat Balance

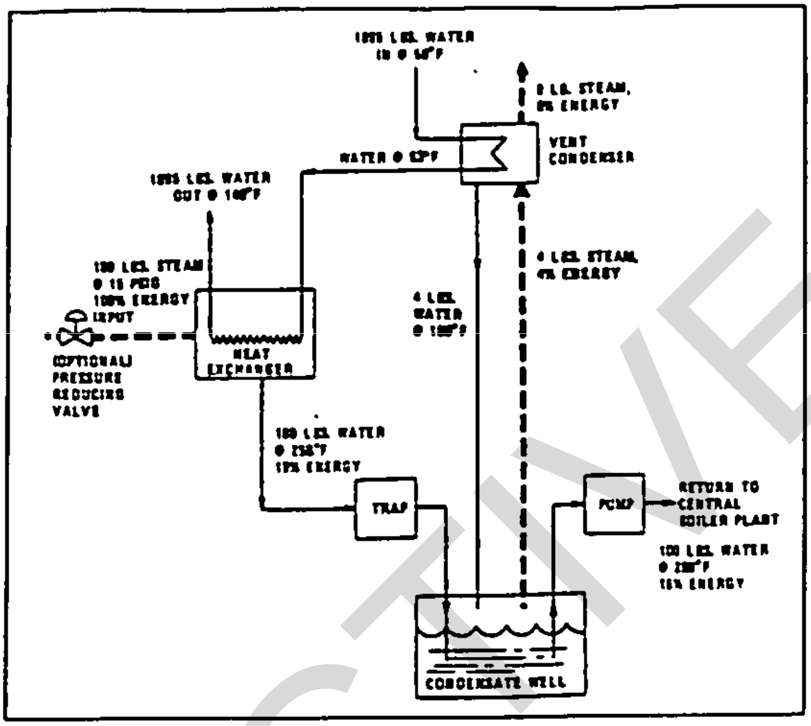


Figure 2
15-psi Steam Heat Balance

2.2.2.3 <u>Heat Balance for a High Temperature Water (HTW) System</u>. Figure 3 illustrates a heat balance for a HTW system at a heat exchanger. It is informative to compare the high temperature water system with a 100-psig steam system. In both cases, 1,125 pounds of water is heated from 50 to 140 degrees F by the heat exchanger. The HTW system returns 56 percent of energy input to the heat exchanger while the steam system returns 14 percent. The HTW system does not have steam flashing losses or condensate losses. The HTW system is clearly a more efficient means of distributing energy from a central boiler plant, if process requirements of the system are such that it is applicable. Appendix A provides heat balance calculations explaining these numbers.

2.2.2.4 <u>Corrosion</u>. A major advantage of the HTW closed-loop distribution system is an inherent reduction in distribution system corrosion as compared to steam/condensate distribution systems. Maintenance, pipe replacement, and energy costs associated with line leaks are thereby reduced, resulting in a significant savings.

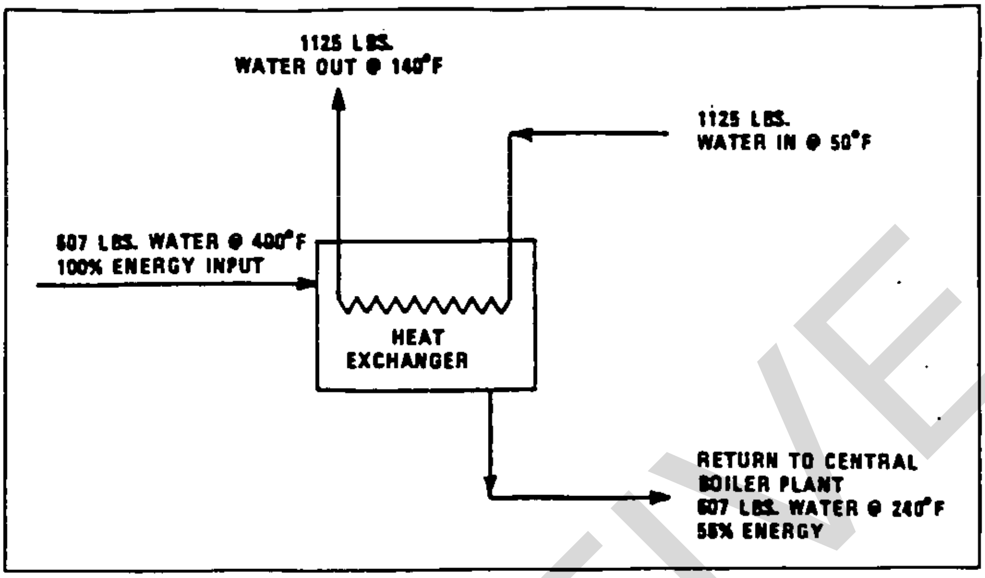


Figure 3
High Temperature Water Heat Balance

2.2.2.5 Stored Thermal Energy. The large amount of stored thermal energy in HTW and MTW distribution systems allows for more effective response to short-duration peak load requirements. Boiler load swings are reduced, and more accurate combustion control is possible. HTW and MTW plants are generally sized for peak loads 10 to 20 percent less than steam plants because of stored thermal capacity in the system.

2.2.2.6 Safety. HTW systems are safer than steam. If a line ruptures, stored thermal energy in the water is dissipated by accelerating the water to higher velocities and flashing it to steam. A fine spray of 180 degree F water occurs, ending 1 to 2 feet from the rupture. The amount of energy exiting a ruptured HTW line is only 5 to 10 percent of the energy exiting a ruptured steam line of the same size.

2.2.2.7 Water Treatment. Due to low makeup water requirements, the capacity of a water treatment system for an HTW and MTW plant is a small fraction of that required for a steam plant. This provides cost savings in equipment, maintenance, and chemical use requirements. Steam plants require more complex water treatment systems, including a deaerator (not required in HTW or MTW plants) to provide oxygen-free water. If not carefully controlled, the deaerator can vent steam, resulting in energy losses. Steam boilers also require blowdown to maintain acceptable water quality, which contributes to makeup water requirements and plant energy losses. Less blowdown is needed (or not required at all) in a hot water boiler.

2.2.2.8 Loss of Steam Pressure and Quality. If distribution lines are long, significant reductions in steam pressure and quality (100 percent quality = 100 percent steam, 90 percent quality = 90 percent steam and 10 percent liquid water, etc.) can occur due to line friction and heat losses.

2.2.3 Low Temperature Water (LTW). LTW plants have the basic advantages of HTW plants relative to steam plants. In addition, the lower system pressure associated with LTW provides a cost advantage due to the lower pressure ratings required for boilers, accessories, and piping. However, LTW plants cannot provide energy at temperatures required for many process, hospital, and laundry applications, thus eliminating them from consideration for many installations.

2.3 Equipment. A central boiler plant is comprised of 10 major categories of equipment, as described below.

2.3.1 Heat-Absorbing Equipment. Heat (energy) from combustion of fuel is transferred to boiler water to generate steam or hot water in the furnace and generating sections of the boiler. Economizers are sometimes provided to recover heat from boiler flue gases (products of combustion) and transfer it to the feedwater. Heat from flue gases can also be absorbed by air heaters for transfer to combustion air before it enters the furnace through the burner or stoker grate. Plant efficiency is closely related to ability of the boiler, economizer, or air heater to absorb heat from the products of combustion.

2.3.2 Fuel-Handling Equipment. Coal-burning plants require facilities for storage of coal, and equipment for moving coal to storage and reclaiming and transferring it at the boiler. Provisions are usually made to move coal directly from the delivery point to the boiler. Mechanical, pneumatic, or hydraulic ash removal systems are necessary in coal-burning plants to dispose of ash from the boiler, stoker, and dust collector hoppers. Oil-burning plants require one or more oil storage tanks with associated transfer pumps, tank heaters, connecting piping, tank lever meters, flow meters, and day tanks. Pumping equipment and piping to burners will be required and oil heaters may be required depending upon oil used. Ash removal equipment may be required in some cases. Gas-burning plants will have a gas pressure reducing station (shutoff valve, strainer, pressure reducing valve, safety relief valve, and gas meter) to reduce incoming line pressure required in distribution piping and burners.

2.3.3 Combustion Equipment. Combustion equipment for oil and gas firing consists of safety shutoff valves, safety devices or interlocks, control valves, and burner(s). The function of the burner is to ignite and burn fuel by efficiently and completely mixing it with combustion air in the furnace. Coal may be fired manually on grates or automatically by stokers, or burned in suspension in a pulverized furnace or fluidized bed.

2.3.4 Air-Handling Equipment. To achieve efficient combustion of fuel, the amount of air delivered to the burner or stoker must be properly matched to the amount of fuel. Forced draft (FD) fans with associated control dampers are used to provide combustion air. Overfire air and reinjection fans for stokers and primary air fans for pulverizers may also be required. Induced draft (ID) fans are used to pull flue gas from the furnace through the boiler bank and any ductwork, economizer, air heater, or dust collector provided.

2.3.5 Controls and Instrumentation. Since operator safety and protection of the boiler are of great importance, boiler feedwater controls and burner safety controls are required to guard against failures due to low boiler water or explosion. Combustion controls regulate fuel and airflow to maintain efficient combustion. The high price of boiler fuel which justifies improved combustion controls also justifies use of recorders and meters to monitor combustion and ensure optimum plant operation.

2.3.6 Pollution Control Equipment. Combustion of fuel may generate a variety of pollutants in excess of limits set by regulatory agencies. Major pollutant emissions of present concern are particulates, carbon monoxide (CO), oxides of sulfur (SO_x), and oxides of nitrogen (NO_x). Use of a fuel lower in ash or sulfur content and modifications to the combustion process can be effective in reducing these emissions. If these fuels are too expensive or combustion modifications are only partially effective, pollution control systems can also be used to bring emissions within acceptable limits. Typical pollution control systems are mechanical collectors, fabric filters, electrostatic precipitators, wet scrubbers, flue gas recirculation, and tall stacks.

2.3.7 Water Treatment Systems. NAVFAC MO-225, Industrial Water Treatment, provides thorough coverage of water treatment subjects and should be referenced if greater detail is required. Proper water treatment prevents scale formation on internal surfaces of the boiler and reduces boiler and distribution system corrosion. Water treatment is often a combination of external and internal techniques. External water treatment includes removal of suspended matter with clarifiers and filters;

reduction of water hardness with lime or zeolite softeners or demineralizers; and reduction of corrosive gases with deaerators. Internal water treatment involves injection of chemicals directly into the boiler to control any impurities remaining after external treatment. These chemicals include caustic to aid precipitation, phosphate for hardness removal, and dispersants to aid precipitate removal by blowdown. Specific equipment is also required for boiler blowdown systems and testing purposes to monitor and maintain a functional water treatment system.

2.3.8 <u>Water Supply Equipment</u>. Feedwater is supplied to steam boilers by means of centrifugal or reciprocating pumps. Centrifugal pumps are also typically used to circulate water through HTW boilers and their associated distribution systems.

2.3.9 <u>Distribution Systems</u>. Energy produced in the central boiler plant, whether in the form of steam or hot water, must be transferred to other buildings through a distribution system. The distribution system also returns unused energy in the form of hot water or condensate to the central plant for recycle. The distribution system consists of insulated, weatherproofed pipelines, valves, pumps, regulators, and heat exchangers. Steam systems also include traps and condensate handling equipment.

2.3.10 <u>Miscellaneous</u>. Each central boiler plant has its own unique set of maintenance tools and spare parts inventory; an electric power distribution system; air compressors; and emergency generator sets.

2.4 Elementary Combustion Principles

2.4.1 <u>Fossil Fuels</u>. Fossil fuels are derived from remains of plant and animal organisms. These organisms used carbon dioxide (CO_2), minerals, water, and energy from sunlight to grow. Over millions of years this material accumulated and original carbohydrates and other organic materials were buried and converted to hydrocarbon or fossil fuels we use today. These fossil fuels are found in solid, liquid, and gaseous form.

2.4.1.1 <u>Coal</u>. Coal is a solid fossil fuel. Characteristics of coal are directly affected by age, since the plant matter from which it was formed first changes to peat, then with sufficient heat, pressure, and time to brown coal or lignite, subbituminous coal, bituminous coal, and finally anthracite - the oldest of coals. If anthracite were submitted to additional pressure and heat, graphite and eventually diamonds would be produced.

In the United States, lignite is found primarily in North Dakota, Montana, and Texas, with proven reserves of 447 billion tons. Subbituminous coal is found in Montana, Wyoming, Washington, and Alaska with proven reserves of 437 billion tons. Bituminous coal is found in at least 28 states with proven reserves of over 800 billion tons. Anthracite is found in Pennsylvania, Alaska, Arkansas, and Virginia with proven reserves of 25 billion tons. Because of its widespread availability and subsequently lower transportation costs, bituminous coal is most frequently used. Table 1 outlines the classification of coals as given by the American Society for Testing and Materials (ASTM) D388, Standard Classification of Coals by Rank. This standard establishes ranges for fixed carbon, volatile matter, and heating value for each class and group of coals.

Coal is a highly complex fuel. Most of its heating value exists in the form of carbon, which is present in two forms, fixed carbon and volatile matter. Volatile matter consists of easily gasified carbohydrates and hydrocarbons. The relationship between these two forms of carbon is one of the primary factors in determining how readily a particular coal burns. Coal analyses may be provided in one of two forms, proximate and ultimate. A proximate analysis includes moisture, volatile matter, fixed carbon, ash, and sulfur on a percent by weight basis. An ultimate analysis includes moisture, carbon, hydrogen, sulfur, nitrogen, oxygen, and ash. These analyses may be given on either an as-received or dry basis, or occasionally on a moisture and ash free basis. Coal is also analyzed for heating value, in British thermal units per pound (Btu/lb), and sometimes for ash chemical analysis and fusion temperatures. Ash-fusion temperatures are important because they are related to slag and ash deposits which can cause operational problems within the boiler or furnace.

2.4.1.2 Oil. Oil is a liquid fossil fuel, normally found far underground (to a depth of 5 miles or more). Oil and natural gas are as old or older than coal and are products of marine plants and organisms which were buried and transformed by bacteria and chemical action into complex hydrocarbons. Oil and gas moved through the sedimentary rock in which it was buried until it was trapped in pockets below solid rock. In general, the deeper in the ground oil and gas are found, the higher their age and quality. Oil we burn today can come from paraffin base, asphalt base, naphthene base, or mixed base crude oil. This oil is refined by fractional distillation at low temperatures and pressures to separate light ends (straight run No. 1 and No. 2 oil) from heavier residual oil. Residual oil may be further processed by cracking, catalytic reforming, or other processes to produce lighter oils such as cracked No. 2 distillate. Cracked oil contains more olefinic and aromatic hydrocarbons and is more difficult to burn than paraffinic and naphthenic hydrocarbons found in straight run oil. Fuel oils are defined in ASTM D396, Standard Specification for Fuel Oils. Table 2 establishes limits for many of the key properties of fuel oil for various standard grades. Table 3 defines a range of analysis for different grades of fuel oils. For additional information on fuel oils and special circumstances, refer to NAVFAC MO-911, Utilization of Navy-Generated Waste Oils as Burner Fuel and NAVFAC MO-230, Maintenance Manual Petroleum Fuel Facilities.

Table 1
Classification of Coal

Class	Group	Fixed Carbon Limits, Percent (Dry, Mineral-Matter-Free Basis)		Volatile Matter Limits, Percent (Dry, Mineral-Matter-Free Basis)		Calorific Value Limits, Btu Per Pound (Moist, Mineral-Matter-Free Basis)	
		Equal or Greater Than	Less Than	Greater Than	Equal or Less Than	Equal or Greater Than	Less Than
I. Anthracitic	1. Meta-anthracite	98	-	-	2	-	-
	2. Anthracite	92	98	2	8	-	-
	3. Semi-anthracite	86	92	8	14	-	-
II. Bituminous	1. Low volatile bituminous coal	78	86	14	22	-	-
	2. Medium volatile bituminous coal	69	78	22	31	-	-
	3. High volatile A bituminous coal	-	69	31	-	14,000	-
	4. High volatile B bituminous coal	-	-	-	-	13,000	14,000
	5. High volatile C bituminous coal	-	-	-	-	11,500 10,500	13,000 11,500
III. Sub-bituminous	1. Sub-bituminous A coal	-	-	-	-	10,500	11,500
	2. Sub-bituminous B coal	-	-	-	-	9,500	10,500
	3. Sub-bituminous C coal	-	-	-	-	8,300	9,500
IV. Lignitic	1. Lignite A	-	-	-	-	6,300	8,300
	2. Lignite B	-	-	-	-	-	6,300

Table 2
Standard Specification for Fuel Oils

Grade of Fuel	Flash Point °C (°F)	Pour Point °C (°F)	Water and Sediment Vol (percent)	Carbon Residue on 10 Percent Bottoms (percent)	Ash Weight (percent)	Distillation Temperatures, °C (°F)		
						10 Percent Point	90 Percent	Point
	Min	Max	Max	Max	Max	Max	Min	Max
No. 1 Distillate	38 (100)	-19 (0)	0.05	0.15	-	215 (420	-	288 (550)
No. 2 Distillate	38 (100)	-6 (20)	0.05	0.35	-	-	282 (540)	338 (640)
No. 4 Light Residual	55 (130)	-6 (20)	0.50	-	0.10	-	-	-
No. 5 Light Residual	55 (130)	-	1.00	-	0.10	-	-	-
No. 5 Heavy Residual	55 (130)	-	1.00	-	0.10	-	-	-
No. 6 Heavy Residual	60 (140)	-	2.00	-	-	-	-	-

Grade of Fuel	Saybolt Viscosity, S				Specific Gravity 60/60°F (Degree API)	Copper Strip Corrosion	Sulfur (percent)
	Universal at 38°F (100°F)		Furol at 50°C (122°F)				
	Min	Max	Min	Max	Max	Max	Max
No. 1 Distillate	-	-	-	-	0.8499 (35 min)	No. 3	0.5
No. 2 Distillate	32.6	37.9	-	-	0.8762 (30 min)	No. 3	0.5
No. 4 Light Residual	45	125	-	-	-	-	-
No. 5 Light Residual	125	300	-	-	-	-	-
No. 5 Heavy Residual	300	900	23	40	-	-	-
No. 6 Heavy Residual	900	9000	45	300	-	-	-

Table 3
Range of Analyses of Fuel Oils

Grade of Fuel Oil	No. 1	No. 2	No. 4	No. 5	No. 6
Weight, percent:					
Sulfur	0.01-0.5	0.05-1.0	0.2-2.0	0.5-3.0	0.7-3.5
Hydrogen	13.3-14.1	11.8-13.9	10.6-13.0*	10.5-12.0*	9.5-12.0*
Carbon	85.9-86.7	86.1-88.2	86.5-89.2*	86.5-89.2*	86.5-90.2*
Nitrogen	Nil-0.1	Nil-0.1	-	-	-
Oxygen	-	-	-	-	-
Ash	-	-	0-0.1	0-0.1	0.01-0.5
Gravity:					
Deg API	40-44	28-40	15-30	14-22	7-22
Specific	0.825-0.806	0.887-0.825	0.966-0.876	0.972-0.922	1.022-0.922
Lb per gal	6.87-6.71	7.39-6.87	8.04-7.30	8.10-7.68	8.51-7.68
Pour Point, F	0 to -50	0 to -40	-10 to +50	-10 to +80	+15 to +85
Viscosity:					
Centistokes @ 100F	1.4-2.2	1.9-3.0	10.5-65	65-200	260-750
SUS @ 100F	-	32-38	60-300	-	45-300
SSF @ 122F	-	-	-	20-40	
Water & sediment, vol %	-	0-0.1	tr to 1.0	0.05-1.0	0.05-2.0
Heating Value:					
Btu per lb, gross (calculated)	19,670-19,860	19,170-19,750	18,280-19,400	18,100-19,020	17,410-18,990

*Estimated.

Note: To obtain Btu/gal, multiply heating value by density:

(Btu/lb) (lb/gal) = Btu/gal

Knowing the grade and specifications of an oil is only a start toward understanding its handling and combustion characteristics. Because sulfur limits are often imposed on fuel oil, refiners and distributors may blend different oils to meet sulfur limits. For example, low sulfur No. 4 oil could be a blend of low sulfur No. 2 and high or medium sulfur No. 6 oil. Problems associated with blended oils may include widely varying viscosity, sludge precipitation, and stratification of different components. Fairly recent problems have been related to No. 4 oil refined from imported paraffin base crude. Paraffin wax from oil can plate out and clog strainers, even though oil is fluid. Heating oil to 90 to 100 degrees F will usually solve this problem. With oil coming from literally every corner of the world, the possible variations are endless and can change with each new tankful. Some of the more common problems are further discussed in Section 4.

2.4.1.3 Natural Gas. Natural gas is formed by the same processes that produce oil. Compared with coal and oil, natural gas is a simple fuel consisting primarily of methane (CH_4, 77 percent to 90 percent by volume) and ethane (C_2H_6, 5 percent to 15 percent by volume). Propane and other more complex hydrocarbons are present in small quantities, and inert components such as carbon dioxide and nitrogen may range from 1 percent to 9 percent by volume. Typical natural gas has a higher heating value of 1,000 Btu per cubic foot and a specific gravity of 0.6 relative to air. Care is required in handling of natural gas in the vapor state. If leaks in piping exist, gas will escape and can be explosive if allowed to collect. Commercial pipeline natural gas has a distinctive "sweet" smell which helps to identify any leakage.

2.4.1.4 Alternate Fuels. Due to rising fuel costs and occasional shortages, it is becoming common to utilize wood, wood waste, municipal waste, agricultural by-products, and other wastes to supplement our fossil resources. These alternate fuels may be mixed with more conventional fuels or burned by themselves to reduce consumption of coal, oil, or gas. This trend will undoubtedly continue and accelerate.

2.4.2 Combustion. Combustion can be defined as rapid oxidation of fuel. It is a chemical reaction in which energy is released, in the form of heat and light, when fuel and oxygen combine. Rapid oxidation will not occur without heat to start the reaction. Fuel, oxygen, heat, and a chemical reaction are necessary for combustion to take place. If any one of these elements is removed, combustion stops. During combustion in a boiler it is important to control fuel, oxygen, and heat so that the fuel is completely burned and maximum use is made of its energy. To achieve controlled and efficient combustion three factors must be considered: time, temperature, and turbulence. Although oxidation is rapid, several seconds may be required to start and complete the combustion process. Temperature varies during the combustion process with minimum temperatures occurring at the beginning and end. Turbulence is necessary to allow fuel to be intimately mixed with oxygen.

2.4.2.1 Chemical Reactions. The following general chemical reactions occur as combustible carbon (C-molecular weight (MW) = 12), hydrogen (H_2-MW = 2), and sulfur (S-MW = 32) combine with oxygen (O_2-MW = 32) to form carbon dioxide (CO_2-MW = 44), water (H_2O-MW = 18), and sulfur dioxide (SO_2 - MW = 64):

$$C + O_2 = CO_2;\ 12\ lb\ C + 32\ lb\ O_2 = 44\ lb\ CO_2$$

$$2H_2 + O_2 = 2H_2O;\ 4\ lb\ H_2 + 32\ lb\ O_2 = 36\ lb\ H_2O$$

$$S + O_2 = SO_2;\ 32\ lb\ S + 32\ lb\ O_2 = 64\ lb\ SO_2.$$

These equations may also be written on a weight basis as follows:

$$1\ lb\ C + 2.66\ lb\ O_2 = 3.66\ lb\ CO_2 + 14{,}093\ Btu$$

$$1\ lb\ H_2 + 7.94\ lb\ O_2 = 8.94\ lb\ H_2O + 61{,}100\ Btu$$

$$1\ lb\ S + 1.00\ lb\ O_2 = 2.00\ lb\ SO_2 + 3{,}983\ Btu$$

The following general chemical reactions occur when the simplest hydrocarbon gases, methane (CH_4 - MW = 16), ethane (C_2H_6 - MW = 30), and propane (C_3H_8 - MW = 44) are oxidized:

$$CH_4 + 2O_2 = CO_2 + 2H_2O;\ 16\ lb\ CH_4 + 64\ lb\ O_2 = 44\ lb\ CO_2 + 36\ lb\ H_2O$$

$$C_2H_6 + 3.5O_2 = 2CO_2 + 3H_2O;\ 30\ lb\ C_2H_6 + 112\ lb\ O_2 = 88\ lb\ CO_2 + 54\ lb\ H_2O$$

$$C_3H_8 + 5O_2 = 3CO_2 + 4H_2O;\ 44\ lb\ C_3H_8 + 160\ lb\ O_2 = 132\ lb\ CO_2 + 72\ lb\ H_2O$$

On the basis of weight per pound of fuel, these equations appear as follows:

$$1\ lb\ Ch_4 + 3.99\ lb\ O_2 = 2.74\ lb\ CO_2 + 2.25\ lb\ H_2O + 23{,}879\ Btu$$

$$1\ lb\ C_2H_6 + 3.74\ lb\ O_2 = 2.93\ lb\ CO_2 + 1.80\ lb\ H_2O + 22{,}320\ Btu$$

$$1\ lb\ C_3H_8 + 3.63\ lb\ O_2 = 2.99\ lb\ CO_2 + 1.64\ lb\ H_2O + 21{,}661\ Btu$$

In some cases, carbon only partially oxidizes to form carbon monoxide (CO) which can then oxidize to form carbon dioxide. A large number of intermediate compounds of carbon, hydrogen, and oxygen may also form between the start of the combustion process and the final products of combustion listed above. These intermediates are of little practical interest to the boiler operator. The heat of combustion listed above for each reaction is in Btu and is called higher heating value (HHV). Some of the heat of combustion (970 Btu per 1 lb H_2O produced) is used to form water and keep it in the vapor state. If this amount of heat is subtracted from the heating values shown above, a quantity called lower heating value (LHV) is obtained. The common practice in the United States is to use HHV in combustion calculations, while LHV is typically used in Europe. General chemical reactions are a good way to calculate fuel and air requirements. They begin to explain combustion and boiler efficiency.

2.4.2.2 Air Requirements. Air we breathe is 76.7 percent nitrogen and 23.3 percent oxygen by weight or 79 percent nitrogen and 21 percent oxygen by volume. We use air to obtain oxygen for the combustion process. Each pound of air contains 0.233 pounds of oxygen. To obtain one pound of oxygen requires 4.29 pounds of air. This is calculated as follows:

$$4.29 \text{ lb air} \; \frac{0.233 \text{ lb } O_2}{1.0 \text{ lb air}} = 1.0 \text{ lb } O_2$$

Each 4.29 pounds of air contains 1.0 pound of oxygen and 3.29 pounds of nitrogen. Nitrogen is not chemically active in the combustion process; however, it lowers flame temperature by absorbing heat and carrying it away from the boiler in flue gas. The combustion equation given in the previous paragraph can be used to calculate the exact quantity of oxygen, and hence air, required to completely react with a given amount of fuel. This quantity of air is called theoretical air. Unfortunately, use and control of the combustion process in a boiler is not perfect and an additional quantity of air called excess air is needed to achieve complete combustion.

2.4.2.3 Excess Air Example. Combustion of 1 pound of No. 2 oil with an analysis of 87 percent carbon, 12 percent hydrogen, 0.5 percent sulfur, and 0.5 percent nitrogen requires theoretical air as determined below:

$$\begin{aligned}
&0.87 \text{ lb C} \times 2.66 \text{ lb } O_2/\text{lb C} &&= 2.31 \text{ lb } O_2 \\
&0.12 \text{ lb } H_2 \times 7.94 \text{ lb } O_2/\text{lb } H_2 &&= 0.95 \text{ lb } O_2 \\
&0.005 \text{ lb S} \times 1.00 \text{ lb } O_2/\text{b S} &&= \underline{0.01 \text{ lb } O_2} \\
&\text{Theoretical Oxygen} &&= 3.27 \text{ lb } O_2
\end{aligned}$$

In a moderately well controlled burner, approximately 20 percent excess air is typically required to ensure complete combustion. Theoretical air = 3.27 lb O_2 x 4.29 lb air/lb O_2 = 14.0 lb air. Total combustion air per pound of fuel required thus becomes:

$$14.0 \text{ lb air} + (14.0 \text{ lb air} \times 0.20) = 16.8 \text{ lb air}$$

If the combustion process is not well controlled, 50 percent excess air may enter the furnace through the burner. Total combustion air per pound of fuel then becomes:

$$14.0 \text{ lb air} + 1\ (14.0 \text{ lb air} \times 0.50) = 21.0 \text{ lb air}$$

2.4.2.4 Higher Heating Values (HHVs). HHVs of fuels are best determined by a calorimeter test. If the ultimate analysis of an oil or coal is known, Dulong's formula may be used to determine the HHV of a liquid or solid fuel. Dulong's formula is given below and may be considered accurate to within 2 or 3 percent. HHV = 14,544 C + 62,028 (H_2-O_2/8) + 4050 S. Carbon, hydrogen, oxygen, and sulfur come from the ultimate analysis and are expressed in percent by weight. Coefficients represent approximate heating values of constituents in Btu/lb and the result obtained is also in Btu/lb. The O_2/8 is a correction applied to hydrogen in fuel to account for the fact that some of the hydrogen is already combined with oxygen to form water. The Dulong formula is not suitable for gaseous fuels because the heat of formation of constituents like methane and ethane is not considered. For gaseous fuels the HHV may be determined by taking a weight average of heating values for each gaseous constituent. Care must be taken in evaluating the heating value of fuel oils. A No. 6 fuel oil may have a LHV than a No. 2 oil when measured on a Btu/lb basis, but since it is more dense, the No. 6 oil could well have more Btu/gallon. This is significant since oil is normally purchased by the gallon rather than by the pound. Table 3 provides a comparison of the API gravity, specific gravity, Btu/lb, and Btu/gallon for ranges of fuel oils.

2.4.3 Combustion of Coal. Fundamentals of coal combustion on a hand-fired grate are described below. A uniform fuel bed 8 inches thick is maintained on the grate. About 50 percent of the air required for combustion enters from below the grate and passes through a layer of ash. Oxygen in this air is consumed while passing through the first few inches of burning fixed carbon. This is called the oxidizing zone. Heat from burning the fixed carbon rises and drives moisture and volatile matter from raw coal in the oxygen-deficient reducing zone at the top of the bed. Remaining fixed carbon from the top of the bed later burns in the bottom of the bed as additional raw coal is added to the top. Volatile matter in vapor form and carbon monoxide just above the bed must be fully mixed with overfire air to complete the combustion process.

At low firing rates it is important to minimize the amount of overfire air to prevent cooling of volatile matter resulting in incomplete combustion and soot formation. At intermediate and high firing rates, the ability to fully mix volatile matter, carbon monoxide, and overfire air determines completeness of combustion and practical excess air levels that can be maintained. Rate of combustion is controlled by the underfire combustion air. Efficiency of combustion is determined by effective turbulent use of overfire combustion air. Stokers may use fans, ducts, air compartments, modulating air dampers, cinder reinjection systems, coal feeders, and moving or vibrating grates to provide better control of the firing rate and efficiency of coal combustion. In some stokers, a portion of coal may be burned in suspension before it falls onto the grate. In underfeed stokers, raw coal is delivered from below the burning coal. Pulverized coal firing systems utilize pulverizers to grind coal to a fine dust. This dust is conveyed by primary combustion air to a burner which serves to ignite the coal and mix additional secondary combustion air with the stream of primary air and coal. Pulverized coal is completely burned in suspension. Principles of coal combustion remain the same for any of these variations. Moisture and volatile matter must be driven off before fixed carbon can be burned and combustion air must be effectively mixed with volatile vapors to efficiently complete combustion.

2.4.4 Combustion of Oil. Combustion of fuel oil occurs after liquid oil is vaporized. The time required for combustion is initially dependent upon the ability of the burner to atomize the oil into fine droplets and provide heat to vaporize the oil. The vapor is then ignited and turbulently mixed with combustion air to stabilize ignition in an ignition zone. Heavy hydrocarbons crack to give the oil flame its yellow color. The burner must supply additional air to mix with remaining fuel with adequate time, temperature, and turbulence for complete combustion. Careful control and adjustment of the flow of air, oil, and atomizing steam/air are needed to achieve maximum efficiency at boiler loads.

2.4.5 Combustion of Natural Gas. Natural gas consists mainly of simple hydrocarbons methane and ethane, and is the easiest fuel to burn, although it can also be the most dangerous. Given the proper time, temperature, turbulence, and excess air, gas can sometimes burn without a visible flame or with a blue flame. If some of the hydrocarbons crack, a yellow flame will be present. One danger of natural gas combustion is that carbon monoxide, which is poisonous in very low concentrations, may be produced if there is insufficient air or insufficient mixing. For safety and efficiency reasons, incomplete combustion should be avoided by proper control of fuel and air. There is a range of air-gas mixtures which burn violently and explosively. This range varies between 8 and 13 percent gas by volume, depending upon the particular hydrocarbon. Leaner mixtures, 0 to 7 percent, do not explode or burn, while richer mixtures typical of the ignition zone in the combustion process burn more slowly and do not explode. If a rich concentration of vapor exists, however, it will gradually diffuse into the air and will at some time be within the explosive range. If this mixture comes in contact with a spark or open flame, an explosion can occur. In order to prevent build-up of such concentrations, safety shutoff valves are installed on natural gas and oil combustion systems and are very important. Purging of the boiler setting both before and after combustion of any fuel is also extremely important in the prevention of explosions.

2.4.6 Soot and Smoke. Understanding causes of soot and smoke is the first step in prevention.

2.4.6.1 Soot. Soot is unburned carbon from fuel. Finely divided soot particles give flue gases a black color. In refining of oil, heavy hydrocarbons are cracked into simpler hydrocarbons, carbon, and hydrogen. This cracking (thermal decomposition) process is also one of the reactions that occurs when a fuel is burned. For example, if methane gas is slowly heated and mixed with air, the gas burns with no visible flame or a blue flame. Methane is oxidized without cracking and several intermediate carbon/hydrogen/oxygen compounds are formed. However, if methane is heated quickly, the gas is cracked into hydrogen and carbon. Carbon particles glow when burnt, giving off a yellow color. If this yellow flame comes in contact with a boiler tube, carbon in the flame can be cooled and deposited on the tube as soot. If a flame containing elemental carbon is not given enough time and proper temperature for combustion, soot will form as the carbon cools. For example, when a boiler is fired beyond its rated capacity, it is required to burn more fuel in the same furnace. When this happens, the time available for combustion is shortened and may become so short that complete combustion is not possible. Another potential time for soot to form is during start-up of a cold boiler or while operating at low fire. Under these conditions, enough heat may be transferred from the flame to cool it below its ignition temperature and cause the formation of soot.

2.4.6.2 Smoke. Smoke seen in boiler flue gas results from the presence of soot and ash from the combustion process. It is difficult to make natural gas fire smoke, but oil and coal, if not properly controlled, will smoke readily due to more rapid cracking of their complex hydrocarbons. While heat loss from unburned carbon may not be significant (tenths of a percent of efficiency), smoke formation indicates a waste of fuel and a possible soot build-up in the furnace and convection passes. Such build-ups can result in large efficiency losses associated with reduced heat transfer and higher boiler exit gas temperatures. Smoke color other than black is less noticeable but can be just as wasteful. Blue smoke from an oil-fired boiler indicates that a portion of the oil is not being cracked, while white smoke generally indicates high excess air levels. In either case, a major burner problem is indicated. It is common practice, when adjusting the combustion process, to start with high excess air and white smoke. At some lower range of excess air no smoke will be visible and finally, at still lower excess air levels, black smoke will occur. Coal-fired boilers often generate white smoke related to ash in the coal.

2.4.6.3 Stack Opacity. Operating with a minimum practical level of smoke as measured by stack opacity indicates a generally well run boiler plant. Stack opacity is measured on a 0 percent (clear) to 100 percent (completely opaque) scale. A practical level of smoke would be less than local opacity limits (typically 10 to 20 percent) and based upon obtaining optimum boiler efficiency. A slight decrease in opacity may not be acceptable if it must be obtained with a large increase in excess air. When burning coal, the amount of carbon in the stoker and collection hoppers should be considered when reviewing excess air and opacity levels.

2.4.7 Flue Gas Analysis and Temperature. Performance of a burner and boiler can largely be determined by analysis and temperature of flue gas. Flue gas temperature at the boiler, economizer, or air heater outlet provides information on boiler cleanliness, firing rate, and efficiency. Flue gas analysis establishes the amount of oxygen, carbon dioxide, and carbon monoxide in flue gas. This analysis is generally on a dry basis by volume since water vapor is condensed before analysis. Given the type of fuel being burned and the oxygen or carbon dioxide level, Tables 4 through 8 can be used to determine combustion efficiency and percent of excess air in flue gas for natural gas, No. 2 oil, No. 6 oil, and coal.

2.4.8 Combustion Efficiency. Boiler combustion efficiency can be determined if proper information is available on fuel analysis, flue gas analysis, combustion air temperature, and stack temperature. American Society of Mechanical Engineers (ASME) PTC 4.1, Steam Generating Units, Power Test Codes, contains industry standards for calculating efficiencies of steam generating units. Figure 4 contains a heat balance for steam generation. Note that this heat balance is greatly simplified when nonapplicable items are set equal to zero. The following paragraphs contain simplified methods and tables used to calculate efficiencies. When calculating efficiency using the heat loss method, loss of heat in flue gas, on a percentage basis, is subtracted from 100 percent to provide the percentage combustion efficiency. The heat lost with flue gas is determined by its temperature and chemical analysis. Amounts of excess air and water vapor are most important in determining their loss. Water is contained in flue gas in its vapor state. Each pound of water vapor requires 970 Btu of energy supplied to the boiler to maintain it in its vapor state. In addition to this 970 Btu/lb, water vapor also contains 80 percent more energy per pound than other flue gas constituents. The effect of this water vapor on boiler efficiency can be illustrated by comparing a natural gas-fired boiler to one fired by oil.

For identical levels of excess air, combustion air temperature, and stack temperature, the natural gas-fired boiler will have a lower combustion efficiency than the oil-fired boiler. This happens because natural gas contains more hydrogen, which reacts with oxygen in air to form water, than oil and thus has more water in flue gas. Using Tables 4 and 6, at 15 percent excess air, 70 degrees F combustion air temperature, and 530 degrees F stack temperature, combustion efficiency of a natural gas-fired boiler is 78.9 percent as compared with 83.4 percent for a No. 6 oil-fired boiler. Tables 4 through 8 are combustion efficiency tables for natural gas, No. 2 oil, No. 6 oil, coal with 3.5 percent moisture, and coal with 9.0 percent moisture, respectively. Combustion efficiency for No. 4 oil may be considered the average of combustion efficiencies for No. 2 oil and No. 6 oil. Expanded versions of tables presented here may be found in the Boiler Efficiency Institute book entitled, Boiler Efficiency Improvement.

2.4.9 Boiler Efficiency. Boiler efficiency is simply defined as the amount of energy in steam or hot water leaving the boiler (E out, Btu/lb x lb/hr = Btu/hr) minus energy in feedwater (E fw, Btu/lb x lb hr) divided by the amount of energy in fuel used (E fuel, Btu/lb x lb/hr).

$$\text{Boiler Efficiency} = \frac{(E\ \text{out} - E\ \text{fw})}{E\ \text{fuel}}$$

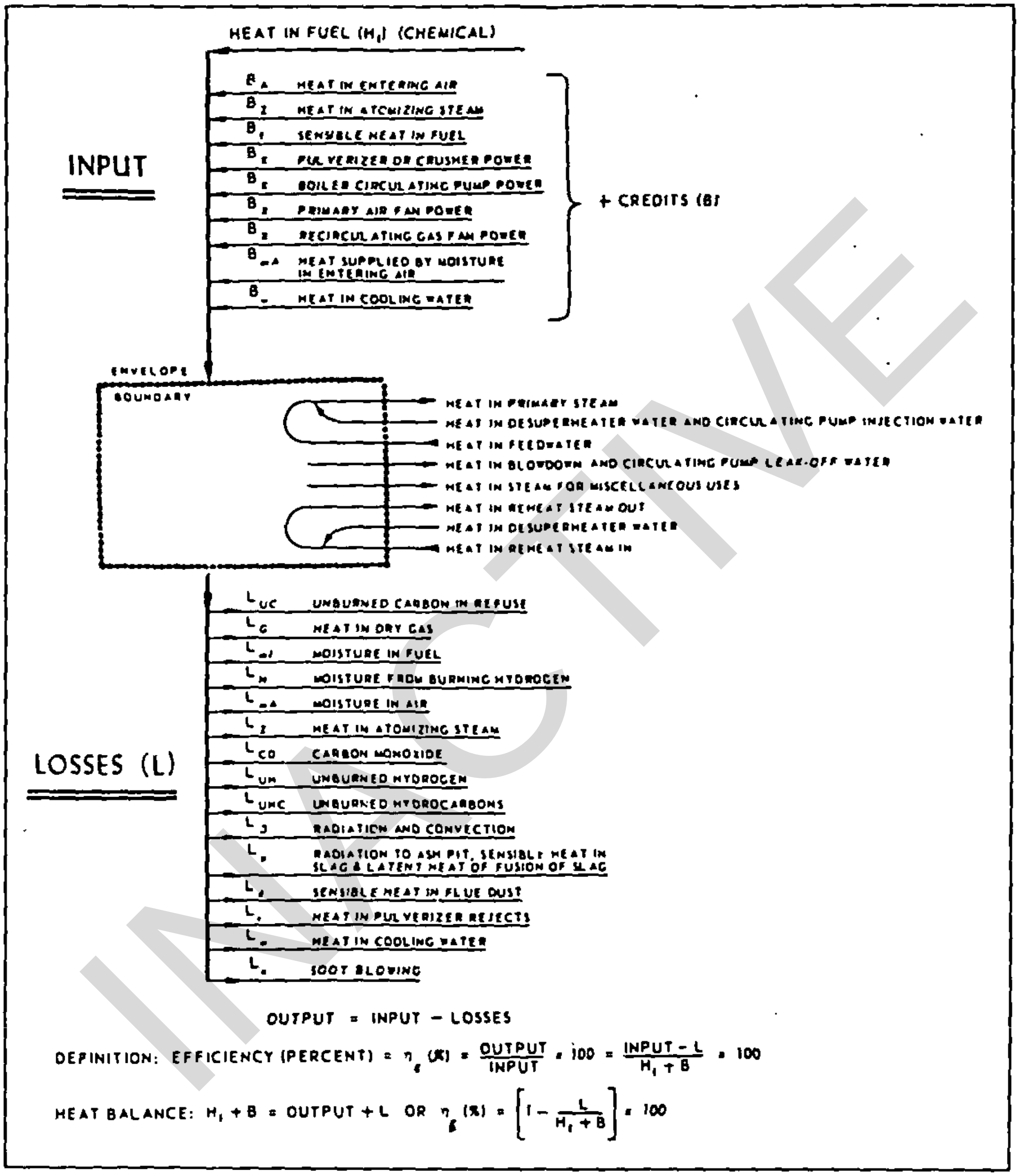


Figure 4
Heat Balance of Steam Generator

Table 4
Combustion Efficiency for Natural Gas

Excess Air (%)	O_2 (%)	CO_2 (%)	Percent Combustion Efficiency Flue Gas Temperature Minus Combustion Air Temperature (°F)					
			180	220	260	300	340	380
0.0	0.0	11.8	86.1	85.3	84.5	83.6	82.8	81.9
4.5	1.0	11.2	86.0	85.1	84.2	83.4	82.5	81.6
9.5	2.0	10.7	85.8	84.9	84.0	83.1	82.2	81.2
12.1	2.5	10.4	85.7	84.8	83.9	83.0	82.0	81.1
15.0	3.0	10.1	85.7	84.7	83.8	82.8	81.8	80.9
18.0	3.5	9.8	85.6	84.6	83.6	82.6	81.7	80.7
21.1	4.0	9.6	85.5	84.5	83.5	82.5	81.5	80.5
24.5	4.5	9.3	85.4	84.3	83.3	82.3	81.3	80.2
28.1	5.0	9.0	85.2	84.2	83.2	82.1	81.1	80.0
31.9	5.5	8.7	85.1	84.1	83.0	81.9	80.8	79.7
35.9	6.0	8.4	85.0	83.9	82.8	81.7	80.6	79.5
40.3	6.5	8.2	84.9	83.7	82.6	81.5	80.3	79.2
44.9	7.0	7.9	84.7	83.5	82.4	81.2	80.0	78.8
49.9	7.5	7.6	84.5	83.4	82.2	80.9	79.7	78.5
55.3	8.0	7.3	84.4	83.1	81.9	80.7	79.4	78.1
67.3	9.0	6.7	84.0	82.7	91.4	80.0	78.7	77.3
81.6	10.0	6.2	83.5	82.1	80.7	79.3	77.8	76.4
98.7	11.0	5.6	83.0	81.5	79.9	78.3	76.8	75.2
119.7	12.0	5.1	82.3	80.6	78.9	77.2	75.5	73.8
145.8	13.0	4.5	81.5	79.6	77.7	75.8	73.9	72.0
179.5	14.0	3.9	80.4	78.3	76.2	74.0	71.9	69.7
224.3	15.0	3.4	79.0	76.6	74.1	71.7	69.2	66.7

Excess Air (%)	O_2 (%)	CO_2 (%)	Percent Combustion Efficiency Flue Gas Temperature Minus Combustion Air Temperature (°F)					
			420	460	500	540	580	620
0.0	0.0	11.8	81.0	80.1	79.3	78.4	77.5	76.6
4.5	1.0	11.2	80.7	79.8	78.9	77.9	77.0	76.1
9.5	2.0	10.7	80.3	79.4	78.4	77.5	76.5	75.5
12.1	2.5	10.4	80.1	79.1	78.2	77.2	76.2	75.2
15.0	3.0	10.1	79.9	78.9	77.9	76.9	75.9	74.9
18.0	3.5	9.8	79.7	78.7	77.6	76.6	75.6	74.6
21.1	4.0	9.6	79.4	78.4	77.4	76.3	75.3	74.2
24.5	4.5	9.3	79.2	78.1	77.1	76.0	74.9	73.8
28.1	5.0	9.0	78.9	77.8	76.7	75.6	74.5	73.4
31.9	5.5	8.7	78.6	77.5	76.4	75.3	74.1	73.0
35.9	6.0	8.4	78.3	77.2	76.0	74.9	73.7	72.5
40.3	6.5	8.2	78.0	76.8	75.6	74.5	73.3	72.0
44.9	7.0	7.9	77.6	76.4	75.2	74.0	72.8	71.5
49.9	7.5	7.6	77.3	76.0	74.8	73.5	72.2	71.0
55.3	8.0	7.3	76.9	75.6	74.3	73.0	71.7	70.4
67.3	9.0	6.7	76.0	74.6	73.2	71.8	70.4	69.0
81.6	10.0	6.2	74.9	73.4	71.9	70.4	68.9	67.4
98.7	11.0	5.6	73.6	72.0	70.4	68.8	67.1	65.5
119.7	12.0	5.1	72.0	70.3	68.5	66.7	64.9	63.1
145.8	13.0	4.5	70.1	68.1	66.2	64.2	62.2	60.2
179.5	14.0	3.9	67.5	65.3	63.1	60.9	58.7	56.4
224.3	15.0	3.4	64.2	61.7	59.1	56.5	54.0	51.4

This table is based on the following fuel analysis (% by weight): carbon-70.8%, hydrogen-23.4%, nitrogen-3.8%, oxygen-1.2%, carbon dioxide-0.8%. The HHV is 21,700 Btu/lb.

Table 5
Combustion Efficiency for No. 2 Oil

Excess Air (%)	O_2 (%)	CO_2 (%)	Percent Combustion Efficiency Flue Gas Temperature Minus Combustion Air Temperature (°F)					
			180	220	260	300	340	380
0.0	0.0	15.6	90.4	89.6	88.8	88.0	87.1	86.3
4.7	1.0	14.9	90.2	89.4	88.6	87.7	86.9	86.0
9.9	2.0	14.1	90.1	89.2	88.3	87.4	86.6	85.7
12.6	2.5	13.8	90.0	89.1	88.2	87.3	86.4	85.5
15.6	3.0	13.4	89.9	89.0	88.1	87.1	86.2	85.3
18.7	3.5	13.0	89.8	88.9	87.9	87.0	86.0	85.1
22.0	4.0	12.6	89.7	88.7	87.8	86.8	85.8	84.9
25.5	4.5	12.3	89.6	88.6	87.6	86.6	85.6	84.6
29.2	5.0	11.9	89.5	88.5	87.4	86.4	85.4	84.4
33.2	5.5	11.5	88.3	88.3	87.3	86.2	85.2	84.1
37.4	6.0	11.2	88.1	88.1	87.1	86.0	84.9	83.8
41.9	6.5	10.8	89.1	88.0	86.9	85.8	84.6	83.5
46.8	7.0	10.4	88.9	87.8	86.6	85.5	84.4	83.2
52.0	7.5	10.0	88.7	87.6	86.4	85.2	84.1	82.9
57.6	8.0	9.7	88.6	87.4	86.2	84.9	83.7	82.5
70.3	9.0	8.9	88.2	86.9	85.6	84.3	83.0	81.6
85.0	10.0	8.2	87.7	86.3	84.9	83.5	82.1	80.6
102.9	11.0	7.4	87.1	85.6	84.1	82.6	81.0	79.5
124.7	12.0	6.7	86.5	84.8	83.1	81.4	79.7	78.0
152.0	13.0	6.0	85.6	83.7	81.9	80.0	78.1	76.2
187.0	14.0	5.2	84.5	82.4	80.3	78.2	76.0	73.8
233.7	15.0	4.5	83.0	80.6	78.2	75.7	73.2	70.7

Excess Air (%)	O_2 (%)	CO_2 (%)	Percent Combustion Efficiency Flue Gas Temperature Minus Combustion Air Temperature (°F)					
			420	460	500	540	580	620
0.0	0.0	15.6	85.5	84.7	83.8	83.0	82.1	81.3
4.7	1.0	14.9	85.2	84.3	83.4	82.5	81.6	80.7
9.9	2.0	14.1	84.8	83.9	82.9	82.0	81.1	80.2
12.6	2.5	13.8	84.6	83.6	82.7	81.8	80.8	79.9
15.6	3.0	13.4	84.3	83.4	82.4	81.5	80.5	79.5
18.7	3.5	13.0	84.1	83.1	82.2	81.2	80.2	79.2
22.0	4.0	12.6	83.9	82.9	81.9	80.9	79.8	78.8
25.5	4.5	12.3	83.6	82.6	81.6	80.5	79.5	78.4
29.2	5.0	11.9	83.3	82.3	81.2	80.2	79.1	78.0
33.2	5.5	11.5	83.0	82.0	80.9	79.8	78.7	77.6
37.4	6.0	11.2	82.7	81.6	80.5	79.4	78.3	77.1
41.9	6.5	10.8	82.4	81.3	80.1	79.0	77.8	76.6
46.8	7.0	10.4	82.0	80.9	79.7	78.5	77.3	76.1
52.0	7.5	10.0	81.7	80.4	79.2	78.0	76.7	75.5
57.6	8.0	9.7	81.2	80.0	78.7	77.5	76.2	74.9
70.2	9.0	8.9	80.3	79.0	77.6	76.2	74.9	73.5
85.0	10.0	8.2	79.2	77.8	76.3	74.8	73.3	71.8
102.9	11.0	7.4	77.9	76.3	74.7	73.1	71.5	69.9
124.7	12.0	6.7	76.3	74.5	72.8	71.0	69.2	67.4
152.0	13.0	6.0	74.3	72.3	70.4	68.4	66.4	64.4
187.0	14.0	5.2	71.7	69.5	67.3	65.0	62.8	60.5
233.7	15.0	4.5	68.2	65.7	63.1	60.6	58.0	55.4

This table is based on the following fuel analysis (% by weight): carbon-86.7%, hydrogen-12.4%, nitrogen-0.1%, sulfur-0.8%. The HHV is 19,500 Btu/lb.

Table 6
Combustion Efficiency for No. 6 Oil

Excess Air (%)	O_2 (%)	CO_2 (%)	Percent Combustion Efficiency Flue Gas Temperature Minus Combustion Air Temperature (°F)					
			180	220	260	300	340	380
0.0	0.0	16.5	91.2	90.4	89.6	88.8	87.9	87.1
4.7	1.0	15.7	91.0	90.2	89.4	88.5	87.7	86.8
10.0	2.0	14.9	90.9	90.0	89.1	88.2	87.3	86.4
12.8	2.5	14.5	90.8	89.9	89.0	88.1	87.2	86.3
15.8	3.0	14.1	90.7	89.8	88.9	87.9	87.0	86.1
18.9	3.5	13.8	90.6	89.7	88.7	87.8	86.8	85.8
22.3	4.0	13.4	90.5	89.5	88.6	87.6	86.6	85.6
25.8	4.5	13.0	90.4	89.4	88.4	87.4	86.4	85.4
29.6	5.0	12.6	90:3	89.2	88.2	87.2	86.2	85.1
33.6	5.5	12.2	90.1	89.1	88.0	87.0	85.9	84.8
37.9	6.0	11.8	90.0	88.9	87.8	86.8	85.7	84.6
42.4	6.5	11.4	89.8	88.7	87.6	86.5	85.4	84.2
47.3	7.0	11.0	89.7	88.6	87.4	86.3	85.1	83.9
52.6	7.5	10.6	89.5	88.3	87.2	86.0	84.8	83.6
58.2	8.0	10.2	89.3	88.1	86.9	85.7	84.4	83.2
71.0	9.0	9.4	88.9	87.6	86.3	85.0	83.7	82.3
86.0	10.0	8.6	88.5	87.0	85.6	84.2	82.7	81.3
104.1	11.0	7.9	87.9	86.3	84.8	83.2	81.7	80.1
126.1	12.0	7.1	87.2	85.5	83.8	82.1	80.3	78.6
153.7	13.0	6.3	86.3	84.4	82.5	80.6	78.6	76.7
189.1	14.0	5.5	85.2	83.0	80.9	78.7	76.5	74.3
236.4	15.0	4.7	83.7	81.2	78.7	76.2	73.6	71.1

Excess Air (%)	O_2 (%)	CO_2 (%)	Percent Combustion Efficiency Flue Gas Temperature Minus Combustion Air Temperature (°F)					
			420	460	500	540	580	620
0.0	0.0	16.5	86.3	85.4	84.6	83.7	82.9	82.0
4.7	1.0	15.7	85.9	85.1	84.2	83.3	82.4	81.5
10.0	2.0	14.9	85.5	84.6	83.7	82.8	81.8	80.9
12.8	2.5	14.5	85.3	84.4	83.4	82.5	81.5	80.6
15.8	3.0	14.1	85.1	84.1	83.2	82.2	81.2	80.2
18.9	3.5	13.8	84.9	83.9	82.9	81.9	80.9	79.9
22.3	4.0	13.4	84.6	83.6	82.6	81.6	80.5	79.5
25.8	4.5	13.0	84.3	83.3	82.3	81.2	80.2	79.1
29.6	5.0	12.6	84.1	83.0	81.9	80.9	79.8	78.7
33.6	5.5	12.2	83.8	82.7	81.6	80.5	79.4	78.2
37.9	6.0	11.8	83.4	82.3	81.2	80.0	78.9	77.7
42.4	6.5	11.4	83.1	81.9	80.8	79.6	78.4	77.2
47.3	7.0	11.0	82.7	81.5	80.3	79.1	77.9	76.7
52.6	7.5	10.6	82.3	81.1	79.9	78.6	77.4	76.1
58.2	8.0	10.2	81.9	80.6	79.4	78.1	76.8	75.5
71.0	9.0	9.4	81.0	79.6	78.2	76.8	75.4	74.0
86.0	10.0	8.6	79.8	78.3	76.9	75.4	73.9	72.3
104.1	11.0	7.9	78.5	76.9	75.2	73.6	72.0	70.3
126.1	12.0	7.1	76.8	75.0	73.3	71.5	69.6	67.8
153.7	13.0	6.3	74.7	72.8	70.8	68.8	66.8	64.7
189.1	14.0	5.5	72.1	69.8	67.6	65.3	63.0	60.7
236.4	15.0	4.7	68.5	65.9	63.3	60.7	58.1	55.4

This table is based on the following fuel analysis (% by weight): carbon-88.4%, hydrogen-10.0%, nitrogen-0.9%, sulfur-0.7%. The HHV is 18,300 Btu/lb.

Table 7
Combustion Efficiency for Coal,
3.5 Percent Moisture, Bituminous

Excess Air (%)	O_2 (%)	CO_2 (%)	Percent Combustion Efficiency Flue Gas Temperature Minus Combustion Air Temperature (°F)					
			180	220	260	300	340	380
0.0	0.0	18.4	92.0	91.2	90.3	89.5	88.6	87.7
4.8	1.0	17.6	91.9	91.0	90.1	89.2	88.3	87.3
10.2	2.0	16.7	91.7	90.8	89.8	88.9	87.9	86.9
16.2	3.0	15.8	91.5	90.5	89.5	88.5	87.5	86.5
22.8	4.0	14.9	91.3	90.2	89.2	88.2	87.1	86.0
26.4	4.5	14.5	91.1	90.1	89.0	87.9	86.9	85.8
30.3	5.0	14.0	91.0	89.9	88.8	87.7	86.6	85.5
34.4	5.5	13.6	90.9	89.8	88.6	87.5	86.3	85.2
38.8	6.0	13.2	90.7	89.6	88.4	87.2	86.1	84.9
43.5	6.5	12.7	90.6	89.4	88.2	87.0	85.8	84.5
48.5	7.0	12.3	90.4	89.2	87.9	86.7	85.4	84.2
53.9	7.5	11.9	90.2	88.9	87.7	86.4	85.1	83.8
59.7	8.0	11.4	90.0	88.7	87.4	86.1	84.7	83.4
65.9	8.5	11.0	89.8	88.4	87.1	85.7	84.3	82.9
72.7	9.0	10.5	89.6	88.2	86.7	85.3	83.9	82.4
80.1	9.5	10.1	89.3	87.9	86.4	84.9	83.4	81.9
88.1	10.0	9.7	89.0	87.5	86.0	84.4	82.9	81.3
106.6	11.0	8.8	88.4	86.8	85.1	83.4	81.7	80.0
129.2	12.0	7.9	87.7	85.8	84.0	82.1	80.2	78.3
157.5	13.0	7.0	86.7	84.6	82.6	80.5	78.4	76.3
193.8	14.0	6.1	85.5	83.1	80.8	78.4	76.0	73.6
242.2	15.0	5.3	83.8	81.1	78.4	75.7	72.9	70.1

Excess Air (%)	O_2 (%)	CO_2 (%)	Percent Combustion Efficiency Flue Gas Temperature Minus Combustion Air Temperature (°F)					
			420	460	500	540	580	620
0.0	0.0	18.4	86.8	85.9	85.0	84.1	83.1	82.2
4.8	1.0	17.6	86.4	85.5	84.5	83.6	82.6	81.6
10.2	2.0	16.7	86.0	85.0	84.0	83.0	82.0	81.0
16.2	3.0	15.8	85.5	84.5	83.4	82.4	81.3	80.3
22.8	4.0	14.9	85.0	83.9	82.8	81.7	80.6	79.5
26.4	4.5	14.5	84.7	83.6	82.4	81.3	80.2	79.0
30.3	5.0	14.0	84.4	83.2	82.1	80.9	79.7	78.6
34.4	5.5	13.6	84.0	82.9	81.7	80.5	79.3	78.1
38.8	6.0	13.2	83.7	82.5	81.3	80.0	78.8	77.6
43.5	6.5	12.7	83.3	82.1	80.8	79.5	78.3	77.0
48.5	7.0	12.3	82.9	81.6	80.3	79.0	77.7	76.4
53.9	7.5	11.9	82.5	81.1	79.8	78.5	77.1	75.7
59.7	8.0	11.4	82.0	80.6	79.2	77.9	76.5	75.0
65.9	8.5	11.0	81.5	80.1	78.6	77.2	75.8	74.3
72.7	9.0	10.5	81.0	79.5	78.0	76.5	75.0	73.5
80.1	9.5	10.1	80.4	78.8	77.3	75.7	74.2	72.6
88.1	10.0	9.7	79.7	78.1	76.5	74.9	73.3	71.6
106.6	11.0	8.8	78.2	76.5	74.7	73.0	71.2	69.4
129.2	12.0	7.9	76.4	74.5	72.6	70.6	68.7	66.7
157.5	13.0	7.0	74.2	72.0	69.9	67.7	65.5	63.3
193.8	14.0	6.1	71.2	68.8	66.4	63.9	61.4	58.9
242.2	15.0	5.3	67.4	64.5	61.7	58.9	56.0	53.1

This table is based on the following fuel analysis (% by weight): ash-5.0%, sulfur-0.92%, hydrogen-5.12%, carbon-77.13%, moisture-3.50%, nitrogen-1.49%, oxygen-6.84%. The proximate analysis is VM-36.14%, FC-55.36%, M-3.5%, ash-5.0%. The HHV of this Class I Group 3 bituminous coal is 13,750 Btu/lb.

Table 8
Combustion Efficiency for Coal, 9.0 Percent Moisture, Bituminous

Excess Air (%)	O_2 (%)	CO_2 (%)	Percent Combustion Efficiency Flue Gas Temperature Minus Combustion Air Temperature (°F)					
			180	220	260	300	340	380
0.0	0.0	18.4	91.0	90.1	89.2	88.3	87.4	86.5
4.8	1.0	17.6	90.8	89.9	89.0	88.1	87.1	86.2
10.2	2.0	16.7	90.7	89.7	88.7	87.7	86.8	85.8
16.2	3.0	15.8	90.5	89.4	88.4	87.4	86.4	85.3
22.8	4.0	14.9	90.2	89.2	88.1	87.0	85.9	84.8
26.4	4.5	14.5	90.1	89.0	87.9	86.8	85.7	84.6
30.3	5.0	14.0	90.0	88.8	87.7	86.6	85.4	84.3
34.4	5.5	13.6	89.8	88.7	87.5	86.3	85.2	84.0
38.8	6.0	13.2	89.7	88.5	87.3	86.1	84.9	83.6
43.5	6.5	12.7	89.5	88.3	87.1	85.8	84.6	83.3
48.5	7.0	12.3	89.3	88.1	86.8	85.5	84.2	82.9
53.9	7.5	11.9	89.1	87.8	86.5	85.2	83.9	82.5
59.7	8.0	11.4	88.9	87.6	86.2	84.9	83.5	82.1
65.9	8.5	11.0	88.7	87.3	85.9	84.5	83.1	81.6
72.7	9.0	10.5	88.5	87.0	85.6	84.1	82.6	81.1
80.1	9.5	10.1	88.2	86.7	85.2	83.7	82.1	80.6
88.1	10.0	9.7	88.0	86.4	84.8	83.2	81.6	80.0
106.6	11.0	8.8	87.3	85.6	83.9	82.1	80.4	78.6
129.2	12.0	7.9	86.5	84.6	82.7	80.8	78.9	77.0
157.5	13.0	7.0	85.6	83.4	81.3	79.2	77.0	74.9
193.8	14.0	6.1	84.3	81.9	79.5	77.1	74.6	72.2
242.2	15.0	5.3	82.6	79.8	77.1	74.3	71.5	68.6

Excess Air (%)	O_2 (%)	CO_2 (%)	Percent Combustion Efficiency Flue Gas Temperature Minus Combustion Air Temperature (°F)					
			420	460	500	540	580	620
0.0	0.0	18.4	85.6	84.7	83.7	82.8	81.8	80.9
4.8	1.0	17.6	85.2	84.2	83.2	82.3	81.3	80.3
10.2	2.0	16.7	84.8	83.7	82.7	81.7	80.6	79.6
16.2	3.0	15.8	84.3	83.2	82.1	81.1	80.0	78.9
22.8	4.0	14.9	83.7	82.6	81.5	80.3	79.2	78.1
26.4	4.5	14.5	83.4	82.3	81.1	80.0	78.8	77.6
30.3	5.0	14.0	83.1	81.9	80.7	79.6	78.3	77.1
34.4	5.5	13.6	82.8	81.6	80.3	79.1	77.9	76.6
38.8	6.0	13.2	82.4	81.2	79.9	78.7	77.4	76.1
43.5	6.5	12.7	82.0	80.7	79.5	78.2	76.8	75.5
48.5	7.0	12.3	81.6	80.3	79.0	77.6	76.3	74.9
53.9	7.5	11.9	81.2	79.8	78.4	77.1	75.7	74.3
59.7	8.0	11.4	80.7	79.3	77.9	76.4	75.0	73.5
65.9	8.5	11.0	80.2	78.7	77.3	75.8	74.3	72.8
72.7	9.0	10.5	79.6	78.1	76.6	75.1	73.5	71.9
80.1	9.5	10.1	79.0	77.5	75.9	74.3	72.7	71.0
88.1	10.0	9.7	78.4	76.7	75.1	73.4	71.7	70.1
106.6	11.0	8.8	76.9	75.1	73.3	71.5	69.6	67.8
129.2	12.0	7.9	75.0	73.0	71.1	69.1	67.0	65.0
157.5	13.0	7.0	72.7	70.5	68.3	66.1	63.8	61.6
193.8	14.0	6.1	69.7	67.2	64.7	62.2	59.7	57.1
2422	15.0	5.3	65.8	62.9	60.0	57.1	54.1	51.2

This table is based on the following fuel analysis (% by weight): ash-8.0%, sulfur-1.91%, hydrogen-4.48%, carbon-67.40%, moisture-9.00%, nitrogen-1.31%, oxygen-7.90%. The proximate analysis is VM-33.86%, FC-49.14%,M-9.0%, ash-8.0%. The HHV of this Class II Group 4 bituminous coal is 12,050 Btu/lb.

Boiler efficiency must always be less than combustion efficiency. Typical boiler efficiencies range from 75 to 85 percent. The main boiler loss is heat lost in flue gas as discussed in the previous paragraph. Other energy losses are associated with heat radiated from the boiler casing, heat carried away by the blowdown water, and heat lost because of incomplete combustion. To achieve maximum boiler efficiency the operator must:

a) Minimize excess air to reduce stack losses.

b) Clean the gas side and water side of boiler tubes to ensure maximum absorption of heat and reduced stack temperatures.

c) Minimize blowdown to reduce blowdown losses.

d) Perform maintenance on burners and controls to minimize unburned fuel.

A more detailed discussion of boiler efficiency is provided in Section 4.

2.4.10 <u>Central Boiler Plant Efficiency</u>. The amount of energy in steam or hot water leaving the plant (E out of plant, Btu/lb x lb/hr) minus the amount of energy in condensate or hot water return (E return, Btu/lb x lb/hr), divided by the amount of energy in fuel (E fuel, Btu/lb x lb/hr) used to produce that steam or hot water is the central boiler plant efficiency.

$$\text{Plant Efficiency} = \frac{(\text{E out of plant} - \text{E return})}{\text{E fuel}}$$

Boiler selection, deaerator control, steam trap maintenance, use of steam driven auxiliaries, and plant building energy conservation are important contributing elements to boiler plant efficiency. Energy losses and use should be controlled to keep plant efficiency as close as possible to boiler efficiency. Use of steam-driven auxiliaries reduces the amount of energy sent out of the central plant and steam losses can result if exhaust steam cannot be used in the deaerator or building heating system. Distribution system losses from the central boiler plant should also be monitored and reported. While distribution system losses are not a part of central plant efficiency, they greatly affect the efficiency of the system. Any makeup water required to replace distribution losses must be heated to feedwater temperature. This requires additional steam to be generated by boilers, thus using additional fuel and lowering plant efficiency. More information is provided in Section 4.

2.5 Principles of Steam and Hot Water Generation

2.5.1 Basic Principles. Generation of steam occurs as a result of two separate processes: (1) combustion, release of heat by burning fuel, and (2) heat transfer, absorption of heat into water. Combustion was discussed in the previous section. A study of the heat transfer process can be made with an elementary boiler as shown in Figure 5. The boiler system can be represented as a container equipped with an outlet pipe and valve, a pressure gage, and a thermometer immersed in water. If a fire is built under the unit and water at 32 degrees F is put into the container with the valve left open, water temperature will rise steadily as the fire burns until a temperature of approximately 212 degrees F is reached. At this time, the temperature will rise no further, but the water will gradually boil off and, if firing is continued long enough, the water will evaporate. If the heat content of the fuel source is accurately measured, it can be demonstrated that to raise the temperature from 32 degrees F to the boiling point, the heat input was 180 Btu for each pound of water. It would also be shown that 970 additional Btu for each pound of water is required to boil off the water. This additional heat is called the latent heat of vaporization and represents heat required to convert the small volume of liquid into a large volume of steam.

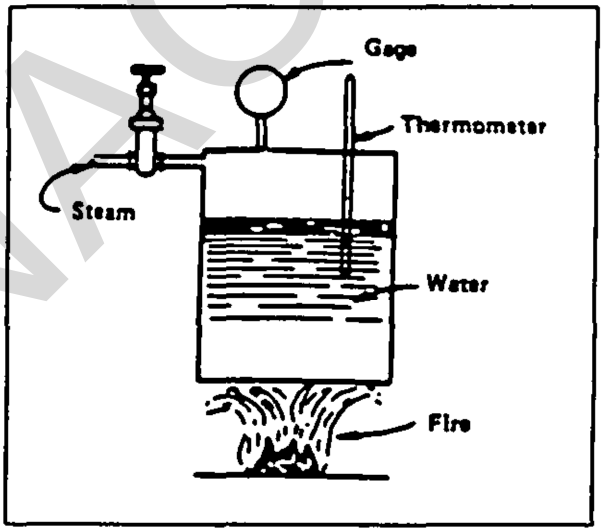


Figure 5
Elementary Boiler

With the valve in a closed position and using another batch of water, the process is repeated and pressure is allowed to build up to 100 psig, then the valve is throttled so that pressure is maintained at 100 psig. The temperature in the container is now approximately 338 degrees F. This is called the saturation temperature for 100-psig pressure. Heat input required to raise 1 pound of water from 32 degrees F up to this saturation temperature is 309 Btu. Energy expended in boiling 1 pound of water to 338 degrees F at 100 psig is 880.6 Btu. The temperature required to boil water increases as pressure increases. The amount of heat put into the liquid to raise it to this boiling point temperature is greater and the latent heat of vaporization is progressively less as pressure increases. Table 9 provides a summary of saturation temperatures, energy in water, energy in steam, and latent heat of vaporization for pressures from 0 to 300 psig. Reference standard steam tables.

Table 9
Water/Steam Characteristics

Pressure (psig)	Saturation Temp (Degrees F)	Energy in Water (Btu/lb)	Energy in Steam (Btu/lb)	Latent Heat of Vaporization (Btu/lb)
0	32 (1)	0	-	-
0	60 (1)	28	-	-
0	212	180	1150	970
15	250	218	1164	946
30	274	243	1172	929
40	287	256	1176	920
50	298	267	1179	912
60	307	277	1182	905
70	316	286	1184	898
80	324	294	1186	892
90	331	302	1188	886
100	338	309	1190	881
110	344	316	1191	875
120	350	322	1192	870
130	356	328	1193	865
140	361	333	1195	862
150	366	339	1196	857
200	388	362	1199	837
250	406	382	1202	820
300	422	399	1203	804

(1) 32 degrees F and 60 degrees F are saturation temperatures of water at 0 psig.

2.5.2 Heat Transfer. Heat transfer is accomplished by three methods: *radiation, conduction,* and *convection.* All three methods are used within a boiler. The heating surface in the furnace area receives heat primarily by radiation. The remaining heating surface in the boiler receives heat by convection from hot flue gases. Heat received by the heating surface travels through metal by conduction. Heat is then transferred from the metal to water by convection. Each of these methods is discussed in more detail below.

2.5.2.1 Radiation. Radiation is the most important method of heat transfer in the furnace. The amount of heat transfer depends on the area of heating surfaces and hot surfaces in the furnace, the difference of the fourth powers (T4) of temperatures of the flame and heating surfaces, and the nature of the flame. For the same temperatures, a coal flame is more radiant than an oil flame and an oil flame is more radiant than a natural gas flame. The same physical laws governing transmission of light also apply to transfer of radiant heat:

a) Heat is transmitted in straight lines

b) Heat can be reflected and refracted

c) Heat is radiated in all directions

Radiant heat can be transmitted through a vacuum, most gases, some liquids, and a few solids. Solid boiler tubes absorb radiant heat from the flame and radiate a small portion of that heat back to the furnace.

2.5.2.2 Conduction. In conduction, heat is transferred through a material in which individual particles stay in the same position. Heat flowing along an iron bar when one end of the bar is held in a fire is a simple example of this process. Conduction occurs when material, called a conductor, is in physical contact with both the heat source and the point of delivery. Heat flows from the hot end to the cold end of the conductor. It makes no difference if the conductor is straight, crooked, inclined, horizontal, or vertical. Material which it is made of has a great effect, however. Metals conduct heat readily while liquids and gases conduct heat more slowly. Some materials conduct heat very poorly, and are called insulators. Common examples of insulators are asbestos, fiberglass, wood, and some types of plastics. Asbestos is no longer used as an insulator because of health risks. The amount of heat transmitted also varies with the length of the path, contact area, and temperature difference.

2.5.2.3 Convection. Transfer of heat by convection occurs, for example, when water flows over a heated surface causing the surface to cool. In convection heat transfer, the gas or liquid medium receives heat from the source, expands, and is pushed away by colder, heavier particles of the medium. Fluid that receives heat then transfers heat to a new location, losing some heat in the process. Heat transfer by convection normally occurs from a lower to a higher elevation. However, transfer in any direction may take place if an external force, such as fans, pumps, or a pressure drop, is applied.

2.5.2.4 Gas Flow Considerations. In most boilers, a large amount of absorbed heat is given up by hot flue gases which sweep over heat-absorbing surfaces. Heat transfer takes place by convection. The quantity of heat transferred can be varied by controlling temperature or quantity of flue gases. Usually both are controlled. Ability of materials to resist damaging effects of high temperatures is the limiting factor in the first case, and the force available for causing flow through the boiler is the limiting factor in the second case. Boiler draft loss or resistance to flow is the force or pressure drop required for gases to flow through a boiler. Draft loss is commonly called draft and may be supplied by a chimney, forced draft fan, or induced draft fan. Draft, which is measured in inches of water, depends primarily on velocity and density of flowing gases, and cross-sectional area and length of gas passage. Draft loss increases with the square of velocity and directly with length of the passage.

It is important to keep velocity at a minimum, consistent with requirements of good convective heat transfer, if maximum output of a boiler installation is to be attained. The cross-sectional area, baffle arrangement, and length of the gas passage are usually fixed. If gas passages are kept free of soot and ash accumulation, gas velocity and draft loss will depend solely on quantity of gas flow which in turn depends on quantity of air supplied to burn fuel. A minimum air supply consistent with good combustion practice therefore minimizes draft loss and helps to maximize heat transfer and boiler output.

2.5.2.5 Water Circulation Considerations. Water circulates in a steam boiler because the density of water is greater than the density of the water/steam mixture (Figure 6). Within the boiler, denser water falls while the less dense mixture rises. Natural circulating forces are reduced as operating pressure of a boiler increases, and increased as percent of steam in the mixture increases. Hot water boilers normally use pumps to force circulation of water through the boiler, because the density difference between cold and hot water is not large enough to cause natural circulation with velocities necessary for good heat transfer.

2.5.2.6 Heat Transfer to Boiler Tubes and Water by Convection. Heat transfer by convection depends on temperature and velocity of gases on one side of the boiler tube and velocity of water on the other side. Increasing velocity of water aids convection and increases heat transfer. This is due to a very thin film of stagnant water which is in contact with the boiler tube. This can be demonstrated by a simple experiment using a Bunsen burner and a metallic vessel containing boiling water as shown in Figure 6. Place the lighted burner under the vessel and observe it closely. Note that the flame spreads into a sheet about 1/30 to 1/40 inch from the vessel. Because of its high conductivity, the temperature of the tube is only a few degrees hotter than the water while the temperature of the burner flame is much higher. Therefore, there must be a large temperature drop through the thin film between the flame and the vessel. This principle applies to both the water and gas sides of the vessel. Heat in the boiler tube must be conducted through the thin stagnant film of water before the active convection process begins. Heat transfer can be greatly increased if this film is reduced in thickness, or eliminated completely. Usually, this is accomplished by increasing flow velocity across the surface and scrubbing the film away. Unfortunately, as was mentioned earlier, increasing velocities increases draft losses and power requirements. The thin film does not affect radiant or conductive heat transfer but only convective heat transfer.

2.5.2.7 Optimizing Heat Transfer. Boiler furnace heat is absorbed by a combination of radiation, convection, and conduction through boiler tubes. Water in boiler tubes is heated by convection. Tubes and other heating surfaces close to fire that do not have a high rate of gas flowing across them receive practically all their heat by radiation. Heating surfaces close to the furnace and across which gas flow is high receive heat by both radiation and convection. Surfaces distant from the furnace receive their heat by convection. Heat transfer can be optimized by controlling excess air, keeping boiler tubes clean, and maintaining optimum gas and water velocities.

a) Excess Air Control. Maintaining low excess air levels in a boiler is important because any air above the required air for combustion is heated and lost up the stack. Theoretical air is the exact amount of air required for combustion. Excess air is additional air above theoretical air. Plant operators should maintain O_2 levels as low as possible while maintaining smoke-free operations. A 1.3 percent reduction in O_2 increases efficiency by approximately 1 percent.

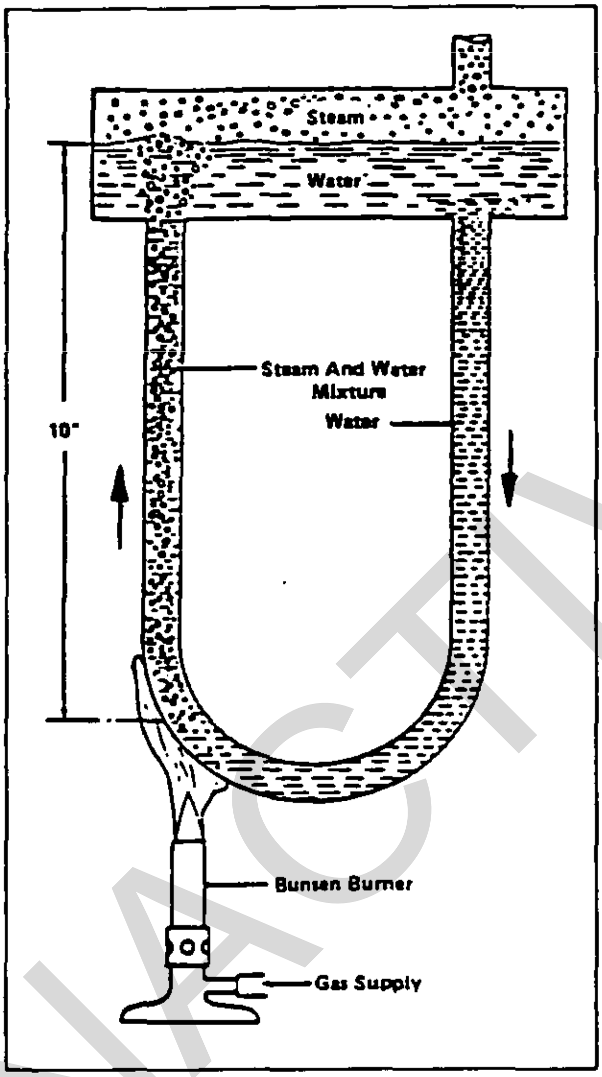


Figure 6
Water Circulation

The amount of excess air directly affects flame temperature E. The rate at which radiant heat is transmitted varies as the fourth power of temperature. The amount of heat transmitted by radiation doubles when the absolute temperature of the radiating source is increased by approximately 19 percent. The rate at which heat is transmitted by radiation from an oil flame can increase by 42 percent by increasing the temperature of the visible flame from 1725 to 1925 degrees F. Reducing excess air used to burn fuel causes the flame temperature to increase. Maximum flame temperature is normally obtained with approximately

3 to 5 percent excess air. A moderate increase in furnace temperature resulting from an excess air reduction can markedly affect the amount of radiant heat absorbed by boiler surfaces.

b) Maintaining Clean Boiler Tubes. Heat loss due to high exit gas temperatures up the stack constitutes one of the major efficiency losses. A 40 degrees F increase in gas temperature up the stack will reduce efficiency by approximately 1 percent. Gas temperature leaving the economizer is controlled by soot blowing which cleans surfaces and improves heat transfer.

The amount of heat transferred by conduction depends on type, thickness, and condition of conductive material as well as the difference in temperature. Heat is readily conducted through metal, while ash, soot, and scale are poor conductors. Figure 7 illustrates the effects of soot and scale. If heating surfaces become coated with soot, scale, or other material, the firing rate of the boiler must be increased to raise gas temperatures and maintain the same amount of heat transfer. Any deposit on either side of the heating surface increases maintenance costs, reduces efficiency, and may cause operator injuries or boiler damage if a tube overheats and ruptures.

c) Maintaining Gas and Water Passages. Keeping gas passages free from accumulations of soot and ash, and maintaining gas baffles in good repair help to ensure proper gas velocities to heat transfer surfaces. Keeping water passages free from accumulations of sludge and scale ensures proper water flow and velocity for cooling of heat transfer surfaces and generating steam or hot water.

d) Maximum Versus Economical Heat Transfer. Maximum and economical heat transfer are not the same. It is rarely possible to operate a boiler at temperatures high enough to obtain the maximum heat transfer rate because of material limitations, particularly furnace brickwork. The maximum temperature that can be safely maintained is determined by, among other considerations, the kind of firebrick used, furnace construction (self-supporting or supported), quantity and kind of ash in the fuel, furnace size, and amount and type of cooling of furnace walls (air cooled or water cooled). It is important to maintain a low gas temperature at the boiler outlet since this results in high boiler efficiency. However, the rate of heat transfer may be relatively low in this area because temperature differences are low. There is a practical limit on the velocity of flue gas based on reasonable fan horsepower requirements and capabilities. Water velocity is fixed by boiler design and cleanliness for any particular firing rate. Reduced water velocity at a lower boiler firing rate results in reduced but more economical heat transfer rates. Most of the above factors are determined by design of the boiler. It is the responsibility of the boiler manufacturer to balance requirements of maximum heat transfer with economics and produce a cost-effective design.

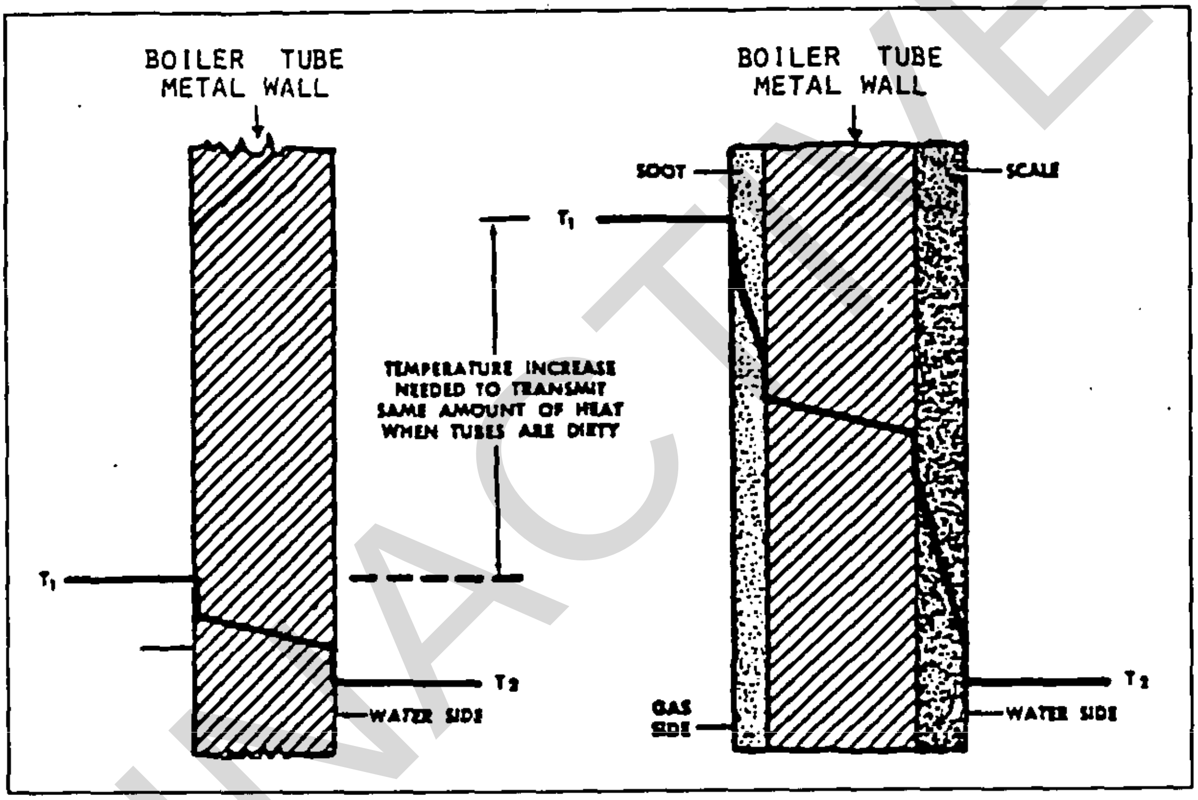


Figure 7
Effects of Soot and Scale on Heat Transfer

Section 3: DESCRIPTION OF EQUIPMENT

3.1 Boilers and Heat Exchangers

3.1.1 Boiler Classifications. There are a few fundamental types of boilers and many variations of each type. Boilers are generally classified as either fire tube or water tube. Boilers are also classified by the form of energy produced; low or high pressure steam; low or high temperature water. Other methods of classifying boilers are listed below:

a) Type of water circulation: natural circulation, forced circulation.

b) Type of steam produced: saturated, superheated.

c) Method of assembly: package, modular, field erected.

d) Type of use: stationary, marine, power, heating.

e) Type of fuel: coal, oil, gas, other.

f) Method of combustion: spreader stoker, fluidized bed, pulverized coal.

g) Boiler capacity: up to 20,700 pounds per hour (up to 600 hp for fire tube boilers; up to 10 million pounds per hour for water tube boilers; up to 200 million Btu per hour for hot water boilers).

3.1.2 Boiler Design Requirements. A boiler must meet the following requirements:

a) Operational safety.

b) Generation of clean steam or hot water at the desired rate, pressure, and temperature.

c) Economy of operation and maintenance.

d) Conformance to applicable codes.

A set of rules for the construction and operation of boilers, known as the ASME Boiler and Pressure Vessel Code, has been widely adopted by insurance underwriters and Government agencies. Section I of the Code contains requirements for power boilers including methods of construction and installation, materials to be used, design, accessories, and inspection. Section IV of the Code contains requirements for heating boilers.

Low pressure steam boilers and LTW boilers are classified as heating boilers. Section VI of the Code provides recommended rules for care and operation of heating boilers, and Section VII provides recommended rules for care of power boilers. Other sections of the Code provide material specifications, nuclear equipment requirements, inspection requirements, and welding qualifications.

3.1.3 Fabrication. Boilers, superheaters, economizers, and other pressure parts must be built using materials and construction methods specified by the applicable sections of the ASME Boiler and Pressure Vessel Code. Repairs to boilers must also be made in accordance with Code requirements. Equipment built and inspected in accordance with the Code must have an ASME stamp. An "H" in a cloverleaf is stamped on heating boilers. An "S" in a cloverleaf is stamped on power boilers.

3.1.3.1 Drums, Shells, or Headers. Boiler drums, shells, or headers are used to collect steam or hot water generated in the boiler and distribute it within the boiler tubes. These components must be strong enough to contain the steam or hot water and to hold the boiler tubes as they expand and contract with changes in temperature. The shells of fire tube boilers may be reinforced by the use of stays to hold the boiler heads in place. These components are generally fabricated with welded seams and connections. Riveted seams are no longer used, although many old riveted boilers are still in operation.

3.1.3.2 Boiler Tubes. Boiler tubes carry water, steam, or flue gases through the boiler. Boiler tubes are installed by expanding or welding them into seats in the drums or headers. The expander tool consists of a tapered pin which fits into a cage containing several small rollers. A different size expander is required for each size tube. During installation, the expander is slipped into the end of the tube and the tapered pin is pushed into the cage until the rollers are against the tube walls. Then the pin is turned with a wrench or motor, forcing the rollers out against the tube, and simultaneously moving the cage into the tube. This action distorts and stretches the tube, forcing it to make a tight seal against the tube sheet. The expander often has a stop which helps prevent overexpanding. Boiler tubes are installed with ends projecting slightly beyond the tube sheets. Projecting ends are flared slightly in water tube boilers and allowed to remain because they are surrounded and cooled by water or steam. Since the tube ends of a fire tube boiler are surrounded by hot gases, they would soon burn off if allowed to project. They are therefore beaded and hammered until flat against the tube sheet. This process also increases the holding power of the tube. It must, however, be performed carefully to avoid damaging the tube.

3.1.3.3 Baffles. Baffles are thin walls or partitions installed in water tube boilers to direct the flow of gases over the heating surface in the desired manner. The number and position of baffles have a marked effect on boiler efficiency. A leaking or missing baffle permits gases to short-circuit through the boilers. Heat that should have been absorbed by the water is then dissipated and lost. With a leaking baffle, tubes may be damaged by the "blow torch" action of the flame or hot gas sweeping across the tube at high velocity, especially if the leak is in or near the furnace. Baffles may be made of iron castings, sheet metal strips, brick, tile, or plastic refractory.

Provisions must be made to permit movement between the baffle and setting walls while still maintaining a gas-tight seal. Iron castings are made in long, narrow sections to fit in the tube lanes and around the tubes. They can be installed only while the boiler is being erected or assembled, and their use is limited by the temperatures they can withstand. Sheet metal strips are formed to fit around the tubes and are easily installed after tubes are in the boiler. Their primary uses are to help distribute flue gas within a pass and to maintain proper tube spacing, rather than to function as baffles between adjacent passes. This type baffle cannot be used in the high temperature areas of the boiler. Brick or tile baffles, made of specially shaped forms which fit between and around the tubes, can be installed after the boiler has been erected and can be used in any area of the boiler. Castable plastic refractory baffles are usually installed by building a form and pouring the refractory like concrete. The forms are then removed after the refractory has set. This type of baffle can be used at any location in the boiler and, if properly designed, can remain gas-tight for long periods. It may be used to repair or replace other types of baffles.

3.1.4 Fire Tube Boilers. Many of the first steam boilers produced were designed with the products of combustion passing inside the tubes. Fire tube boiler design has developed primarily in the direction of the Scotch-type boiler shown in Figure 8. The Scotch boiler is shop fabricated and is capable of supplying saturated steam at pressures below 250 psig at capacities usually below 20,000 lb/hr. At pressures above 250 psig, the natural circulation of water and steam in this design is not adequate for good heat transfer. At capacities above 20,000 lb/hr, the shell diameter becomes too large to be economical. Scotch boilers come in two, three, and four gas pass designs, as illustrated in Figure 9. With more gas passes and more heat transfer surface, boiler exit gas temperatures are lower and efficiencies are higher. Wet back construction in a Scotch boiler means that a waterwall is provided at the outlet of the first pass or furnace. Wet back construction reduces the high maintenance costs often associated with dry back designs. Scotch-type fire tube boilers can effectively fire natural gas and fuel oils. Coal is a less desirable fuel because the first tubes are not easily cleaned and ash removal is restricted. Advantages of the Scotch boiler include the ability to respond to rapid load swings due to the large volume of stored water/steam in the shell, low initial cost, low maintenance costs, and general ease of control. Disadvantages include the difficulty of producing superheated steam and pressure and capacity limitations. Scotch boilers are also used to produce low temperature water. The other common type of fire tube boiler is the horizontal return tubular (HRT) design, illustrated in Figure 10. The firebox in this type of boiler permits the burning of coal using stokers or fluidized beds.

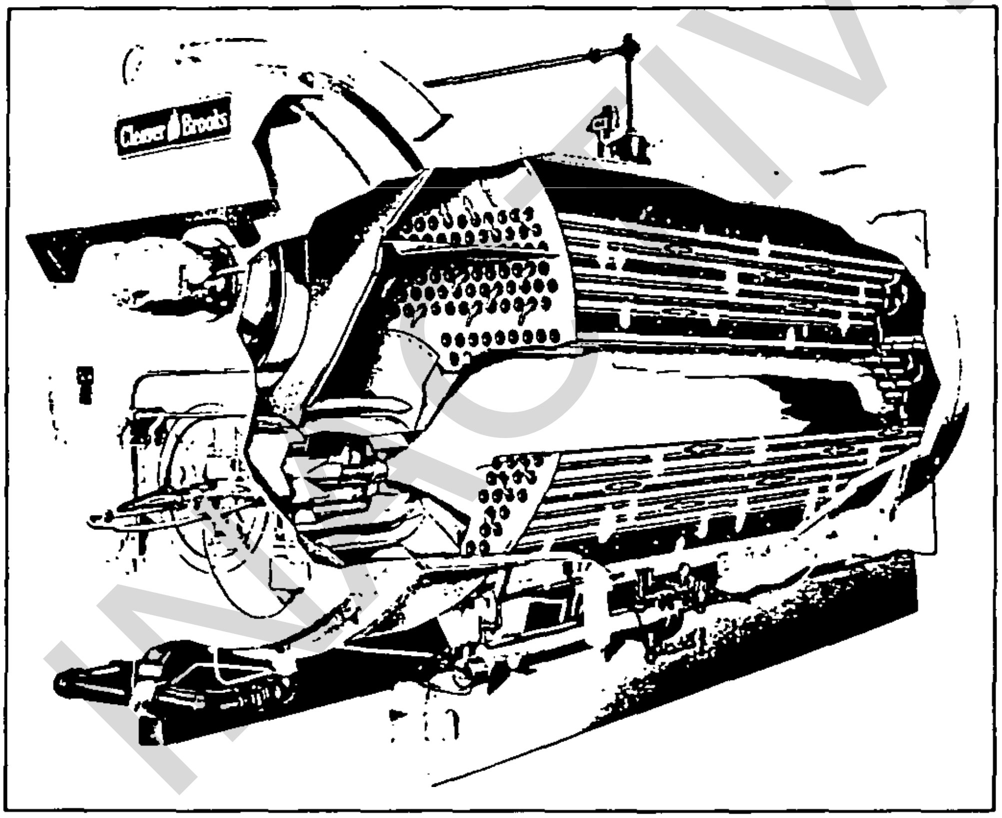


Figure 8
Four-Pass Scotch Boiler

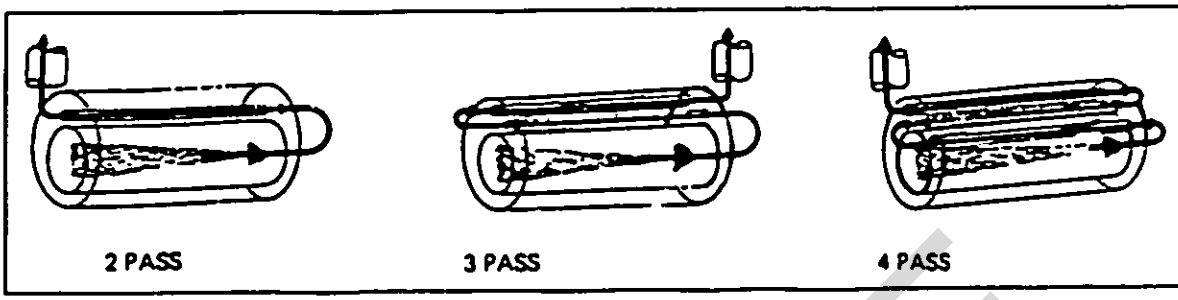


Figure 9
Two-, Three- and Four-Pass Scotch Boiler Designs

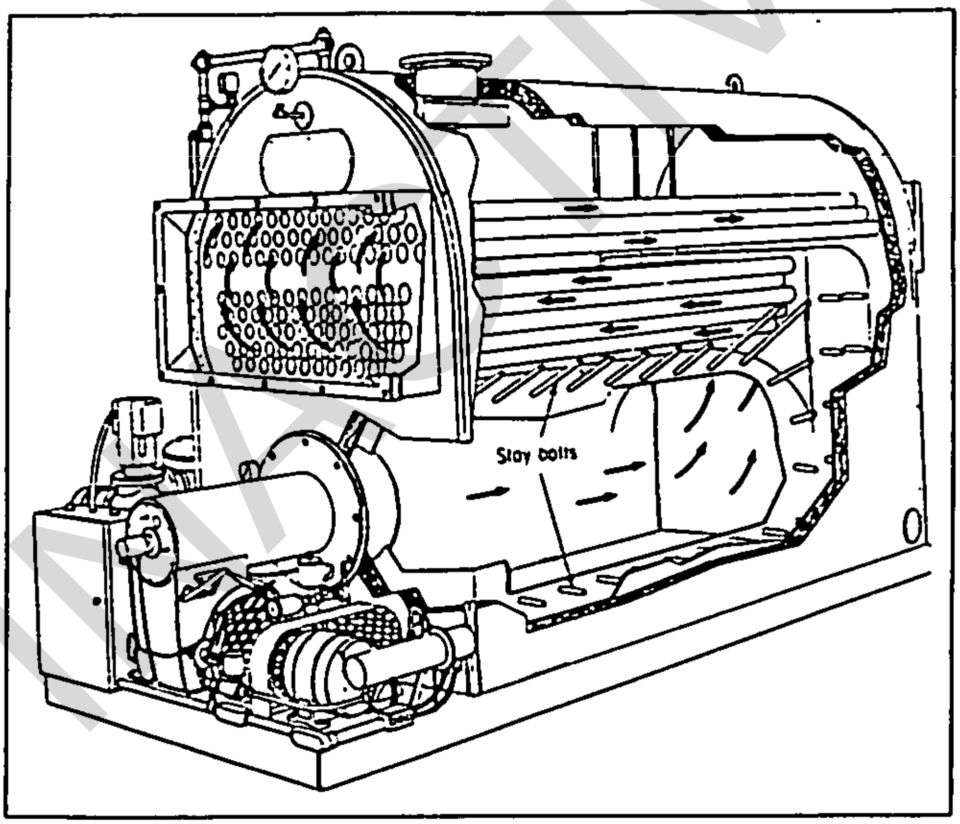


Figure 10
Horizontal Return Tubular Boiler

3.1.5 Water Tube Boilers. Water tube boilers were developed for a variety of reasons, including the need for higher pressures, higher capacities, superheated steam, faster response to load changes, and increased safety due to reduced water volume. Water tube boilers have water inside the tube and flue gases on the outside. Early straight tube design boilers were replaced with today's bent tube designs to increase the amount of available heat transfer surface, to solve mechanical problems, and for general economic reasons. Figure 11 illustrates a four-drum boiler with a water-cooled back wall. The bottom drum is called a mud drum because of the tendency of boiler sludge to collect in this low area. Upper drums are called steam drums. Water enters the top rear drum, passes through tubes to the bottom drum, and then up through tubes to two front drums. A mixture of steam and water is discharged into these drums; steam returns to the top rear drum through the upper row of tubes while water travels through tubes in lower rows. Steam is removed near the top of the rear drum by a dry pipe extending across the drum, and is discharged through the steam outlet header. Baffles are arranged to encourage flue gas flow over boiler tubes for good heat transfer. Two-drum boilers have generally replaced three- and four-drum units in modern construction, because they are less expensive to construct.

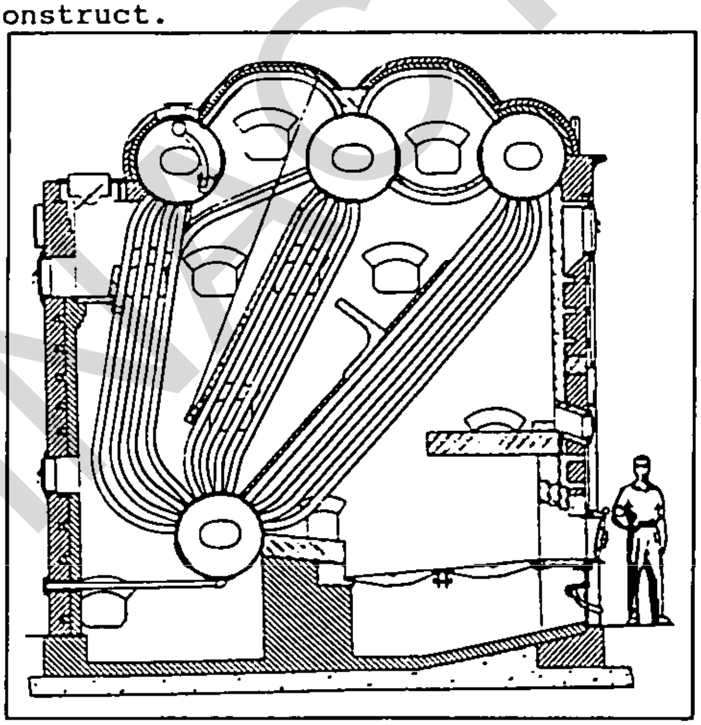
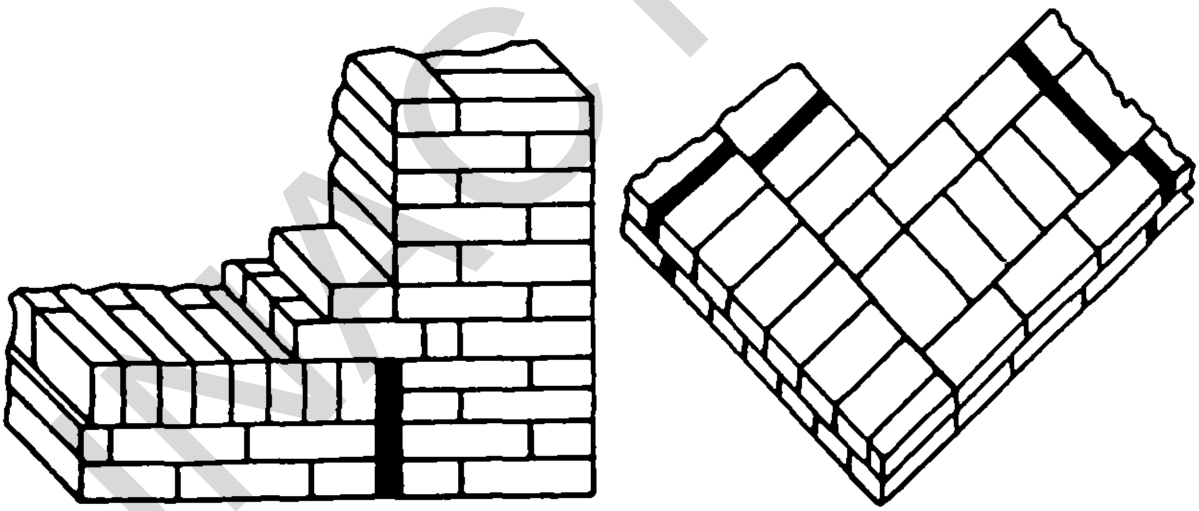


Figure 11
Four-Drum Water Tube Boiler

3.1.5.1 Refractory Furnaces. Early boiler designs utilized refractory furnaces as combustion zones. Some furnaces used arches and bridge walls to reflect heat and maintain high temperatures in specific zones for burning anthracite and other hard coals. Since prolonged exposure to high temperature damages refractory material, it is necessary to maintain the heat liberation rate (Btu per hour per cubic foot of furnace volume) of refractory furnaces within reasonable limits. These limits depend upon the type of refractory used, type of fuel, firing method, type of heating surface exposed to the radiant heat, and type of cooling mechanism used. Maximum heat liberation rates for refractory furnaces are in the ranges of 25,000 to 35,000 Btu per hour per cubic foot at full load. In refractory wall construction, it is important to allow for the thermal expansion which occurs as the refractory is heated to operating temperatures. Figure 12 illustrates typical expansion joint arrangements. The development of high alumina super-duty firebrick, insulating firebrick, block insulation, castable refractory, and plastic refractory have greatly improved refractory life and reduced radiation losses from boiler furnaces.



Floor to Wall Expansion Joints

Corner Construction With Staggered Expansion Joints (18" Wall)

Figure 12
Refractory Expansion Joints

3.1.5.2 Waterwall Construction. Waterwalls were developed to allow the use of higher firing rates and higher furnace heat release rates, while reducing heat losses and maintenance. Improvements to waterwall furnaces and associated casings and lagging also reduced air infiltration into the boiler, reducing excess air levels and improving boiler efficiency. The four types of waterwall construction are: tube and tile, tangent tube, studded tube, and membrane wall (Figure 13). The tube and tile construction, which was developed first, provided only a partial solution to the maintenance and heat loss problems. Minimum practical tube spacing was limited by the ability to economically roll the tubes into drums or headers. This, in turn, limited the amount of heat transfer surface added and the amount of protection given to the refractory, thus limiting the practicality of tangent tube construction.

Studded tube construction was then developed and was highly effective. In areas with high heat releases such as bridge walls and arches, studded tubes covered with refractory are especially effective. Flue gas can still leak through studded tube wall construction under some circumstances, resulting in corrosion of boiler tubes, and lagging. To obtain completely gas-tight construction and maximize heat transfer, membrane waterwall construction was developed and remains the best, though the most expensive, waterwall design.

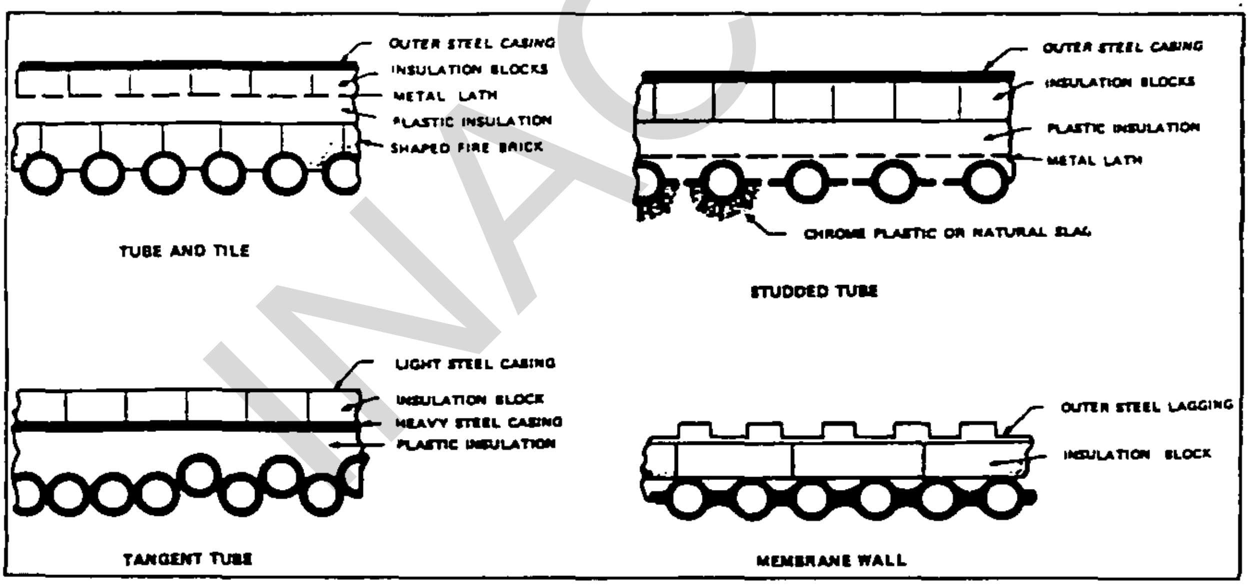


Figure 13
Waterwall Construction

3.1.5.3 Steam Drum Internals. Steam drums are equipped with mechanical separators to ensure that the steam leaving the boiler does not contain solids or other impurities and that steam-free water is made available to continue the natural circulation process in the boiler. A dry pipe, the earliest device used, was placed inside the shell or drum just below the steam outlet nozzle. Numerous small holes drilled in the upper half of the dry pipe cause separation of the steam from the water. The trend in boiler design toward ever higher heat transfer rates makes separation of water and steam more difficult and limits the application of the dry pipe.

Combinations of baffles, cyclone type separators, corrugated scrubbers, and perforated plates are now used to effectively separate water and steam. Figure 14 illustrates modern steam drum internals. Cyclones are arranged in a row and receive the water/steam mixture tangentially from the boiler waterwall and generating tubes. Water is spun to the outside of the cyclone and exits through the open bottom of the cyclone. Steam is less dense and thus stays in the center and exits through the open top of the cyclone. Scrubbers further reduce the amount of water entrained. Solids in condensed steam from a well-designed steam drum should be less than 3 ppm.

3.1.5.4 Generating Surface. Boiler tubes that connect the upper and lower drums are called generating surfaces and are included with the waterwall surface in computing the total heating surface. Many different tube spacings are used, depending on the type of fuel being fired. The tubes may be in-line or staggered. A staggered tube arrangement would not be acceptable for coal-fired or heavy oil-fired boilers due to its susceptibility to ash build-up; however, it provides better heat transfer for gas-fired or light oil-fired units.

3.1.5.5 Superheaters. Some processes and turbines require steam that is superheated above the saturated steam temperatures. Figure 15 illustrates a two-drum boiler equipped with a superheater, waterwalls, spreader stoker, and economizer. Steam from the steam drum is directed to a superheater inlet header and then through superheater tubes to the outlet header and steam outlet. A superheater can be arranged in many ways and may be located behind a row of generating tubes. These tubes cool furnace gases somewhat before reaching the superheater tubes and shield the superheater tubes from radiant heat.

3.1.5.6 Package Boilers. Packaged water tube boilers are factory assembled, complete with combustion equipment, mechanical draft equipment, automatic controls, and accessories. These factory assembled packages can be purchased in capacities exceeding 200,000 lb/hr. Package boilers are available in three basic configurations: "D," "A," and "O" (Figure 16). Figure 17 illustrates a type "D" package boiler arranged for oil and gas firing. Note that the flame travels lengthwise down the furnace where combustion is completed. Flue gases then make a 180-degree turn and come back to the burner end of the boiler, exiting from the side of the generating bank tubes. Historically, package boilers have been designed to fire only natural gas and oil. Coal firing has not been practical due to the high ash content of coal which would plug the boiler generating banks. Package boilers have been widely and successfully applied for central boiler plant service.

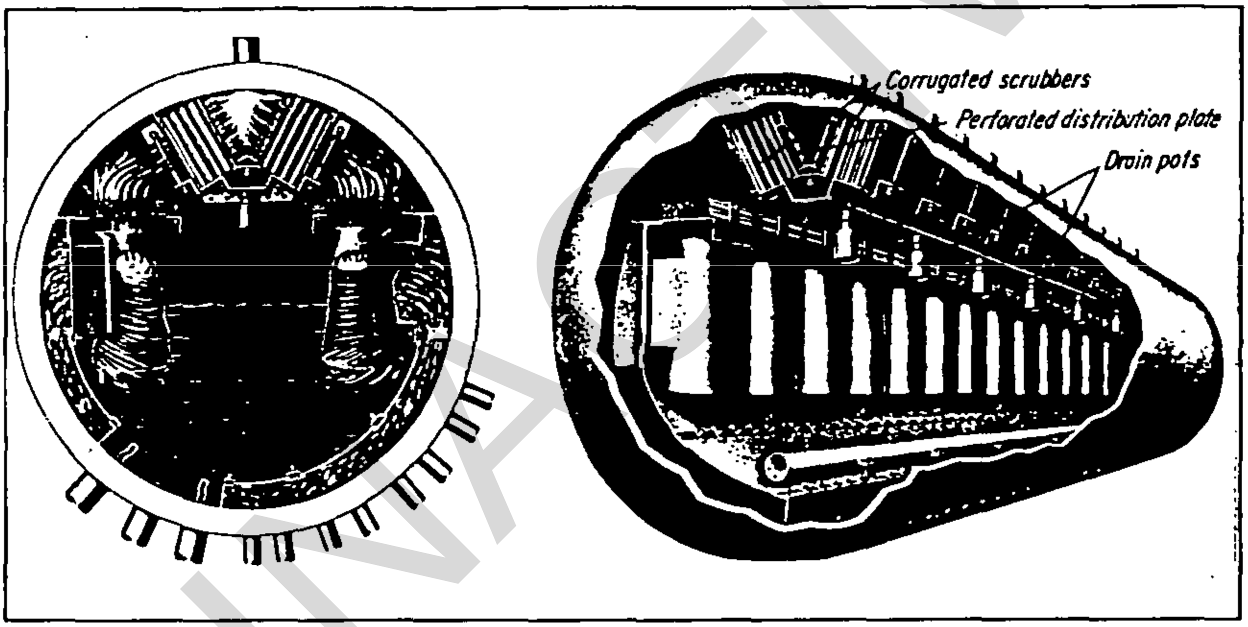


Figure 14
Steam Drum Internals

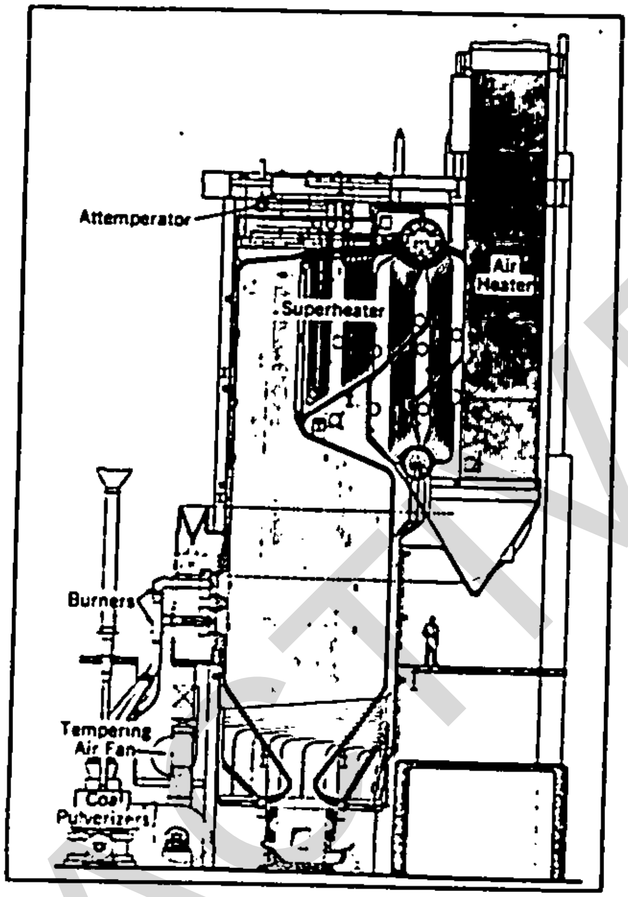


Figure 15
Superheater in Two-Drum Boiler

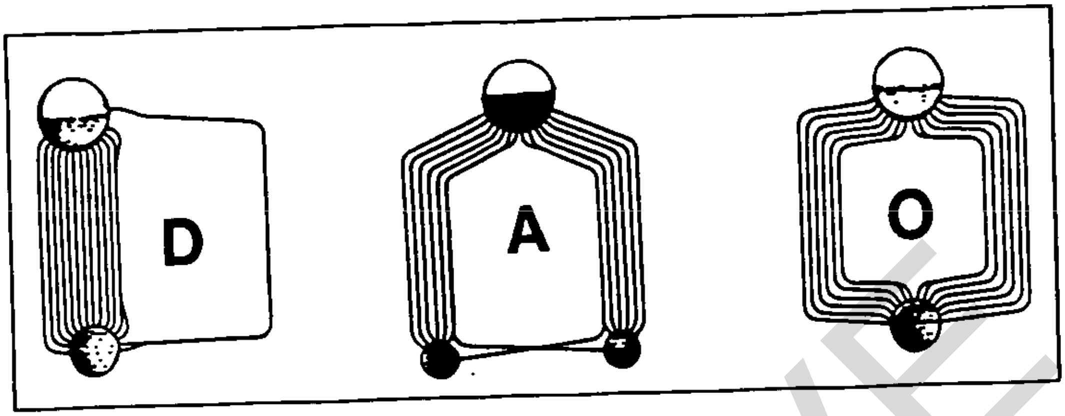


Figure 16
Package Boiler Configurations

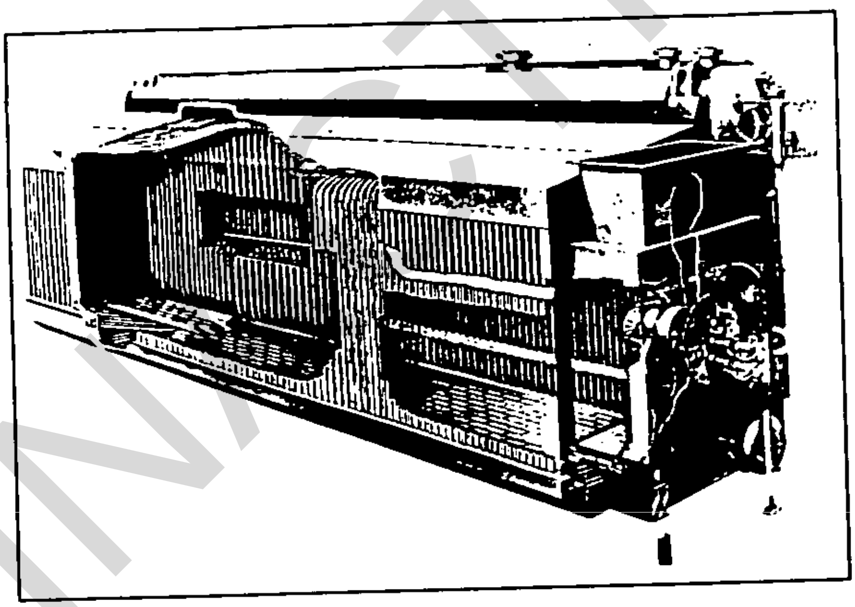


Figure 17
"D" Package Boiler

3.1.6 Hot Water Generators. Hot water generators are often called hot water boilers, even though little or no boiling occurs. Modified Scotch boilers and a variety of package boilers are available. These boilers have limited and uneven water circulation characteristics if natural circulation is utilized because of the small natural circulation forces available. Special boilers have been developed that use forced circulation to improve heat transfer rates. The main difference in a water tube hot water generator is the steam and mud drums are replaced with headers. The hot water generator is connected to a hot water distribution system. As water is heated in the hot water generator, the water expands. When the hot water is distributed to various heat exchangers, the water cools and contracts. Figure 18 illustrates some typical end uses for a low temperature water system. An expansion tank, pressurized by either steam, a static water head, or inert gas, is provided to adjust for these volume changes. One or more centrifugal pumps are required to circulate water through the system. Figure 19 illustrates a high temperature water system equipped with an expansion tank, a circulating pump for the generator, and a circulating pump for the distribution system. Many other arrangements are possible.

3.1.7 Economizers. Economizers are used to recover heat from the boiler flue gases and thereby increase boiler efficiency. The heat absorbed by the economizer is transferred to the boiler feedwater flowing through the inside of the economizer tubes. Because feedwater temperatures are much lower than saturated steam temperature, an effective temperature differential exists, enabling good heat transfer and low economizer exit gas temperatures. Continuous tube construction is common. Bare tubes are used for coal-fired boilers, while fin tubes or extended surfaces are commonly used on gas- and oil-fired units. Figure 20 shows a continuous bare tube economizer. Figure 21 illustrates a steel-finned extended surface economizer. The extended surface promotes heat transfer from the gas by providing more heating surface. Care must be taken when selecting the number of fins per inch. Extended surface economizers on natural gas-fired boilers may use up to nine fins per inch, while only two fins per inch would be used for heavy oil-fired applications.

Provision for cleaning with soot blowers is necessary for economizers on coal-fired boilers or some oil-fired boilers. Economizers are usually arranged with gas flow down and water flow up. This maximizes heat transfer and helps to avoid water hammer. Economizers are usually designed with water temperatures below the saturated temperature of the water to avoid producing steam. Economizers should be equipped with a three-valve bypass on the water side to allow servicing or bypassing water at low boiler loads. This helps to minimize economizer corrosion when high sulfur fuels are burned. Figure 22 provides curves which establish minimum metal temperatures allowable for corrosion protection in economizers and air heaters. Methods for avoiding corrosion during idle or standby periods are discussed in par. 4.3.16. Economizers are pressure parts and, as such, must be manufactured and stamped in accordance with the ASME Boiler and Pressure Vessel Code.

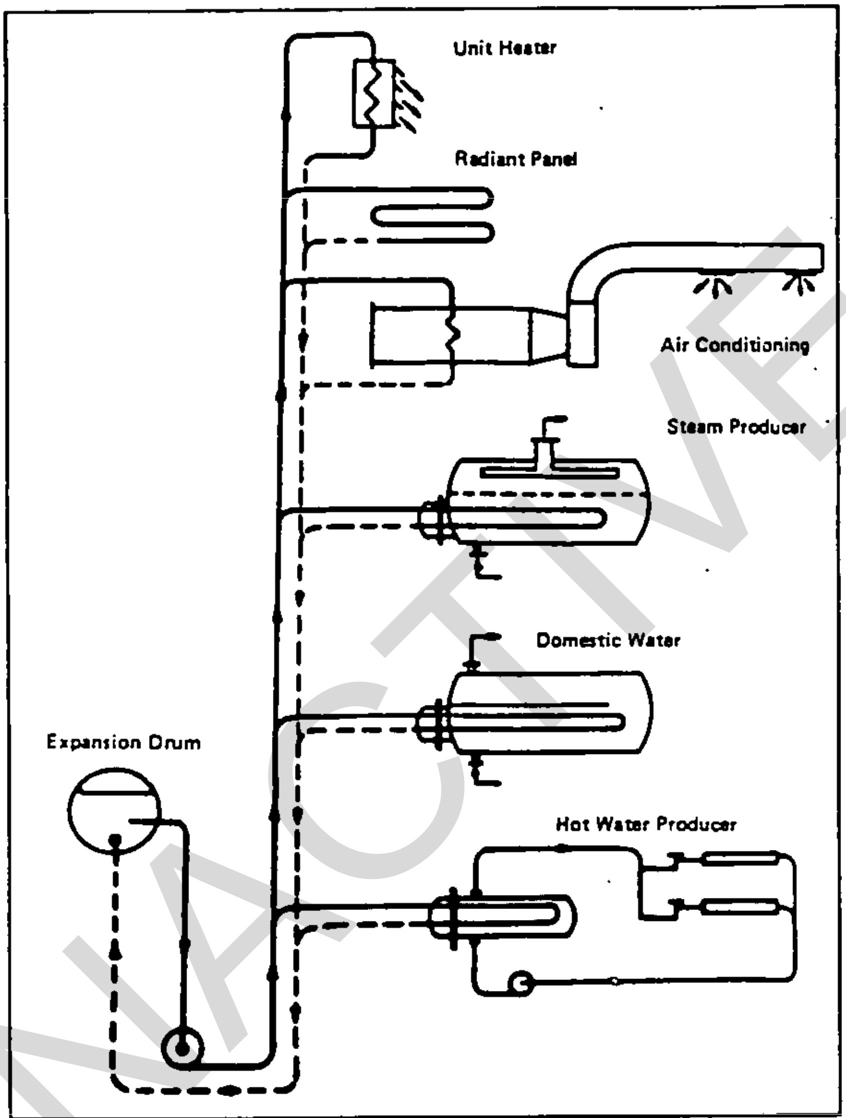


Figure 18
Hot Water End Uses

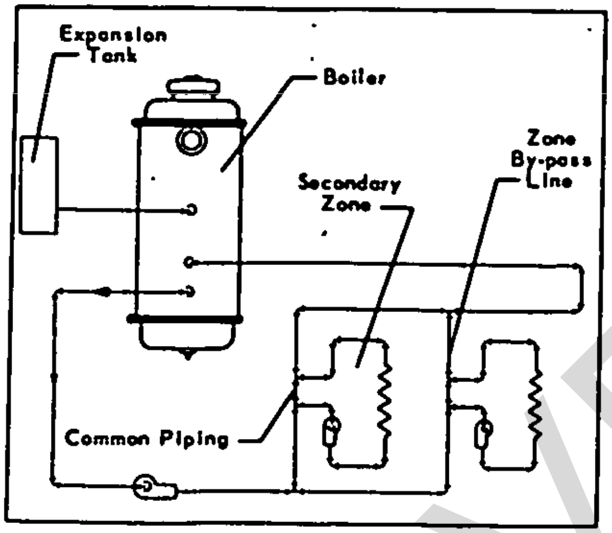


Figure 19
High Temperature Hot Water
Distribution System

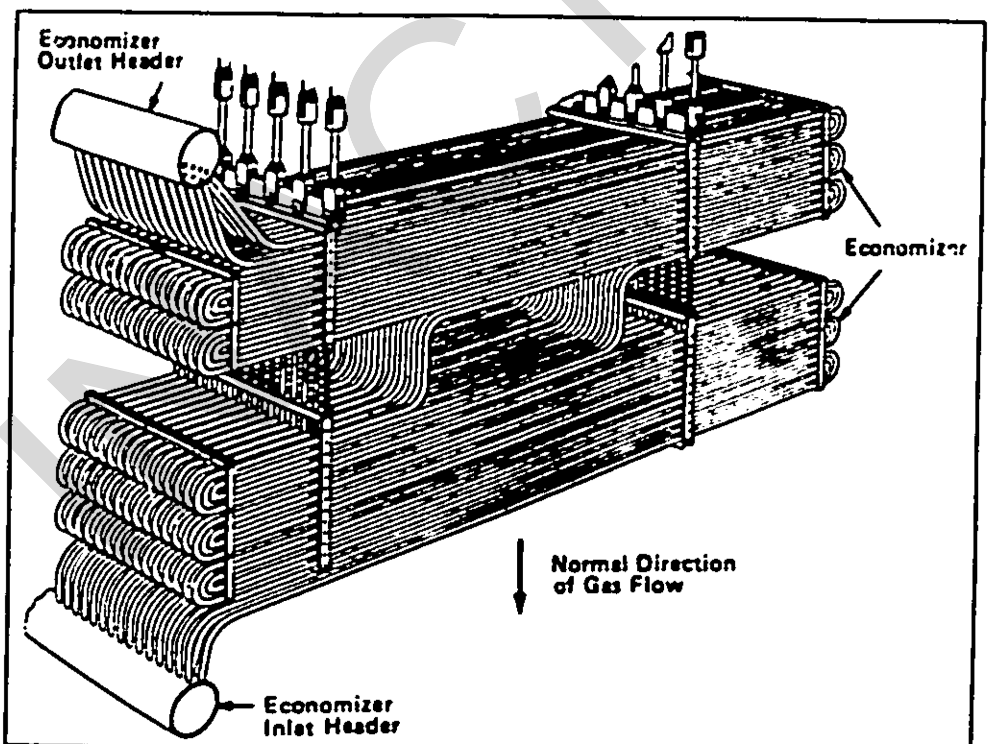


Figure 20
Bare Tube Economizer

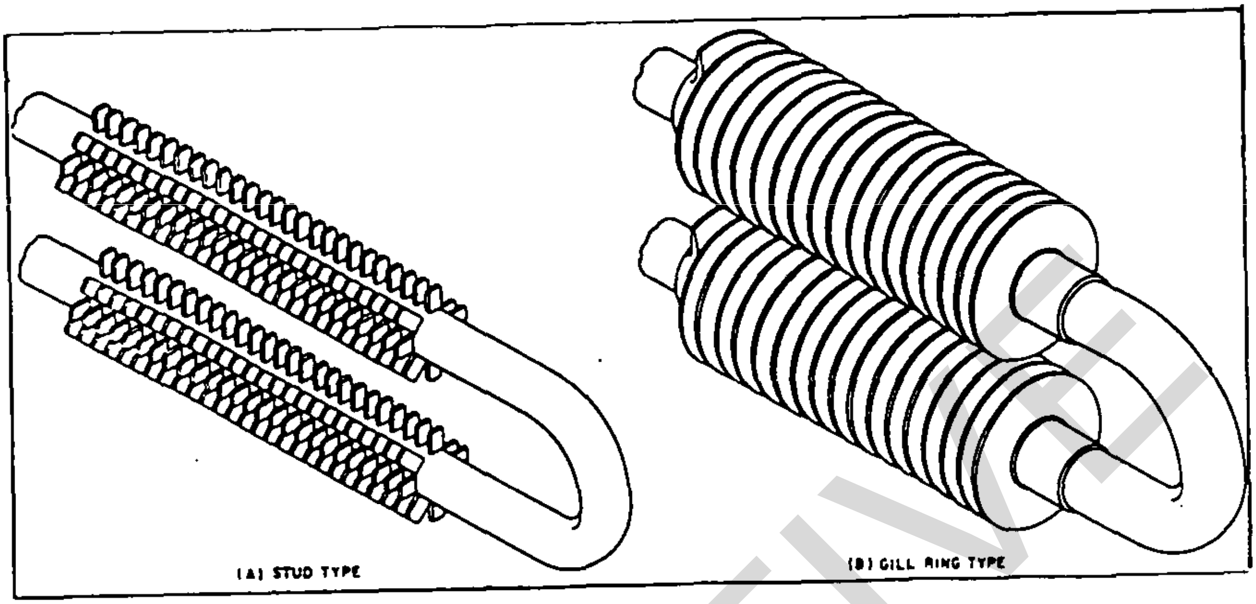


Figure 21
Extended Surface Economizer

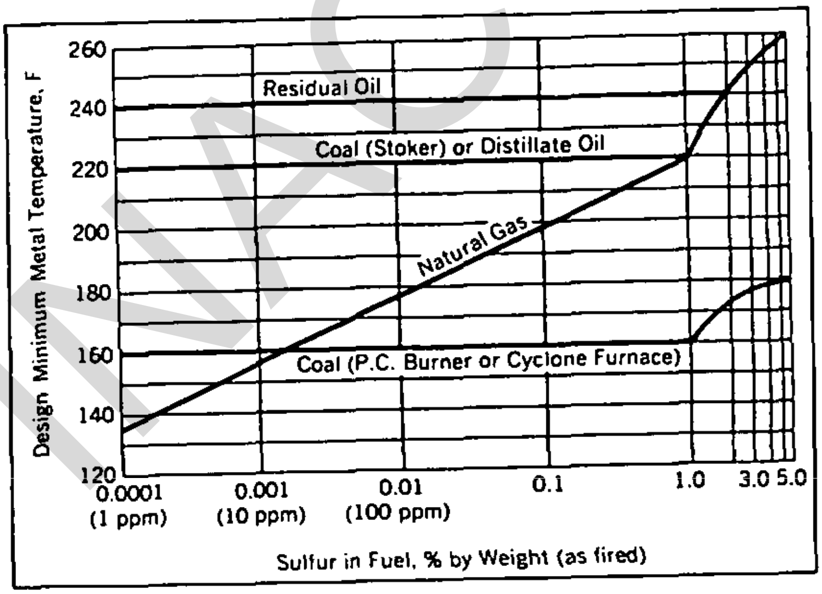


Figure 22
Cold End Corrosion - Minimum Metal Temperatures

3.1.8 Air Heaters. Air heaters, like economizers, are used to recover heat from boiler flue gases and thereby increase the boiler efficiency. Heat absorbed by the air heater is transferred to the combustion air before the air enters the burners and boiler. This preheated air not only improves efficiency by recovering otherwise lost heat, but also can improve the combustion of some fuels by promoting higher furnace temperatures. There are two general types of air heaters: recuperative and regenerative. Recuperative air heaters, like the tubular air heater illustrated in Figure 23, transfer heat from the hot flue gases on one side of the tube to the combustion air on the other side of the tube. Regenerative air heaters, like the rotary heat wheel illustrated in Figure 24, transfer heat indirectly by heating a plate with the hot gas and then rotating that hot plate into the cool combustion air which then absorbs the heat. Rotary heat wheels are equipped with seals that separate the flue gas side from the combustion air side of the wheel. Air infiltration from the air side to the gas side is minimized but not eliminated, and is a factor that must be considered when sizing forced and induced draft fans. Provisions for soot blowers are required if dirty or high ash fuels are being fired. Cold end corrosion is more of a problem in an air heater than an economizer because of the low entering combustion air temperatures. Figure 22 establishes minimum allowable metal temperature if corrosion is to be controlled. Cold air bypass ducts and dampers, hot air recirculation, steam coil air heaters, and low level economizers are examples of methods for preheating the combustion air before it enters the air heater. These methods help control cold end corrosion but also reduce the efficiency of the system by raising exit gas temperatures.

3.2 Boiler Accessories and Fittings

3.2.1 ASME Requirements. To ensure safe operation, the ASME Boiler and Pressure Vessel Code requires that boilers be equipped with a water gage glass and gage cocks, water column, pressure gage, and safety valves. Forced circulation, HTW boilers that have no water line do not require a gage glass and gage cocks, but a temperature gage is required. Detailed requirements for the location and installation of these accessories on power boilers are found in Section I of the Code, and requirements for heating boilers are in Section IV. Section IV requires each boiler to be equipped with two controls to cut off the fuel supply to prevent steam pressure or water temperature from exceeding boiler limits. These controls are pressure operated for steam boilers and temperature operated for hot water boilers. Low water fuel cutoff instrumentation is also required. Oil- and gas-fired boilers must be equipped with suitable flame safeguard controls, safety limit controls, and burners which are approved by a nationally recognized organization.

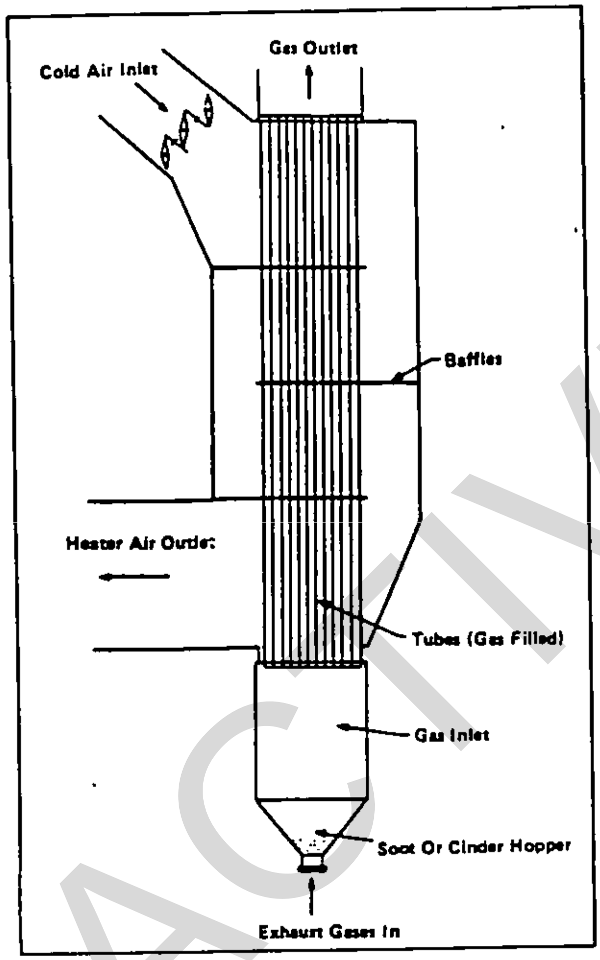


Figure 23
Tubular Air Heater

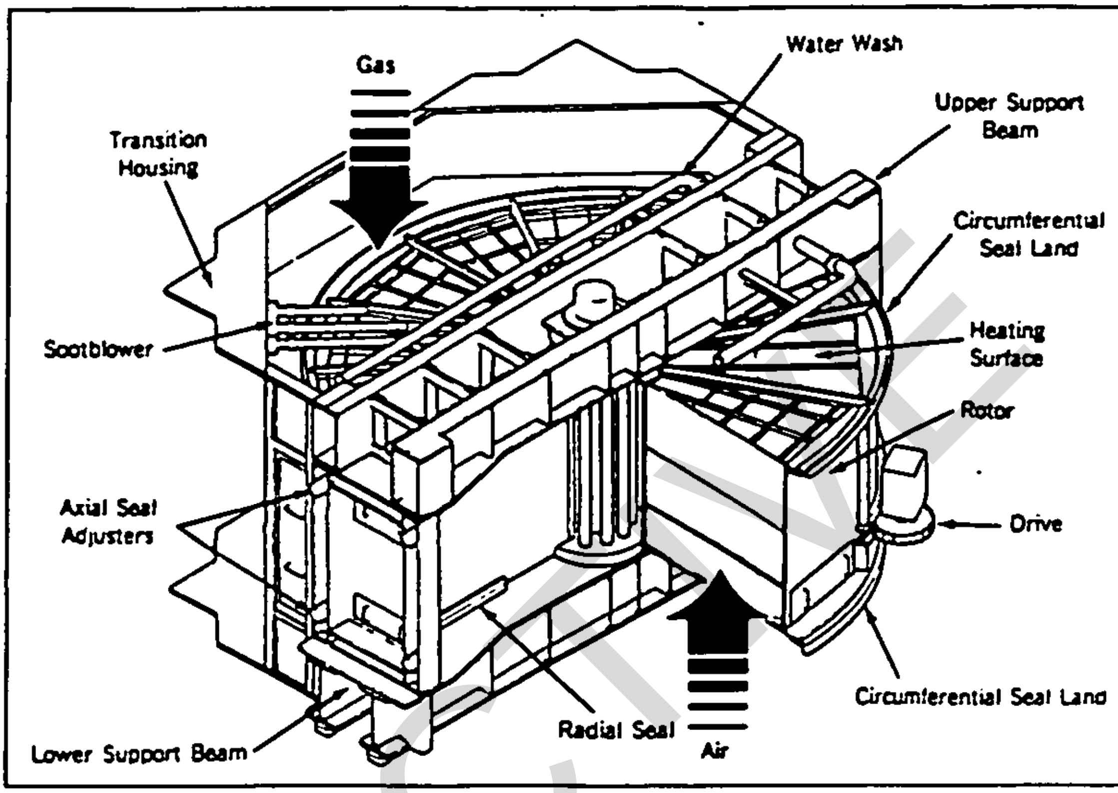


Figure 24
Regenerative Air Heater

3.2.2 Gage Glass, Gage Cocks. Each boiler must have at least one water gage glass. If the operating pressure is 400 psig or greater, two gage glasses are required on the same horizontal line. Each gage glass must have a valved drain, and the gage glass and pipe connections must not be less than 1/2-inch nominal pipe size (NPS). The lowest visible part of the gage glass must be at least 2 inches above the lowest permissible water level, which is defined as the lowest level at which there is no danger of overheating any part of the boiler during operation. For horizontal fire tube boilers, the gage glass is set to allow at least 3 inches of water over the highest point of the tubes, flues, or crown sheet at its lowest reading. Figure 25 illustrates a typical water gage. Each gage consists of a strong glass tube connected to the boiler or water column by two special fittings. These fittings sometimes have an automatic shutoff device that functions if the water glass falls. Requirements for the fabrication of these shutoff devices are also given in the ASME Code. When the boiler operating pressure exceeds 100 psig, the gage glass must be furnished with a connection to install a valved drain to some safe discharge point. Each boiler must have three or more gage or try cocks located within the visible length of the gage glass. Gage cocks are used to check the accuracy of the boiler water level as indicated by the gage glass. They are opened by handwheel, chainwheel, or lever, and are closed by hand, a weight, or a spring. The middle cock is usually at the normal water level of the boiler; the other two are spaced equally above and below it. Spacing depends on the size of the boiler.

3.2.3 Water Columns. A water column is a hollow cast iron, malleable iron, or steel vessel having two connections to the boiler. The top connection enters the steam space of the boiler through the top of the shell or head, and the water connection enters the shell or head at least 6 inches below the lowest permissible water level. Pipe used to connect the water column to the boiler may be brass, iron, or steel, depending on the pressure; it must be at least 1 inch in diameter. Valves or cocks are used in these connecting lines if their construction prevents stoppage by sediment deposits and if the position of the operating mechanism indicates whether they are open or closed. Outside screw-and-yoke gate valves are generally used for this service. Lever lifting gate valve or stop cocks with permanently attached levers arranged to indicate open or closed position may also be used. These valves or cocks must be locked open. Crosses are generally used in place of elbows or tees on piping between the water column and the boiler to facilitate cleaning the line. A valved drain or blowdown line is connected to the water column for removal of mud and sediment from the lines and column. Ends of blowdowns should be open and located for ease of inspection. The water column shown in Figure 25 is equipped with high and low water alarms which operate a whistle to warn the operator. The whistle is operated by either of the two floats.

3.2.4 Pressure Gage, Temperature Gage. Every boiler must be equipped with an easily readable pressure gage. The pressure gage must be installed so that it indicates pressure in the boiler at all times. Each steam boiler must have the pressure gage connected to the steam space or to the steam connection of the water column. A valve or cock must be placed in the gage connection adjacent to the gage. An additional valve or cock may be located near the boiler, provided that it is locked or sealed in the open position. No other shutoff valves may be located between the gage and the boiler. The pipe connection must be of ample size and arranged so that it may be cleared by blowing out. For a steam boiler, the gage or connection must contain a syphon or equivalent device which will develop and maintain a water seal to prevent steam from entering the gage tube. Pressure gage connections must be suitable for the maximum allowable working pressure and temperature. Connections to the boiler must not be less than 1/4-inch NPS. Where steel or wrought iron pipe or tubing is used, it must be at least 1/2-inch inside diameter. The dial of the pressure gage must be graduated to approximately double the pressure at which the safety valve is set, and it should never be less than 1-1/2 times this pressure. Every hot water boiler must also have a temperature gage located and connected for easy readability. The temperature gage must be installed so that it indicates the boiler water temperature at or near the outlet connection at all times.

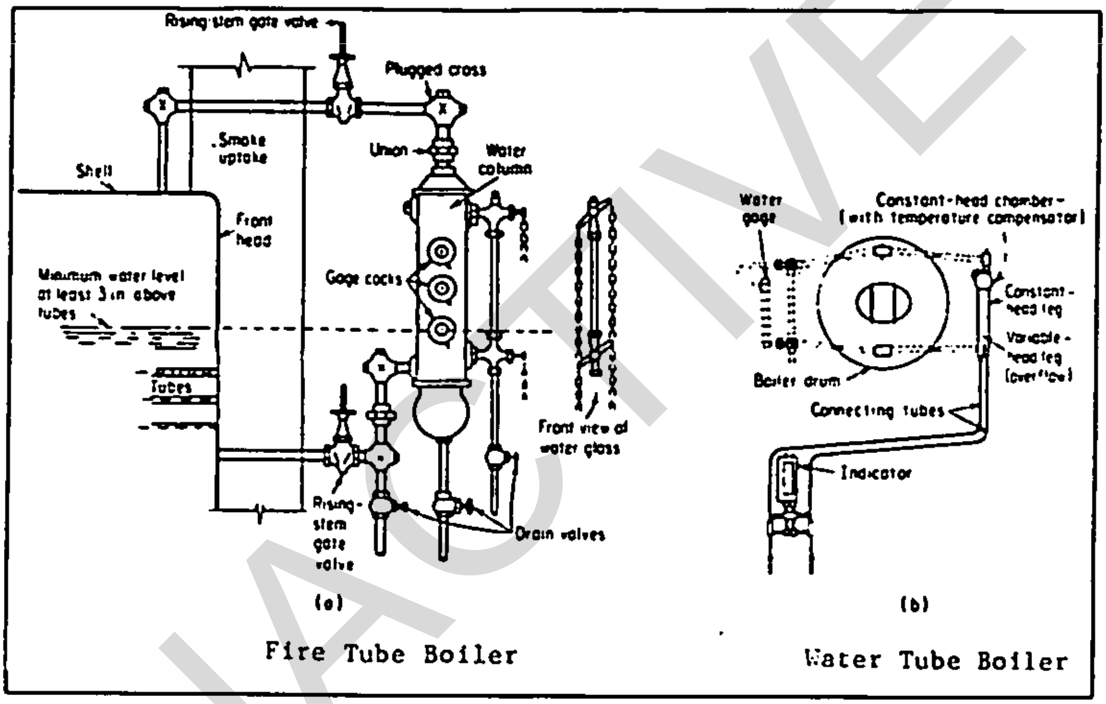


Figure 25
Water Gage Glass, Water Column

3.2.5 Safety Valves. Safety valves are installed to prevent excessive pressure build-up in the boiler, superheater, or economizer. Safety valves are designed to quickly pop to the full open position when the steam pressure rises to the set point, and to quickly close when the pressure drops a preset amount (blowdown or blowback). They must close tightly without chattering or leakage, and remain tightly closed after reseating. Their construction, installation, and performance are rigidly prescribed in the ASME Code. No valve or stop is permitted between the boiler and safety valve, and the discharge line must be supported separately to prevent any undue stress on the valve.

A recommended method of installation is shown in Figure 26. Any economizer which may be shut off from the boiler must have one or more safety valves. Every superheater must also have one or more safety valves located near the superheater outlet. A safety valve is defined as an "automatic pressure relief device actuated by a static pressure upstream of the valve and characterized by full opening pop action." A safety valve is used for gas or vapor service, including steam. Hot water boilers use a safety relief valve which is defined as an "automatic pressure actuated relief device suitable for use either as a safety valve or relief valve, depending on the application." Safety valves and safety relief valves are constructed so that the failure of any part cannot obstruct the free and full discharge of steam or water from the valve. Safety relief valves, like safety valves, must be manufactured and stamped in accordance with the ASME Code.

3.2.5.1 Types of Safety Valves. One common type of safety valve is the huddling chamber safety valve illustrated in Figure 27. This safety valve opens rapidly because of the additional area on which steam pressure is exerted as soon as the valve starts to lift from the seat, and because of the reaction of the steam on the seat. This second action resembles the action which causes a free air, water, or steam hose to whip around when the discharge velocity is high. The area between the valve seat and the adjusting ring is called the huddling chamber. As seen in Figure 27, the clearance between the inside of the adjusting ring and the feather is comparatively small. The boiler pressure is exerted on the area of the feather which is equal to the inside area of the seat bushing. As soon as the seat is slightly displaced, steam starts to flow through the valve because of the excessive boiler pressure. The steam cannot escape between the feather and the adjusting ring as fast as it is flowing through the seat. As a result, pressure builds up under the feather. This, in turn, increases the force available for pushing the valve off the seat. The flow of steam is turned by the feather, and this also exerts a force to open the valve. These two forces cause the valve to pop open. Because of the larger area subjected to the steam pressure and the reactive force of the flowing steam, the valve does not close until the pressure drops below the pressure that caused it to open. The difference between the set or popping pressure and the closing pressure is called the blowdown. Jet flow and nozzle reaction safety valves are other common types.

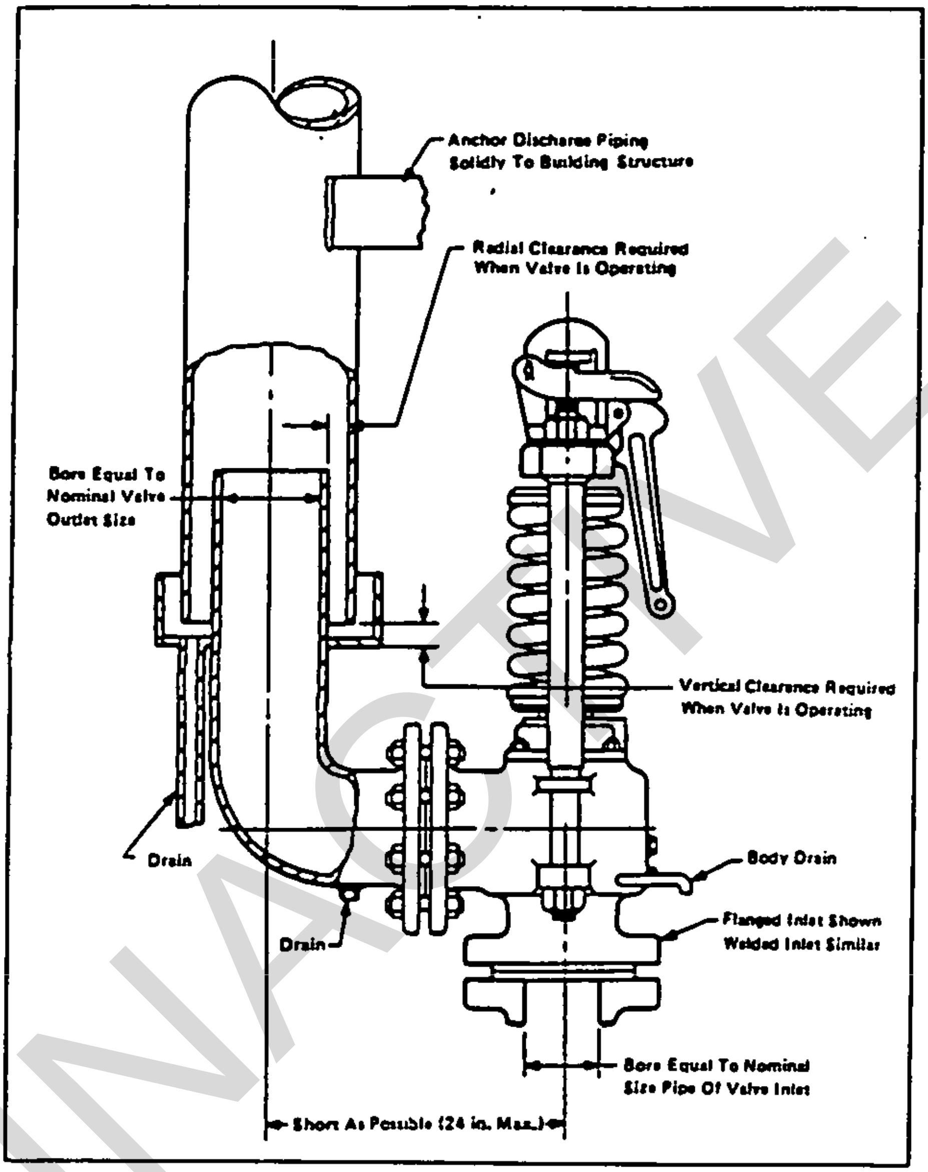


Figure 26
Safety Valve Installation

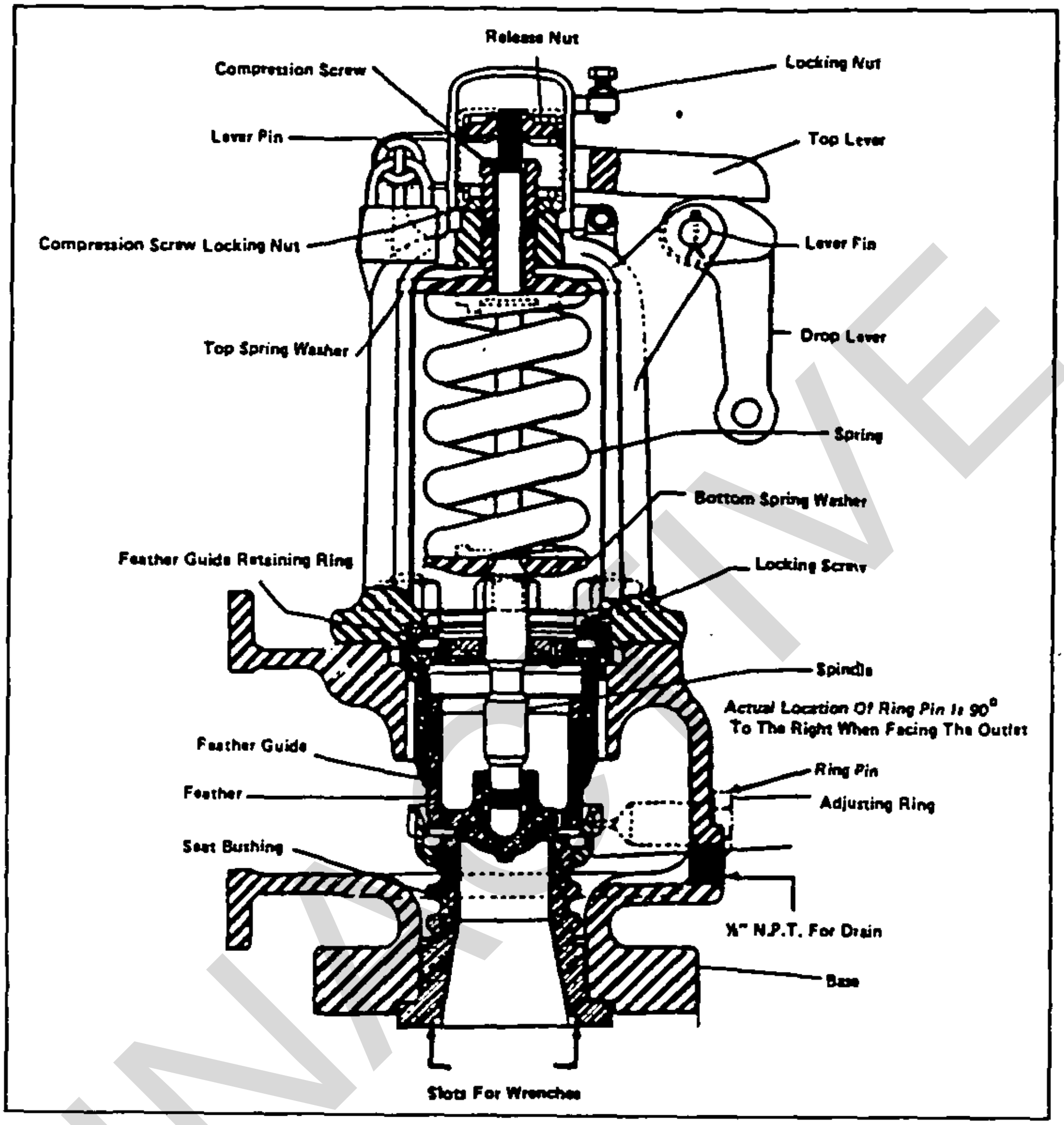
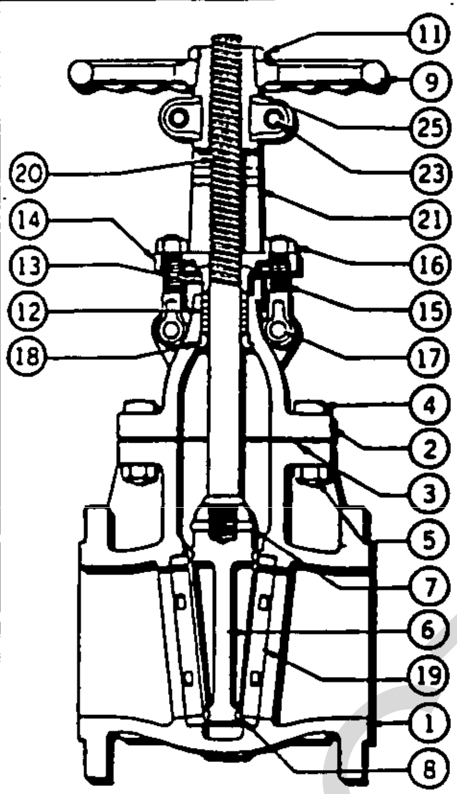


Figure 27
Huddling Chamber Safety Valve

3.2.5.2 <u>Safety Valve Capacity</u>. The safety valve capacity for each boiler must be such that the valve or valves will discharge the steam that can be generated by the boiler without allowing the pressure to rise more than 6 percent above the highest pressure at which any valve is set, and in no case to more than 6 percent above the maximum allowable working pressure. The safety valve capacity must be in compliance with the ASME Code and must not be less than the maximum designed steaming capacity as determined by the manufacturer. The required steam relief capacity (in lb/hr) of the safety relief valves on a high temperature water boiler is determined by dividing the maximum output in Btu/hr at the boiler nozzle by 1,000. Economizer safety valve capacity is calculated from the maximum heat absorption in Btu/hr divided by 1,000.

3.2.5.3 Safety Valve Settings. One or more safety valves on the boiler proper must be set at or below the maximum allowable working pressure. If additional valves are used, the highest pressure setting must not exceed the maximum allowable working pressure by more than 3 percent. The complete range of pressure settings of saturated steam safety valves on a boiler must not exceed 10 percent of the highest pressure to which any valve is set. The pressure setting of safety relief valves on high temperature water boilers may exceed this 10 percent range because safety relief valves in hot water service are more susceptible to damage and subsequent leakage than safety valves relieving steam. It is recommended that the maximum allowable working pressure of the boiler and the safety relief valve setting for HTW boilers be selected substantially higher than the desired operating pressure to minimize the frequency of safety relief valve lift.

3.2.6 Boiler Outlet Valves. Each steam discharge outlet from a boiler, except the safety valve and superheater connections, must have a stop valve. If the valve is over a 2-inch pipe size, it must be the outside screw and yoke rising-spindle type; the spindle position indicates whether the valve is open or closed (Figure 28). A plug-type cock may be used if the plug is held in place by a gland or guard, if it allows remote indication of opening or closing, and if it is used with a show-opening mechanism. When two or more boilers are connected to a common header, the steam connection from each boiler having a manhole opening must be fitted with two stop valves and a free blow drain between them. Stop valves should consist, preferably, of one nonreturn valve set next to the boiler area, and a second valve of the outside screw and yoke type. However, two outside screw and yoke type valves may be used. The nonreturn valve is a type of check valve which can be held closed (Figure 29). It can be opened only by pressure in the boiler, and it closes when the boiler pressure is lower than the header pressure, a condition which may be caused by a burst tube, loss of fire, etc. The valves require a very small difference in pressure for proper operation. A dashpot is provided to prevent chattering or rapid movement of the valve. Ladders and catwalks, chains, or other means for operating the valves from the operating floors in boiler rooms should be provided.



NO.	DESCRIPTION
1	BODY
2	BONNET
3	BONNET GASKET
4	BONNET BOLT
5	BONNET BOLT NUT
6	DISC
7	DISC PIN
8	DISC RING—TRIM 6
9	HANDWHEEL
11	HANDWHEEL NUT
12	PACKING
13	PKG. GLAND
14	PKG. GLAND FLG.
15	EYEBOLT
16	EYEBOLT NUT
17	EYEBOLT RIVET
18	REPKG. SEAT BUSHING
19	SEAT RING
20	STEM
21	YOKE
23	YOKE BOLT
25	YOKE BUSHING

Figure 28
Outside Screw and Yoke Gate Valve

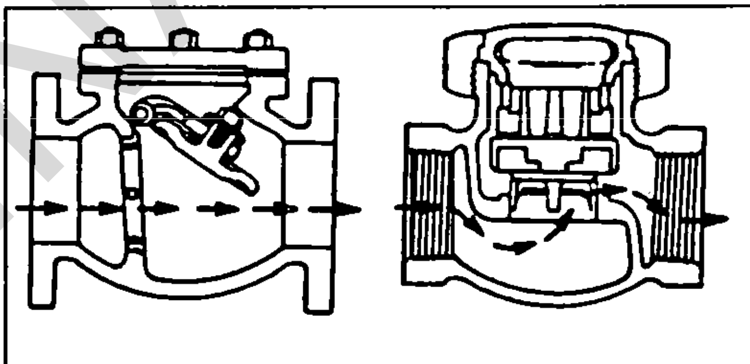


Figure 29
Nonreturn Check Valve

3.2.7 Blowoff Valves and Piping. Each boiler must have at least one blowoff connection installed at the lowest water space available to allow removal of sludge. The pipe used must not be less than 1 inch or over 2-1/2 inches. Extra-strong pipe must be used for pressures above 100 psig. The blowoff line must be protected from direct furnace heat by brickwork or other heat-resisting material which is constructed to allow for inspection of the pipe. This is necessary because sediment collects in the blowoff line and, since there is no circulation of the water, the pipe may easily become overheated and burn out. Care must be taken to ensure ample room for expansion and contraction at the junction of the pipe and the setting. One slow opening valve may be used in the blowoff line for pressures up to 100 psig. Two slow opening valves, or a slow opening valve and cock, are required for pressures above 100 psig. A typical blowdown valve set is shown in Figure 30. A slow opening valve requires at least five complete turns of the operating mechanism to change from the completely open to the completely closed positions and is used to avoid shock to the piping and possible injury to personnel. Valves that have dams or pockets where sediment can collect must not be used. Boiler blowdown is provided for the control of dissolved and suspended solids that concentrate in steam boilers.

3.2.8 Fusible Plugs. Fusible plugs are sometimes used on fire tube boilers to provide added protection against low water. They are constructed of bronze or brass with a tapered hole drilled lengthwise through the plug and filled with a low melting alloy consisting mostly of tin. There are two types of fusible plugs, fire actuated and steam actuated.

3.2.8.1 Fire-Actuated Plug. Fire-actuated plugs are filled with an alloy of tin, copper, and lead with a melting point of 445 to 450 degrees F. They are screwed into the shell or a special tube at the lowest possible water level. One side of the plug is in contact with the fire or hot gases, and the other side with water. As long as the plug is covered with water, the tin does not melt. If the water level drops below the plug, the tin melts and is blown out. The boiler must then be taken out of service to replace the plug. Fusible plugs of this type are renewed regularly once a year. The old castings should not be reused, but should be replaced with new plugs obtained from the boiler manufacturer.

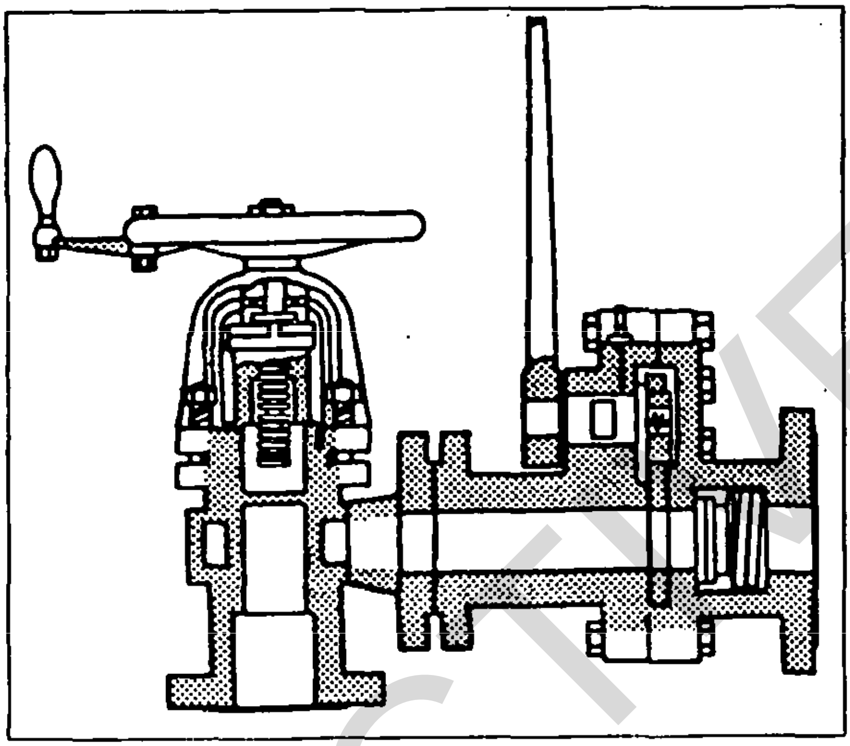


Figure 30
Blowdown Valve Set

3.2.8.2 Steam-Actuated Plug. The steam-actuated plug is installed on the end of a pipe outside the drum. The other end of the pipe, which is open, is at the lowest permissible water level. A valve is usually installed between that of the steam in the boiler. The pipe is small enough to prevent water from circulating inside it and cooling the plug. Water around the plug is much cooler than the water in the boiler as long as the end of the pipe is below the water level. However, if the water level drops below the open end of the pipe, cool water runs out of the pipe and steam condenses on the plug. Steam melts the plug and steam blows out, warning the operator. This type of plug can be replaced without taking the boiler out of service by closing the valve in the plug line.

3.2.9 Soot Blowers. Soot, fine ash, and cinders can collect on boiler tubes and cause a substantial decrease in the heat transfer rate. These substances are very poor conductors of heat; in addition, when excessive amounts are deposited on the tubes, passages become plugged and gas flow is restricted.

Brushes, scrapers, hand lances, and occasionally soot blowers are used to remove these deposits in fire tube boilers. Hand lances and mechanical soot blowers are used to clean water tube boilers.

3.2.9.1 Brushes, Scrapers, and Hand Lances. Brushes and scrapers are made in various sizes to fit the boiler tubes. They are fastened to a long handle, usually a piece of pipe, and pushed through the tubes. Automatic brushing systems with vacuum dust collecting attachments are effective and common. A hand lance is a piece of pipe supplied with compressed air or steam. Occasionally, a special head is attached to the hand lance. The hand lance may be needed to remove deposits of ash or slag even on boilers equipped with mechanical soot blowers.

3.2.9.2 Mechanical Soot Blowers. Permanently mounted mechanical soot blowers are used on water tube boilers. These blowers are mounted on the setting walls or boiler supporting structure at several points, to clean as much of the surface as is practical. Blowers consist of a head that admits steam or air and turns the element, the element itself that distributes the steam or air, and the necessary bearings, piping, and other supports.

The head consists of an operating mechanism, usually a chain or handwheel operating two gears, for turning the element within a limited arc; a poppet valve for admitting and controlling the flow of steam or air to the element; and a cam for opening and closing this valve (Figure 31). The poppet valve is adjusted at start-up to obtain proper steam or air regulation. The cam is cut or adjusted to establish the proper blowing arc and prevent steam or air from striking and cutting the baffles, drums, tubes, or headers.

Elements are tubes containing a number of nozzles. These nozzles are spaced along the element to blow between the boiler tubes for lance blowing, or at a number of tubes for mass blowing. When elements are installed for lance blowing, it is important that the nozzle spacing fit the boiler tube spacing and that the elements are located properly. Failure to observe these precautions may result in cut tubes because of the high velocity of discharge from the nozzles. Elements are made of plain, carburized, or alloy steel, depending on the temperature to which they are to be subjected; elements are supported at regular intervals by bearings clamped on the boiler tubes. The distance between these bearings is determined by flue gas temperature in that specific area.

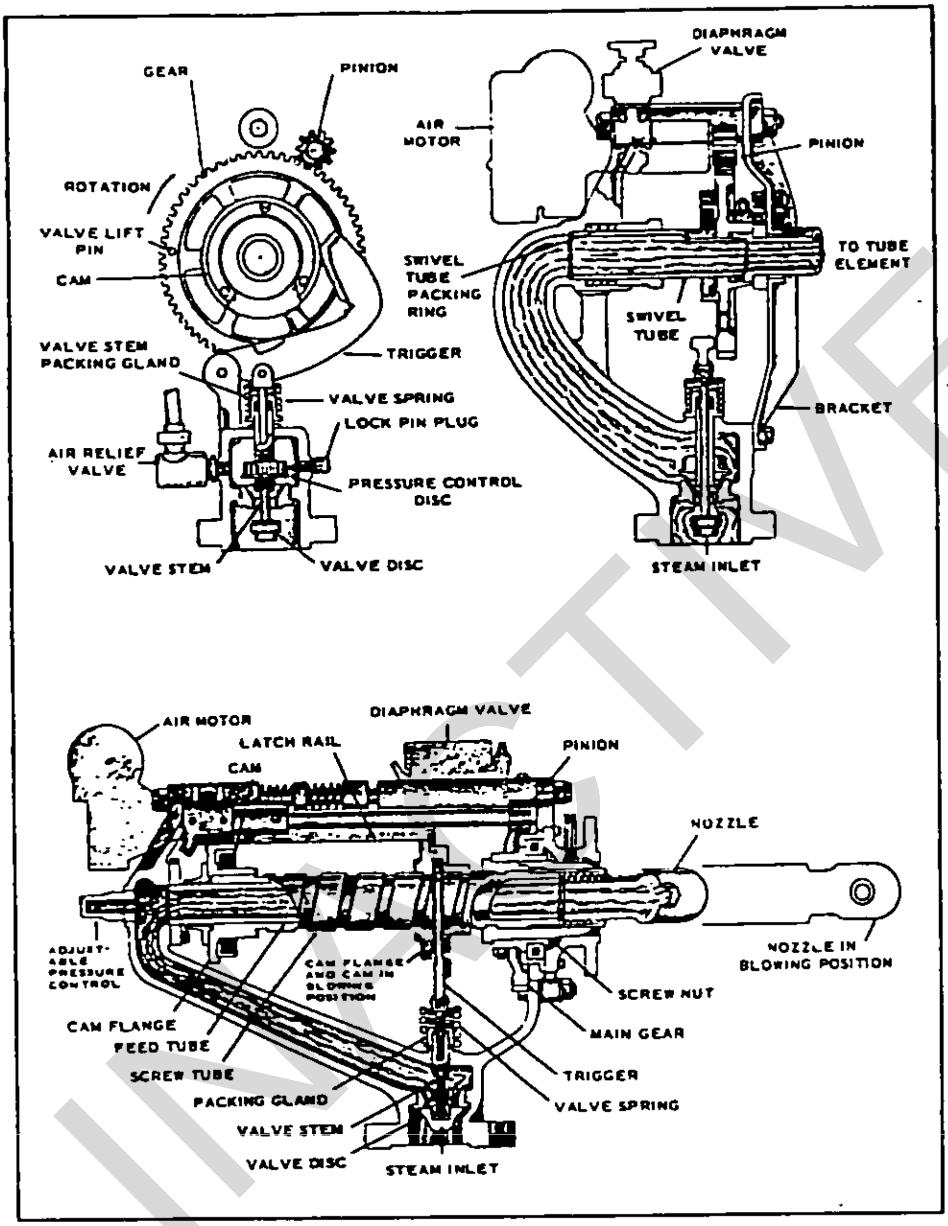


Figure 31
Mechanical Soot Blower

3.3 <u>Fuel-Handling and Combustion Equipment</u>

3.3.1 <u>Coal Combustion Equipment</u>. Coal may be fired by one of four methods:

a) Manually on stationary grates

b) Automatically by stoker

c) In suspension as pulverized coal

d) In a fluidized bed

Manual firing of coal using stationary grates is not used in modern central heating plants because of the limited capacity of hand-fired grates and the amount of labor necessary to operate the equipment. This handbook contains no further discussion of manual firing. The following paragraphs describe the combustion equipment required for the other methods of coal firing and typical coal specifications applicable to each method.

3.3.1.1 Stokers. Stokers were developed to automate and increase the capacity of the simple hand-fired grate. Automatic fuel feed and ash disposal systems were added to reduce the labor requirements, and capacity was increased by the addition of forced draft fans, control dampers, and air compartments to promote better fuel and air mixing. The result is that stokers have several advantages over hand firing: they permit the use of cheaper grades of fuel, maintain better furnace conditions, increase combustion efficiency, require less labor, and increase the boiler capacity. Stokers may be divided into four general classes: underfeed, spreader, traveling or chain grate, and vibrating grate. Spreader, traveling, chain, and vibrating stokers are overfeed stokers, in that fuel is fed from above the bed. Each type has its own application, depending primarily on the characteristics of the fuel used. The choice of the proper stoker also depends upon factors such as the size and capacity of the boiler, the ash content and clinkering characteristics of fuel, and the amount of draft available.

3.3.1.2 Underfeed Stokers. Underfeed stokers receive their name from the fact that fresh fuel is supplied below the burning zone. The fuel bed consists of three zones: fresh or green coal on the bottom, the coking zone in the middle, and the incandescent or burning zone on the top. Fresh fuel enters the bottom of one end of a retort, is distributed over the entire retort, and is forced to move gradually to the top where it burns. As the coal travels up from the bottom of the retort, its temperature gradually rises, causing the volatile matter to distill off, mix with the air supply, and pass up through the hotter zones of the fuel bed. The temperature of the mixture of volatile matter and air gradually increases until the mixture ignites and burns. The mixture may burn just below the surface of the fuel bed or immediately above it. The coke remaining after the volatile matter has distilled off continues to move to the top; its temperature gradually rises above its ignition temperature and burns. The vertical movement of the coal through the bed is accompanied by movement of the burning coke toward the ash discharge area. The combustion process is practically completed by the time the remaining material reaches this area. The remaining combustible matter or fuel completes its combustion in this area before the ash is removed. Air enters through openings in the stoker called tuyeres, which are usually located at the top or sides of the retort.

Underfeed stokers may be classified by the number of retorts (single, double, or multiple) and the method of feeding (screw or ram). Single retort stokers may be screw or ram feed. Figure 32 illustrates a single retort, screw feed ram distributor stoker. Multiple retort stokers usually combine a gravity or overfeed action with the underfeed, and are always ram feed. They are used only on large boilers. Coal sizing requirements are established by the stoker manufacturer, with a top size of 1-1/2 to 2 inches and not more than 50 percent slack being typical. The principal elements of an underfeed stoker are hoppers, feeders, retorts, and a combustion air fan. Each is discussed in the following paragraphs.

a) Hoppers. Hoppers with a capacity of several hundred to several thousand pounds of coal are provided to supply fuel to the feeder. Some hoppers are equipped with agitators but most depend on the slope of hopper sides to prevent coal from bridging. Offset hoppers are occasionally used to permit access to the boiler front.

b) Feeders. Feed screws or reciprocating rams may be used to deliver coal from the hopper to the stoker retort as shown in Figure 32. Even distribution of coal is obtained by the shape of the screw, shape of the retort, and the stroke of distributing rams. The coal feed rate is controlled by a drive mechanism which adjusts the speed of the screw or ram. An electric motor or steam turbine is used to drive the stoker via a mechanical or hydraulic speed reducer. Ram feed stokers may utilize oil, air, or steam driven cylinders to move the ram, and are generally set up to allow multiple feed rates. Shear pins or relief valves are provided to protect the equipment against overload or binding. Belt guards and gear and shaft covers are provided for operator protection.

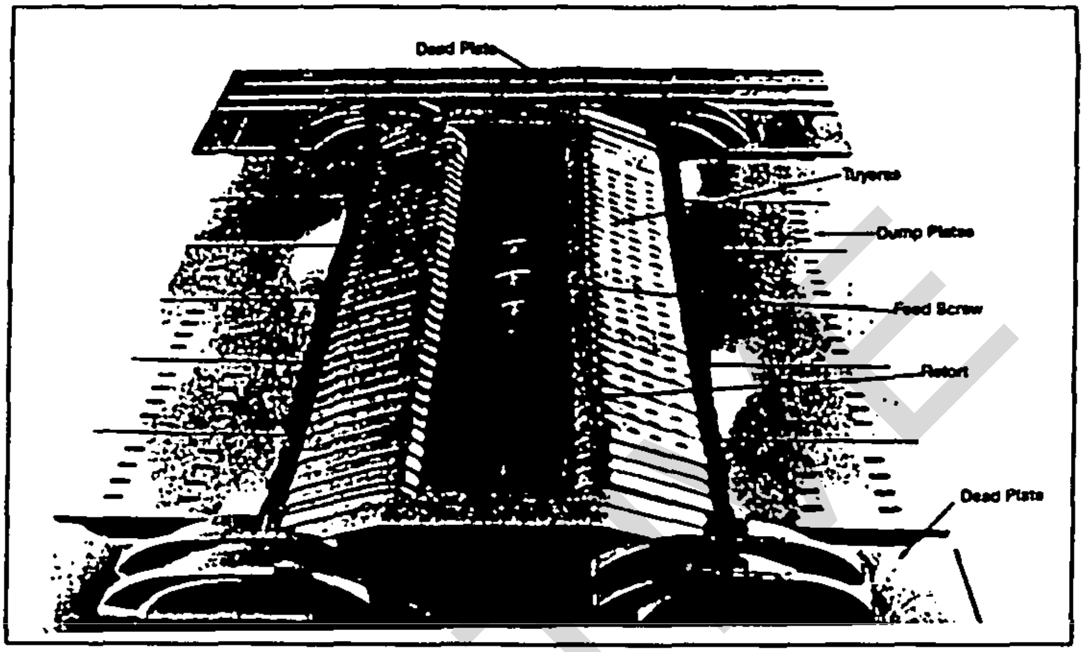


Figure 32
Screw-Fed Single-Retort Stoker

c) Retorts. Size and shape of the retort depends on the coal-burning capacity of the stoker. Retorts in the smaller units are nearly square, while those in larger units are oblong. The tuyeres or tuyere blocks through which air is admitted to the fuel bed are made in comparatively small sections to allow for expansion and to minimize thermal stress. The tuyere blocks form the top of the retort and are surrounded by either dead plates or dump plates. Dump plates are ordinarily made to permit air to pass through them. Tuyere blocks may be high and slope away from the retort, or recessed below the dead plate. They may be of either stationary or movable design.

d) Combustion Air Fan. Centrifugal or axial fans are used to supply air to a windbox under the retort and to overfire air ports. The windbox may be divided into zones to permit better control of combustion air. Volume of the air supplied is controlled by inlet or outlet control dampers on the fan. Airflow should be controlled automatically to correspond to changes in the firing rate. Methods of control are discussed in par. 3.4.2.

e) Fuel Characteristics. In practical applications, fuels ranging from lignite to anthracite have been burned successfully on single retort underfeed stokers. However, this type of stoker is most widely used for Eastern caking and mildly caking bituminous coals and many of the Midwestern free burning coals, especially those having an ash fusion temperature sufficiently high for successful utilization in the relatively thick fuel beds that characterize underfeed burning. For satisfactory stoker operation, coal sizing is as important as coal analysis. The size of coal best suited for single retort stokers is that designated commercially as 1-inch to 1-1/2-inch nut and slack, preferably containing not more than 50 percent slack. Slack is defined as coal of a size that will pass through a 1/4-inch round hole screen. For multiple retort underfeed stokers, the ideal coal should vary in size from 2 inches to slack, with not more than 50 percent slack. The volatile content should preferably be between 20 and 30 percent, the ash content should range between 6 and 8 percent, and the ash softening temperature should be above 2400 degrees F in a reducing atmosphere. Iron content of the ash should not be more than 20 percent as Fe_2O_3 for this range of softening temperatures and not more than 15 percent if the softening temperature is between 2200 and 2400 degrees F.

3.3.1.3 <u>Spreader Stokers</u>. Spreader stokers combine some of the best features of hand and pulverized coal-firing methods. This method of coal feed permits smaller particles to burn in suspension in the furnace, approximating the action of pulverized coal firing. The remainder of the coal is deposited on top of the burning coal, as in hand firing. Other similarities to pulverized coal firing are the presence of fly ash in flue gases, the wide range of fuel which can be handled, and responsiveness to rapid load fluctuation. Spreader stokers are not affected by the caking or noncaking properties of coal to the same extent as other types of stokers, and they can handle coal ranging in size from dust to about 1-1/4 inches. The furnace volume to permit fines to be burned in suspension is usually about 50 percent larger than that required for an underfeed stoker. The depth of the grate is limited by the ability of the stoker to spread coal evenly, and its width is limited by the width of the boiler; however, several stoker units can be placed side by side to provide the necessary capacity. Spreader stokers with combined traveling grates have been applied to boilers with capacities up to 400,000 pounds of steam per hour. Although the ability to burn inexpensive coal screenings is one of the chief advantages of spreader stokers, fly ash emissions increase greatly as the percentage of fines is increased. Thus, under most conditions, spreader stokers require some type of dust collectors. Spreader stokers operate with comparatively thin fuel beds, are sensitive to load changes, and are well adapted to regulation by automatic combustion control equipment. The thin fuel bed is a decided advantage in following fluctuating loads. Figure 33 illustrates a power dumping type spreader stoker. The principal elements of a spreader stoker are described below.

a) Feed Mechanism. The feed mechanism consists of the feeder and the spreader. The spreader is constructed with either an underthrow or overthrow rotor. An overthrow rotor receives the coal directly and throws it into the furnace. An underthrow rotor picks coal out of a circular tray and throws it into the furnace. Figure 34 illustrates a chain type feeder with an overthrow rotor. Paddles (rotor blades) are usually set in either two or four rows around the rotor, with those in one row twisted at an angle to throw the coal to the right, and those in the next row arranged to throw it to the left. In some designs, the paddle is curved to provide uniform crosswise distribution. An oscillating plate or ratchet-driven roll feeder is used to supply coal to the rotor. The rate at which coal is fed is regulated by varying the length of the stroke of the oscillating plate or the speed at which the roll is turned. Speed or position adjustments are also provided to regulate distribution of fuel along the length of the grate. The feeder mechanism, grates, and air supply are usually constructed to operate as a unit. Feeders are usually driven from a single line shaft, with each having its own drive gearing. When dumping grates are used, sections of the fire can be cleaned alternately by shutting off fuel to one feeder and allowing fuel to burn out in that section of grate before dumping. Variable speed-driven mechanisms are similar to those found on underfeed stokers. Variable speed motors often replace mechanical gearing to drive the individual feeder and distribution shaft on newer designs.

b) Overfire Air Fan. A separately driven centrifugal fan is provided to supply overfire air necessary to maintain proper fuel and air mixing and complete combustion. A portion of the overfire air may also be used to cool the feed mechanism and aid in distribution of coal.

c) Cinder Reinjection System. Since the spreader stoker burns a significant percentage of coal in suspension, carry-over of unburned coal is common. To improve boiler efficiency by reducing this unburned carbon loss, fly ash and coal can be collected in a mechanical collector at the boiler outlet and put back into the boiler furnace. This is done by use of a cinder reinjection fan and aspirator which picks up fly ash and coal and pneumatically conveys it back to the furnace via special piping and reinjection ports.

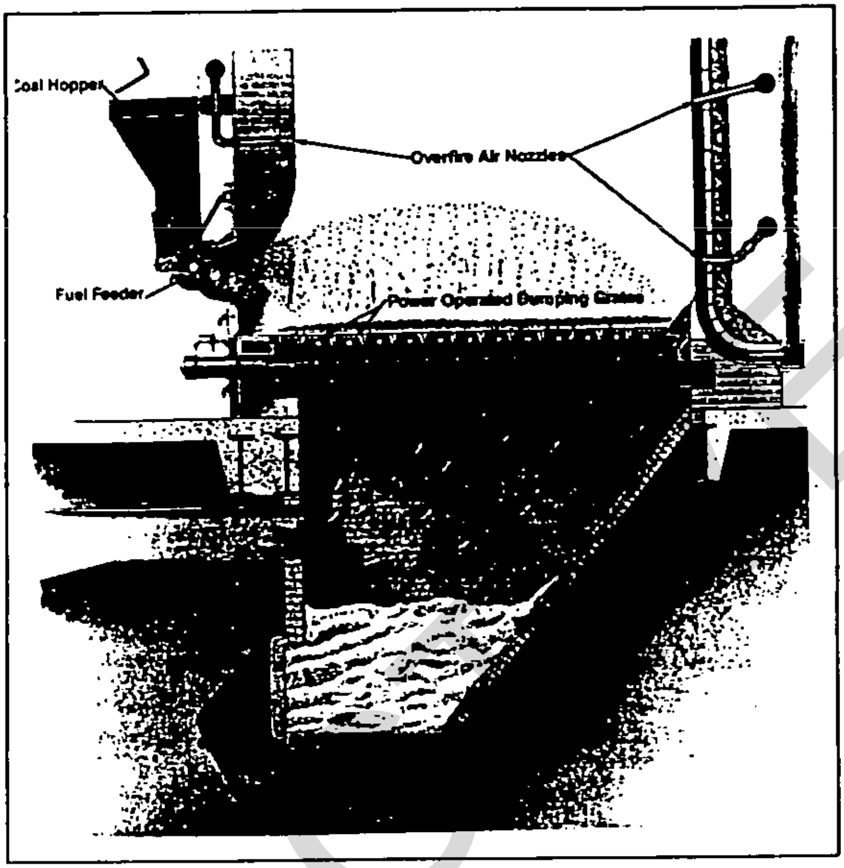


Figure 33
Power Dump Grate Spreader Stoker

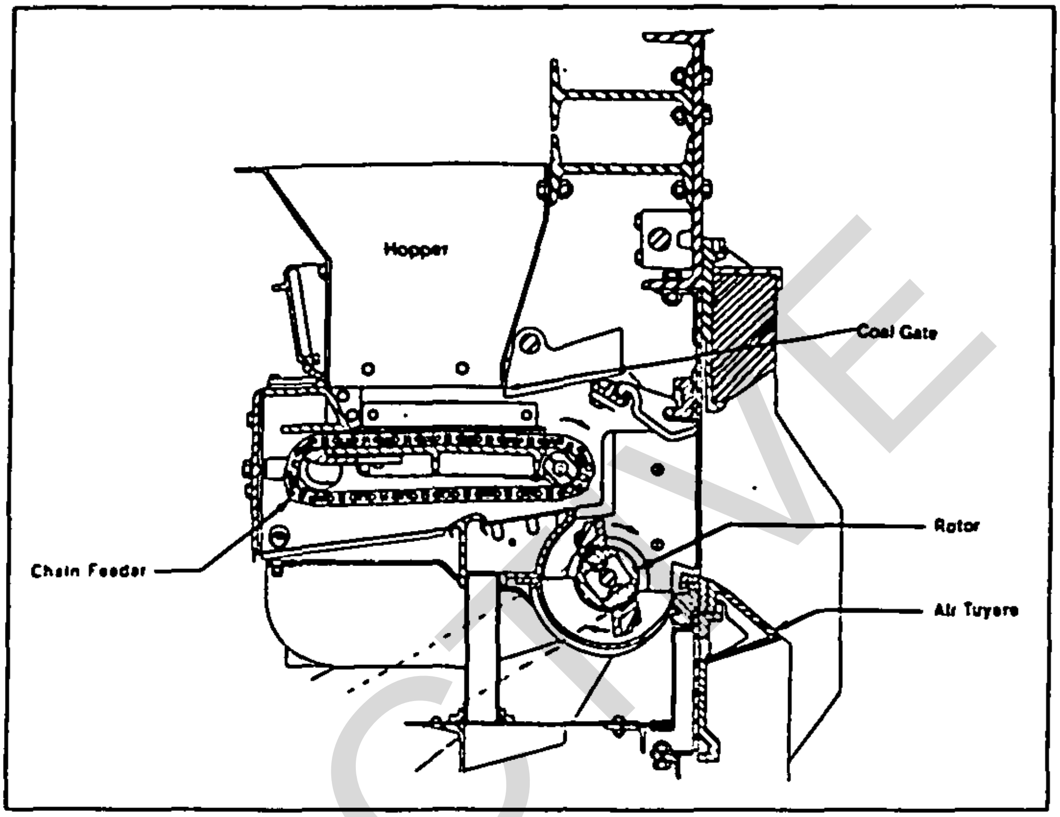


Figure 34
Chain-Type Overfeed Spreader

d) Grates. Stationary, dumping, vibrating, and traveling grates may be used with a spreader stoker installation. Traveling grates are most commonly used on modern installations. Provision is made under the grates for proper air distribution and ash collection. Figure 35 illustrates a spreader stoker with traveling grate installation.

e) Combustion Air Fan. As with all stokers, combustion air under pressure is needed to ensure complete and efficient combustion and control. Inlet or outlet dampers are provided to control the airflow rate.

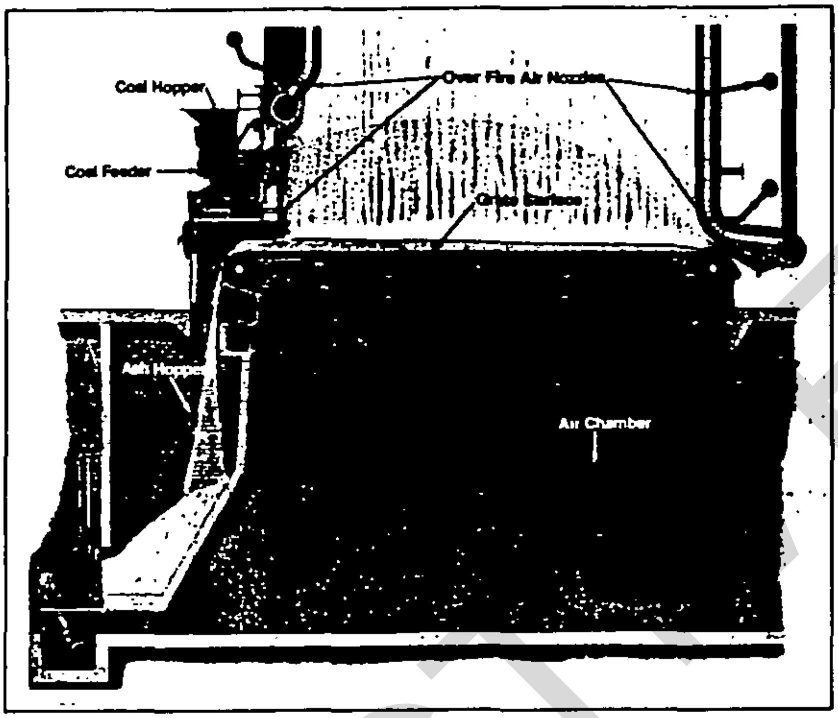


Figure 35
Traveling Chain Grate Stoker

f) Fuel Characteristics. Spreader stokers were developed to burn lower grades of coal, but they are capable of handling all ranks from semi-anthracite to lignite, plus numerous waste and by-product fuels. As might be expected, spreader stoker performance is best when quality and sizing are good. The thin, quick-burning fuel bed requires a relatively small size fuel. The spreader stoker will burn fuel ranging from slack or carbon, all through 1/8- or 1/4-inch screen, to 1-1/4-inch or 1-1/2-inch nut and slack. Considerable range in size content is necessary for satisfactory distribution, and if there is a good balance between coarse and fine particles the burning rate and ash bed thickness are practically uniform over the entire grate surface.

3.3.1.4 Traveling Grate and Chain Grate Stokers. These types of stokers consist of an endless belt grate which moves slowly and conveys the burning coal from the feed end to the ash discharge end of the stoker. With chain grate stokers, links are assembled so that as they pass over the rear idler drum, a scissor-like action occurs between links. This action helps to break loose clinkers which may adhere to the grate surface.

Traveling grate stokers do not have this scissor action and therefore are not normally used with clinkering coals. Figure 35 illustrates a traveling chain grate stoker. Traveling or chain grates may be used with the spreader feeders discussed above, or coal may be placed directly on the stoker, as described below.

a) Feed Mechanism. A hopper on the front of the stoker has an adjustable gate that regulates the depth of the fuel bed. The rate of feeding coal to the furnace is regulated by changing the speed at which the grate travels. The amount of ash carry-over from the furnace is kept to a minimum with this feeding method, and fly ash injection, typical of spreader stokers, is not required. Figure 35 illustrates the overfeed of coal onto a chain grate.

b) Combustion Air. Space between the grates is divided into zones and flow of air to each of these zones is controlled by dampers. This is necessary if uniform combustion is to be attained, because resistance of the fuel bed to flow of air decreases as grates move to the rear. It would be practically impossible to get proper air distribution if these zones were not provided. Overfire air is also provided to complete combustion of volatile matter driven off from the fuel bed.

c) Fuel Characteristics. Fuels most widely used on traveling grate stokers are anthracite, semi-anthracite, noncaking or free-burning bituminous coal, subbituminous coal, lignite, and coke breeze. Some bituminous coals of the caking type may be burned on traveling grate stokers if coal is of an optimum size, has been allowed to weather, and is tempered to approximately 15 percent moisture. Coal sizing for traveling grate stokers may be related to the ASTM classification of coal by rank (ASTM D388).

3.3.1.5 Vibrating Stokers. In this type of stoker, grates are inclined at an angle of about 14 degrees. Coal is fed from a hopper at the front of the furnace. The fuel bed is progressed by intermittent grate vibrations. Ash is discharged over the end of the grate (Figure 36). Furnace water tubes are positioned under stoker grates to cool grate bars; and air compartments are provided to control combustion air. Overfire air is generally provided at two elevations. The firing rate is controlled by adjustment of a hopper feed gate, frequency of grate vibration, combustion air dampers, and overfire air dampers.

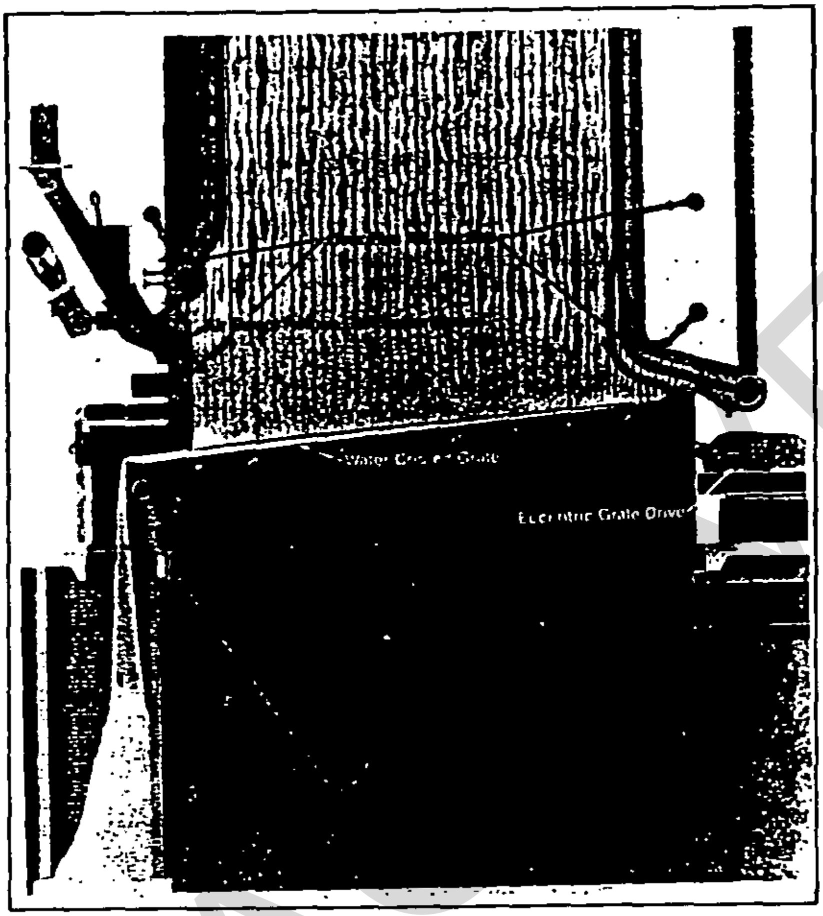


Figure 36
Water Cooled Vibrating Grate Stoker

a) Fuel Characteristics. The water cooled vibrating grate stoker is suitable for burning a wide range of bituminous and lignite coals. Even with coals having a high free swelling index, gentle agitation and compaction of the fuel bed tends to keep the bed porous without the formation of large clinkers generally associated with low ash fusion temperature coals. A well-distributed, uniform fuel bed can be maintained without blow holes or thin spots.

3.3.1.6 <u>Pulverizers</u>

a) General. The function of a pulverized coal system is to pulverize coal, deliver it to the fuel-burning equipment, and burn it in the boiler with a minimum of excess air. Burning pulverized coal becomes cost effective in large capacity systems (over 100,000 lb/hr steam flow) and can offer several advantages over stoker coal, such as:

(1) Ability to achieve much higher capacities.

(2) Ability to use coal sizes from fires up to 2 inches.

(3) Improved response to load changes.

(4) Increased thermal efficiency because of lower excess air requirements and lower carbon loss.

(5) Less manpower requirements.

c) Types of Pulverizers

(1) Ball Mill. The ball mill consists of a horizontal rotating cylinder filled with a charge of steel balls of various sizes to a level just below the halfway mark. The interior of the cylinder is fitted with cast iron liners and is rotated at speeds of 20 to 30 rpm. Balls are carried part way around the circumference of the cylinder and fall toward the center. Coal intermingling with balls is pulverized. Hot air passing through the cylinder dries the coal and removes the fines.

(2) Bowl Mill. Material fed to the pulverizer falls to the center of the revolving bowl where it is thrown by centrifugal force between the grinding ring in the revolving bowl, and the rolls. Pressure for grinding is imparted to the rolls by springs. A typical bowl mill is shown in Figure 37. Air enters the mill housing below the bowl and passes upward past the bowl, where it picks up the partially pulverized coal that has been discharged over the edge of the grinding ring. The air and pulverized coal mixture is carried into an adjustable classifier where a spinning action is imparted to the mixture. The degree of spin determines the sizing of the finished product. The oversize is returned to the bowl from regrinding.

(3) Ball-Race Pulverizers. In ball-race pulverizers (Figure 38), balls used as the grinding element are confined between two races. The balls are driven by rotating the upper or lower race, or the intermediate race in the case of multi-ring units. Pressure for crushing is supplied by springs forcing the race together. Coal circulation is affected by means of preheated air under pressure supplied by a blower. Fines and coarse particles are carried to a classifier. Coarse particles are returned for regrinding while fines are carried onto burners. Fineness of coal at the outlet of the classifier is regulated by adjustable vanes.

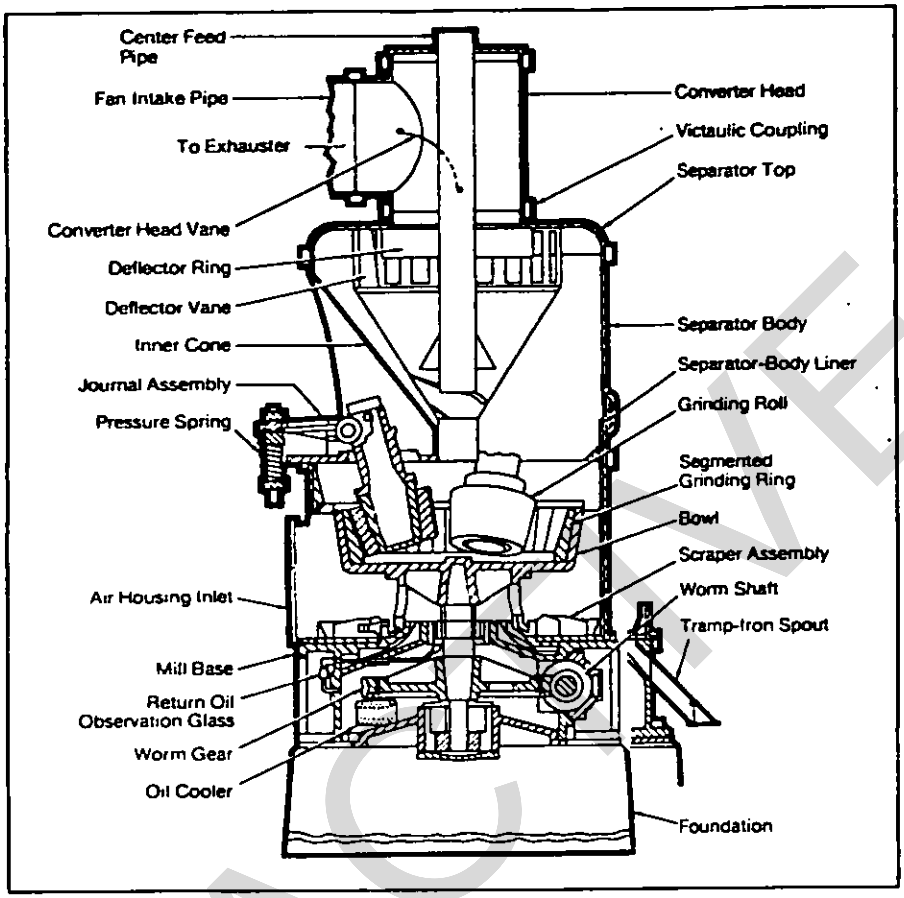


Figure 37
Bowl Mill

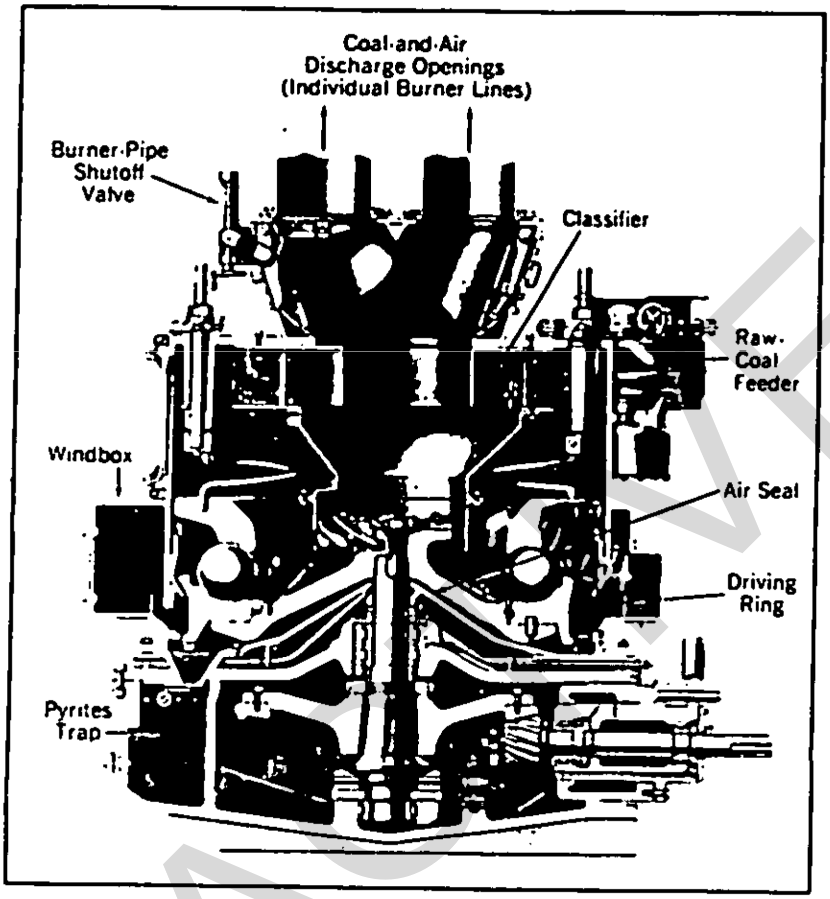


Figure 38
Ball Race

(4) Attrition Pulverizers. Figure 39 illustrates a pulverizer that combines impact and attrition forces. Coal and primary air enter the unit through a feed chute. A series of hammers makes up the primary pulverizing stage which breaks down and lumps to a granular size. Partly ground coal passes around the outside of the rotor into the final pulverizing stage, which consists of stationary and rotating pegs. Coal in the turbulent airstream rubs against the pegs and other coal particles to be reduced by attrition.

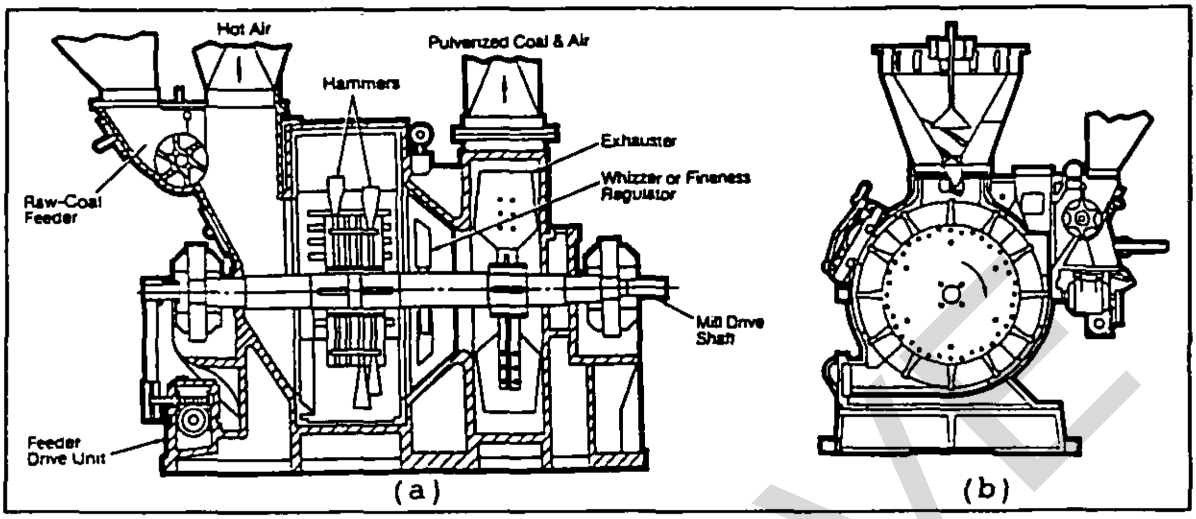


Figure 39
Attrition

3.3.1.7 Fluidized Bed. Fluidized bed combustion is a relatively new method of burning coal while complying with sulfur dioxide emission regulations. In fluidized bed combustion, coal is introduced into a bed of limestone or sand particles which is kept in a fluidized state by a flow of high pressure air from forced draft (FD) fans. Combustion takes place in the bed. The sulfur in the fuel combines chemically with limestone in the bed, forming calcium sulphate and calcium sulphite which can be removed with the ash handling system, eliminating the need for scrubbers to clean flue gases. The main advantage of the fluidized bed boiler is its ability to control sulfur dioxide emissions. However, it also has the ability to burn a wide variety of fuels as discussed below. The disadvantages of fluidized bed boilers are added electrical operating costs associated with larger combustion air fans necessary for fluidizing the bed, higher particulate and unburned carbon carryover from the furnace, and high initial cost. Figure 40 illustrates a fluidized bed fire tube boiler. Fluidized bed water tube boilers are also available. Note that a baghouse or precipitator is required for particulate control.

a) Fuel Characteristics. Fluidized bed boilers may be used to burn almost any fuel, including not only bituminous and anthracite coals but also lignite, refuse, wood, and various solid waste fuels.

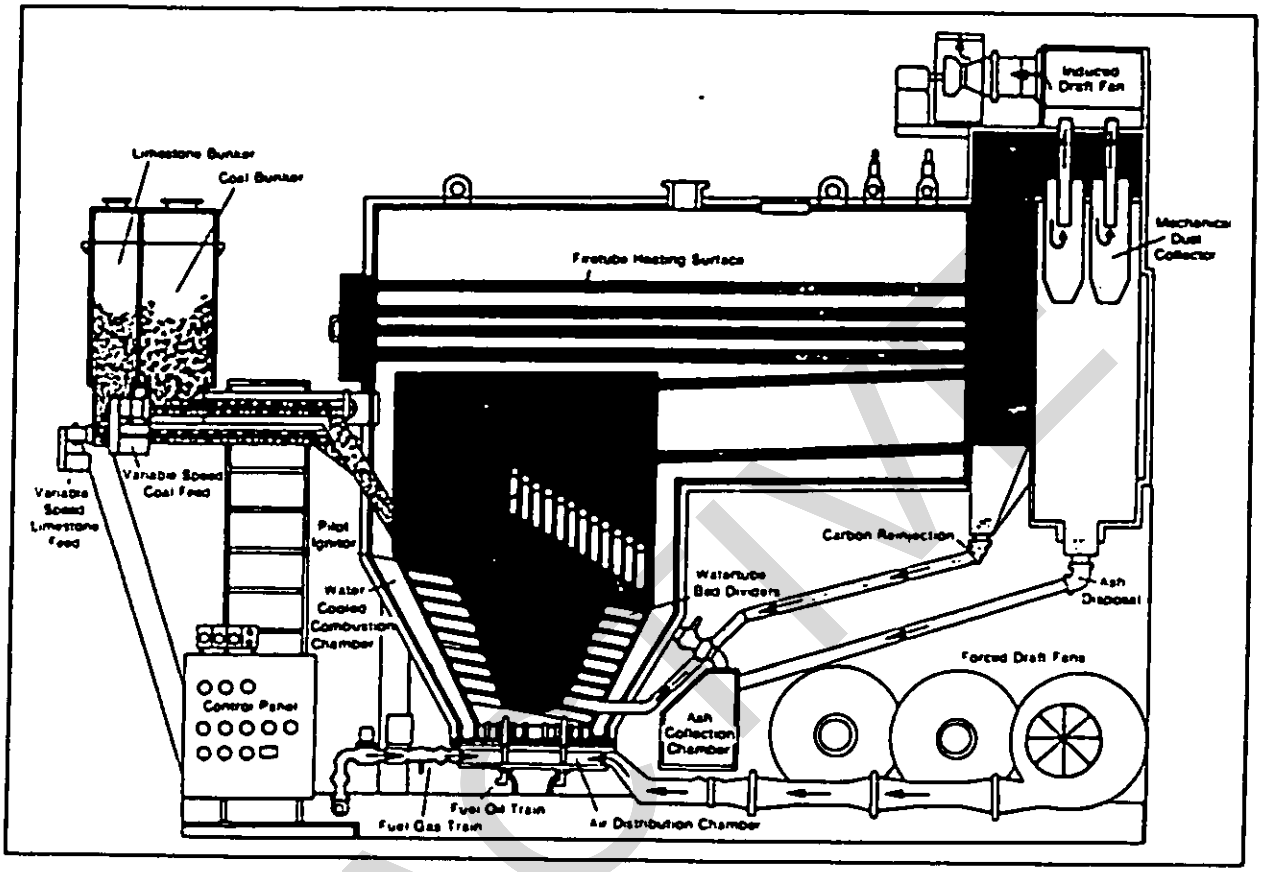


Figure 40
Fluidized Bed Fire Tube Boiler

3.3.2 Coal-Handling Equipment. A great many types of coal-handling equipment with capacities ranging from a few tons to several hundred tons per hour are available. The kind of equipment selected is determined by such factors as size of plant, total amount of fuel to be burned, method of receiving the coal (rail, truck, or water), regularity of delivery, kinds of coal available, and relative locations of the plant and storage areas. It is usually advantageous to keep a certain amount of coal in storage, in case deliveries are delayed for any reason. The amount of coal stored depends on the rate at which it is burned, space available for storage, and frequency of delivery. The quantity stored should normally be sufficient to operate for 90 days or longer at peak demand.

3.3.2.1 Storage. Coal may be stored in covered bins or bunkers, in silos, or in the open. Only relatively small amounts of coal can be stored in bunkers and silos. The amount that can be stored on the ground is limited only by the space and coal handling equipment available. If coal is to be stored on the ground, the selected area should be prepared to reduce loss of fuel due to mixing with foreign material. The site may be leveled and firmly packed, stabilizing materials may be used, or a concrete or asphalt surface may be laid. Silo storage is divided between live and dead storage. The dead storage in silos should be shifted at least once per month. Where obvious heating occurs, shifting of dead storage should be as often as required to minimize spontaneous heating and to avoid fires.

3.3.2.2 Coal Handling in Plant. Figure 41 illustrates a typical coal handling system. It includes the following major components: tractor truck hopper, feeder, bucket elevator or conveyor, bunker or silo, and a coal weighing device.

a) Hoppers. Hoppers receive coal from trucks or coal cars and deliver it to a feeder or conveyor system. Hoppers usually have grates made of steel rods or bars to prevent passage of oversized material that could plug or damage the conveying equipment.

b) Feeders. Many types of feeders are available to convey and regulate the flow of coal from the hopper to the bucket elevator or other parts of the system. Apron feeders and flight feeders are continuous chain feeders that are often used. Final selection is dependent on the particular site characteristics.

c) Bucket Elevators. A bucket elevator consists of an endless chain, twin chains, or belt to which buckets are attached. It is used to lift coal vertically. The three most common types of bucket elevator discharges are centrifugal, perfect, and continuous (Figure 42). Elevator boots are provided with cleanout doors for removing dropped coal. Some bucket elevators can also convey coal horizontally. Belt conveyors and drag-type flight conveyors are other effective devices for delivering coal to bunkers.

d) Bunkers and Silos. Bunkers and silos provide covered storage of coal. Bunkers are made of steel and are often lined with a protective coating to minimize corrosion and abrasion. Hopper bottom and discharge gates are provided to remove coal from the bunker. Silos are constructed of either steel or concrete and are often provided with live storage sections and reserve storage sections.

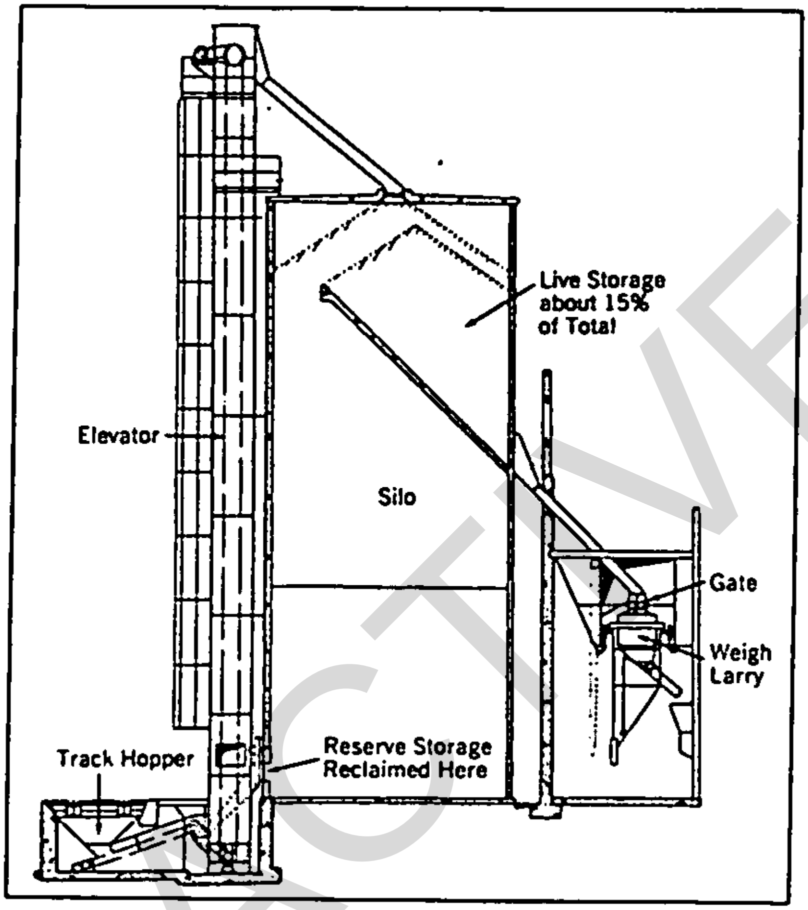


Figure 41
Coal Handling System

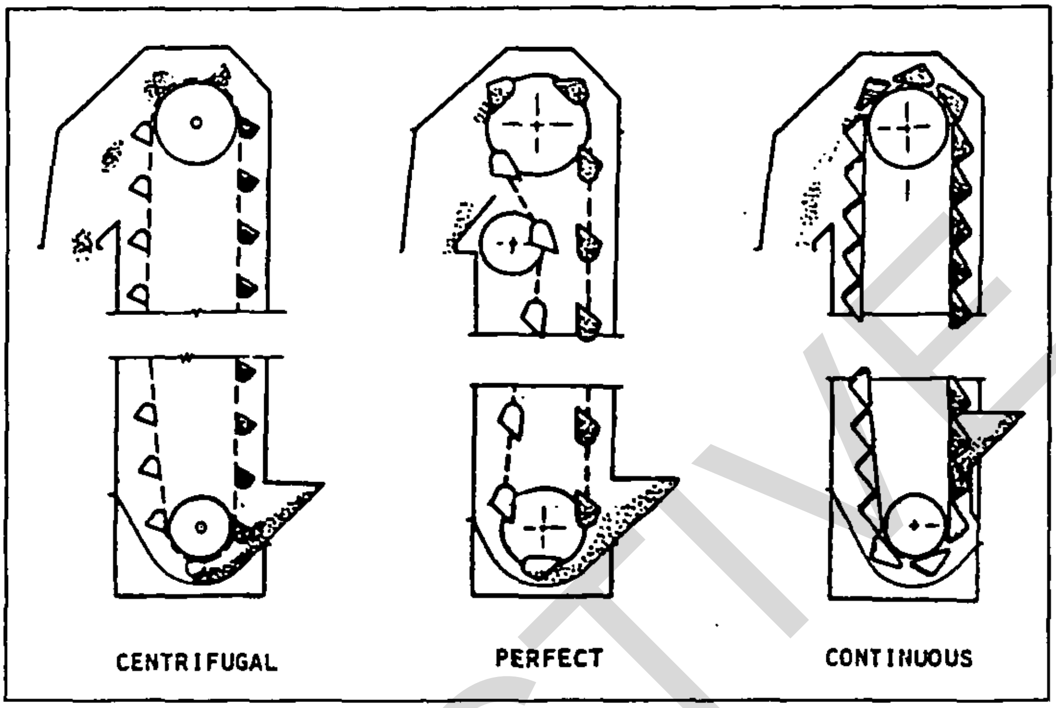


Figure 42
Types of Bucket Elevators

e) Coal Weighing. Knowledge of quality and quantity of coal used is essential for efficient operation of a boiler plant. No standard method of weighing coal can be prescribed, since many types of equipment are available for doing the job manually or automatically. Coal may be weighed directly with weighing equipment, or indirectly with equipment that measures its volume. Weighing equipment ordinarily consists of automatic or semiautomatic weigh larries. As shown in Figure 43, a weigh larry consists of a framework that supports a hopper mounted on scale beams. The framework can be moved over various bunkers. The coal hopper of the larry is filled and the weight determined and recorded. The larry is then moved to desired stoker hopper and dumped. Coal scales that weigh coal automatically are also available. One type of scale consists of three major assemblies: a belt feeder, weigh hopper with bottom dump gate, and weigh lever with controls. A mechanical register is provided to record amount of coal delivered. A belt feeder transfers coal into the weigh hopper until the weigh lever is balanced. The weigh hopper is then dumped and the cycle is repeated.

3.3.3 Ash Handling Equipment. Ash typically requires removal from several collection points in the boiler. Ash that is removed directly from the furnace or stoker is termed "bottom ash" and may be in hard, agglomerated clinkers. Ash that is removed from various dust collection points is termed "fly ash" and tends to be light, fluffy, and relatively free flowing. Ash is generally handled together and disposed of in a permitted landfill, especially on small systems. Depending on individual circumstances, it may be desirable to segregate the bottom and fly ash and handle them separately. This could be advantageous, for instance, if a commercial market existed for one of the products (fly ash may be used in the manufacture of concrete; bottom ash may be used as a winter road treatment, etc.). Medium and large plants generally employ complete ash disposal systems, while small plants may use simpler and less automatic equipment. The three general types of ash handling systems are pneumatic, hydraulic, and mechanical. Combinations of these three systems are often used.

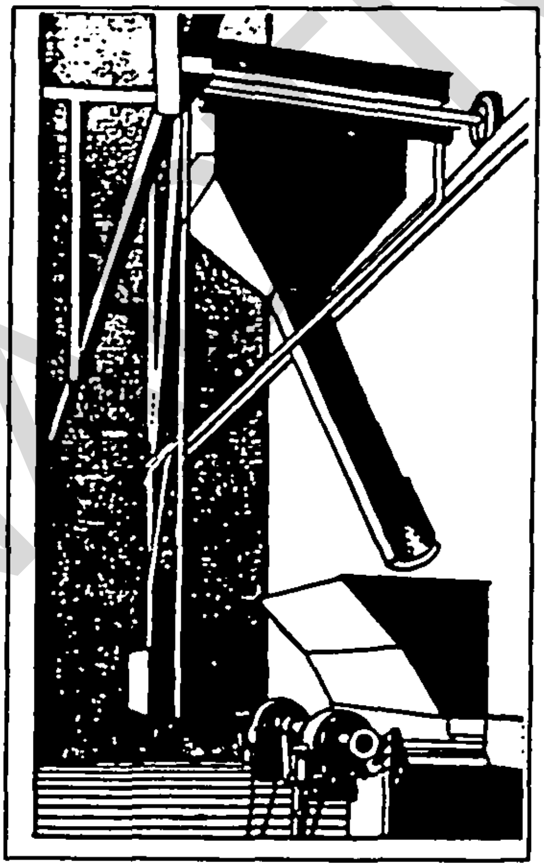


Figure 43
Weigh Larry

3.3.3.1 <u>Pneumatic Ash Handling</u>. Figure 44 illustrates a vacuum-type pneumatic ash handling system. In this illustration, the vacuum is created by a steam exhauster; however, motor-driven vacuum pumps are also available. Intake hoppers provided at desired locations admit ash to the system. One end of the ash conveying line is open, and suction created by the exhauster causes a rapid flow of air through the line. Dry ash is admitted to primary and secondary ash receivers, which are equipped with counterbalanced drop doors. A timer limits the period of operation to short cycles to permit dumping ashes into the silo. As the system goes into operation, negative pressure in the receivers closes and seals the drop doors. At the end of each cycle, the doors swing open when pressure is equalized, and drop ashes into the silo below. The air washer condenses incoming steam from the exhauster, washing out ash and dust particles exhausted to the atmosphere. The mixture of water and dust passes to a sump, where dust settles and water is drawn off to waste.

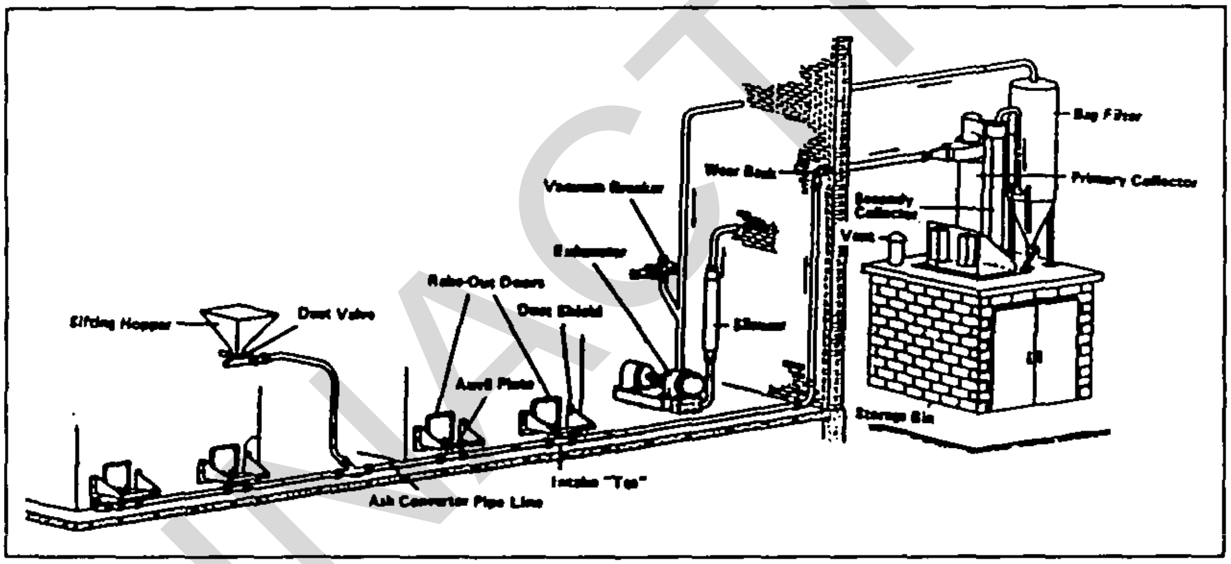


Figure 44
Pneumatic Ash Handling System

It is necessary to clean the sump periodically to prevent clogging the sewer. An exhaust silencer is available for this system where desired. An unloader is usually provided and consists of an inclined revolving drum containing water sprays that wet the ashes as they are discharged from the bottom of the silo. Vacuum systems are limited in the distance they can move ash effectively, and pressurized pneumatic systems or combination vacuum/pressure systems are available if the conveying distances become too great. Pneumatic systems are most commonly used for conveying fly ash but are also occasionally used for bottom ash on small systems.

3.3.3.2 Hydraulic Ash Handling. Figure 45 illustrates a hydraulic ash handling system. This is a pressure velocity system in which force is provided by a series of high pressure water jets. When the system operates, ash is taken from the ash jet hopper beneath the boiler. Sprays and water jet nozzles flush material out of the hopper and through a grid which retains any large clinkers for breaking. Some systems are equipped with clinker grinders. The ash is then jetted through an abrasion resistant sluice gate to a sump pit or landfill. Fly ash and dust are aspirated pneumatically from dust hoppers by water jet exhausters and passed through an air separator where air is collected and vented to the atmosphere. Finally, the mixture of fly ash, dust, and water is discharged through the sluice gate to the sump pit or landfill. Hydraulic systems are normally used for bottom ash conveying. They are used infrequently on new installations due to environmental and water usage regulations.

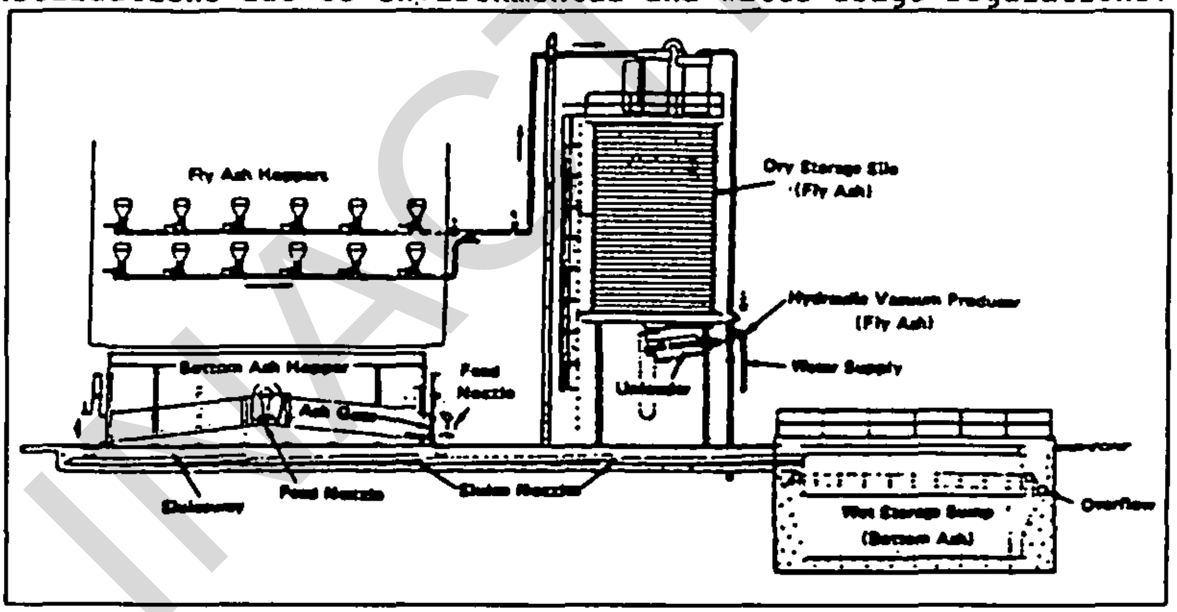


Figure 45
Hydraulic Ash Handling System

3.3.3.3 Mechanical Ash Handling. Drag, screw, and bucket conveyors can be used to move ash from boiler ash pits to storage bins, silos, or containers. Mechanical systems are used primarily with small stoker fire boilers, and may be utilized for either bottom ash or fly ash.

3.3.4 Oil-Firing Equipment. Oil has a number of advantages over coal when used to generate steam or hot water: cost of fuel handling is lower, less labor is required for operation and maintenance, less storage space is required, initial cost of the oil system is lower, and higher efficiencies are possible. In addition, oil does not normally deteriorate in storage; it is a clean burning fuel and is easy to control. A disadvantage of oil is the greater danger of explosions (which leads to more elaborate flame safety controls), and its cost (which is two or three times higher than coal on a heating value basis). Refer to pars. 2.4.1.1 and 2.4.5 for a more detailed discussion of fuel oil and the combustion process, and to Table 3, which presents physical properties of common grades of fuel oil. The operator should be familiar with the fundamental principles of combustion to make the best use of this concentrated and valuable fuel.

3.3.4.1 Types of Oil Atomizers. Burners in central heating plants utilize three types of atomizers: atomizers using steam or air, pressure atomizers, and rotary cup atomizers. The purpose of atomization is to break fuel into fine particles that readily mix with combustion air. Fuel then burns with a clean hot flame, being vaporized and oxidized by the resulting combustion before cracking takes place. In pressure atomizing burners, the fineness of spray increases as pressure increases and as viscosity is lowered. When No. 6 oil is burned, a pulsating flame may result if viscosity is reduced to a point where the preheat temperature tends to vaporize fuel. The burner manufacturer should recommend a proper viscosity operating range. Proper preheating of oil will be discussed in par. 4.3.6.

a) Fluid Atomizers. Fluid atomizers use either steam or air to break fuel oil into a fine mist. Steam atomizers operate by mixing oil and steam inside the atomizer tip under pressure. As the steam and oil mixture leaves the tip, steam rapidly expands, breaking oil into small droplets to begin the combustion process. Figure 46 illustrates a steam atomizer. Steam is supplied to the atomizer at a pressure of between 10 and 20 psi above oil pressure. Under normal conditions, a steam atomizer uses approximately 1/10 pound of steam to atomize 1 pound of oil. This amounts to about 2/3 of 1 percent of the boiler steam output. Some modern atomizers use as little as 0.03 pounds of steam while older designs may use more steam. Compressed air may also be used in place of steam to atomize oil. An air atomizer uses energy developed by the air compressor to replace energy in steam generated in the boiler. Air atomizers are commonly used when steam is not available, on smaller boilers generating less than 20,000 pounds of steam per hour, and for firing more easily atomized oils, such as No. 2 and No. 4 grades. Air atomizers are often used for cold start-up of a boiler, then replaced by steam units as the plant pressure builds up. Both steam and air atomizers are effective when used with a good burner to control combustion air mixing. Automatic control of the firing rate is possible over a range of 15 to 100 percent of capacity.

b) Pressure Atomizers. Pressure atomizers use pressures of 600 psig or more to accelerate oil into the furnace through the atomizer tip. Oil is spun inside the tip and leaves as a cone of oil that thins out and breaks apart into fine droplets for combustion. The advantage of pressure atomizers is the simplicity of the system. The disadvantages are high pressure required and the fact that the turn down range is limited to 75 to 100 percent of capacity if effective atomization is to be maintained. This type of atomizer is also sensitive to oil viscosity, and small passages in the atomizer tips tend to clog and wear. Pressure atomizers are not frequently used on modern central heating plants.

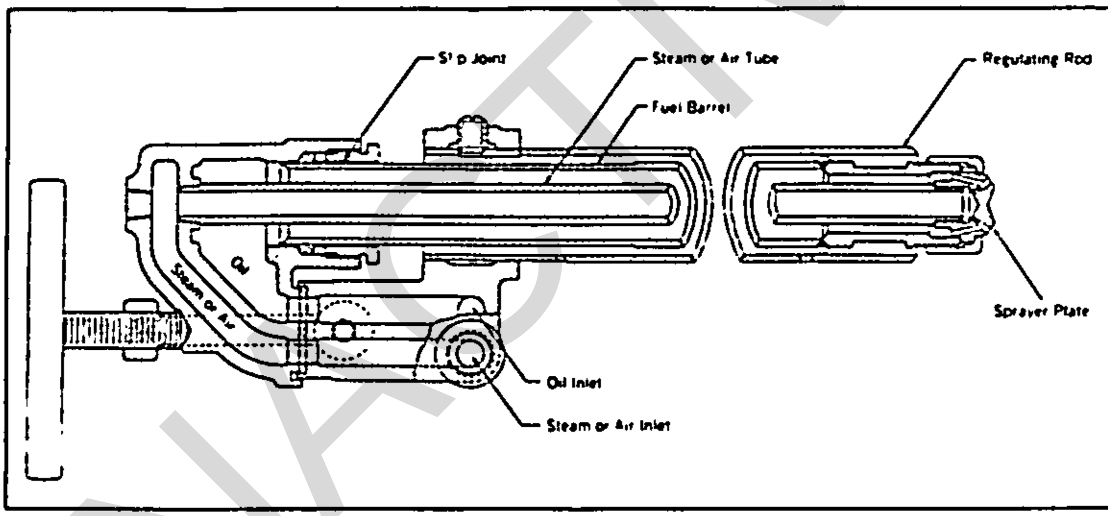


Figure 46
Steam Atomizer

c) Rotary Atomizer. The rotary atomizer uses energy from a spinning cup and primary air from a small fan. A thin cone of oil is spun off the end of the cup and, aided by the primary air, thins out, and breaks apart into fine droplets. Rotary atomizers can be fairly effective when combined with burners using forced draft fans. Natural draft rotary atomizer burners, as developed in the 1930's, do not compare favorably with modern forced draft burners and, in general, rotary atomizers do not have any significant advantages over fluid and pressure types. They have disadvantages of limited capacity and electric horsepower requirements for driving the rotary cup and the primary air fan. They generally become uneconomical for boiler capacities above 20,000 pounds of steam per hour, and are seldom used in modern burners.

3.3.4.2 Types of Burners. Once oil is effectively atomized, the next step is to effectively mix it with combustion air. Three general types of burners are available: register, low excess air, and package burners. These burners incorporate an igniter for automatic light-off and a provision to mount flame scanners to prove igniter and/or main flame. Effectiveness of a burner is measured by its ability to complete combustion of fuel with a minimum of excess air throughout the firing range. Excess air levels at 100, 75, 50, and 25 percent load should be determined when evaluating burner effectiveness. Refer to par. 4.4.1 and Table 19 for more information.

a) Register Burners. Register burners are characterized by one or more circular registers that admit combustion air into the burner throat as shown in Figure 47. An impeller is provided to protect the atomizer from the direct blast of combustion air and to provide a zone to stabilize ignition. The refractory throat helps to control airflow and velocity, and the hot refractory helps to stabilize ignition by radiating heat back into the base of the flame. Adjustment of air registers, either initially or continually with load swings, helps to ensure that optimum air velocities are available for the combustion process. Register burners may be used with ambient or preheated air, oil atomizers, and/or gas burning equipment. Capacities from 10 to 200 million Btu/hr are common.

b) Low Excess Air (LEA) Burners. LEA burners were developed to achieve lower excess air levels, throughout the burner load range, than are possible with register burners. A venturi section ensures uniform airflow at the burner outlet. An impeller is used to swirl a portion of air into atomized oil. The remainder of air moves axially through the burner at a velocity designed to cause it to mix later with fuel and impeller swirled air. The advantage of the LEA burner is its ability to operate at LEA levels, with subsequent improvements in efficiency. The main disadvantage is a long, narrow flame which is not well suited for many furnace configurations. Very accurate combustion controls are needed to take advantage of this burner's LEA capability.

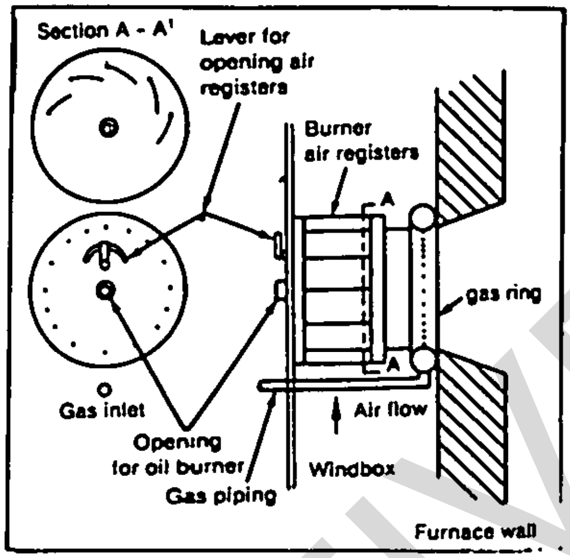


Figure 47
Register Burner

c) Low-NO_x Burners. To meet environmental regulations, manufacturers have developed burners that are capable of reducing NO_x emissions without adversely affecting efficiency or performance. These low-NO_x burners control mixing of fuel and air in a pattern that keeps the flame temperature down and dissipates heat quickly. Whereas conventional burners mix secondary air with the primary fuel air stream as soon as they are injected into the furnace, creating a high intensity combustion process, low-NO_x burners establish distinctly separate primary and secondary combustion zones, thereby staging the flame at the burner.

Basically, the same techniques for NO_x reduction apply to the burner as were used in the furnace. Thus, almost all burner modifications rely on some form of LEA staged combustion and/or internal flue gas recirculation to reduce NO_x emissions. Overfire air in combination with low-NO_x burners offers even further reduction.

d) Package Burners. Package burners include the forced draft fan and its air control damper, oil and/or gas control valves, actuators, igniters, flame safety system, and combustion controls as a shop assembled unit. Cost and performance capability of package burners vary widely. Not all packages are suitable for every application. Every burner application requires careful consideration to ensure that the proper burner, controls, and accessories are applied. Package burners should be capable of automatic start-up, shutdown, and modulating firing rate. Package burners are available for firing rates of several gallons to several hundred gallons per hour. Either register or LEA burners may be supplied as packages; and rotary, pressure, or fluid atomizers may be used.

3.3.5 Oil Storage and Handling. Aboveground and underground fuel storage tanks are available as illustrated in Figures 48 and 49. These tanks are provided with some or all of the following auxiliary equipment and connections: fill, vent, return, sludge pump-out, low suction, high suction, steam smothering, firefighting connections, gage connection, suction box, suction or tank heater, steam connection, level indicator, temperature indicator, access manholes, ladders, piping, valves, and double wall containment for underground fuel storage tanks not shown in Figure 49. The amount of storage capacity installed depends on the mission of the base, availability of dependable supply, and frequency of delivery. Storage tanks and oil-burning equipment must be installed in accordance with the National Fire Protection Association (NFPA) 30, Flammable and Combustible Liquids Code, and NFPA 31, Standard for the Installation of Oil-Burning Equipment.

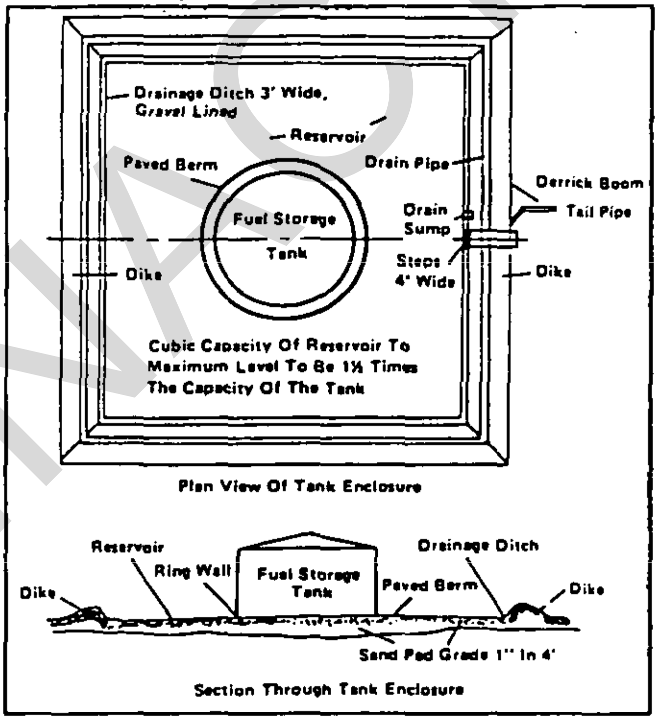


Figure 48
Arrangement of Aboveground Fuel Oil Tank

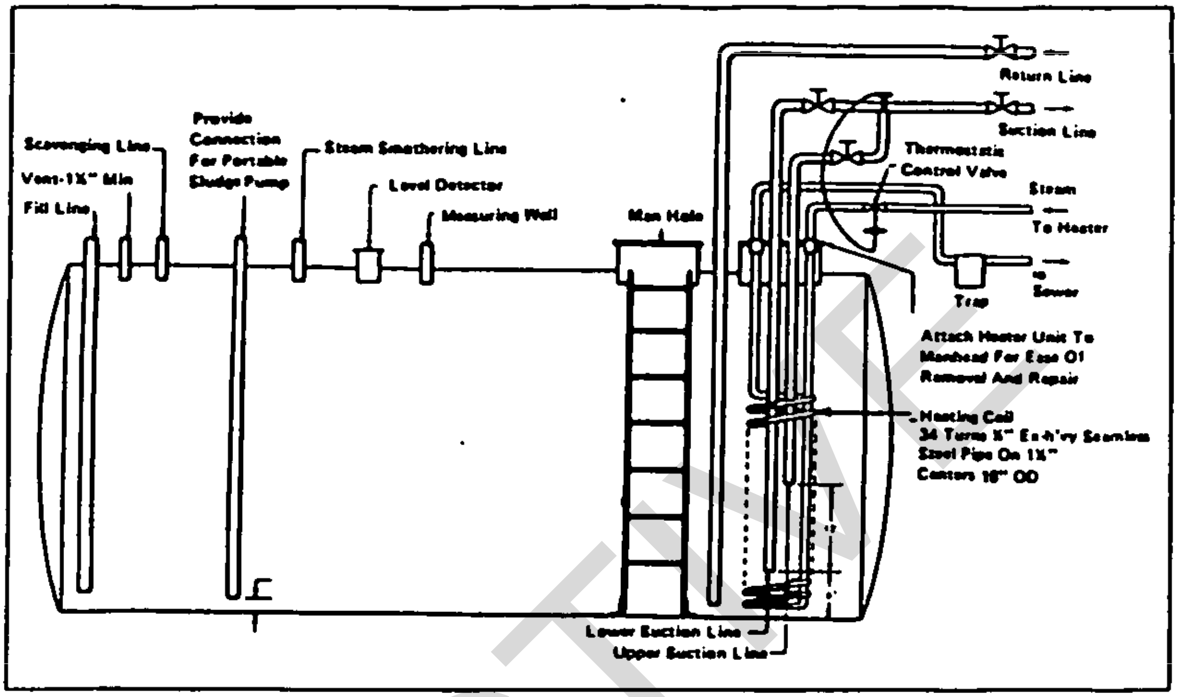


Figure 49
Underground Fuel Oil Storage Tank

3.3.5.1 Fuel Oil Preparation. No. 2 and No. 4 oil normally only require a pump set to transfer oil from storage to the burner. Paraffin base No. 4 oil may also require a small amount of heating. Use of day tanks and transfer pumps may be necessary if main storage tanks are located remotely from the plant. No. 5 and No. 6 oil require pumping and heating equipment to prepare and move oil to the combustion equipment. Figure 50 illustrates a duplex pumping and heating set. A pressure regulatory valve is provided to return unneeded oil to the storage or day tank before it is heated. This avoids overheating of storage tanks in addition to maintaining the desired oil pressure. Insulation of oil, steam, and condensate lines is required, and electric or steam heat tracing of lines may be required in some applications.

3.3.5.2 Safety Equipment. The NFPA establishes requirements for safe boiler operation for boilers with 10,000 pounds of steam per hour and larger. These requirements are contained in NFPA 8501, Standard for Single Burner Boiler Operation. Figures 51 and 52 show schematic arrangements of safety equipment for oil-fired water tube and fire tube boilers, respectively. Standards for oil-fired multiple burner boilers are found in NFPA 8502, Standard for the Prevention of Furnace Explosions/Implosions in Multiple Burner Boiler-Furnaces. For boilers rated less than

10,000 pounds of steam per hour, Underwriters Laboratories Inc., Underwriters Laboratories of Canada, or other nationally recognized organizations establish safety requirements and tests, and approve safety equipment.

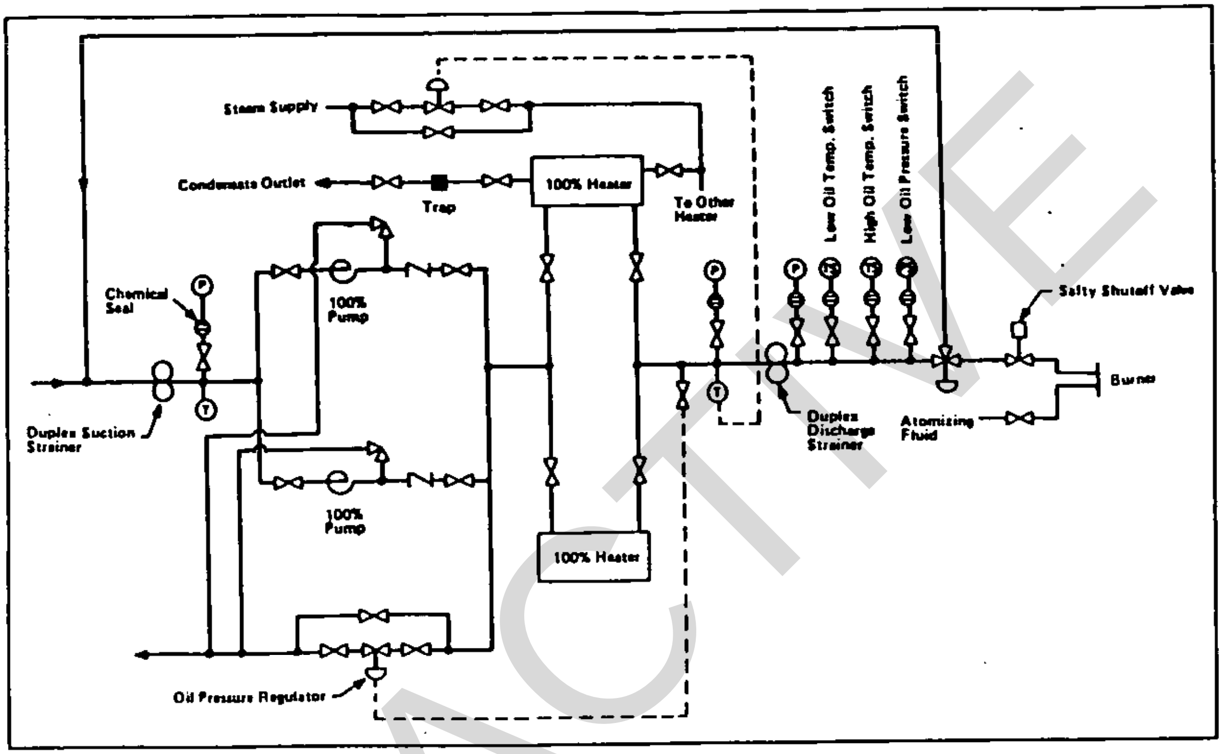
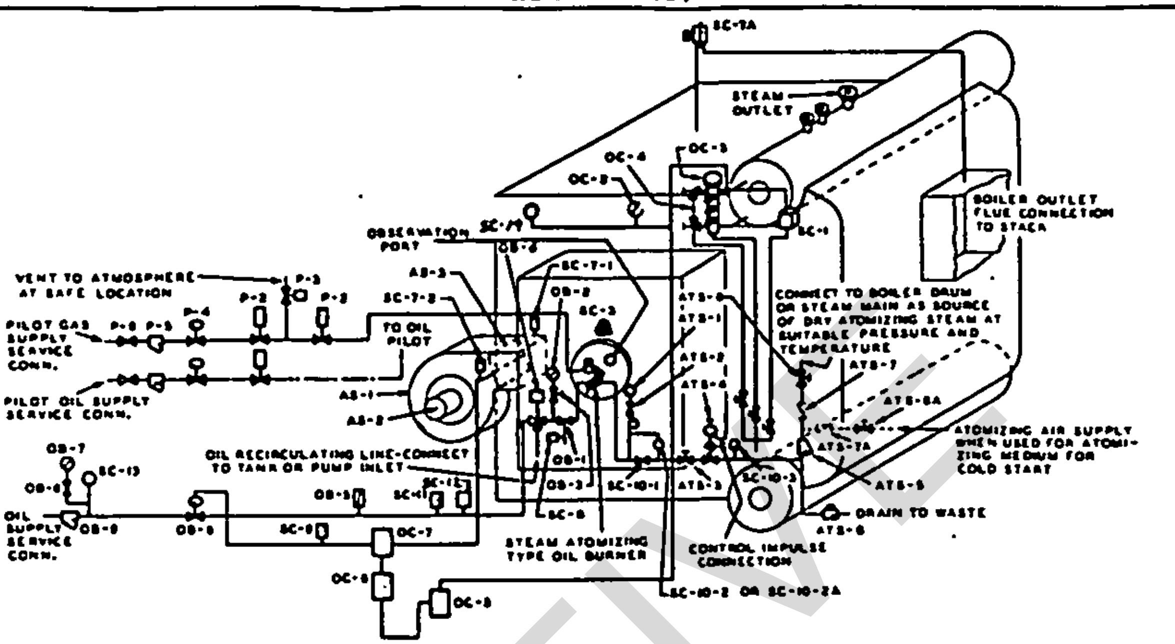


Figure 50
Fuel Oil Pumping and Heating Equipment



Typical Schematic Arrangement of Safety Equipment, Fuel Oil-Fired Watertube Boiler with One (1) Burner, Supervised Manual Controls.

LEGEND

Atomizing Steam System:

ATS-1	Burner atomizing steam pressure gage
ATS-2	Burner atomizing steam pressure gage cock
ATS-3	Atomizing steam shutoff valve manual
ATS-4	Atomizing steam differential pressure control valve
ATS-5	Atomizing steam supply strainer
ATS-6	Atomizing steam supply trap
ATS-7	Atomizing steam supply check valve
ATS-7A	Atomizing air supply check valve
ATS-8	Atomizing steam supply shutoff valve
ATS-8A	Atomizing air supply shutoff valve

Air System:

AS-1	Forced draft fan
AS-2	Forced draft fan motor
AS-3	Forced draft fan control damper at inlet or outlet

Igniter (Pilot) System — Gas or Oil:

P-2	Safety shutoff valves, auto. opening, spring closing (NC)
P-3	Vent valve auto. closing, spring opening (NO)
P-4	Pressure regulating valve, optional depending on igniter pressure requirements
P-5	Strainer
P-6	Manual plug cock

Oil Burner System:

OB-1	Manual oil shutoff cock
OB-2	Oil burner pressure gage
OB-3	Oil burner pressure gage cock
OB-4	Safety shutoff and recirculating valve
OB-5	Oil temperature thermometer or gage (Note 3)
OB-6	Oil control valve
OB-7	Oil supply pressure gage
OB-8	Oil supply pressure gage cock
OB-9	Oil strainer

Safety Controls and Alarms: (All switches in "hot" ungrounded lines. See 4-6.Q)

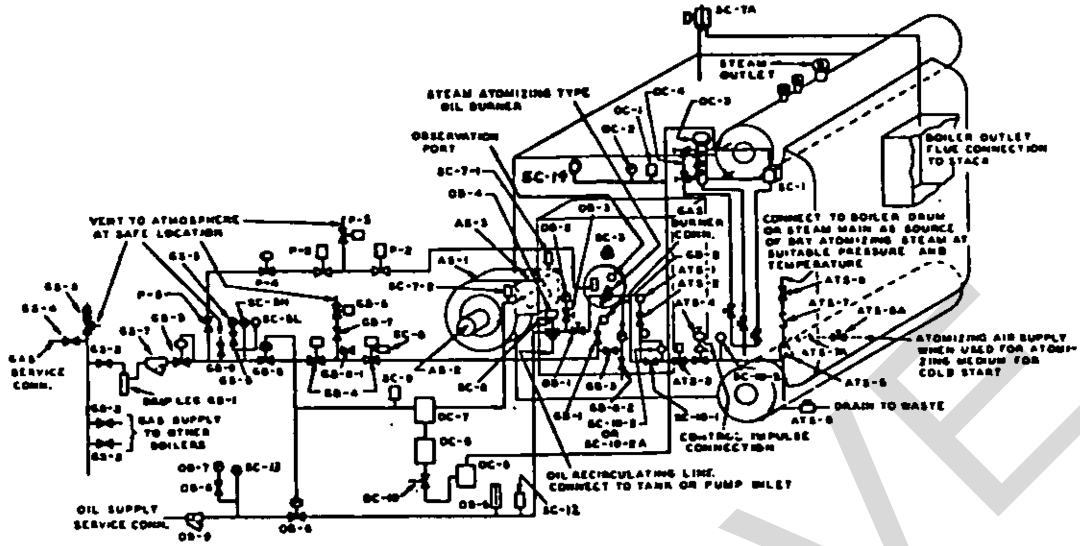
SC-1	Low water cut out integral with column or separate from water column.
SC-3	Flame scanner
SC-7-1	Windbox pressure switch (Note 1)
SC-7-2	Fan damper position switch (Note 1)
SC-7A	Purge airflow switch (Note 1)
SC-8	Closed position interlock on OB-1
SC-9	Light-off position interlock
SC-10-1	Atomizing steam flow interlock orifice
SC-10-2	Atomizing steam flow interlock differential pressure switch
SC-10-2A	Atomizing steam pressure interlock switch
SC-10-3	Atomizing steam supply pressure interlock switch
SC-11	High oil temperature alarm (Note 3)
SC-12	Low oil temperature alarm (Note 3)
SC-13	Low oil supply pressure interlock
SC-14	Excessive steam pressure interlock

Operating Controls & Instruments

OC-2	Steam drum pressure gage
OC-3	Water column with high and low level alarms
OC-4	Water gage and valves
OC-5	Steam pressure controller
OC-6	Manual auto. selector station
OC-7	Combustion control drive unit or units

NOTES.
1. Purge airflow may be proved by providing either SC-7-1 and SC-7-2 (and similar devices for other dampers which are in series) or SC-7A.
2. Atomizing steam interlock may be accomplished by providing either SC-10-1 and SC-10-2 or SC-10-2A and SC-10-3.
3. Temperature alarm and thermometer omitted for light oils which do not require heating
4. Arrangement shown is applicable to straight mechanical pressure atomizing oil burners by omitting atomizing steam system.

Figure 51
Safety Equipment, Fuel Oil-Fired Water Tube Boiler



Typical Schematic Arrangement of Safety Equipment, Gas- and Oil-Fired (alternately) Watertube Boiler With One (1) Burner, Automatic (recycling) or Automatic (non-recycling) Controls.

LEGEND

Atomizing Steam System:	
ATS-1	Burner atomizing steam pressure gage
ATS-2	Burner atomizing steam pressure gage cock
ATS-3	Atomizing steam shutoff valve
ATS-4	Atomizing steam differential pressure control valve
ATS-5	Atomizing steam supply strainer
ATS-6	Atomizing steam supply trap
ATS-7	Atomizing steam supply check valve
ATS-7A	Atomizing air supply check valve
ATS-8	Atomizing steam supply shutoff valve
ATS-8A	Atomizing air supply shutoff valve
Gas Supply System:	
GS-1	Drip leg
GS-2	Manual plug cock
GS-3	Gas supply pressure reducing valve
GS-4	Manual gas supply shutoff valve
GS-5	Gas supply pressure gage
GS-6	Gas supply pressure gage cock
GS-7	Gas cleaner
GS-8	Relief valve
Air System:	
AS-1	Forced draft fan
AS-2	Forced draft fan motor
AS-3	Forced draft fan control damper at inlet or outlet
Igniter (Pilot) System	
P-2	Safety shutoff valves, auto. opening, spring closing (NC)
P-3	Vent valve, auto. closing spring opening (NO)
P-4	Gas pressure regulating valve optional depending on igniter pressure requirements
P-6	Manual plug cock
Gas Burner System:	
GB-1	Manual plug cock
GB-2	Gas burner pressure gage
GB-3	Gas burner pressure gage cock
GB-4	Safety shutoff valves, auto. opening, spring closing (NC)
GB-5	Vent valve, auto. closing spring opening (NO)
GB-6	Gas fuel control valve
GB-7	Vent line manual plug cock (locked or sealed in open position)
GB-8-1	Leakage test conn. upstream safety S.O. valve
GB-8-2	Leakage test conn. downstream safety S.O. valve
GB-9	Manual plug cock for venting high pressure from supply when required
Oil Burner System:	
OB-1	Manual oil shutoff valve
OB-2	Oil burner pressure gage
OB-3	Oil burner pressure gage cock
OB-4	Safety shutoff and recirculating valve(s)
OB-5	Oil temperature thermometer or gage (see Note 4).
OB-6	Oil control valve
OB-7	Oil supply pressure gage
OB-8	Oil supply pressure gage cock
OB-9	Oil strainer
Safety Controls and Alarms: (All switches in "hot" ungrounded lines. See 4-8.8)	
SC-1	Low water cut out integral with column or separate from water column
SC-3	Flame scanner
SC-5H	Gas supply high pressure switch
SC-5L	Gas supply low pressure switch
SC-7-1	Windbox pressure switch (Note 2)
SC-7-2	Fan damper position switch (Note 2)
SC-7A	Purge A.F. switch (Note 2).
SC-8	Closed position interlock on OB-4 and GB-4
SC-9	Light-off position interlock
SC-10-1	Atomizing steam flow interlock orifice
SC-10-2	Atomizing steam flow interlock differential pressure switch
SC-10-2A	Atomizing steam pressure interlock switch
SC-10-3	Atomizing steam supply pressure interlock switch
SC-12	Low oil temperature interlock (Note 4)
SC-13	Low oil supply pressure interlock
SC-14	Excessive steam pressure interlock
Operating Controls & Instruments:	
OC-1	High steam pressure switch (Note 1)
OC-2	Steam drum pressure gage
OC-3	Water column with high & low level alarms
OC-4	Water gage and valves
OC-5	Steam pressure controller
OC-6	Manual auto. selector station
OC-7	Combustion control drive unit or units
OC-10	Modulating control low fire start positioner

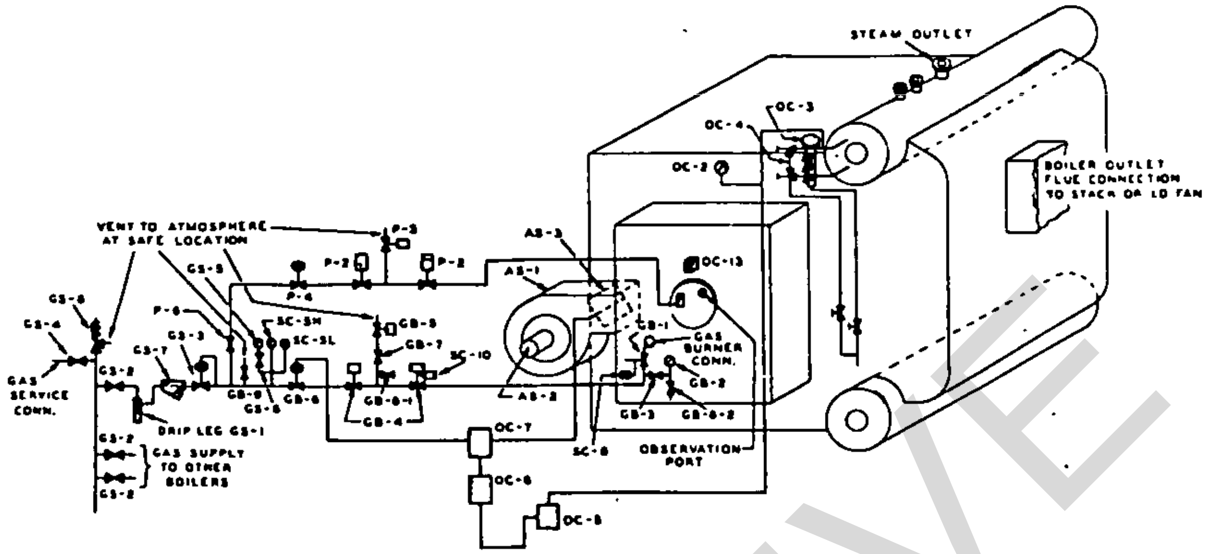
NOTES.
1. With automatic non-recycling control, an overpressure shutdown requires a manual restart.
2. Purge airflow may be proved by providing either SC-7-1 and SC-7-2 (and similar devices for other dampers which are in series) or SC-7A.
3. Atomizing steam interlock may be accomplished by providing either SC-10-1 and SC-10-2 or SC-10-2A and SC-10-3.
4. Temperature interlock and thermometer omitted for light oils which do not require heating.
5. Arrangement shown is applicable to straight mechanical pressure atomizing oil burners by omitting atomizing steam system.

Figure 52
Safety Equipment, Gas- and Oil-Fired Water Tube Boiler

3.3.6 Gas-Firing Equipment. Natural gas is an easy and clean fuel to burn and requires less equipment and maintenance than coal or oil systems. Its disadvantages include higher cost than coal, uncertain and limited availability, and a greater danger of explosion. Pars. 2.4.1.3, 2.4.6, and 2.4.6.1 describe the potential for explosions and some of the necessary precautions. Early gas-firing equipment used gas velocity to aspirate air into the burner throat, where it was premixed with the gas before burning. Premix burners are now used for igniter service. The advent of forced draft fans and the need for increased burner capacity brought about the development of nozzle mix gas burners. Nozzle mix burners are capable of handling gas over a wide range of pressures depending on the design. Types of nozzle mix burners include ring, gun, and multiple spud. NFPA 8501 establishes requirements for safe operation of gas-fired boilers. Figures 52 and 53 show schematic arrangements of safety equipment for gas-fired fire tube and water tube boilers. Standards for natural gas-fired multiple burner boilers are found in NFPA 8502. For boilers rated less than 10,000 pounds of steam per hour, standards are set by Underwriters Laboratories Inc., Underwriters Laboratories of Canada, ASME CSD-1, Controls and Safety Devices for Automatically Fired Boilers, and other nationally recognized organizations.

3.3.7 Liquefied Petroleum Gas (LPG). LPG is used for igniter service and occasionally as a standby fuel for natural gas or oil-fired installations. LPG is also used on smaller remotely located boilers where natural gas service is not available. LPG is a combination of propane and butane maintained in a liquid state through storage under pressure. NFPA 58, Standard for the Storage and Handling of Liquefied Petroleum Gases and NFPA 54, National Fuel Gas Code, Part 2 establish requirements for storage and handling of LPG.

3.4 Controls and Instrumentation. Controls and instrumentation are an integral and essential part of central boiler plants. They serve to ensure safe, economic, and reliable operation of equipment. They range from the simplest of manual devices to completely automated, microprocessor-based systems for control of boilers, turbines, and even end users of energy. The subjects of controls and instrumentation are so intimately related that they are difficult to separate, and are discussed in parallel in the following section. Only those systems and items which are commonly used in central boiler plants are discussed. Many of the controls existing in Navy power plants are pneumatic; however, nearly all new controls are electronic based with microprocessors.



Typical Schematic Arrangement of Safety Equipment, Natural Gas-Fired Watertube Boiler with One (1) Burner, Manual Controls.

LEGEND

Gas Supply System:

- GS-1 Drip leg
- GS-2 Manual plug cock
- GS-3 Gas supply pressure reducing valve
- GS-4 Manual gas supply shut-off valve
- GS-5 Gas supply pressure gage
- GS-6 Gas supply pressure gage cock
- GS-7 Gas cleaner
- GS-8 Relief valve

Air System:

- AS-1 Forced draft fan
- AS-2 Forced draft fan motor
- AS-3 Forced draft fan control damper at inlet or outlet

Igniter (Pilot) System:

- P-2 Safety shut-off valves, auto. opening, spring closing (NC)
- P-3 Vent valve, auto. closing, spring opening (NO)
- P-4 Gas pressure regulating valve optional depending on igniter pressure requirements.
- P-6 Manual plug cock

Gas Burner System:

- GB-1 Manual plug cock
- GB-2 Gas burner pressure gage
- GB-3 Gas burner pressure gage cock
- GB-4 Safety shut-off valves, spring closing (NC)
- GB-5 Vent valve, auto. closing, spring opening (NO)
- GB-6 Gas fuel control valve
- GB-7 Vent line manual plug cock (locked or sealed in open position)
- GB-8-1 Leakage test conn. upstream safety S.O. valve
- GB-8-2 Leakage test conn. downstream safety S.O. valve
- GB-9 Manual plug cock for venting high pressure from supply when required

Safety Controls and Alarms: (All switches in "hot" ungrounded lines. See 4-6.6)

- SC-5H Gas supply high pressure switch
- SC-5L Gas supply low pressure switch
- SC-8 Closed position interlock on GB-1
- SC-10 Open position interlock on GB-4

Operating Controls & Instruments:

- OC-2 Steam drum pressure gage
- OC-3 Water column with high & low level alarms
- OC-4 Water gage and valves
- OC-5 Steam pressure controller (optional)
- OC-6 Manual auto. selector station (included if OC-5 furnished)
- OC-7 Combustion control drive unit or units
- OC-13 Pilot manual control station

Figure 53
Safety Equipment, Natural Gas-Fired Water Tube Boiler

3.4.1 Feedwater-Drum Level Controls. The importance of an adequate, properly controlled supply of feedwater to a boiler cannot be overemphasized. Boiler feedwater pumps and injectors (par. 3.6.3), low water fuel cutoffs (par. 3.4.3), and feedwater heaters (par. 3.6.2) are part of an effective feedwater system. Steam boilers also require drum level controls to maintain the water level within limits established by the manufacturer. Operating with water levels that are too high may cause carryover of water from the drum, while operating with levels that are too low can result in boiler tube failures due to insufficient cooling. Feedwater regulators are used to adjust the feedwater flow rate and maintain proper levels. Five types of feedwater regulators are commonly used: positive displacement, thermohydraulic, thermostatic, pneumatic level transmitter/controller, and electronic level transmitter/controller. Each is described below.

3.4.1.1 Positive Displacement. The positive displacement feedwater regulator (Figure 54) is connected to the boiler drum or water column so that the average water level in the chamber is in line with that of the drum. The rise and fall of the float with the water level actuates a balanced feed valve through a suitable system of levers, and reduces or increases flow of water to the boiler. The entire mechanism is in the pressure space and there are no stuffing boxes to leak or bind. The float is initially charged with a small amount of alcohol, which vaporizes and pressurizes in the float to counteract boiler pressure exerted on the outside of the float. The valve and linkage are designed to give a gradual and continuous change in water flow between high and low limits. This type of control will maintain a different water level for each steam flow produced by the boiler.

3.4.1.2 Thermohydraulic. Operation of the thermohydraulic or vapor generator type of feedwater regulator (Figure 55) depends upon the principle that steam occupies a greater volume than the water from which it was formed. The equipment consists of a generator, a diaphragm operated valve, and the necessary connecting pipe and tubing. The central tube of the generator is connected to the boiler drum or water column, with the tube inclined so that normal drum water level is slightly above the center of the generator. The generator, tubing and diaphragm chamber are filled with hot water. In operation, heat from steam in the upper portion of the inner tube raises the temperature of water surrounding that portion of the tube and converts part of it to steam. This increases pressure in the generator, forcing part of the water out of the generator until the water level is the same in both the inner and outer tubes. Water that is forced out of the generator moves the diaphragm and opens the valve. When water level in the boiler rises, some of the steam in the generator condenses and lowers the pressure. The spring on the valve forces water into the generator, closing the valve in the process. Fins are installed on the generator to radiate away some of the heat absorbed, thus preventing excessive pressures in the generator circuit and increasing the speed of response of the regulator. This type of regulator establishes a relationship between water level in the drum and the valve opening. Therefore, for each stream flow rate, a slightly different water level will be maintained.

3.4.1.3 Thermostatic. Operation of the metal thermostat or expansion type of regulator (Figure 56) depends upon expansion and contraction of an inclined metal tube. The expansion tube is mounted on a steel frame in such a way that it is under constant tension. It is connected to steam and water spaces of the boiler so that it contains only steam when water is at its lowest level. The tube is then expanded to its maximum length. As water level in the boiler rises, water also rises in the tube, causing it to cool and contract. The tube is connected to a balanced valve in the feedwater line by a system of levers that move the valve as the tube length changes. The feedwater valve is at its maximum opening when water level is low and the tube is filled with steam, and closes as water level rises and the tube shortens. Note that all of the above regulators increase the flow of water as the level drops.

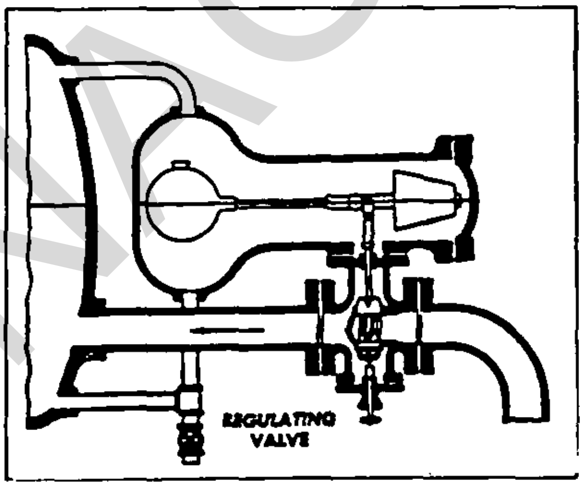


Figure 54
Positive Displacement
Feedwater Regulator

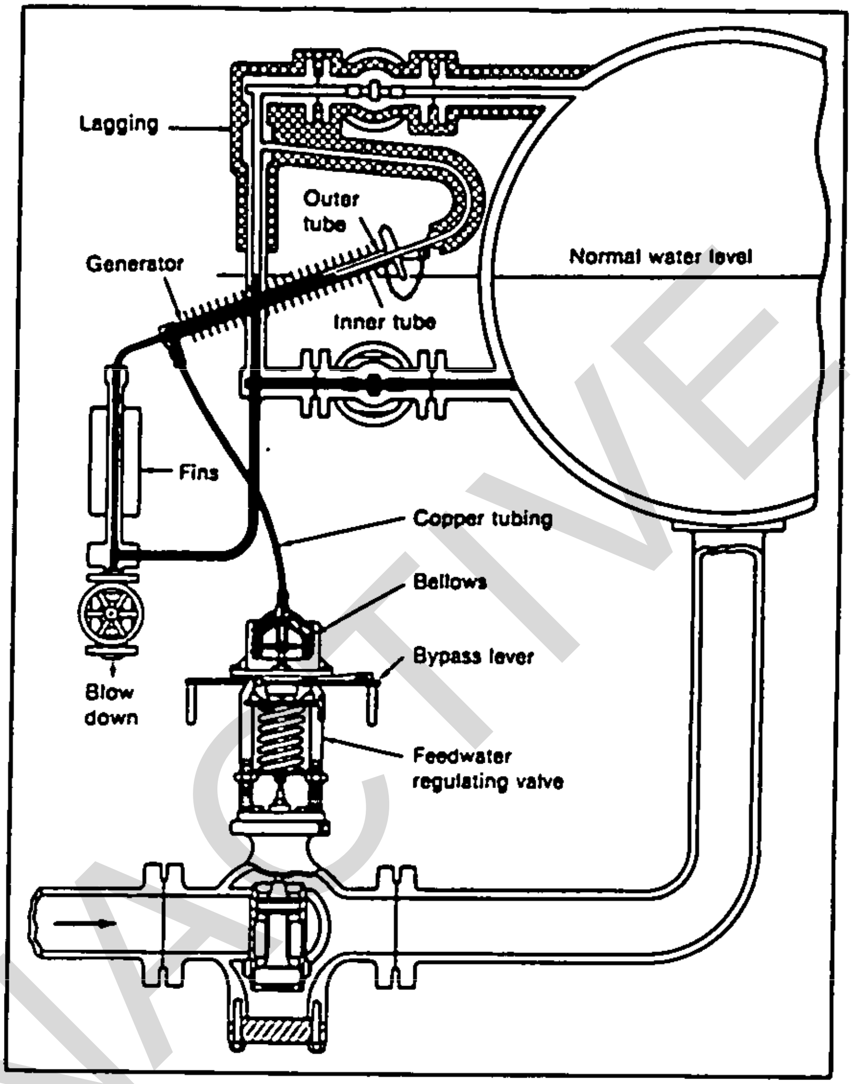


Figure 55
Vapor-Generator/Thermohydraulic
Feedwater Regulator

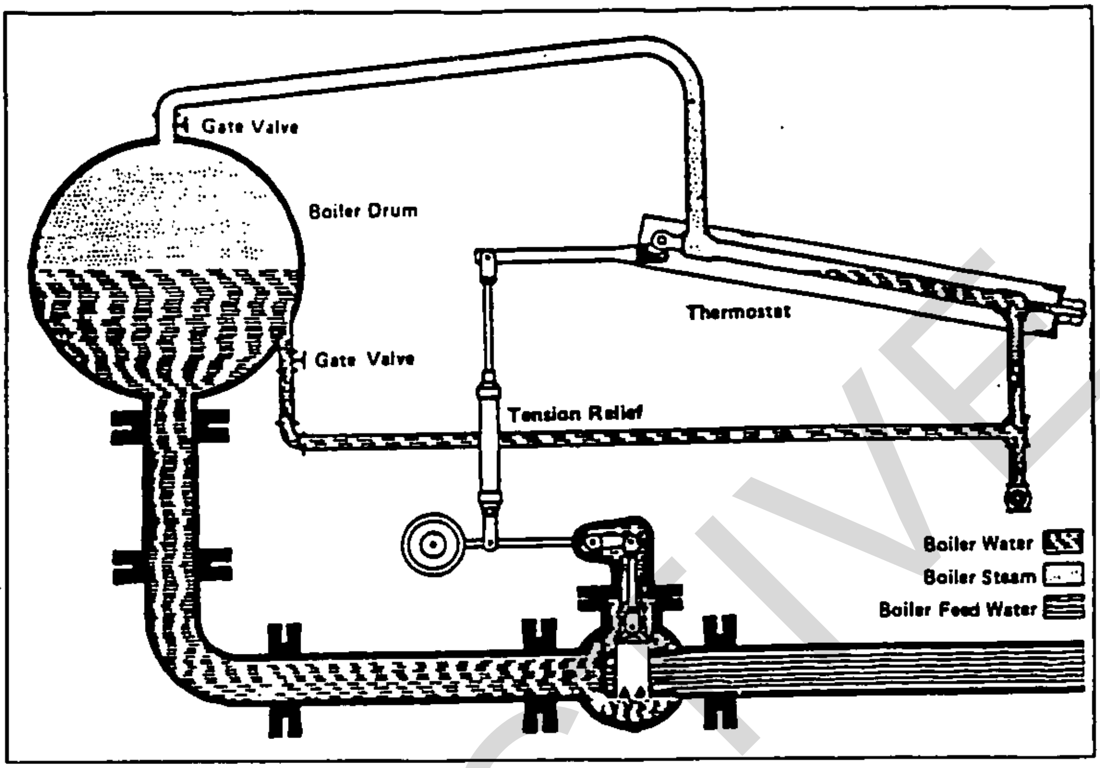


Figure 56
Thermostatic/Metal Expansion Feedwater Regulator

3.4.1.4 Drum Level Transmitter. A typical arrangement of a drum level measuring transmitter is shown in Figure 57. The transmitter is a differential pressure device in which the output signal increases as differential pressure decreases. Typically, the differential pressure range is approximately 30 inches with a zero suppression of several inches. To determine the measuring instrument calibration, necessary design data are the location of upper and lower pressure taps into the boiler drum with respect to normal water level, operating pressure of the boiler drum, and ambient temperature around external piping. With these data and the desired range span of the transmitter, exact calibration can be calculated by using the standard thermodynamic properties of steam and water.

On the high pressure side of the measuring device, effective pressure equals boiler drum pressure plus the weight of a water column at ambient temperature, and having a length equal to distance between two drum pressure connections. On the low pressure side, effective pressure equals boiler drum pressure, plus the weight of a column of saturated steam having a length from the upper drum pressure connection to the water level.

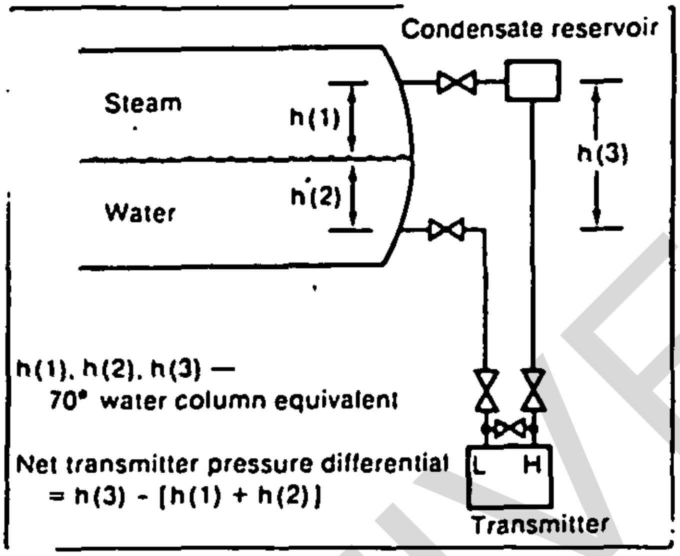


Figure 57
Drum Level Transmitter -
Connection and Calibration

a) Pneumatic Transmitter/Controller. As boiler firing rates increased with the development of the modern water cooled furnaces, water storage capacity decreased and feedwater control became more difficult. A steam drum in a modern boiler can be emptied of water in minutes if the supply is shut off. Changes in steam pressure result in expansion or swelling of the steam/water mixture and false water level indications. Mechanical controls discussed previously have limited capabilities and slow response times, and pneumatic controls were developed to provide more accurate drum level control. Basic to pneumatic systems are a drum level transmitter to sense level, a manual/automatic station to allow manual control during start-up, and a controller to determine the adjustment required to the feedwater valve. Single-, two-, and three-element feedwater controls are available.

b) Electronic Transmitter/Controller. One-, two-, and three-element feedwater control systems are also available utilizing electronic transmitters, manual/automatic stations, and controllers (Table 10). Electric or pneumatic actuators can be used as final control drives for the feedwater control valve. An electro-pneumatic (I/P) transducer is required to convert the electric signal into a pneumatic signal when pneumatic actuators are used.

Table 10
Feedwater Control Symbols

FIT	Flow indicating transmitting
LIT	Level indicating transmitter
A	Manual signal generator
f(x)	Final controling function
A T	Hand/automatic control station
Δ	Subtracting unit
K	Proportional controller
K ∫	Proportional-plus-integral controller
Σ	Summer
f(t)	Signal lag unit

(1) Single Element. Single-element controls use a drum level transmitter with a manual/automatic station and controller to send a signal to position the feedwater control valve. The controller can be adjusted to provide responsive and accurate control. Single-element control is adequate for systems with gradual load changes.

(2) Two Element. In two-element controls, both drum level and steam flow levels are measured and used to control the feedwater (Figure 58). Because steam flow is measured, this control system can sense and respond to load changes before they result in drum level changes. The system can thus compensate for swelling and shrinking in the boiler and drum which occur as the pressure changes during load swings. Two-element control is recommended for systems with frequent and large load changes.

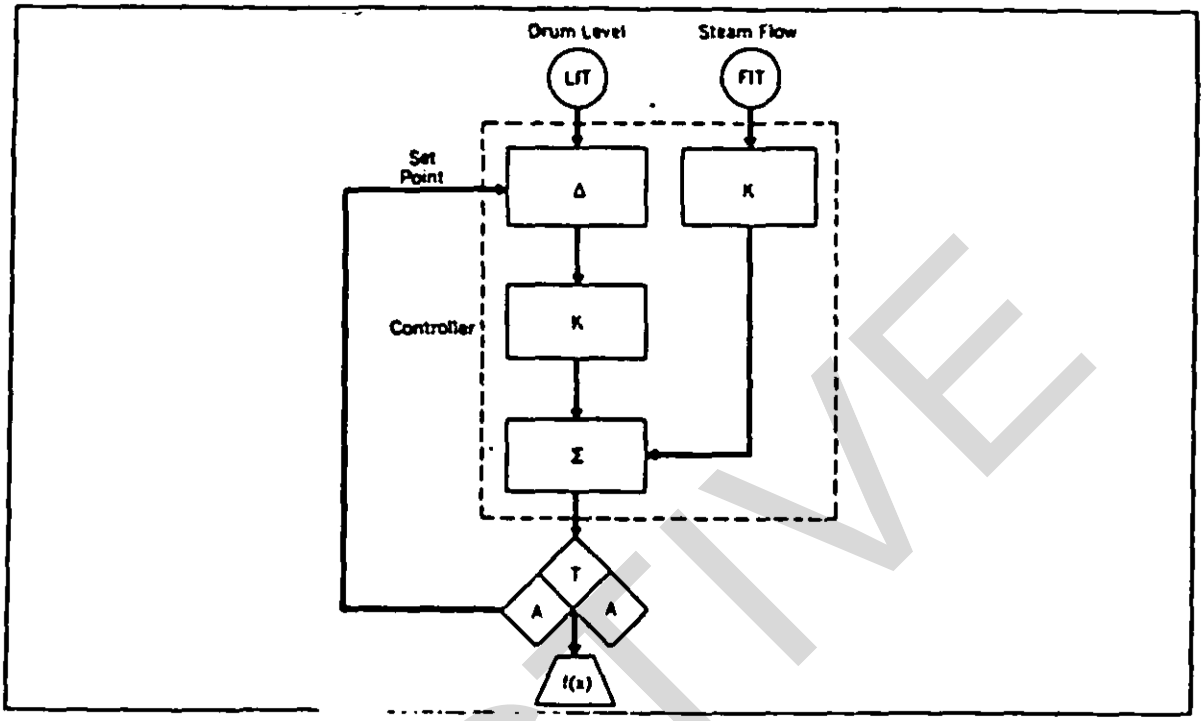


Figure 58
Two-Element Feedwater Controls
(reprinted with permission of Babcock & Wilcox, from Steam, Its Generation & Use, 39th Ed.)

(3) Three Element. Three-element controls sense feedwater flow in addition to drum level and steam flow. Three-element systems can compensate for changes in feedwater flow that may occur due to feedwater pressure, temperature change, or feedwater valve inaccuracies. This level of control is not normally necessary except for very large boilers used in systems with large load changes, or in boilers producing superheated steam for use in a turbine.

3.4.2 Combustion Controls. Combustion controls adjust fuel and airflows to satisfy boiler demand. Steam pressure, which changes with changes in demand, serves as the input signal by which the boiler firing rate is controlled. In hot water boilers, water temperature leaving the boiler is used as the input signal. A combustion control system must maintain an efficient fuel/air ratio. For boilers equipped with induced draft fans or tall stacks, combustion controls must also adjust fan inlet dampers or boiler outlet dampers to control furnace draft. Combustion controls systems are comprised of the following general types of components: sensing elements, actuators, transmitters, control drives, controllers, control valves, indicators, dampers, and recorders. These components may be combined in an endless variety of arrangements to provide almost any degree of sophistication required.

3.4.2.1 Control Concepts. Open-loop and closed-loop control are both used in the boiler plant. Open-loop control (also called feed-forward) takes an input demand signal and generates a single output in response to the demand. The result of the control action is not considered. Closed-loop (or "feedback") control monitors a system variable and automatically generates an output to adjust the system. If the system remains out of balance, the control will continue to change its output until the desired result is obtained. A simple pneumatic actuator on a valve is an example of open-loop control (Figure 59). The actuator receives a signal and generates an output, the movement of its shaft. This same pneumatic actuator could be converted to closed-loop control by equipping it with a positioner (Figure 60). The actuator receives a signal and generates an output to move the shaft. The shaft position is measured as feedback. If the shaft is not in the desired position, the output from the positioner is automatically readjusted, and the shaft is moved again until it is in the correct position. A basic advantage of closed-loop control is that it provides more accuracy of adjustment due to its ability to overcome hysteresis losses. Hysteresis losses are caused by friction in linkages, valves, actuators, and other mechanical items. The effect of hysteresis is to cause a valve or mechanism to stop at a slightly different adjustment each time. A typical open-loop control may be able to control position within ± 5 percent of a desired setting, whereas a closed-loop control can typically control to approximately ± 1 percent. Closed-loop control is available as one-, two-, or three-mode control using proportional, integral, or derivative responses. These different responses are discussed below.

a) Proportional. Proportional control (also called gain control) is the simplest form of closed-loop control. In proportional control, the difference between a setpoint and a system variable is measured, and corrective action is taken by adjusting the control output. A proportional steam pressure control system is illustrated in Figure 61. Steam pressure setpoint and actual steam pressure are compared, and an output is generated in proportion to the difference. Figure 62 illustrates proportional control. For a proportional gain setting of 5, the fuel valve is opened 5 percent for each 1 percent drop in steam pressure. Proportional gain, or simply gain, is defined as "the control output change, in percent, divided by the system variable change, in percent."

Gain = (percent change in control output)/(percent change in system variable)

Proportional band is the inverse of gain, expressed in percent.

Proportional = (1/gain) X 100 = (percent change in system variable)/(percent change in control output) X 100

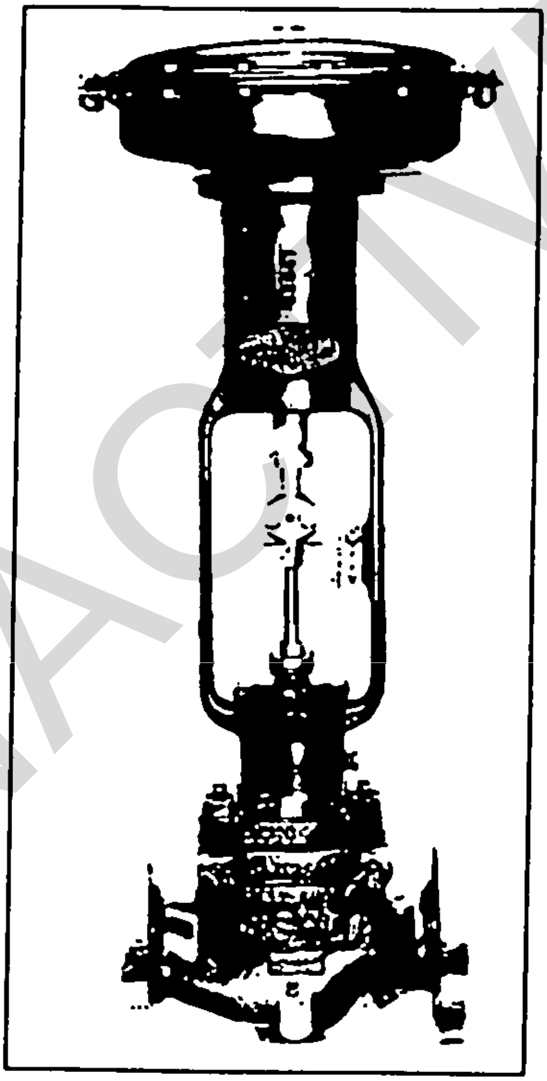


Figure 59
Control Valve With
Pneumatic Actuator

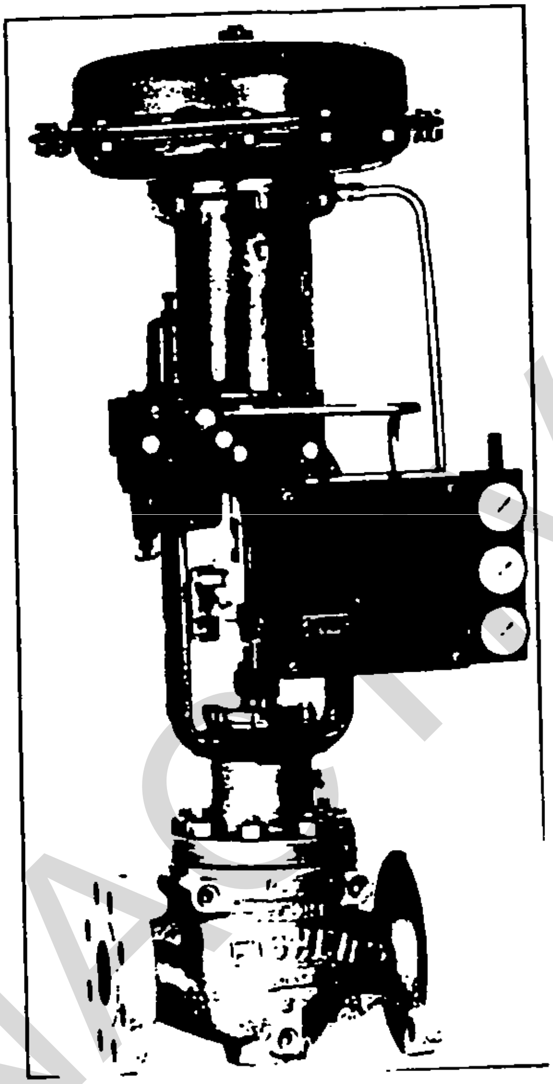


Figure 60
Control Valve With
Pneumatic Actuator
and Positioner

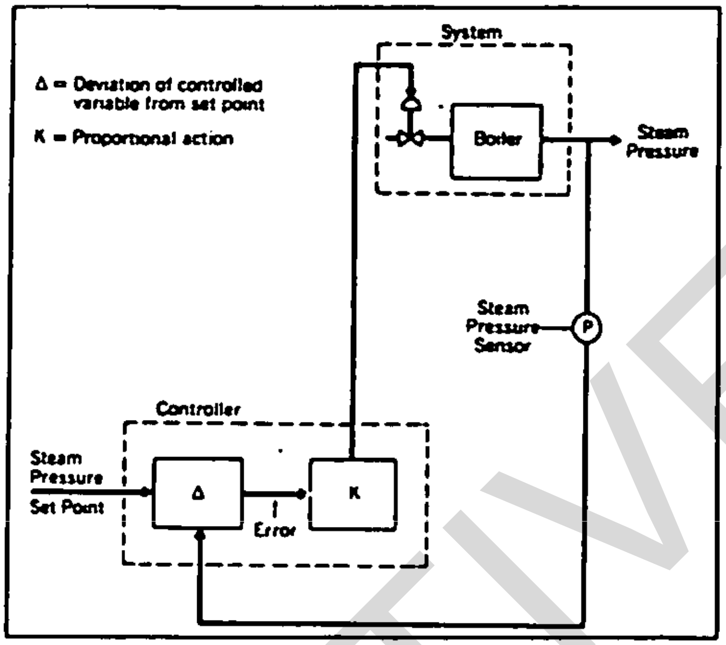


Figure 61
Steam Pressure Control System

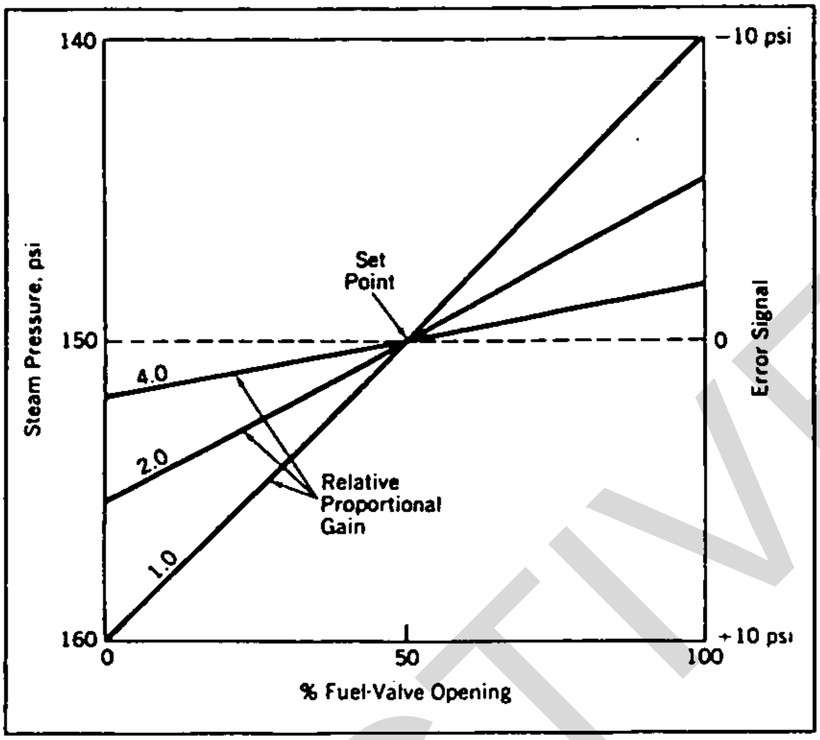


Figure 62
Proportional Control

Thus, a gain of 5 is equivalent to a proportional band of 20. Figure 63 illustrates the response of a steam pressure control system to a change in steam flow. Note that offset or deadband is the difference between setpoint and steam pressure. The following observations should be noted about proportional control:

(1) Proportional control operates and establishes steady-state positions because a difference exists between the setpoint and system variable. In the example shown in Figure 62, only at the 50 percent fuel valve position would steam pressure exactly match the setpoint. At other fuel valve positions, a difference of up to 10 psi from setpoint would be required to maintain the fuel valve position that would satisfy a steam flow demand.

(2) The larger the gain (or the smaller the proportional band) of a control, the greater the response of the control to changes in the system variable, and the smaller the deadband.

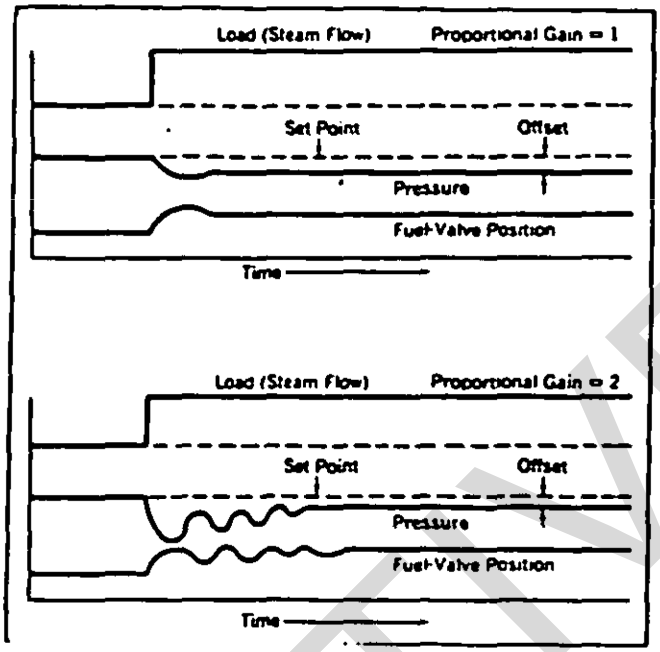


Figure 63
Proportional Response

(3) The smaller the gain (or the larger the proportional band), the smaller the response to changes in the system variable, and the larger the deadband.

(4) A large gain may not be stable. A fuel valve cycling between full open and full closed is an example of unstable operation.

b) Integral. Integral (also called reset) control was developed to improve the accuracy of proportional control. Integral action works to eliminate the deadband which is inherent in proportional control. Integral control adjusts the control output in steps based upon the offset and the time the offset has existed. Adjustment continues until the setpoint and the system variable are the same or until maximum or minimum output is reached. Figure 64 illustrates proportional plus integral control response to a change in steam flow. Proportional plus integral control is also called two-mode control. Reducing the integral time increases the integral control response, while increasing the integral time reduces the control response.

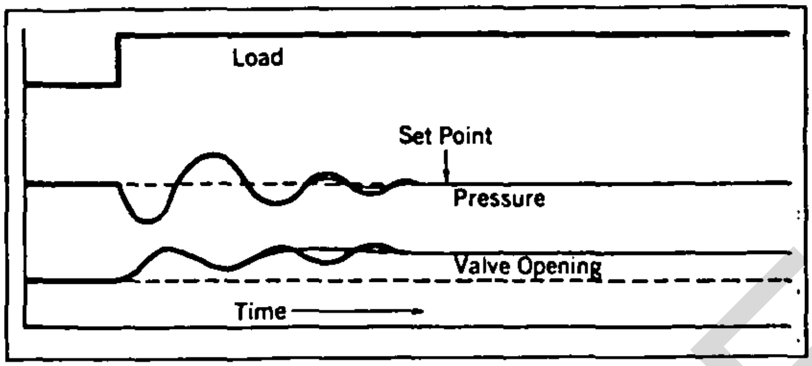


Figure 64
Proportional Plus Integral Response

c) Derivative. Derivative is a mathematical term that considers the rate of change. In some systems, derivative (or rate) response can improve the speed and accuracy of the control by anticipating a trend before an actual change occurs. Proportional plus integral plus derivative control is called three-mode control; it is rarely used in a steam heating plant but can be very effective in a hot water plant by recognizing change in direction of a system variable. For example, when the rising boiler outlet water temperature starts to fall, the fuel valve should be opened to supply heat to satisfy the new demand for hot water, even though the setpoint may not have been reached yet. Reducing the derivative time increases the derivative control response, while increasing the derivative time decreases the response. Too much derivative control can dampen other control responses.

3.4.2.2 Controls for Stoker-Fired Boilers. Combustion controls for stoker-fired boilers must have the ability to adjust the fuel/air ratio to compensate for changes in coal heating values, moisture, bed thickness, forced draft fan performance, and ambient air changes. Spreader stokers, which burn a portion of coal in suspension, react differently than underfeed, traveling, chain, and vibrating stokers. Spreader stokers respond best to a change in fuel feed rate, while grate burning stokers respond well to changes in airflow rates. Two types of control, parallel positioning control and series/parallel control, are commonly used with stokers.

a) Parallel Positioning Control. Figure 65 illustrates a parallel positioning control system. A deviation of steam pressure from setpoint results in the master controller signaling the fuel actuator and the combustion and overfire air actuators to reposition themselves to a higher firing rate. Two fuel/air ratio control stations are provided to allow the operator to adjust and trim the combustion and overfire air supply. A furnace pressure controller monitors the furnace pressure and adjusts the induced draft (ID) fan inlet damper to maintain a slightly negative pressure in the furnace. Manual/automatic stations are provided to allow manual control.

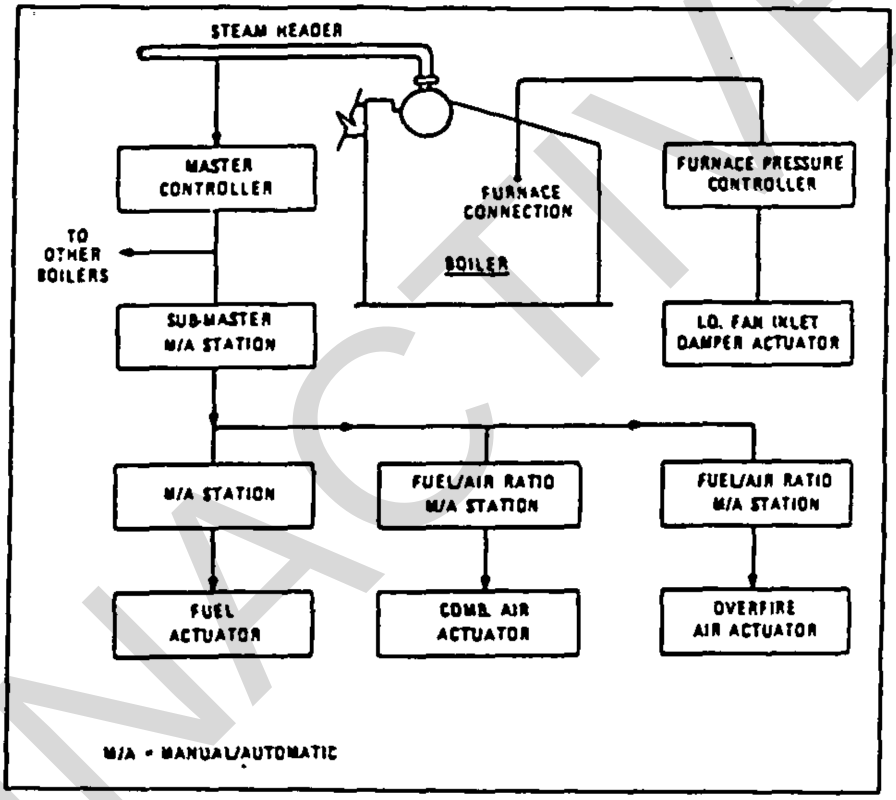


Figure 65
Parallel Positioning Control System

b) Series/Parallel Control. Figure 66 illustrates the series/parallel system. In this system, steam pressure is used to control fuel feed rate and steam flow to control the airflow rate. A combination airflow and steam flow meter is discussed in par. 3.4.4. Operators use this type of meter as a guide to control the relationship between air required to burn fuel and air actually supplied. The steam generation rate is used as a measure of air required, while the flow of gases through the boiler setting is used as a measure of air supplied. By comparing the two, a check on the air-to-fuel ratio in the furnace can be obtained. This type of meter has been in use for many years and is commonly called a "boiler meter." The series/parallel control combines positioning control for fuel with metering control for airflow. Initial calibration and repeatability of the airflow signal are very important. Overfire air fans are also modulated with boiler load to obtain best combustion results at the lowest possible excess air levels. Although this feature has not been shown in Figure 66, it would be provided for many applications.

3.4.2.3 Controls for Oil- and Gas-Fired Boilers. Parallel positioning and parallel metering combustion controls are available for oil- and gas-fired boilers. Either type may be equipped with trimming controls to adjust fuel/air ratio based upon the oxygen level in flue gas. Pneumatic, electric, electronic, and computer operated controls are available.

a) Parallel Positioning Control. With the compactness of modern oil- and gas-burner packages, it is possible to use a single set of jackshaft and levers to control both fuel and air. Figure 67 illustrates a typical jackshaft system. The master regulator is a proportional control that senses steam pressure and generates a rotary output, which moves the jackshaft. Adjustable valves are used to control and characterize fuel and gas flow. These valves, together with the mechanical linkage that connects them to the forced draft (FD) dampers, establish the fuel/air ratio. This system is effective if fuel and air conditions remain constant and the linkage is tight and accurately adjusted. Some parallel positioning control systems replace the jackshaft by using a pneumatically or electronically generated fuel/air ratio and individual actuators for each fuel valve and fan damper. This approach, which is illustrated in Figure 65, can be more accurate and more easily adjusted or trimmed. Positioning control systems assume that fuel and air flows always change the same amount for each change in valve or damper position. They are open-loop control systems.

b) Parallel Metering Controls. If fuel and air flow to the burner are metered, a controller can be used that receives feedback from the metering device and further adjusts the fuel or air actuator. This ensures that when a specific fuel or air flow is demanded, it is actually delivered to the fire. This becomes a closed-loop control system and is known as parallel metering control. A parallel metering system is illustrated in Figure 68. This type of system is commonly used on larger sizes of steam boilers.

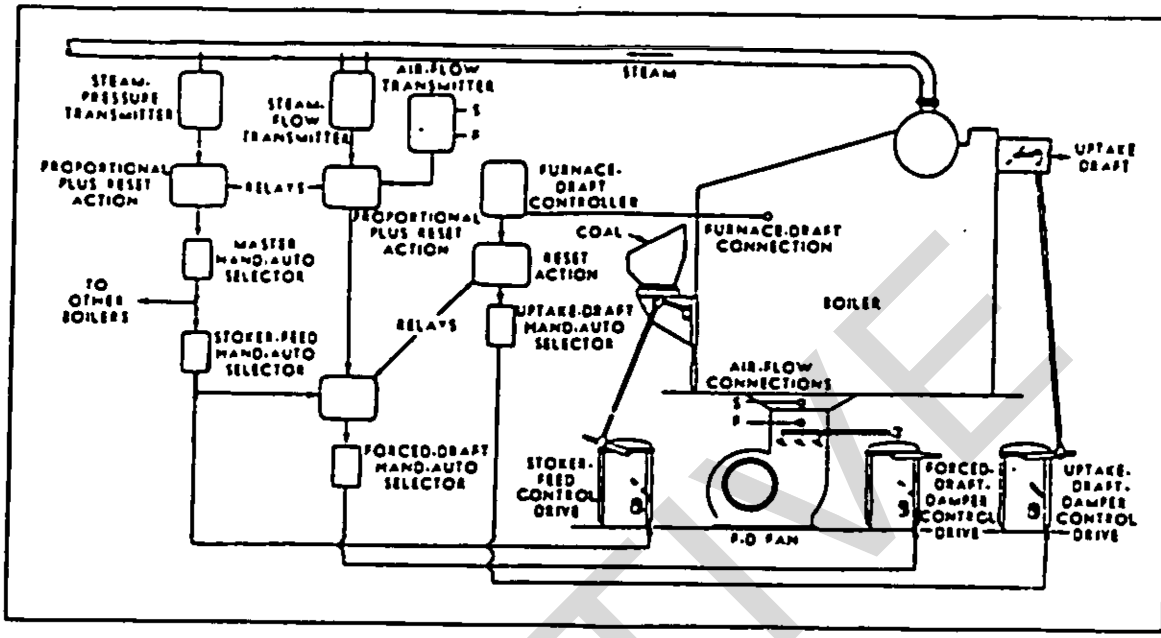


Figure 66
Series/Parallel Control

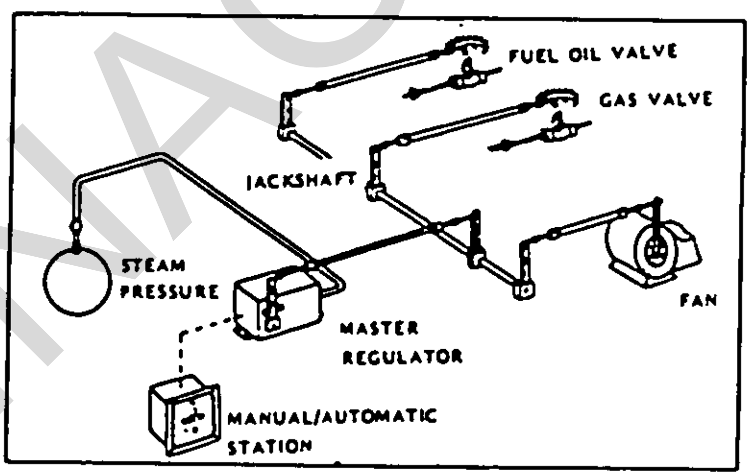


Figure 67
Jackshaft Control System

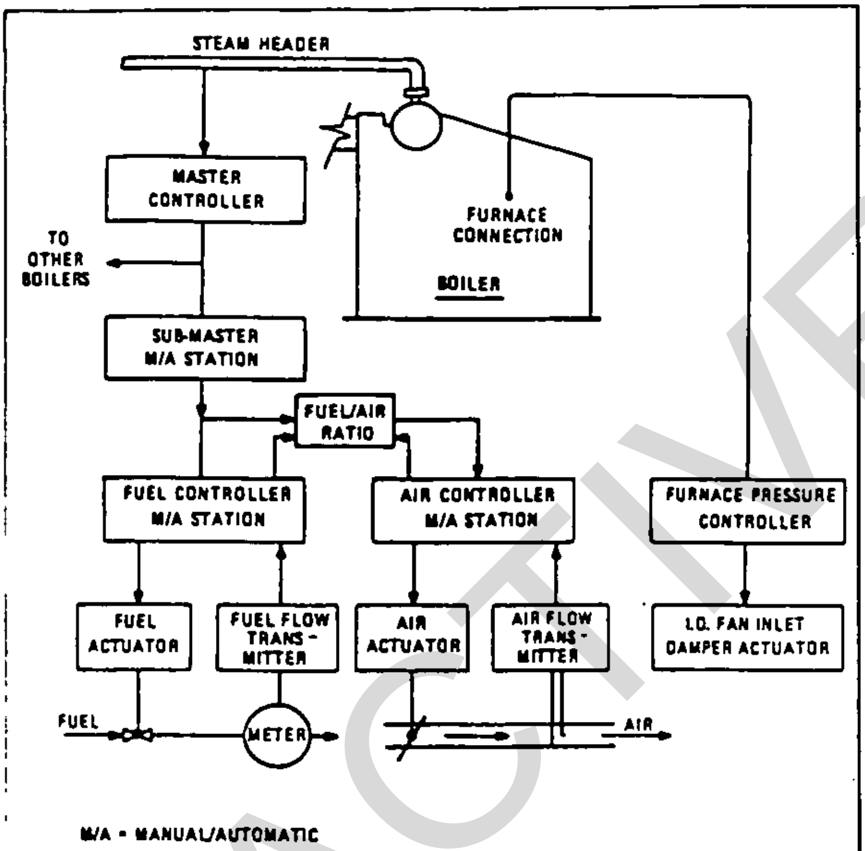


Figure 68
Parallel Metering Control

c) Oxygen Trim Control. On most modern oil- and gas-fired boilers, as well as many coal-fired units, oxygen analyzers are used as combustion guides for the operators. Oxygen content in flue gas verifies proper air/fuel ratio. Control systems have been developed to allow automatic adjustment of air/fuel ratio, based upon the reading of the oxygen analyzer. These systems are called oxygen trim control systems. Figure 69 illustrates a typical oxygen trim control, although many other arrangements are also available. These controls are not applicable to all systems because trim adjustments are small. If accuracy of an actuator is ±5 percent and the trim required is 2 percent, oxygen trim will not be effective. The following conditions must exist before oxygen trim can be effectively added to a boiler:

(1) Air infiltration into the boiler must be minimal, since the trim controller cannot distinguish between air that entered through the burner and infiltration air. The flame

could be starved for air at the burner and produce smoke, while still registering excess air at the analyzer. Trim control can also become unstable if the leakage rate changes.

(2) Combustion equipment must be capable of operation at the new air/fuel ratio. This can be tested manually. A burner cannot be expected to operate automatically at a low oxygen level if it cannot do so manually.

(3) Existing combustion control components must be able to operate accurately. Oxygen trim can be expected to compound any deficiency in an existing system.

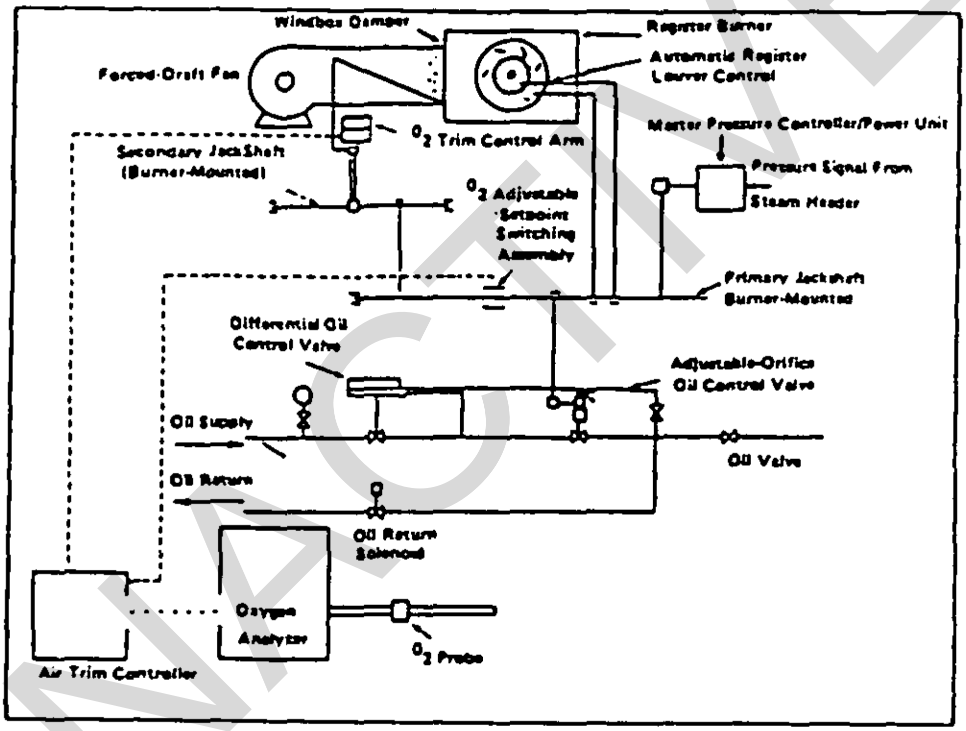


Figure 69
Oxygen Trim Control System

3.4.3 <u>Boiler Safety Control</u>. Boilers are equipped with safety devices to minimize the risk of low water- and explosion-related damage. Figures 51 through 53 illustrate typical safety systems. A typical oil- or gas-fired boiler safety control system includes the following components:

a) Low water fuel cutoff switch.

b) High steam pressure or high water temperature switch.

c) Flame scanner(s).

d) Gas supply high pressure switch.

e) Gas supply low pressure switch.

f) Combustion airflow switch.

g) Purge airflow switches.

h) Fuel safety shutoff valves with closed position switches.

i) Fuel control valves with low fire position switch.

j) Manual valves, cocks, strainers, and traps.

k) Atomizing steam or air switch(es).

l) Atomizing steam or air shutoff and control valves.

m) Low oil pressure switch.

n) High furnace pressure switch (for boilers with induced draft fans).

o) Fan motor switch(es).

p) Control logic.

NFPA 8501 (for single burner systems), NFPA 8502 (for multiple burner gas-fired systems and for multiple burner oil-fired systems), and ASME CSD-1 establish rules for operation of the equipment listed above. Notes on some of the more important items are given below.

3.4.3.1 <u>Control Logic</u>. Control logic provides for the following actions:

a) Prepurging the boiler below light-off.

b) Proper operation of limits and interlocks.

c) Low-fire start aid release to modulation sequence.

d) Trial for igniter flame sequence. The igniter is shut off at the end of the trial for main flame.

e) Trial for main flame ignition sequence.

f) Main flame or normal operation

g) Safe shutdown of the system.

h) Boiler post purge.

Electronic controls are available that receive flame scanner signals and provide the control sequences listed above when connected to the proper switches, valves, and motor starters. Electronic controls are equipped with self-checking circuits that prove the controls to be operational. Figure 70 shows an electronic programming control incorporated into a simple control cabinet typical of a fire tube boiler application. Note that motor starters, draft control, and a draft indicator are included. Relay logic has been commonly used in the past on multiple burner applications, but many new systems are operated and monitored by programmable controllers.

3.4.3.2 Low Water Fuel Cutoff. Float/magnet and electrode low water fuel cutoff devices are commonly used (Figures 71 and 72). Their purpose is to eliminate the major cause of boiler failure, i.e., firing a boiler with a low water level. If such a condition exists, the limit circuit is opened and fuel to the boiler is shut off. Because of its importance, the low water fuel cutoff is a device that requires manual reset. The electrode type low water fuel cutoff uses probes or electrodes to sense the water level. When the water level is above the low water electrode, electricity is conducted to ground and a sensing relay coil is energized. Another relay is used to provide the manual reset feature required. Momentary electric circuitry can be provided to bypass the low water fuel cutoffs to allow blowdown of the equipment without disrupting normal operation.

3.4.3.3 Pressure and Temperature Switches. A variety of different types of pressure switches are required to measure the wide range of pressures present in a boiler. Pressures range from a few inches of water in the furnace to hundreds of pounds per square inch in the steam drum. Figure 73 illustrates a mechanical type pressure element with a mercury-filled switch typically used for applications in the range of 5 to a few hundred psig. Diaphragm-type mechanisms with snap action switches, as shown in Figure 74, are used for air pressure measurements in the inches of water range. In both cases, a change in system pressure causes the sensing element to deflect, activating the switch mechanism. Temperature switches can use liquid- or vapor-filled bulbs or bimetallic elements to activate similar switch mechanisms (Figure 75).

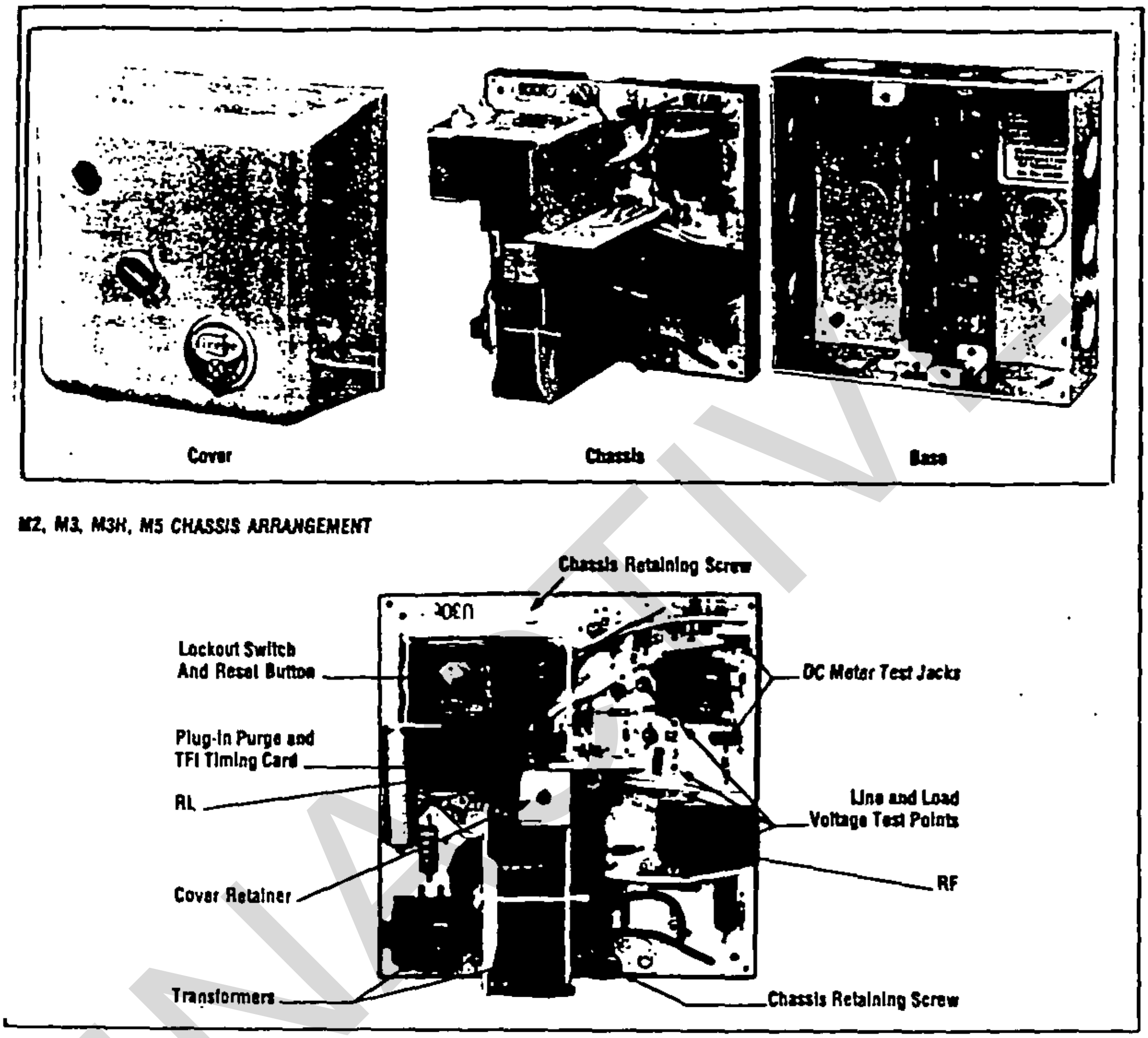


Figure 70
Electronic Programing Control in a Boiler Panel

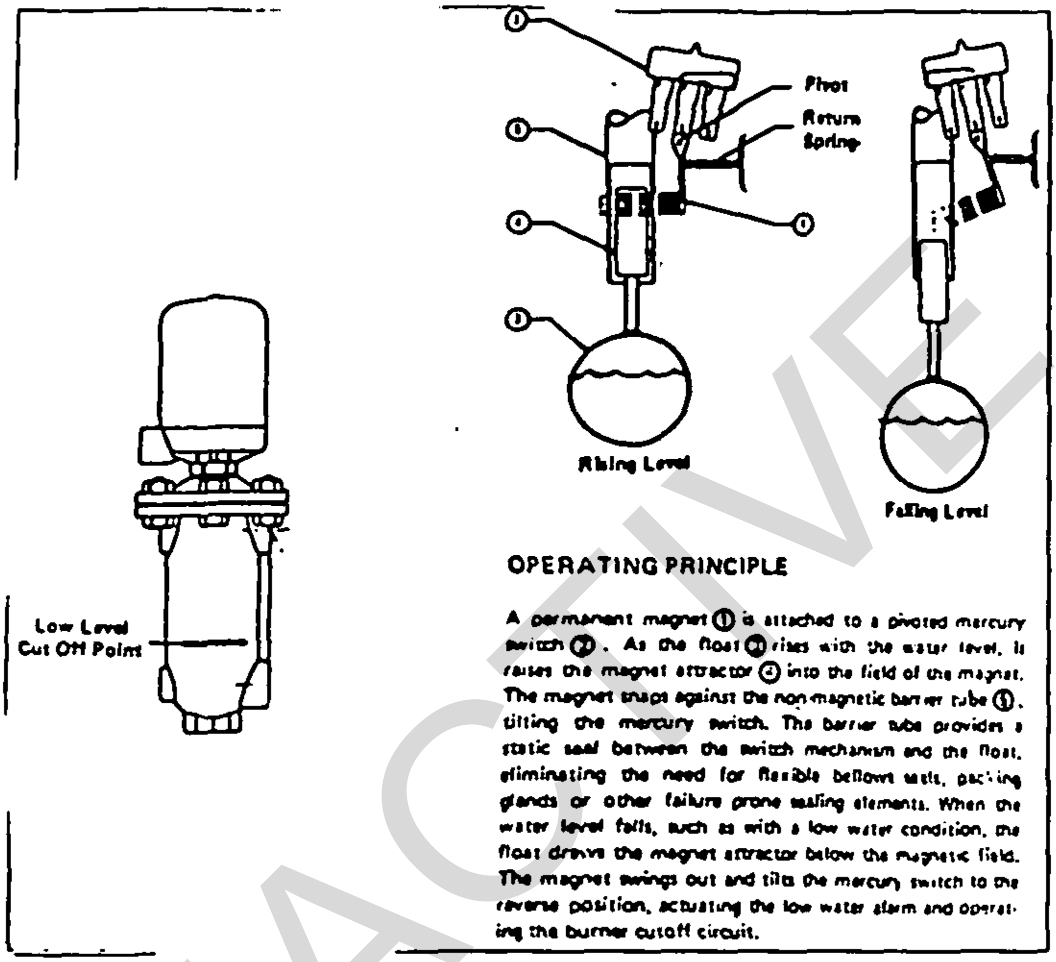


Figure 71
Float/Magnet Low Water Fuel Cutoff

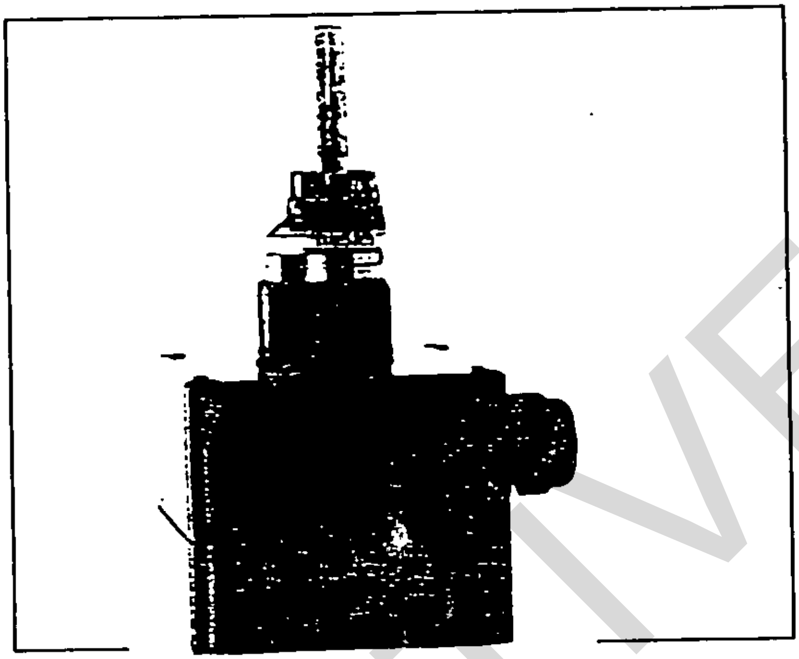


Figure 72
Resistive Type Low Water Fuel Cutoff

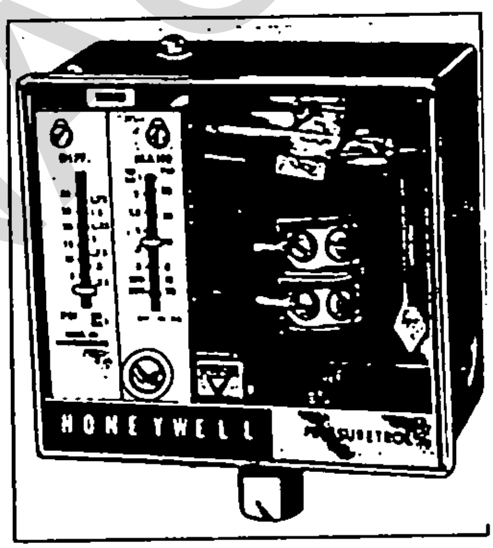


Figure 73
Mechanical Type
Pressure Switch

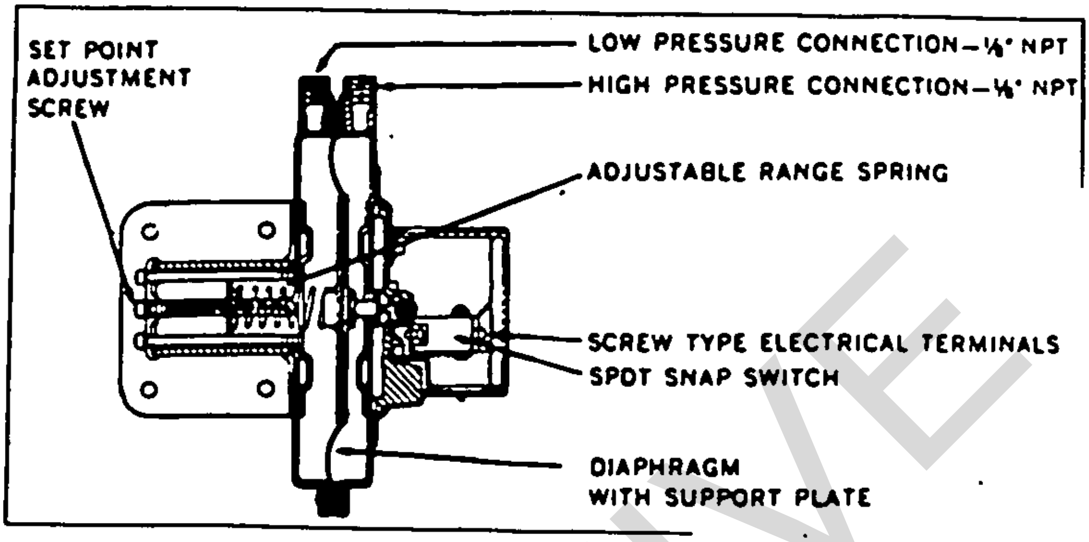


Figure 74
Diaphragm Pressure Switch

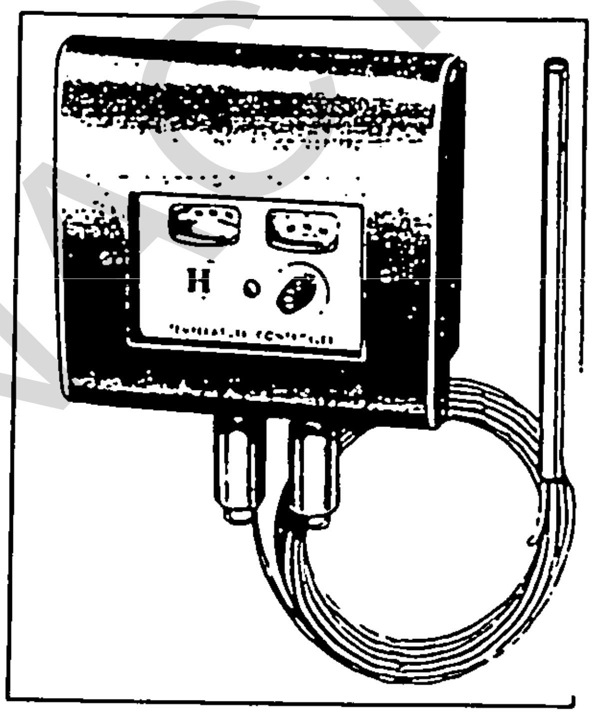


Figure 75
Temperature Switch

3.4.3.4 Flame Scanners. Flame scanners that view the ultraviolet range of light are commonly called UV scanners. Lead sulfide scanners that view the infrared and visible range of light are also common. Self-checking scanners, like the UV scanner shown in Figure 76, are equipped with shutters that allow the scanner's electronic controls to prove that the scanner components are properly functioning. New types of scanners and electronics are also available which measure the frequency of the light observed and account for the fact that the base of a flame generates light at a frequency of many hundred cycles per second, while the tips generate light less than 60 cycles per second. Frequency scanners are especially effective in multiple burner applications because they can discriminate well between the flames from various burners.

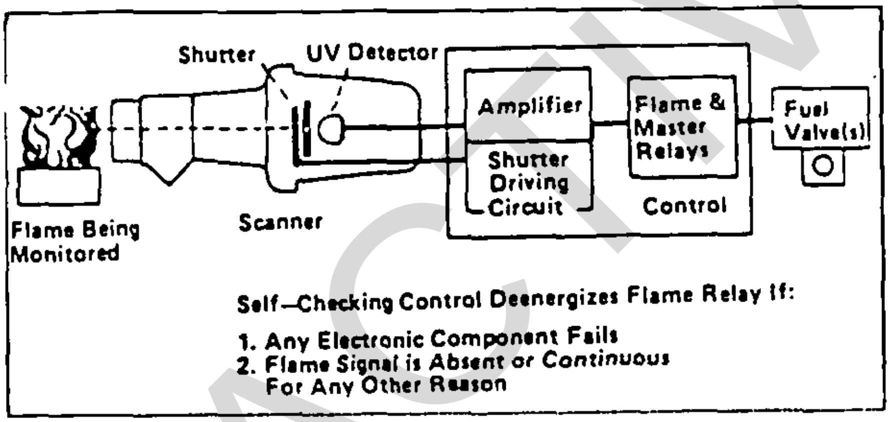


Figure 76
U-V Flame Scanner

3.4.3.5 Annunciators. Figure 77 illustrates a typical annunciator system. Annunciators are frequently used in boiler plants to perform the following functions:

a) Provide continuous monitoring of important operating conditions such as temperature, pressure level, vibration, main flame, bearing cooling, and other conditions associated with the boiler safety control and plant systems.

b) Alert operators to off-normal condition(s).

c) Require operator acknowledgment of off-normal condition(s).

d) Advise operator when the condition returns to normal.

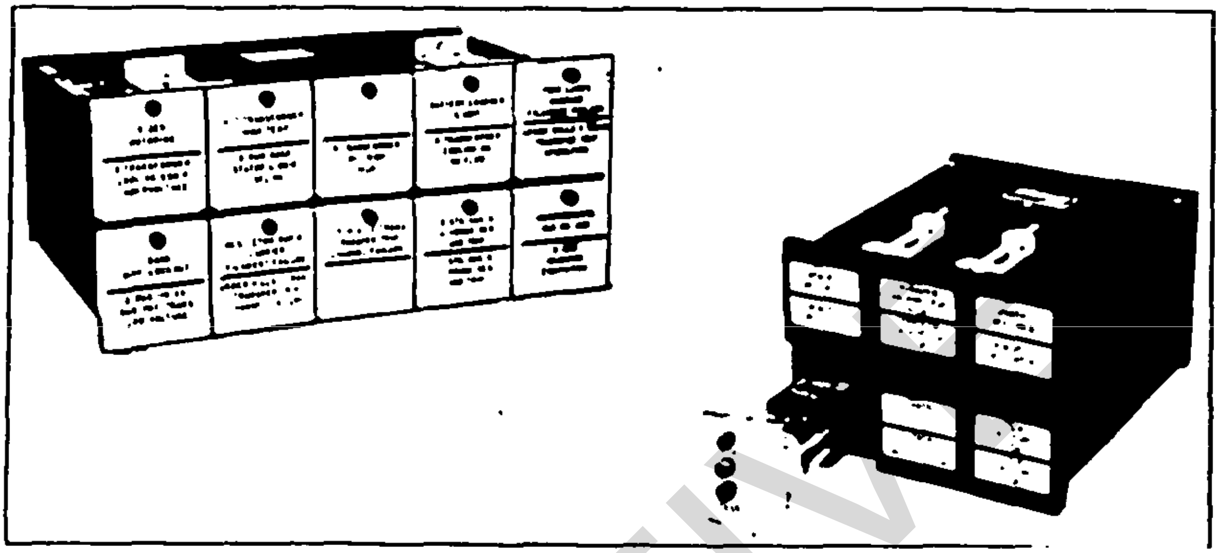


Figure 77
Annunciator

3.4.4 Additional Controls and Instrumentation. There are many types of controls and instruments that are applied to Navy boiler plants. Some provide only measurement functions, while others provide both measurement and control. Some of the common types of instrumentation for measurement and control are discussed below.

3.4.4.1 Air-Flow Steam-Flow Meter. The air-flow steam-flow meter, which is also commonly called a "boiler meter," is typically applied in series/parallel combustion control systems to provide the operator with a guide to control the relationship between the air required to efficiently burn fuel and air actually supplied. A more detailed discussion on flow meters is contained in par. 3.4.4.4.

3.4.4.2 Temperature Controls. Direct-acting, pilot-operated, and pneumatic or electronic temperature controls are available. Direct-acting temperature control regulators, shown in Figure 78, consist of a bellows-operated valve directly connected by capillary tubing to a temperature bulb. The bellows, capillary, and bulb systems are filled with a liquid, gas, or liquid-vapor combination. The bulb is inserted wherever temperature is to be controlled, as in a feedwater heater or hot water heater, and the valve is mounted in the steam or hot water line supplying the heat. Temperature changes at the bulb produce an expansion or contraction of the bellows and subsequent movement of the valve stem. An adjustable compression spring opposes expansion of the bellows and provides a means to adjust the controlled temperature. Direct-acting regulators, while simple, reliable, and inexpensive, are of limited capacity, and the valve and bulb must be located within the practical length of the capillary.

a) Pilot-Operated Valves. Pilot-operated valves are available for larger capacity and more flexibility of installation. Pilot-operated valves may be operated by either internal or external pilot valves. A bulb and capillary system controls the movement of a small pilot valve. Variable loading pressure produced by the pilot valve controls movement of the control valve. Figure 79 shows a pilot-operated temperature control valve. Both direct-acting and pilot-operated temperature regulators are proportional devices.

b) Pneumatic and Electronic Temperature Controllers. For improved control accuracy, two-mode (proportional plus integral) temperature controllers are available using either pneumatic or electronic components. Filled bulbs, bi-metal elements, thermocouples, and resistance temperature devices (RTDs) are used as sensing elements. The pneumatic or electronic controllers compare the sensed temperature with a setpoint and generate an output to control an actuator/valve. The actuator may be either pneumatic or electric.

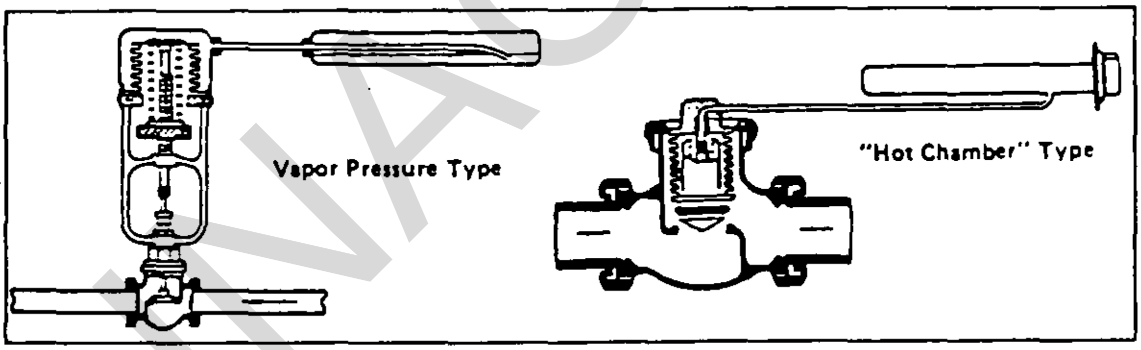


Figure 78
Direct-Acting Temperature Regulator

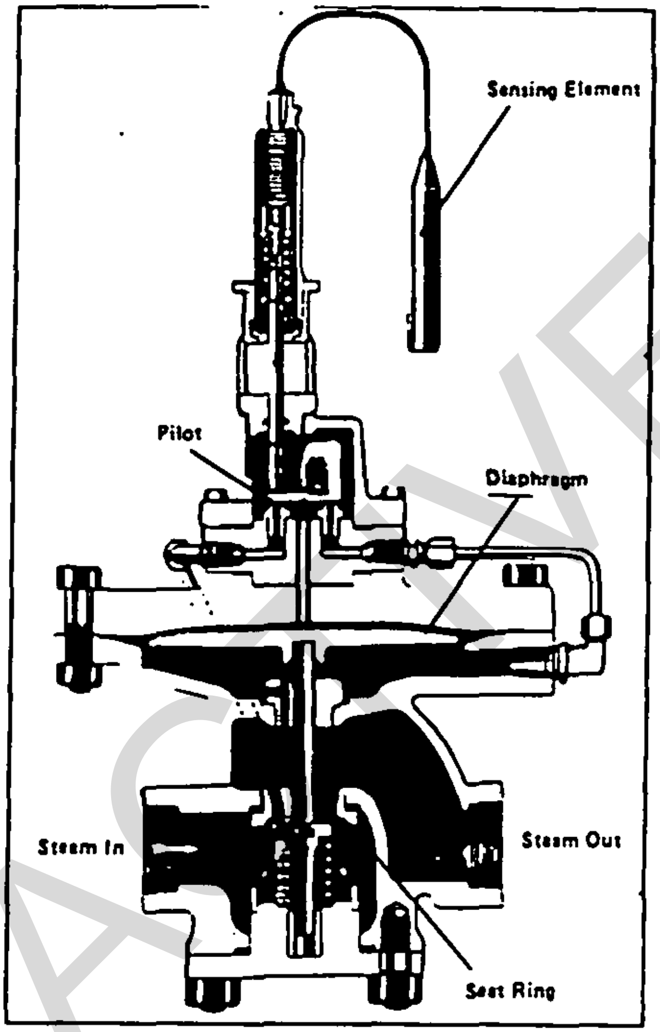


Figure 79
Pilot-Operated Temperature
Control Valve

3.4.4.3 Pressure Controls. Pressure controllers may be divided into two general types. One type maintains a set pressure in one part of the system while pressure in the other part fluctuates or changes within certain limits. An example of this type of control is a pressure-reducing valve, which maintains a set pressure on the discharge side by controlling the flow of steam, air, or gas. The second type of control maintains a constant pressure differential between two points and also controls the flow. This type of control is often applied to a boiler feedwater system to maintain a fixed differential between the pressure of water supplied at the feed valve and the pressure in the steam drum. The pressure controller may consist of either a self-contained device which operates the regulating valve directly, or a pressure-measuring device, such as a Bourdon tube, which operates a pneumatic controller. The controller positions the regulating valve or mechanism to maintain desired conditions. Operation of pressure-reducing and differential-pressure valves depends upon a load applied to a diaphragm or piston, balancing the force exerted by a spring. The pressure load is applied to both sides of the diaphragm or piston in a differential pressure valve, but to only one side in a pressure-reducing valve. A spring or weight is used to balance the valve in either case.

a) Pilot-Operated Pressure-Reducing Valve. The valve shown in Figure 80 is a self-contained pressure-reducing valve, which operates as follows: The deliver pressure acts on the bottom of the diaphragm, tending to push it up. This movement is opposed by the spring, and the diaphragm assumes a position dependent upon these two forces. The pilot valve is held against the diaphragm by a spring, so any movement of the diaphragm causes the pilot valve to move. One side of the pilot valve is connected to the supply pressure, and the other to the top of the piston which is in contact with the main valve. The spring on the bottom of the main valve holds the valve against the piston and supplies the force necessary to move the piston up. When the valve is in equilibrium (that is, when flow through it is sufficient to maintain discharge pressure at the desired level), any drop in pressure on the discharge side causes the spring to push the diaphragm down and open the pilot valve further. The pilot valve, in turn, transmits a pressure to the chamber above the piston and causes the piston to move downward. This opens the main valve and increases the flow, building up discharge pressure until the valve is once again in equilibrium. The reverse occurs if discharge pressure rises. Discharge pressure setpoint is regulated by adjusting the spring.

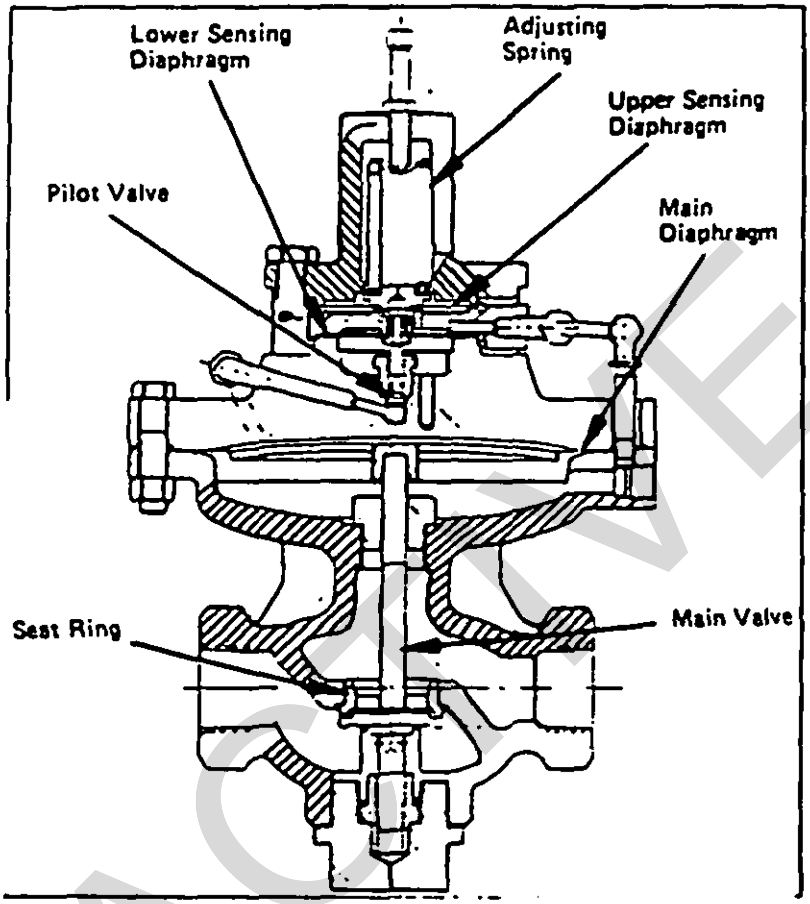


Figure 80
Pilot-Operated Pressure-Reducing Valve

b) Diaphragm Pressure-Reducing Valve. The valve in Figure 81 is equipped with a diaphragm actuator and is used for many purposes. It is commonly connected to a pneumatic controller to serve as a pneumatic control valve. When used as a pressure-reducing valve, the pressure to be controlled is applied to the top chamber and a movement of the diaphragm is transmitted directly to the control valve. An increase in pressure pushes the diaphragm out against the resistance of the spring and closes the valve until equilibrium is established. The controlled pressure can be varied by adjusting the compression in the spring. Figure 82 illustrates a self-contained diaphragm pressure-reducing valve. The outlet pressure balances the force of the spring within the valve body. The remote pressure sensing capability of the previous valve is eliminated by the simplicity of this valve.

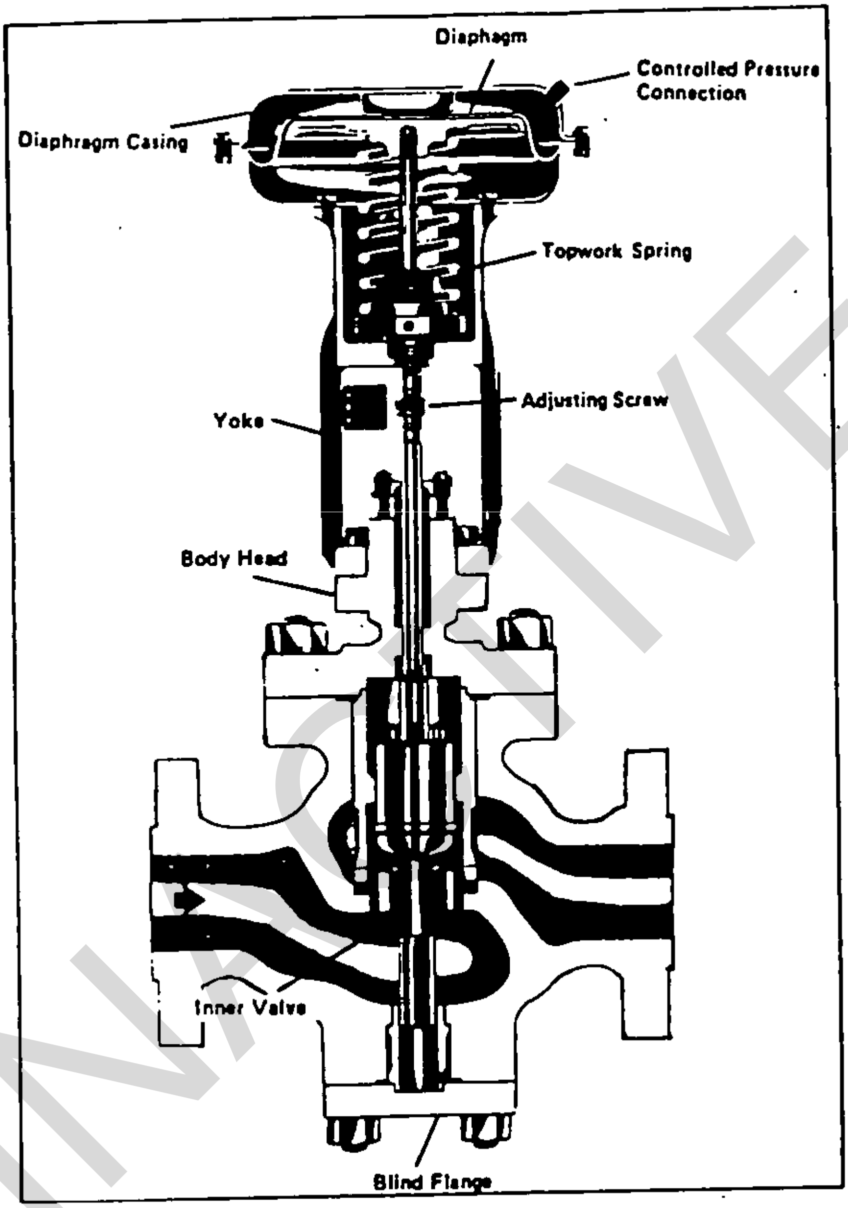


Figure 81
Diaphragm Actuator Pressure-Reducing Valve

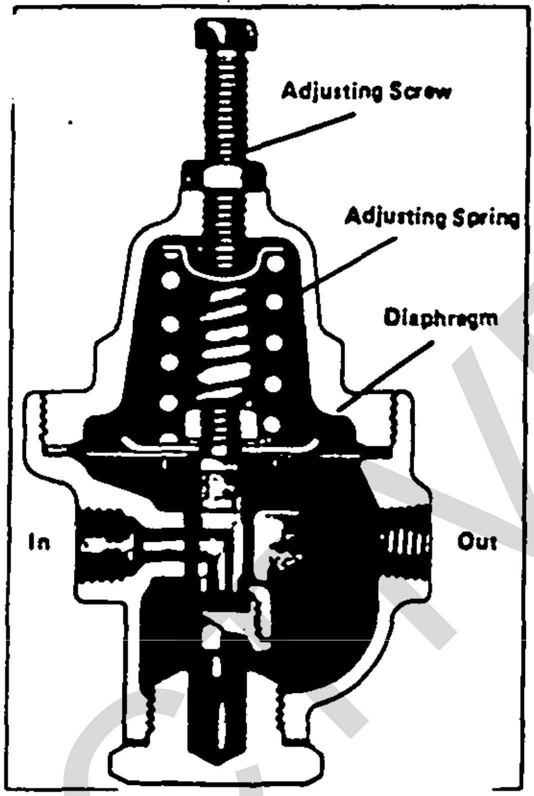


Figure 82
Self-Contained Diaphragm
Pressure-Reducing Valve

c) Differential Pressure-Reducing Valve. In the valve shown in Figure 83, a pressure-tight chamber is provided on each side of the diaphragm, and a spring is used to control the differential between the two pressures. The top and bottom chambers are connected to the two pressures to be controlled. When the force on the top chamber of the diaphragm is equal to the force on the bottom plus the spring force, the valve is said to be in equilibrium. If the bottom chamber pressure changes, the spring acts on the diaphragm to cause the pressures to vary simultaneously, maintaining a constant differential.

d) Steam Differential Pressure-Reducing Valves. Figure 84 illustrates a differential pressure-reducing valve typically used to control atomizing steam to oil burners. An oil sensing line is connected to the top chamber of the valve. The pressure of the oil and spring are added together to balance the pressure of the steam and to adjust the valve position. Force applied by the spring establishes the differential pressure between the oil and steam.

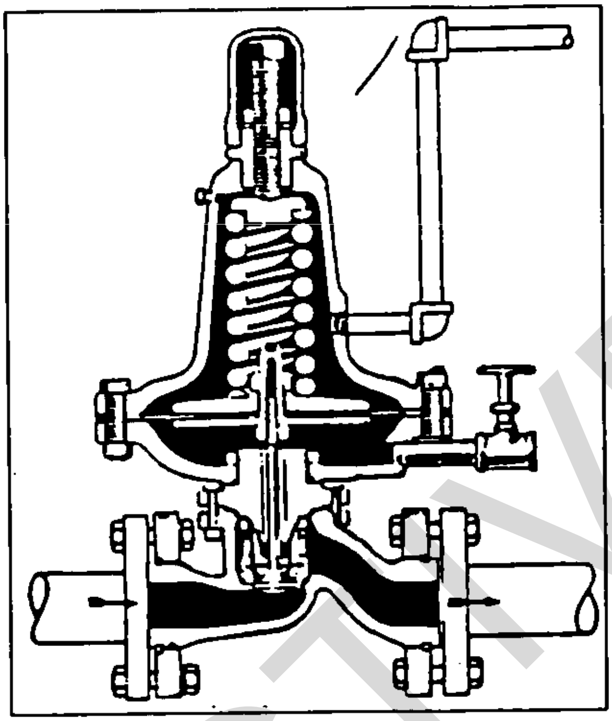


Figure 83
Differential
Pressure-Reducing Valve

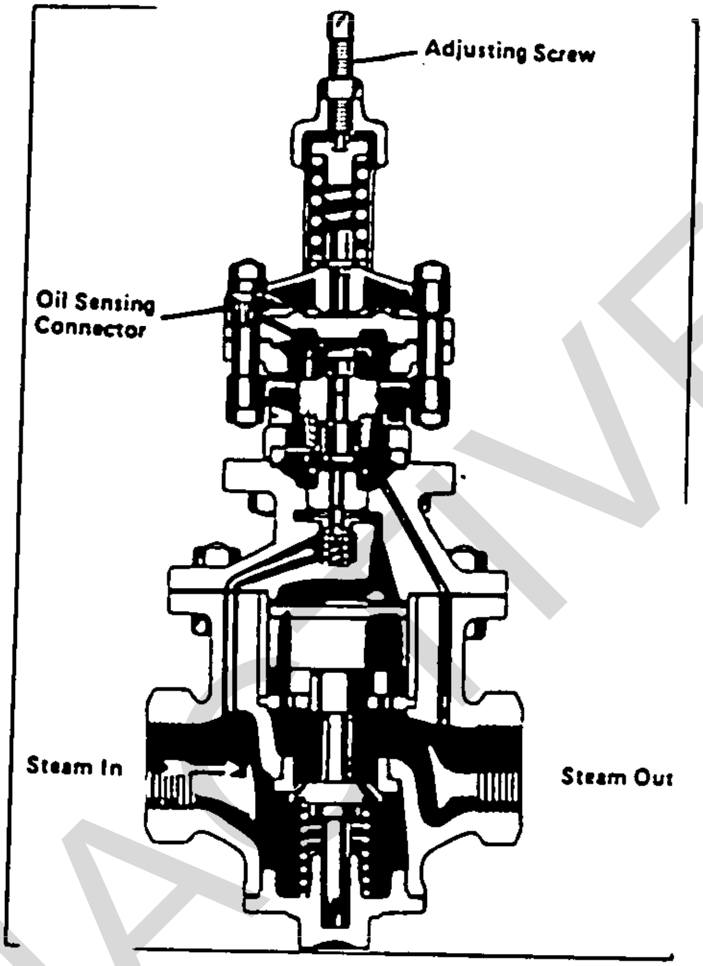


Figure 84
Steam Differential
Pressure-Reducing Valve

3.4.4.4 Flow Meters. Eight types of flow measuring elements are typically found in central heating plants:

a) Differential pressure (orifice)

b) Pitot tubes

c) Vortex shedders

d) Variable area

e) Volumetric/positive displacement

f) Propeller and turbine

g) Weirs and flumes

h) Electromagnetic flow meter

These measuring elements may be connected to recorders, indicators, or totalizers to provide information on plant operation.

(1) Differential Pressure Meters (Orifice). Differential pressure flow meters measure pressure loss created by fluid flow through a pipeline restriction such as an orifice, flow nozzle, or venturi (Figure 85). Water, steam, or gas flowing through a restriction increases in velocity and decreases in pressure. The pressure drop increases by the square of flow or velocity. Thus, if an orifice has a pressure drop of 100 inches of water at 100 percent flow, the pressure drop is only 1 inch of water at 10 percent flow. This explains why it is difficult for differential flow meters to provide accurate information at low flow rates. Figure 86 illustrates a steam flow recorder equipped with a Ledoux bell. The Ledoux bell is shaped to take the square root of a signal from the line restriction. Movement of the bell is transmitted through a system of levers and links to a pen which records the flow on a chart. Pneumatic transmitters like the one shown in Figure 87 are available to replace the function of the Ledoux bell. Very accurate electronic transmitters are also available.

(2) Pitot Tubes. Pitot tubes are used to measure flow in ducts and pipes. They are portable and are used where spot checks of flow are required. Pitot tubes are well suited for low to medium flow in large ducts (Figure 88). Flow does not pass through the pitot tube; instead it impacts on the pitot and causes higher pressure. The difference between higher impact pressure and static pressure relates to velocity of the fluid.

(3) Vortex Shedder Flow Meters. Vortex shedders operate over a wide flow range with high accuracy. They are unaffected by changes in viscosity and density of fluid, and they are relatively easy to install. They operate on the principle that a bluff body immersed in a flow sheds vortices alternately from its sides (see Figure 89). Vortices impart an oscillating motion to fluid flow. Since there is a direct relationship between velocity and the frequency of vortex shedding, this method can be utilized for flow measurement.

(4) Variable Area Meters. In a variable area or rotameter, fluid passes upward through a tapered meter tube which contains a float. Float position indicates rate of fluid flow.

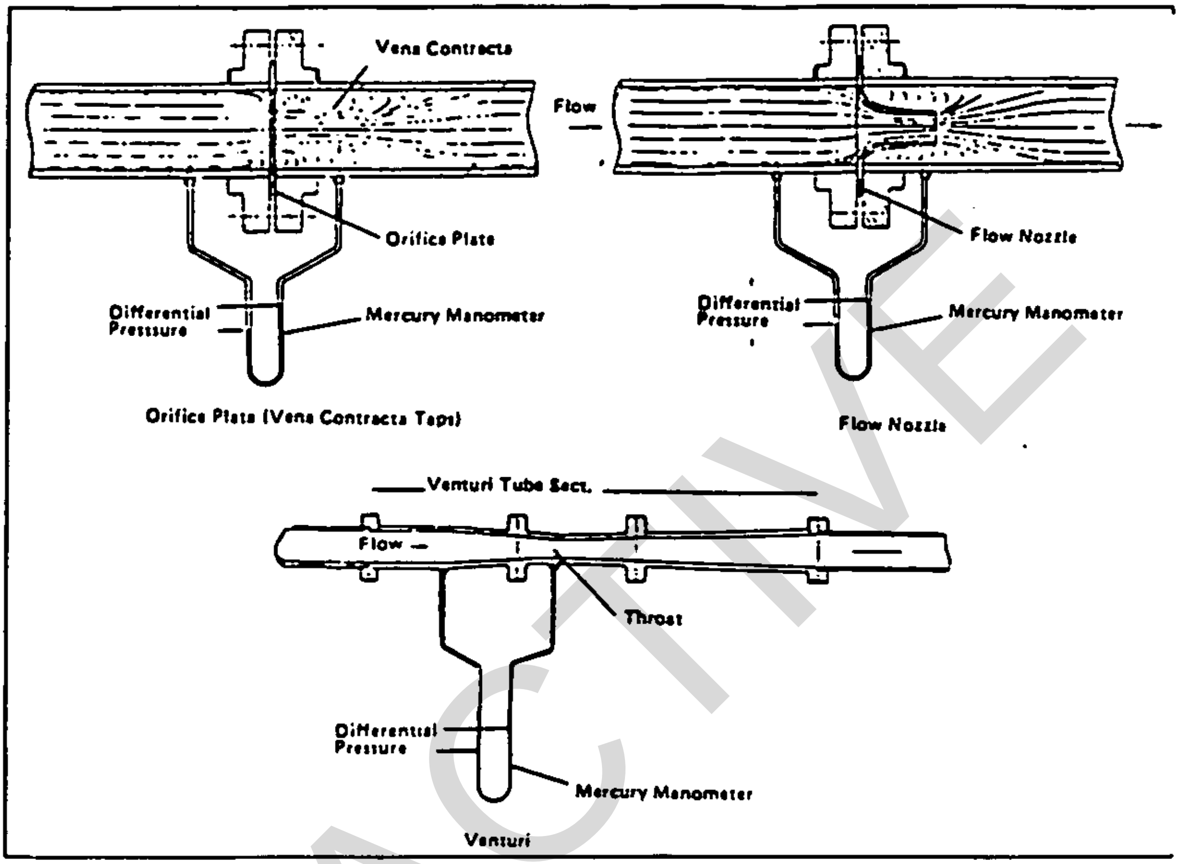


Figure 85
Orifice, Flow Nozzle, and Venturi

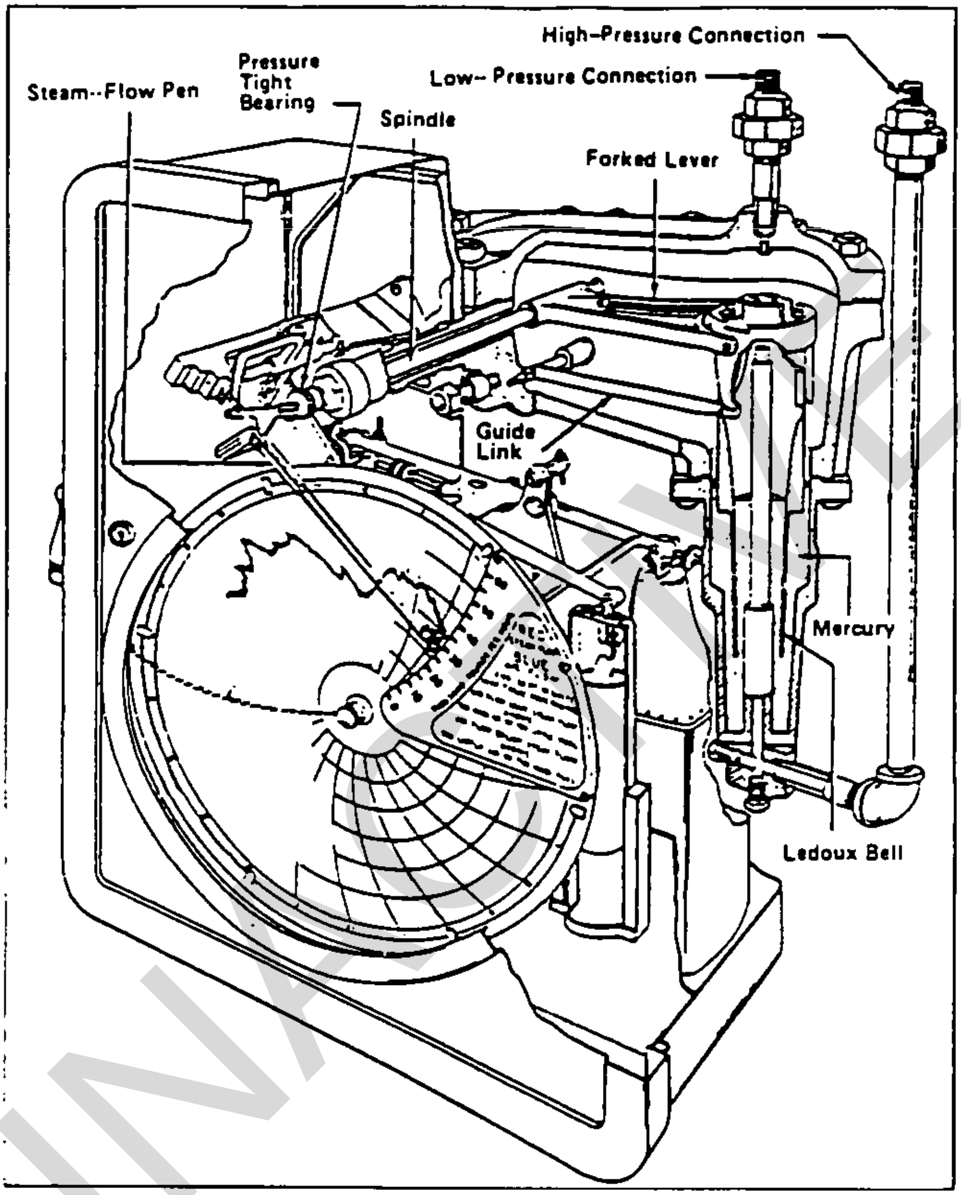


Figure 86
Steam Flow Recorder

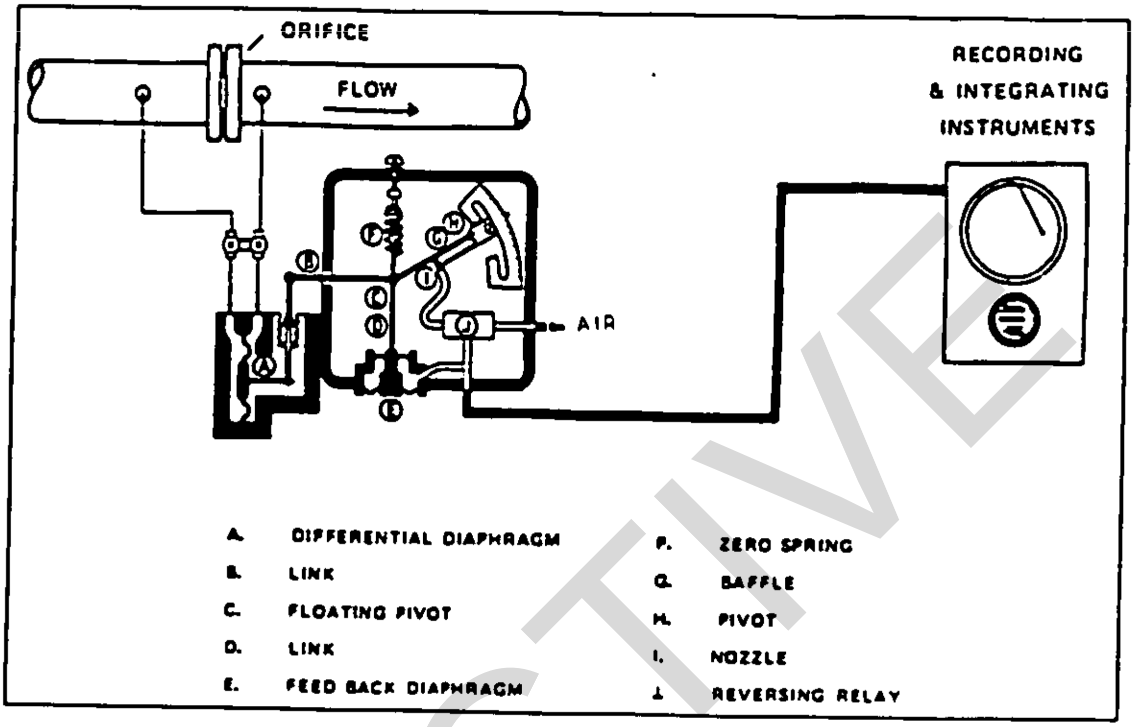


Figure 87
Pneumatic Differential Pressure Transmitter

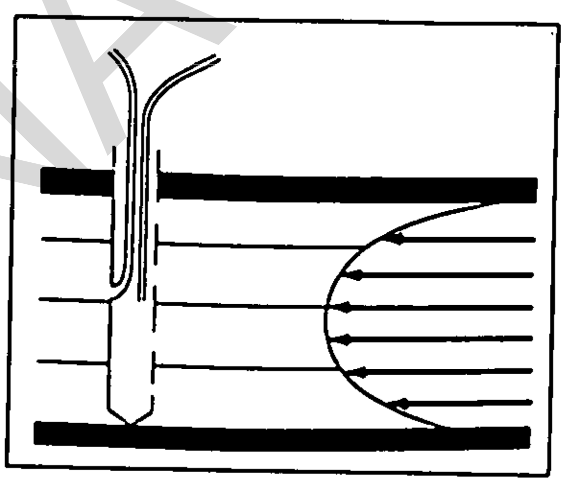


Figure 88
Pitot Tube Design and
Installation

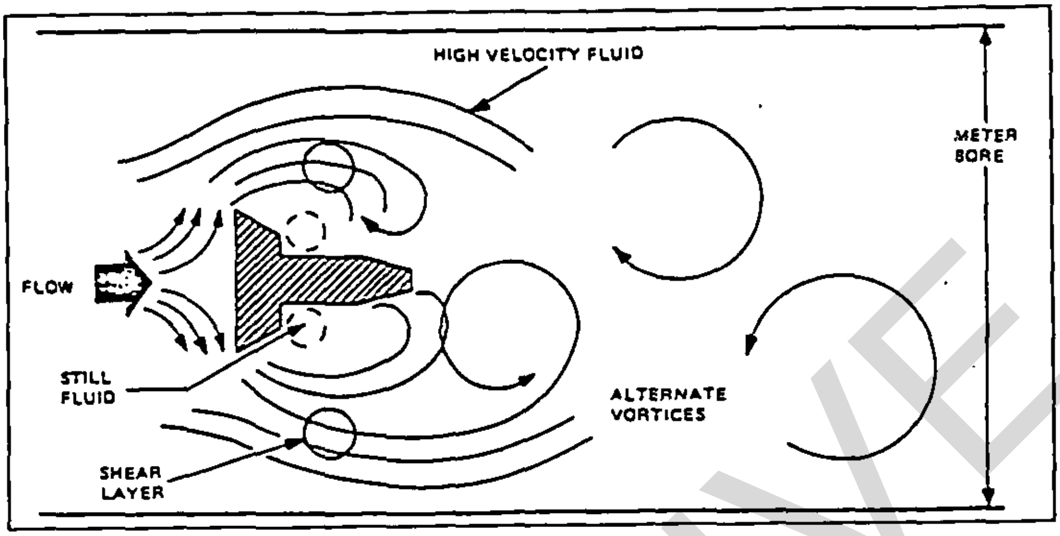


Figure 89
Vortex Shedding Phenomenon

(5) Volumetric Meters. Volumetric or positive displacement meters are frequently used to measure gas, oil, or water and are equipped with a dial register that indicates the total volume of flow. Figure 90 illustrates a positive displacement meter for oil service. These meters can also be equipped to generate flow rate signals.

(6) Turbine Meters. In turbine meters, the rotational velocity of the propeller or turbine is proportional to fluid velocity or flow. Flow rates are measured by electronic equipment which senses this rotational velocity and converts it to a volumetric reading. Figure 91 illustrates a turbine meter.

(7) Weirs and Flumes. Changes of liquid flow rates through the weir or flume cause a change in the upstream liquid level. Float-actuated level indicators are used to indicate flow rate.

(8) Electromagnetic Flow Meter. A magnetic flow meter consists of a transmitter and a primary flow tube surrounded by electromagnetic coils. A process fluid moving through the magnetic field generates a voltage, which is proportional to fluid velocity. The transmitter converts these voltages to an appropriate output signal.

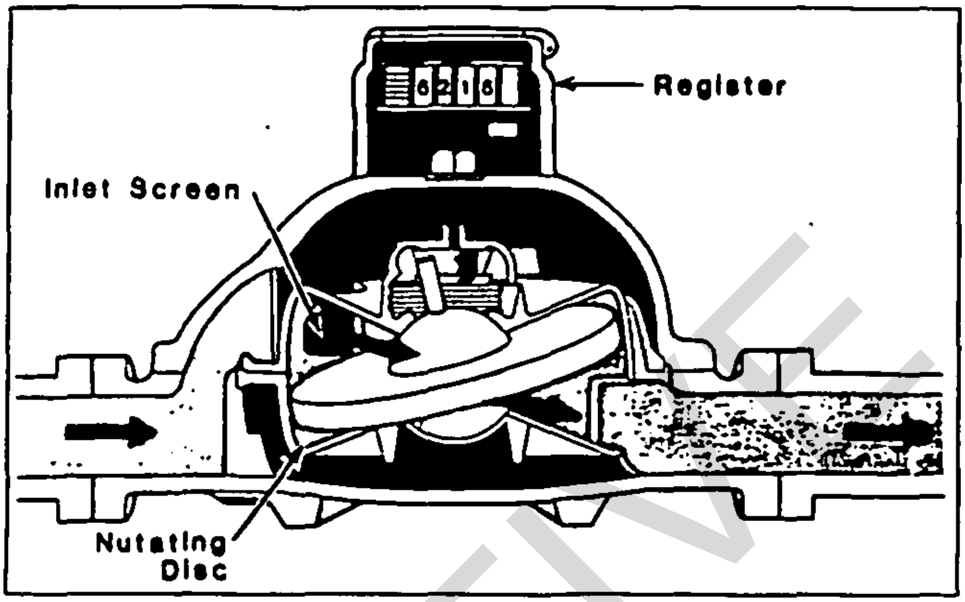


Figure 90
Positive Displacement Meter

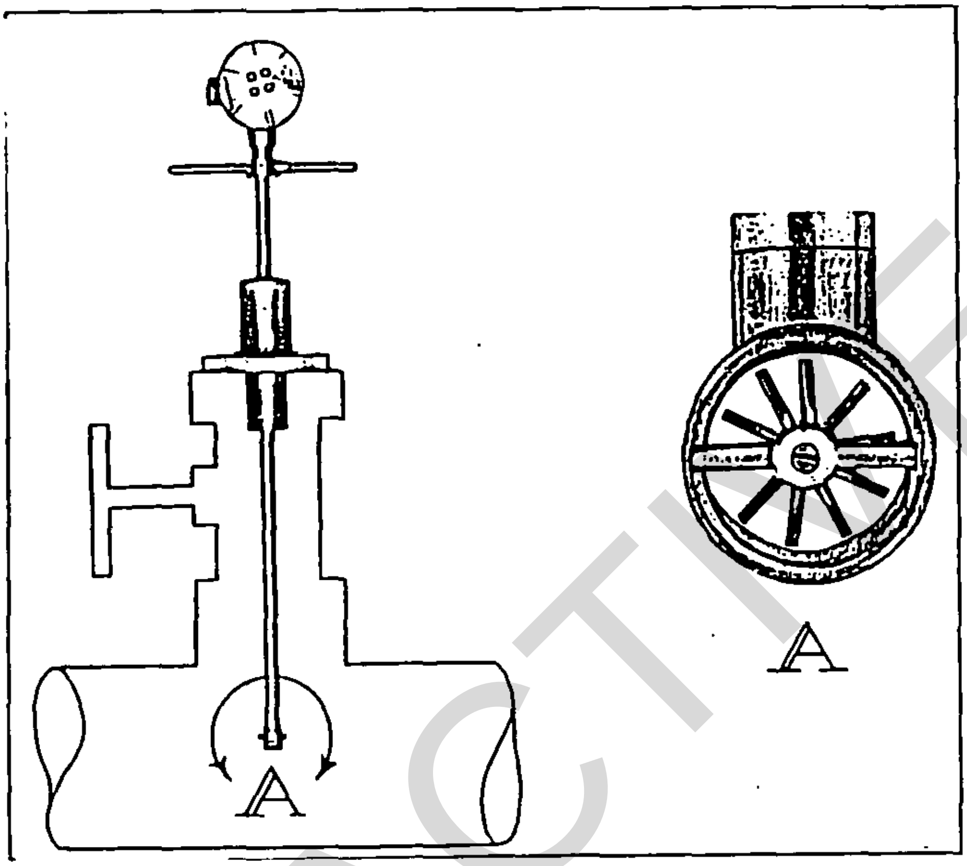


Figure 91
Turbine Meter

3.4.4.5 Pressure Gages. A number of devices may be used to measure pressure. The Bourdon tube is the one most commonly applied in boiler plants.

a) Bourdon Tube Pressure Gage. The measuring element of the Bourdon tube gage (Figure 92) is a tube of oval cross section bent into an arc which is closed at one end and connected to the source of pressure at the other. This oval cross section changes its shape with changes in pressure. When pressure within the tube increases, the cross section tends to become circular and causes the tube to straighten. Movement of the free end of the Bourdon tube is transmitted through a gear and pinion to a pointer which indicates the change in pressure. The shape of the tube and the material from which it is made depend upon the pressure range for which the gage is to be used. This type of gage can be used to measure pressures either above or below atmospheric. When using a gage to measure steam pressure, a siphon or water leg must be used to ensure that hot steam does not come into direct contact with the tube.

b) Other Types of Pressure Gages. Diaphragm gages are used for measurement of small differentials in inches of water where total pressure does not exceed about 1 psig. For high static pressures, opposed bellows gages (Figure 93) are available to read a wide range of differential pressures. They are suitable for reading fluid pressure drops through boiler circuits and can be used to measure differentials from 2 to 1,000 psi at pressures up to 6,000 psig. More sophisticated devices for measurement of pressures and differential pressures are also on the market. Generally described as transducers, they are based on a variety of principles. Some examples are transducers using a strain gage mounted on a diaphragm, or those using a crystal which undergoes a change in electrical resistance as the element is deformed. Since such elements require elaborate and frequent calibration, they have not historically been used as basic instruments in boiler plants. However, with their rapidly increasing reliability and ease of application, pressure transducers are finding wider application and will become more frequently seen.

3.4.4.6 Draft Gages. A draft gage is a form of pressure gage that measures pressures in the range of inches of water column. Draft gages typically are used to measure air pressures at the furnace, windbox, and boiler outlet. Inclined and U-tube manometers and diaphragm draft gages are common.

a) Manometers. Figure 94 shows an inclined and U-tube manometer. The inclined manometer consists of an inclined leg and a reservoir filled with gage oil. In a typical inclined manometer, the length of the scales is 12 inches for each inch of water draft measured. It is important to use the gage oil for which the manometer was designed to obtain accurate readings, since the gage reading is dependent on the density of the oil. This information is normally stamped on the manometer body.

b) Diaphragm Draft Gages. The draft gage shown in Figure 95 uses a thin metal diaphragm fastened to a flat cantilever spring. Atmospheric pressure is exerted on top of the diaphragm, and draft on the bottom. This pressure differential causes the diaphragm to move down. Downward movement is resisted by the cantilever spring. Motion of the cantilever spring is transmitted through a chain to the counterbalanced pointer and produces an indication on the scale which is directly proportional to the draft. The pointer in this gage moves in an arc. The area of the diaphragm is large, thus greatly magnifying the force available for moving the pointer.

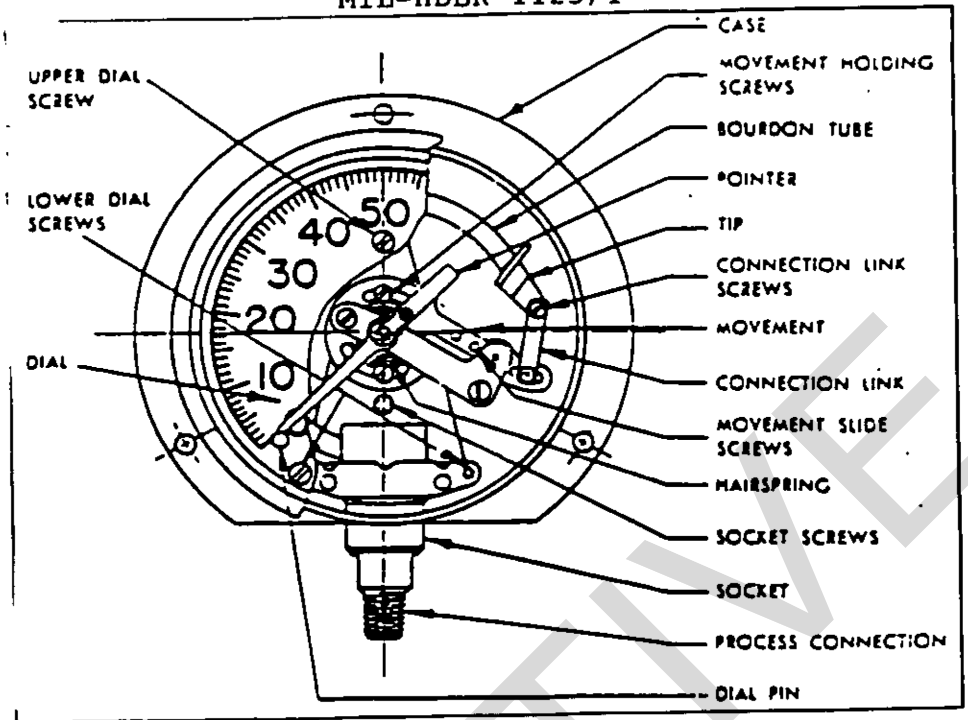


Figure 92
Bourdon Tube Pressure Gage

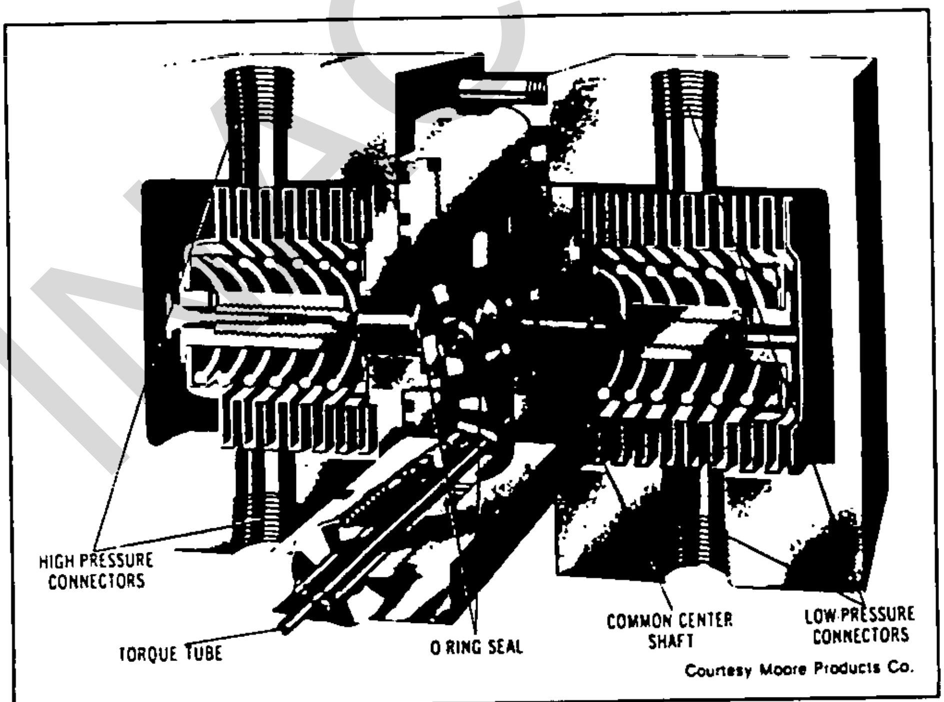


Figure 93
Opposed Bellows Differential Pressure Gage

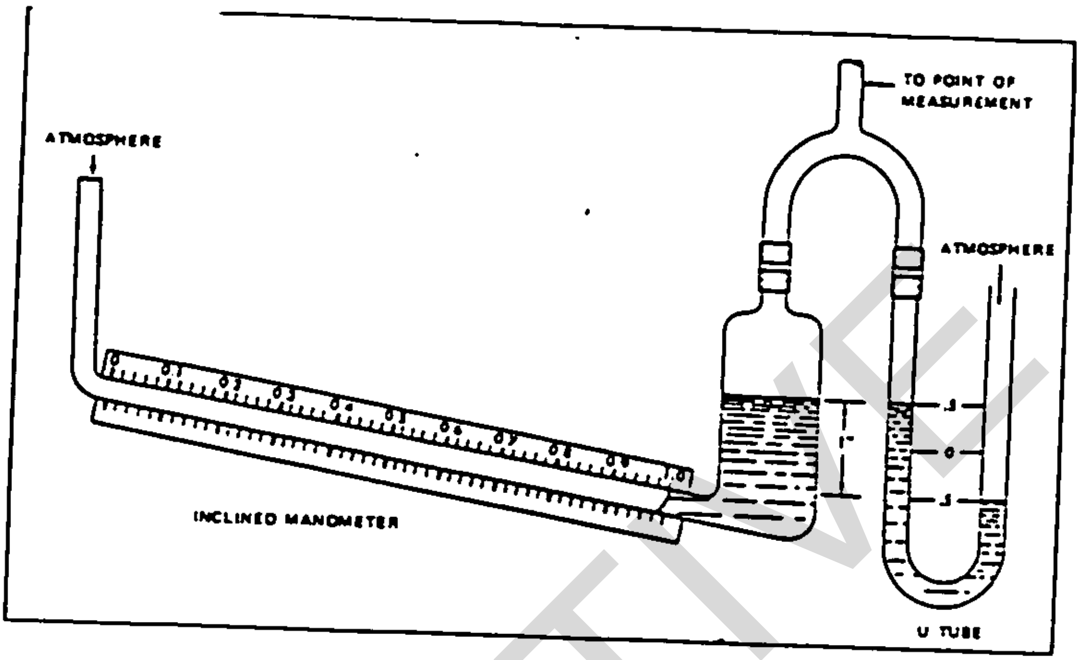


Figure 94
Inclined/U-Tube Manometer

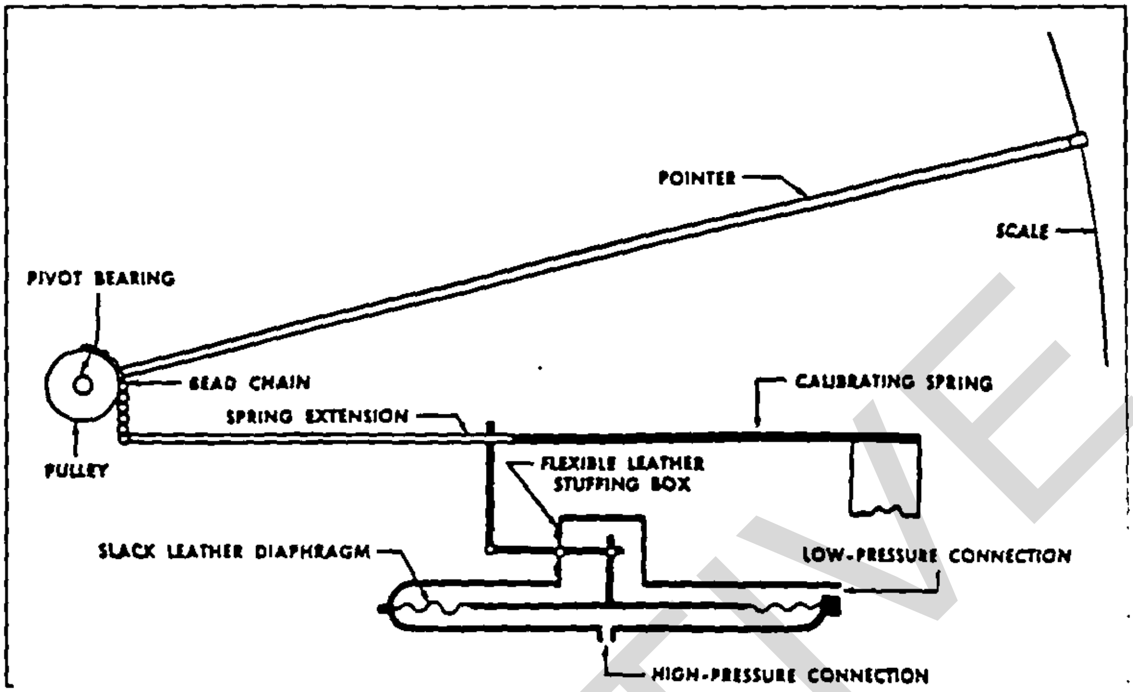


Figure 95
Diaphragm Draft Gage

3.4.4.7 Flue Gas Analyzers. A variety of flue gas analyzers may be installed in central boiler plants. Their purpose is to allow the operator to more efficiently monitor and operate the plant and to ensure compliance with environmental regulations.

a) Oxygen Analyzer. The percentage of oxygen in boiler flue gas is an effective combustion guide. Continuous monitoring of oxygen levels can be accomplished by using a zirconium oxide oxygen analyzer as shown in Figure 96. The analyzer consists of a sampling system which pulls flue gas into the zirconium oxide cell located in an electric furnace. At approximately 1,700 degrees F, the cell responds to the percentage of oxygen in flue gas by generating a small electric current. Analyzer electronics evaluate the electric current from the cell and produce an output signal to an indicator, recorder, or combustion trim control system.

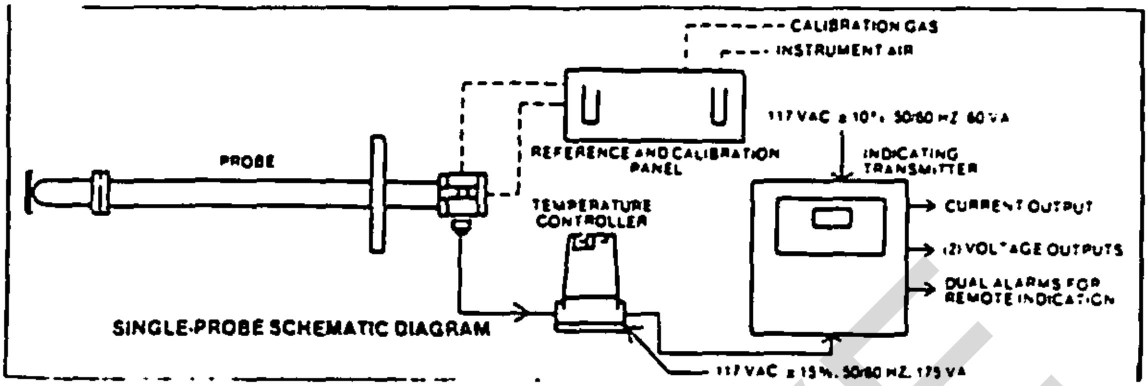


Figure 96
Zirconium Oxide Oxygen Analyzer

b) Carbon Monoxide Analyzer. Carbon monoxide (CO) in flue gas indicates incomplete combustion due to either a lack of sufficient combustion air or inefficient mixing of fuel and air. Modern boiler plants may be equipped with CO analyzers to provide the operator with an indication of how much CO exists. CO in flue gas is converted to an electric signal through oxidation on the surface of a catalyst-coated element and measurement of the heat produced. Analyzer electronics provide an output signal proportional to the concentration of CO in the sample stream. The output is sent to a recorder, or occasionally used as a trimming input to the combustion control system. Historically, reliability has been a problem with CO analyzers. However, as technology improves, their reliability is expected to improve, and their use in combustion control systems will become more common. CO trim is applicable only to oil- and gas-fired boilers, and its use is limited by essentially the same criteria as those noted for oxygen trim systems.

c) Smoke Density Indicator. Coal- and oil-fired plants are often provided with smoke density indicators and recorders. These units usually consist of a light source and photoelectric cell mounted on opposite sides of the stack, an electronic system to condition the cell signal, and an indicator or recorder mounted on the panel.

d) SO_2 and NO_x Analyzers. Continuous monitoring of pollutants is sometimes required by environmental regulations. Sulfur dioxide (SO_2) and oxides of nitrogen (NO_x) are the pollutants most commonly required to be monitored. Several different types of analyzers are available to monitor pollutants by extractive means: non-dispersive infrared (NDIR), ultraviolet photometric (UV), and electrochemical analyzers for both SO_2 and

NO_x, chemiluminescence analyzers for NO_x, flame photometric and fluorescence analyzers for SO_2. Each of these analyzers has its own advantages and disadvantages, and the technology is rapidly changing. A detailed analysis of up-to-date technology and environmental agency requirements is recommended before analyzers of this type are installed.

3.4.4.8 Temperature Gages. Temperature is measured by a number of devices, the most common of which is the mercury- or liquid-filled industrial thermometer. When remote indication or recording of temperature is needed, for example to monitor flue gas temperature leaving the boiler, then bulb/capillary, pneumatic, or electronic sensors and transmitters can be provided and connected to an indicator or recorder. Temperature devices can also be used to provide feed-forward or feedback signals to a control system.

3.4.4.9 Recorders. A variety of recorders are available to provide a permanent record of almost any variable that can be measured. Some recorders may be connected directly to the instrumentation which provides the recorded signal, such as the air-flow steam-flow meter. Others are remotely mounted and receive an electronic or pneumatic signal from the instrumentation element. Typical strip chart recorders are illustrated in Figure 97. These models can record up to three separate process variables on a 4-inch-wide strip chart, while other models may record up to 20 variables. Both strip charts and circular charts in typical use in boiler plants generally record two to four variables.

3.5 Pollution Control Equipment

3.5.1 Pollution Regulations. Control of pollutants from combustion of fossil fuels in central boiler plants may be required. Boiler plant emission regulations are issued by Federal, State, and local environmental agencies, with the most stringent regulation usually being imposed. Two general types of regulations exist: point source regulations and ambient air quality standards. With recent enactment of the Clean Air Act and increasing emphasis on the environment, regulations are becoming very strict. It is important to have a complete understanding of regulations and environmental impacts prior to specifying new plant equipment.

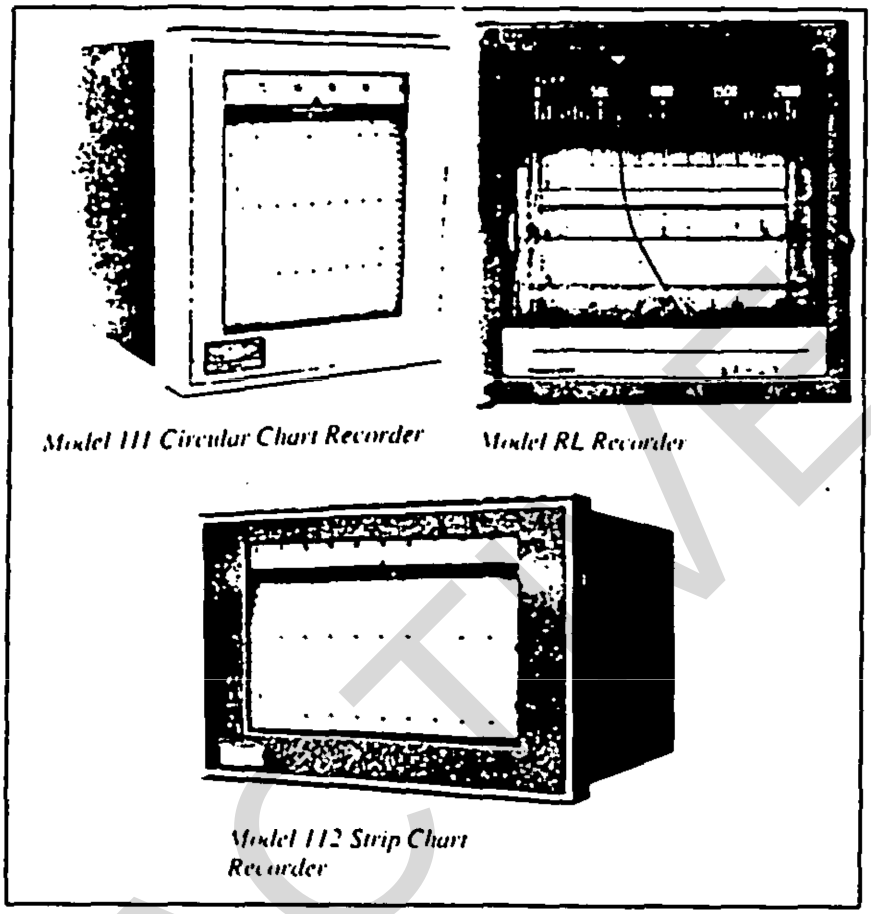


Figure 97
Strip Chart Recorders

3.5.1.1 Point Source Regulations. Point source regulations place limits upon the quantity of pollutant which may be emitted from any stack, regardless of its relationship to local air quality. These regulations should be considered to be the minimum regulations, and, if applicable, must always be met. For regulations, most Federal, State, and local agencies have minimum size limitations.

3.5.1.2 Ambient Air Quality Standards. Ambient air quality standards may be applicable to any size boiler. These standards require that emissions from the unit be considered, as they affect the air quality of the surrounding area. Consideration must be given to meteorological effects and other pollution sources in the area in determining allowable emission levels. Emission levels determined under ambient air quality standards may be the same as, more stringent than, or less stringent than applicable point source regulations for a given boiler plant. Actual determination of applicable limits usually warrants a separate study by a consultant.

3.5.2 Types of Pollutants and Control Methods. Details on installation and operation of air pollution control systems are discussed in U.S. Army Technical Manual (TM) 5-815, Air Pollution Control Systems for Boilers and Incinerators.

3.5.2.1 Oxides of Nitrogen. NO_x is the generic name for a group of pollutants formed from various combinations of nitrogen and oxygen. The principal form generated by boilers is nitric oxide, NO. NO is formed when the nitrogen in fuel and air reacts at high temperature with oxygen from the air. It can be controlled in existing boilers by careful adjustments and modification to burners aimed at lowering peak flame temperatures in the furnace and by minimizing the amount of free oxygen available in the highest temperature combustion zones. New boilers purchased to meet specific NO_x emission regulations will generally have these modifications designed into them. In addition, they will also be designed with larger furnaces and more water cooled surface in the burner zone to improve heat transfer characteristics and to further reduce the peak combustion temperature attained. Flue gas recirculation is another form of NO_x control. Some of the modifications and adjustments that can be implemented are listed in Table 11, as well as advantages and disadvantages of each and the anticipated reduction in NO_x emissions.

3.5.2.2 Oxides of Sulfur. The primary oxide of sulfur (SO_x) formed by combustion of fossil fuel is sulfur dioxide or SO_2. SO_2 is formed when sulfur from fuel combines with oxygen from the air in high temperature zones of the furnace. In a conventional boiler, essentially all the sulfur that enters with the fuel converts to SO_2. No practical form of combustion modification has been developed to reduce SO_2 generation in the furnace. To control the release of SO_2 emissions to the atmosphere, it is necessary to either burn a fuel having a lower sulfur content, or use some type of flue gas desulfurization equipment (also called scrubbers) to remove the SO_2 after it leaves the boiler. The most common types of scrubbers used on boilers are lime or limestone slurry types, magnesium oxide slurry, double alkali, and lime dry scrubbers. Some of the performance characteristics of these are summarized in Table 12. The SO_2 removal systems mentioned above are expensive both to purchase and to operate, and in most cases they cost more than the entire boiler plant. For this reason, they are not cost effective and generally not used unless dictated by regulations. They are very rarely seen on smaller plants, because compliance with regulations are generally by means of low sulfur fuel. Atmospheric fluidized bed boilers are also becoming more commonly applied when control of SO_2 emissions is required. These are generally more cost effective than scrubbers but have not been commonly applied because of their limited operating experience (refer to par. 3.3.1.7).

Table 11
Comparison of NO_x Reduction Techniques

Technique	Potential NO_x Reduction (%)	Advantages	Disadvantages
Load Reduction	25-60	Easily implemented; no additional equipment required	Reduction in generating capacity; possible reduction in boiler thermal efficiency.
Low Excess Air Firing (LEA)	15-40	Increased boiler thermal efficiency	A combustion control system which closely monitors and controls fuel/air ratios is required; possible increase in particulate emissions; increased slagging and ash deposition with coal-fired units.
Two-Stage Combustion	40-50	-	Boiler windboxes must be designed for this application. Not recommended for coal-fired units. Furnace corrosion and particulate emissions may increase.
Off-Stoichiometric Combustion (Coal)	15-45	-	Control of alternate fuel-rich and fuel-lean burners may be a problem during transient load conditions.
Reduced Combustion Air Preheat	10-50	-	Not applicable to coal-fired units; reduction in boiler thermal efficiency; increase in exit gas volume and temperature; reduction in boiler load.
Flue Gas Recirculation	20-50	Possible improvement in combustion efficiency and reduction in particulate emissions	Boiler windbox must be modified to handle the additional gas volume; ductwork, fans, and controls required.

Table 12
Performance Characteristics of
Flue-Gas Desulfurization Systems

System Type	SO_x Removal Efficiency (%)	Pressure Drop (inches of water)	Recovery and Regeneration	Operational Reliability	Retro-fit to Existing Installations	Advantage	Disadvantage
Limestone, Scrubber Injection Type	30-40	Greater than 6"	No recovery of lime	High	Yes	High reliability; no boiler scaling.	Low efficiency; scaling and plugging of nozzles and surfaces in scrubber solids disposal.
Lime, Scrubber Injection Type	90+	Greater than 6"	No recovery of lime	Low	Yes	High efficiency; no boiler scaling; less scaling in scrubber than limestone in some cases.	Low reliability; solids disposal to landfill.
Magnesium Oxide	90+	Greater than 6"	Recovery of M_gO and sulfuric acid	Low	Yes	High efficiency; no solids disposal.	Low reliability; corrosion and erosion of scrubber and piping; need precleaning of flue gas.
Double Alkali Systems	90-95		Regeneration of sodium hydroxide and sodium sulfites	Unknown	Yes	Absorption efficiency potentially higher than other systems; scaling problems reduced; produces solid rather than liquid waste.	Solids buildup in reactor system; problems with dewatering systems.
Lime, Dry Scrubbing	70-90	8" - 10" including baghouse	Lime/limestone may be recovered	Unproven but potentially high	Yes	Lower cost; relatively simple operation; produces solid waste; takes advantage of alkali content of coal ash; uses existing technology.	Unproven operational reliability; applicable only to low/medium sulfur coal; must be used in conjunction with baghouse/precipitator.

3.5.2.3 Particulate. Particulate matter, also called fly ash, is the pollutant that is of most concern to boiler operators. It is comprised primarily of unburned carbon and the portion of ash that is carried through the boiler by the flue gas stream. The quantity of particulate matter generated is strongly dependent upon the characteristics of the fuel. In general, the higher the ash content of fuel, the higher the particulate emissions. Therefore, coal produces a large amount of fly ash, natural gas produces essentially none, and fuel oil produces a moderate but widely varying amount, depending upon its grade and characteristics.

Particulate emissions may be controlled to a certain extent by careful attention to burners and combustion characteristics of the boiler. However, control of this type is essentially limited to oil firing, since the total particulate matter produced from oil is low and usually contains a large percentage of unburned carbon. Proper combustion control can minimize this unburned carbon and thus substantially reduce the total particulate emission. With coal, incoming fuel may contain 10 to 12 percent ash, as much as 80 to 90 percent of which may be carried out as fly ash. This ash far outweighs the small percentage of unburned carbon which is produced in the furnace due to incomplete combustion. Changes and adjustments to burners that minimize the unburned carbon are, therefore, largely ineffective in reducing total particulate emissions. (This is not meant to imply that proper burner adjustment and operation should be ignored on coal-fired boilers, since gains in thermal efficiency can still be realized due to a decrease in unburned carbon and reductions in excess air.)

When coal is to be fired in a boiler, it is necessary to provide particulate emission control by means of a collection device in the flue gas stream between the boiler and the stack. Several suitable types of devices exist, as itemized in Table 13 and discussed in pars. 3.5.3 through 3.5.6. In addition to these devices, under some circumstances, tall stacks may be considered a particulate control device. Although they do not remove particulate matter, tall stacks can cause particulates to be more widely dispersed in the atmosphere, and thus can be a means of meeting ambient air quality regulations.

3.5.2.4 Pollutants from Natural Gas. Of the fuels commonly burned, natural gas is the cleanest. The only pollutant generally associated with natural gas is NO_x. Since natural gas contains no ash or sulfur, there is no generation of particulate matter or SO_2.

Table 13
Performance Characteristics of
Particulate Control Devices

Device	Maximum Removal Efficiency	Typical Pressure Drop	Advantages	Disadvantages
Mechanical Collector	90-95%	3-6	High reliability; well proven; compact.	Low efficiency on small particle sizes.
Electrostatic Precipitator	99%+	0.2-0.8	High efficiency over a wide range of particle sizes; well proven; reliable; low pressure drop.	High capital cost; very sensitive to ash analysis.
Fabric Filter	99%+	3-6	High efficiency; reliable if properly designed; insensitive to coal type.	Potentially high maintenance; high capital cost; not compatible with oil-only firing; maximum operating temperature of 550 degrees F.
Wet Scrubber	99%	20-25	High efficiency; can handle high temperatures and heavy loadings.	High capital cost; high O&M cost; solid waste disposal problems; complicated control system; water supply and disposal problems; weatherproofing may be required.

3.5.2.5 Pollutants From Oil. When oil is burned in a boiler, a variety of pollutants can be formed including NO_x, SO_x, and particulates. The grades of oil most commonly burned are No. 2, and No. 6. No. 2 oil is a highly refined, clean-burning oil having little ash or sulfur, and emissions can generally be controlled by burner adjustments without resorting to specialized pollution equipment. No. 6 oil is less refined and therefore cheaper. It can contain up to about 0.5 percent ash and 3.5 percent sulfur. These higher amounts of ash and sulfur lead to higher emission levels. Particulate emission levels from No. 6 oil often become high enough to warrant use of particulate control devices. While SO_2 emissions can also become high enough to violate regulations, use of scrubbing equipment with small boilers is not generally cost effective, and regulations are usually met by conversion to an oil having a lower sulfur content.

3.5.2.6 Pollutants From Coal. Boilers burning coal will almost always require a device to control particulate emissions. NO_x and SO_2 emissions will also be high from most coals. Whether or not control of NO_x and SO_2 is required depends upon the regulation in effect in the particular locality in question. Control of NO_x emissions is accomplished by proper design, proper adjustment, and proper boiler and burner operation. Control of SO_2 emissions would usually be achieved by the use of low sulfur coal. In very few instances would use of SO_2 scrubbing equipment be cost effective on small boilers.

3.5.3 Mechanical Collectors. The term "mechanical collector" refers to a widely used type of particulate-collection device in which dust-laden gas enters tangentially, into a cylindrical or conical chamber or series of chambers and leaves through a central opening. The resulting vortex motion or spiraling gas flow pattern creates a strong centrifugal force which separates dust particles from the carrier gas stream by virtue of their inertia. The particles migrate to the cyclone walls by means of gas flow and gravity and fall into a hopper. Because of the pattern of gas flow through the collector, mechanical collectors are often referred to as cyclones. Cyclones may be classified according to their gas inlet design, dust discharge design, gas handling capacity, collection efficiency, and their arrangements. Two common types of cyclones are the conventional medium-efficiency single cyclone, and the multicyclone.

3.5.3.1 Single Cyclone. Single cyclones are used to collect coarse particles when high collection efficiency and space requirements are not major considerations. Collection efficiencies of 50 to 80 percent of particles greater than 10 microns are common. A typical configuration is shown in Figure 98. Single cyclones are 4 to 12 feet in diameter and are limited to about 20,000 actual cubic feet per minute gas flow. More than one unit can be combined in parallel to accept greater gas flows.

3.5.3.2 Multicyclones. When higher collection efficiencies or higher gas flows are required, it is common to employ the multicyclone. This device combines into a single plenum a large number of small diameter cyclones (6 to 12 inches) of a type shown in Figure 99. Due to the small diameter, higher inertial forces are generated and collection efficiencies are higher. In addition, it is possible to design multicyclones to handle virtually any gas flow simply by adding more cyclone tubes and mounting more than one unit in parallel into the gas stream.

3.5.3.3 Other Cyclones. Other types of cyclones less commonly used are the high-efficiency single cyclone and the wetted cyclone. The principal characteristics of the four types of cyclones are summarized in Table 14.

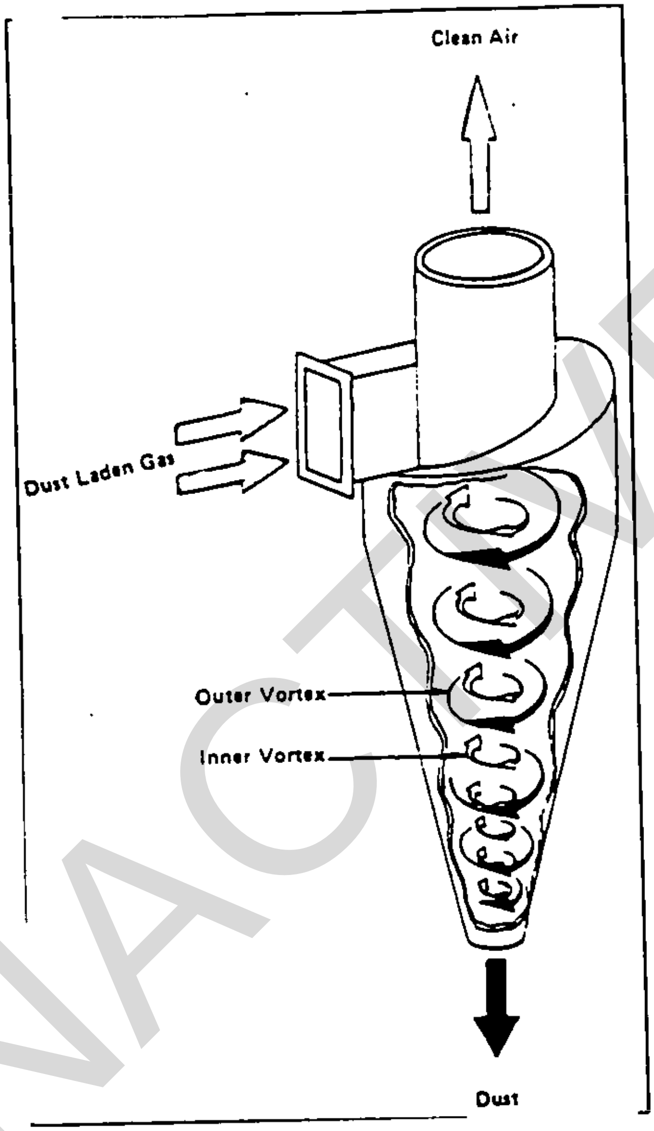


Figure 98
Medium Efficiency Cyclone
Configuration

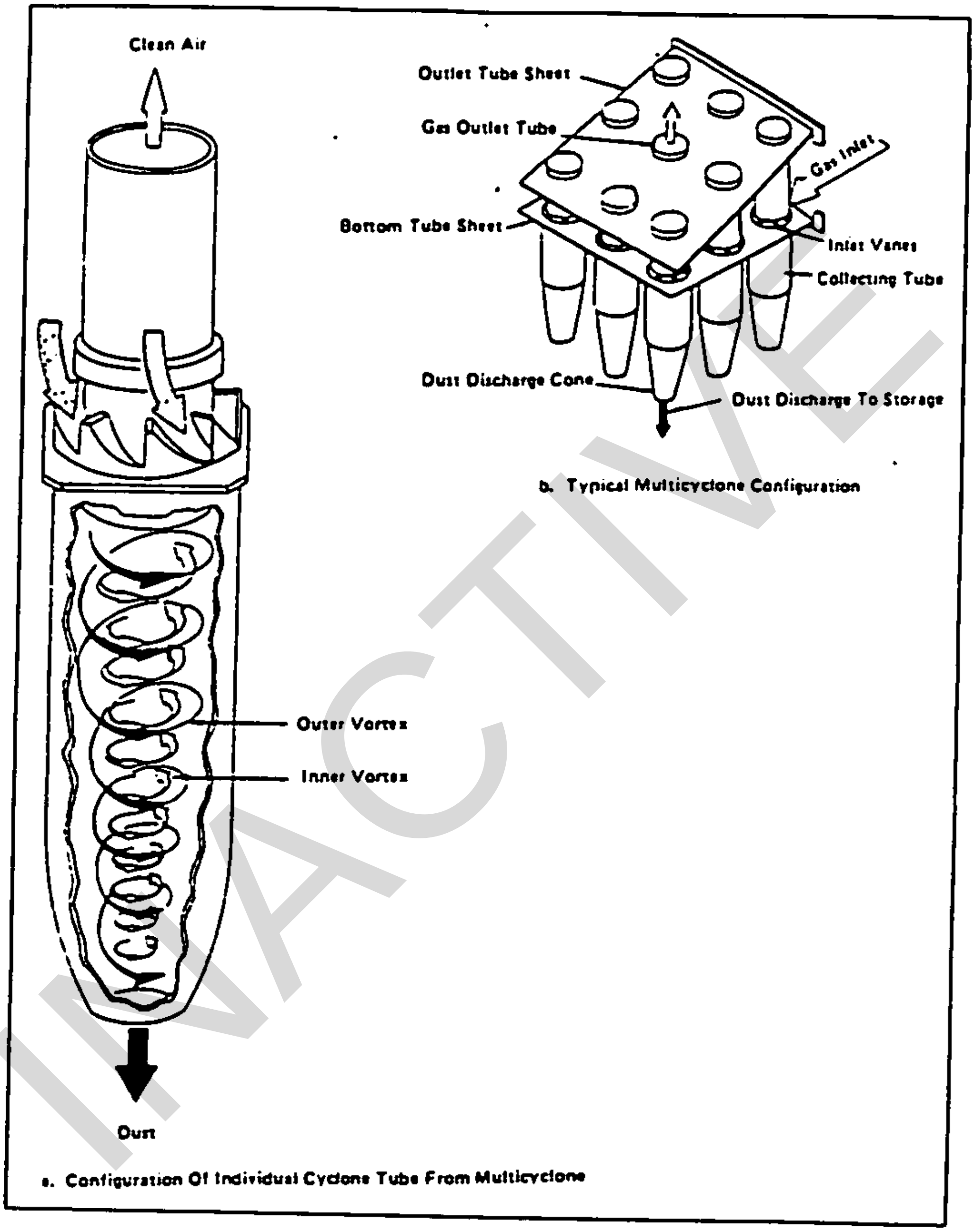


Figure 99
Multicyclone Configuration

Table 14
Characteristics of Mechanical Dust Collectors

Type	Body Diameter (ft)	Gas Flow (ft^3/min)	Pressure Drop (in-H_2O)	Inlet Velocity (ft/s)	Collection Efficiency (%)	Application	Other
Medium-Efficiency Single Cyclone	4-12	1,000-20,000	0.5-2	20-70	50-80	Material handling Exhaust gas precleaner	Large headroom requirements. Limited to large, coarse particles; large grain loadings.
High-Efficiency Single Cyclone	Less than 3	100-2,000	2-6	50-70	80-95	Industrial boiler particulate control	Smaller space requirement; parallel arrangement; inlet vane flow controls needed continuous dust removal system purge operation.
Multi-cyclones	0.5-1	30,000-100,000	3-6	50-70	90-95	Industrial and utility boiler particulate control	Plenums required. Problems: gas recirculation fouling; continuous dust removal system, flow control.
Wetted Cyclone	Less than 3	100-2,000	2-6	50	90-95	Boiler application (low sulfur fuel) (low temperature)	Water rate 5-15 gal/1,000 ft^3/min; corrosion-resistant materials.

Note: Cyclone collection efficiency must be evaluated for each specific application, due to the sensitivity of cyclone performance on gas and dust properties and loadings.

3.5.3.4 Collection Efficiency of Cyclones. The ability of a cyclone to separate and collect particles from a gas stream is dependent primarily upon the design of the cyclone, size and quantity of dust particles, and the pressure drop through the cyclone. Typical collection efficiencies for various types of cyclones, operating in various applications, are given in Tables 14 and 15. Efficiency estimates for a given application can be made by utilizing the cyclone manufacturer's fractional efficiency curves. An example of a typical fractional efficiency curve is shown in Figure 100. These curves are determined by actual testing of similar prototypes in the manufacturer's laboratory. Total collector efficiency is determined by multiplying the percent weight of particles in each size range by the collection efficiency corresponding to that size range, and determining the sum of the collected weights as a percentage of the total weight of dust entering the collector.

Table 15
Removal Efficiencies of Uncontrolled
Particulate Emissions From Combustion Processes
(Percent Removed, Medium Efficiency)

Fuel/Firing Mode	Cyclone	Multicyclone
Oil/steam or mechanical atomizer	30-40	40-50
Coal/spreader stoker	75-85	90-95
Coal/chain grate or underfeed stoker	50-70	85-90
Coal/pulverized	50-70	85-90
Coal/cyclone	30-40	40-50

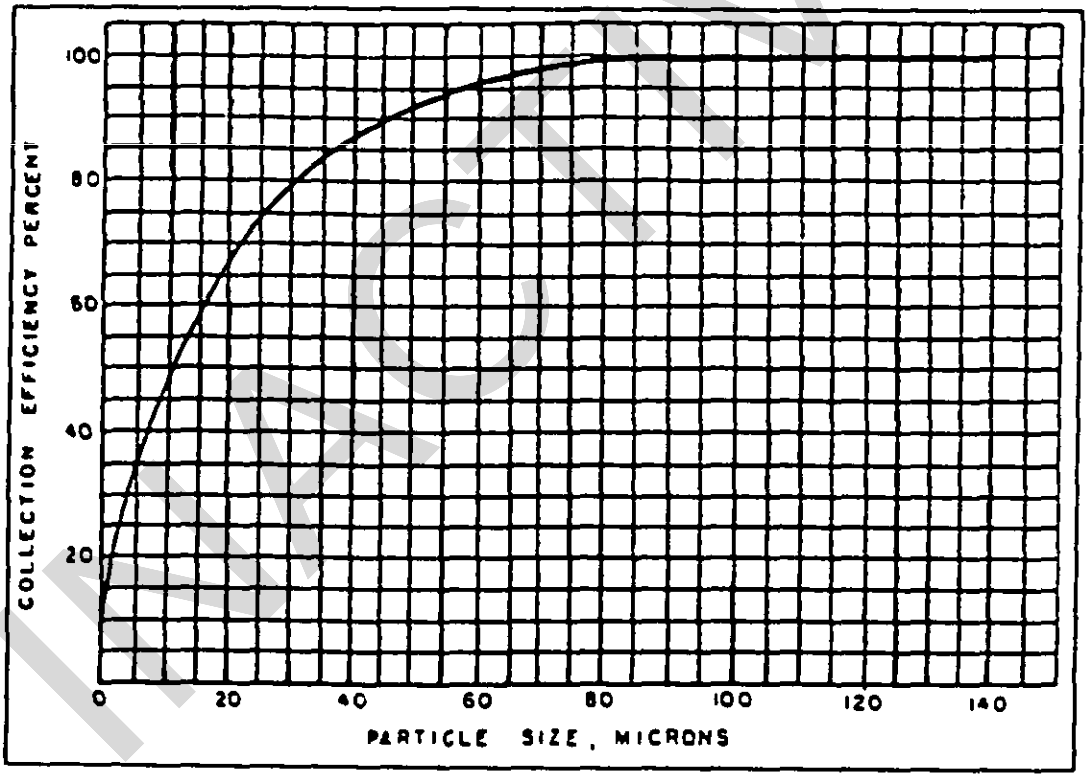


Figure 100
Cyclone Fractional Efficiency Curve

3.5.3.5 Pressure Drop and Energy Requirements. Through any given cyclone, there will be a loss in static pressure of gas between the inlet and outlet. This pressure drop is the result of entrance and exit losses, frictional losses, and loss of rotational kinetic energy in the exiting gas stream. The cyclone pressure drop increases approximately as the square of the inlet velocity. Energy requirements in the form of fan horsepower are directly proportional to the volume of gas handled and the static pressure drop. A rule of thumb estimate of fan energy requirements is that one quarter of one horsepower is required per 1,000 actual cubic feet per minute of gas per 1-inch water pressure drop. Thus, a mechanical collector applied to a 40,000 lb/hr boiler (approximately 16,000 actual cubic feet per minute flue gas flow) and designed to operate at 3.0-inch water pressure drop would require about 12 horsepower in fan power.

3.5.3.6 Cyclone Performance. For cyclone installation, it is desirable to have as high a collection efficiency and as low a pressure drop as possible. Actual in-plant performance will vary from day to day due to changes in operating conditions such as gas flow, dust load, and particle size. In general, changes that increase pressure drop or particle size will improve the collection efficiency, and changes that decrease pressure drop or particle size will decrease efficiency.

3.5.3.7 Application for Particulate Collection. Mechanical collectors are used as primary particulate collection devices when the particulate dust is coarse, when inlet loading is heavy, or when high collection efficiency is not a critical requirement. Since collection efficiencies are low compared to other types of control devices, mechanical collectors are not usually suitable as the primary means of control when emission regulations are stringent. In this case, one of the devices discussed later in this section must be applied.

3.5.3.8 Application as Precleaners. Another common application of cyclones is as a precleaner in solid fuel combustion systems, such as stoker-fired and pulverized coal-burning boilers. In these units, large coarse particles may be generated and a cyclone collector may be installed ahead of an electrostatic precipitator or baghouse to remove these particles. In the case of a stoker/baghouse combination, a mechanical collector is almost mandatory, since hot or burning particles are often carried over the fuel bed and could ignite the bags. A combination installation is also ideal from a performance standpoint when applied to a precipitator, because the cyclone exhibits increased collection efficiency during high gas flow and dust loading conditions, while the precipitator shows an increase in efficiency during decreased gas flow and dust loading. The two devices complement each other to provide good efficiency over a wide range of gas flow and dust loading conditions.

3.5.3.9 Application for Reinjection. Fly ash carried over from a spreader stoker often contains a high percentage of unburned carbon. This constitutes a loss in heating value and, therefore, efficiency. Since the particles are fairly coarse, a medium efficiency cyclone can collect them effectively with a minimum of added fan horsepower. An additional small fan can then be used to reinject the collected material into the furnace for more complete combustion. This type of cyclone arrangement is typically used ahead of a precipitator or baghouse, which serves as the final collection device.

3.5.3.10 Effect of Firing Modes. The method by which fuel is fired can have a major effect on the suitability of a mechanical collector for the application. This is due to differences in particle size distribution in the flue gas from the different firing modes. Thus, if the same coal were to be fired in two identical boilers, one using a spreader stoker and the other using a chain grate stoker, the mechanical collector could collect the ash from the spreader stoker-fired boiler more efficiently, because it generates coarser fly ash. Table 15 illustrates the optimum expected performance of mechanical collectors for particulate removal in various combustion process applications.

3.5.4 Fabric Filters. Fabric filters, commonly called baghouses, are used to remove particulate from the flue gas stream. Filters are made of woven or felted high temperature fabric, such as fiberglass or Teflon. They are normally manufactured in the form of a cylindrical bag, although other configurations are possible. These elements are contained in a metal housing which has gas inlet and outlet connections, a dust storage hopper, and a cleaning mechanism. In operation, dust-laden gas flows through cloth filters, and dust is removed from the gas stream as it passes through the filter cloth. Filters are cleaned periodically.

3.5.4.1 Housing Design. For practical reasons, most baghouses used for boiler flue gas are designed to operate on negative pressure and are located between the last heat trap and the induced draft fan. Pressurized baghouses are very rare. Negative pressure baghouses are constructed with a welded steel, gas-tight housing. It is usually divided into two or more compartments, each having a dust collection hopper beneath it. Hoppers and housing are insulated, and the fan is located on the clean side of the collector.

3.5.4.2 Filter Arrangement. Filters are usually cylindrical but may also be of the flat panel type. The cylindrical types have the advantage of maximizing total cloth area per square foot of floor area, since they can be made very long. They typically have a length to diameter ratio of about 30:1. They can be arranged to collect the dust on either the inside or the outside of the cylinder. Flat panel filters consist of large, flat areas of cloth stretched over adjustable frames. Flow direction is usually horizontal. Flat panel filters have the advantages of frames. Flow direction is usually horizontal. Flat panel filters have the advantages of allowing slightly more filter area per cubic foot of collector volume and of allowing the panels to be manually cleaned by brushing if excessive dust build-up occurs.

3.5.4.3 Filter Cleaning Methods. Dust may be removed from filters by several methods. The most common methods applied are shaking, reverse gas flow, and reverse pulse.

a) Shaking. A few baghouse designs use a rigid frame and a motor-driven oscillator mechanism to gently shake dust loose from the bags. However, this is rarely used on modern design units because it increases bag wear and shortens bag life.

b) Reverse Gas Flow. See Figure 101. The reverse gas flow cleaning method uses a fan to gently backwash the bags with high volume, low pressure, clean flue gas taken from the baghouse outlet. This causes dust which has accumulated on the bags to drop off into the hoppers. Baghouses of this design use low air-to-cloth ratios and thus require more bags and a larger housing to handle the same gas flow. In addition, a spare compartment must be provided, since the compartments must be taken off-line for cleaning.

c) Pulse Jet. See Figure 102. The pulse jet cleaning method utilizes a short blast of high pressure air (90 to 100 psig) to blow backwards through the bag and dislodge dust so that it can drop into the collection hopper. This design has several advantages over the reverse gas flow method and is gradually becoming the dominant design in the industry. Its primary advantages relate to its higher air-to-cloth ratio and subsequently smaller physical size. This leads to lower initial cost, fewer bags, and lower space requirements. Other advantages are lower horsepower requirements for generating the cleaning air, fewer moving parts, and the fact that compartments may be cleaned either on- or off-line. Its main disadvantage is that the bags, although fewer in number, must be considerably heavier, and therefore more expensive, to withstand the severe cleaning cycles.

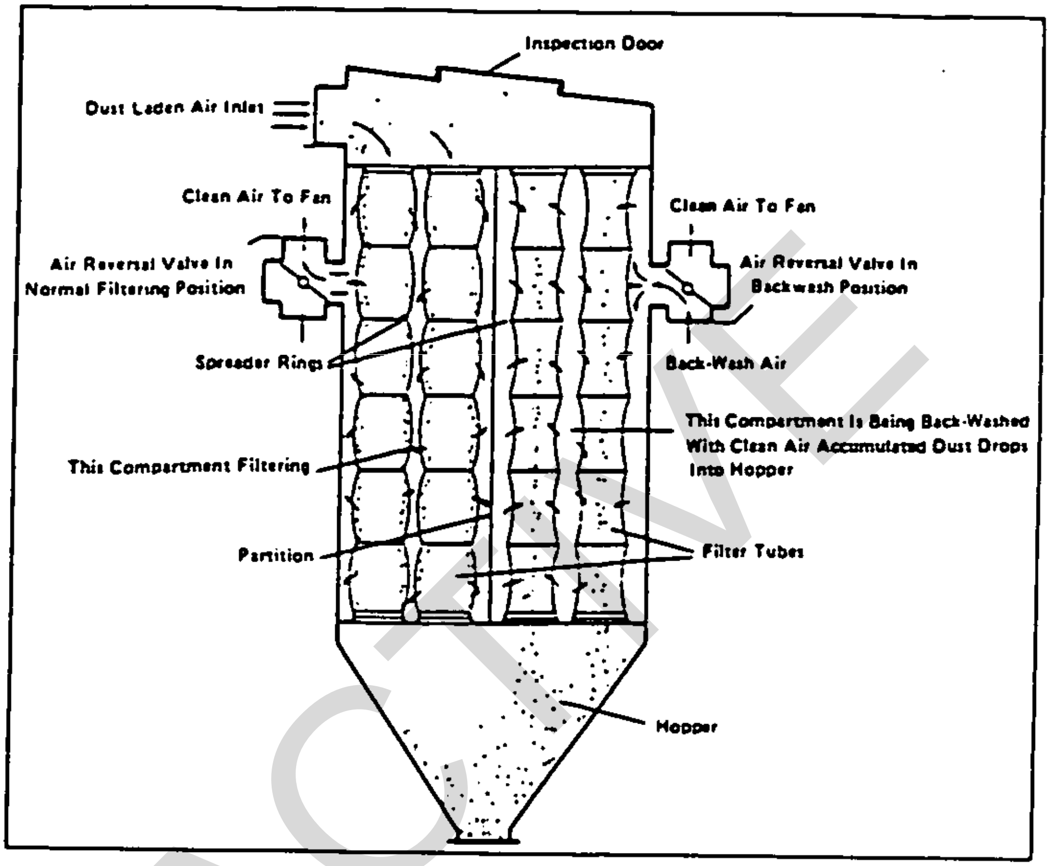


Figure 101
Reverse Flow Baghouse

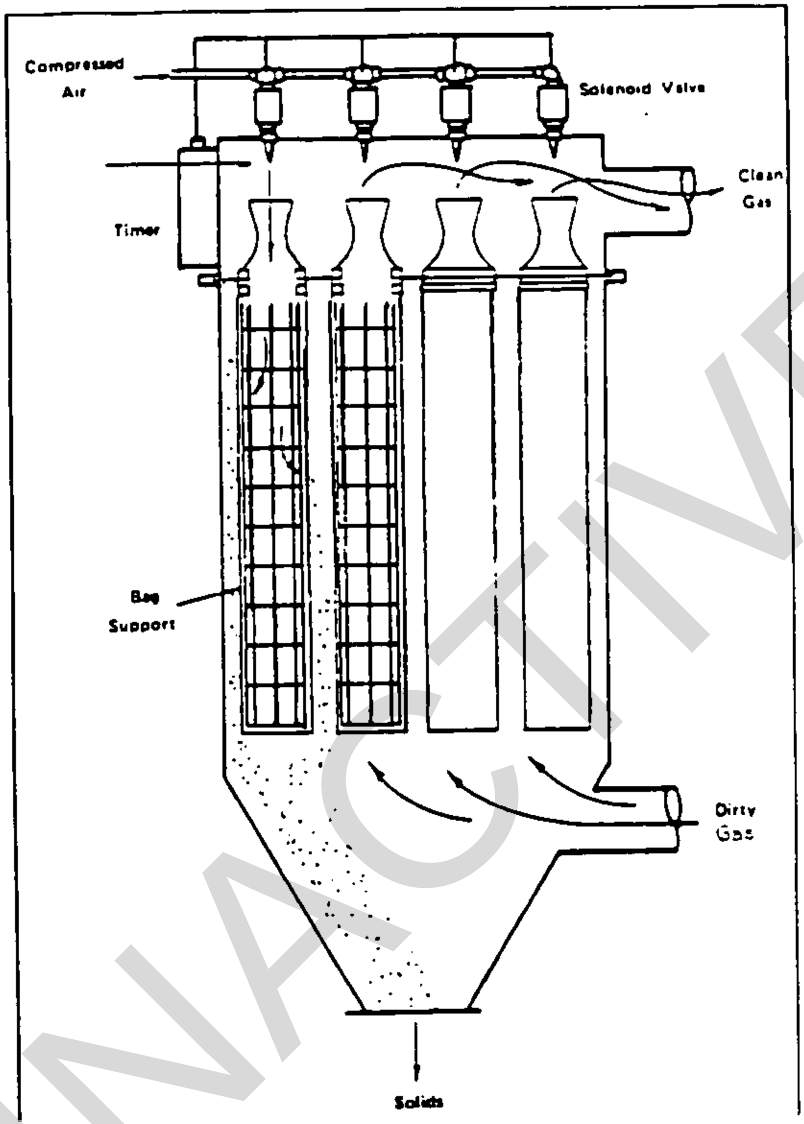


Figure 102
Pulse Jet Baghouse

3.5.4.4 Energy Requirements. The primary energy requirement of a baghouse is the fan horsepower necessary to move flue gas through the unit. Resistance to flow arises from the pressure drop across the filter cloth, friction losses through ducts and dampers, and turbulent flow losses. Power is also required to drive the cleaning equipment.

3.5.4.5 Application of Fabric Filters. Properly designed fabric filters may be applied to most coal-fired boiler applications, either as part of a new installation or on a retrofit basis. The flue gas temperature into the fabric filter must be maintained above the sulfuric acid dew point but below the maximum permissible filter cloth temperature. Temperature requirements are discussed more fully in Section 4. Application to oil-fired boilers is not generally recommended, since unburned oil tends to cause the filters to plug or blind. A bypass around the baghouse is generally utilized for boilers that must burn both coal and oil.

3.5.5 Electrostatic Precipitators. An electrostatic precipitator (ESP) is a device that removes particles from a gas stream by means of an electric field (Figure 103). The electric field imparts a positive or negative charge to the particle and attracts it to an oppositely charged plate. Provision is also made to remove dust particles from collection plates to dust hoppers located below the precipitator. The entire precipitator is enclosed in a metal housing which has a flue gas inlet and outlet and is connected into the boiler lines between the boiler and stacks. ESPs may be operated under either pressure or suction conditions, with gas flow either horizontal or vertical. Many configurations are possible, depending upon the desired application. Common applications are discussed below.

3.5.5.1 Electrode Design. Most electrostatic precipitators are of the parallel plate design with horizontal gas flow. The plates carry a positive charge and act as the collecting electrode. A large number of negatively charged high voltage discharge electrodes are spaced between the plates. These electrodes impart a negative charge to the particles in the gas stream which are then attracted to the positively charged collection plates. The particles adhere to the plates until they are removed by the cleaning system. This electrode system can be designed in two basic configurations.

a) Weighted Wire. In the weighted wire design, both plates and wires are suspended from the top and allowed to hang vertically by gravity. Weights are attached to the wire to maintain proper tension. Precise alignment is necessary so that both sets of electrodes maintain the relationships required for best efficiency. Weighted wire construction has been used for many years, and is well proven and relatively inexpensive.

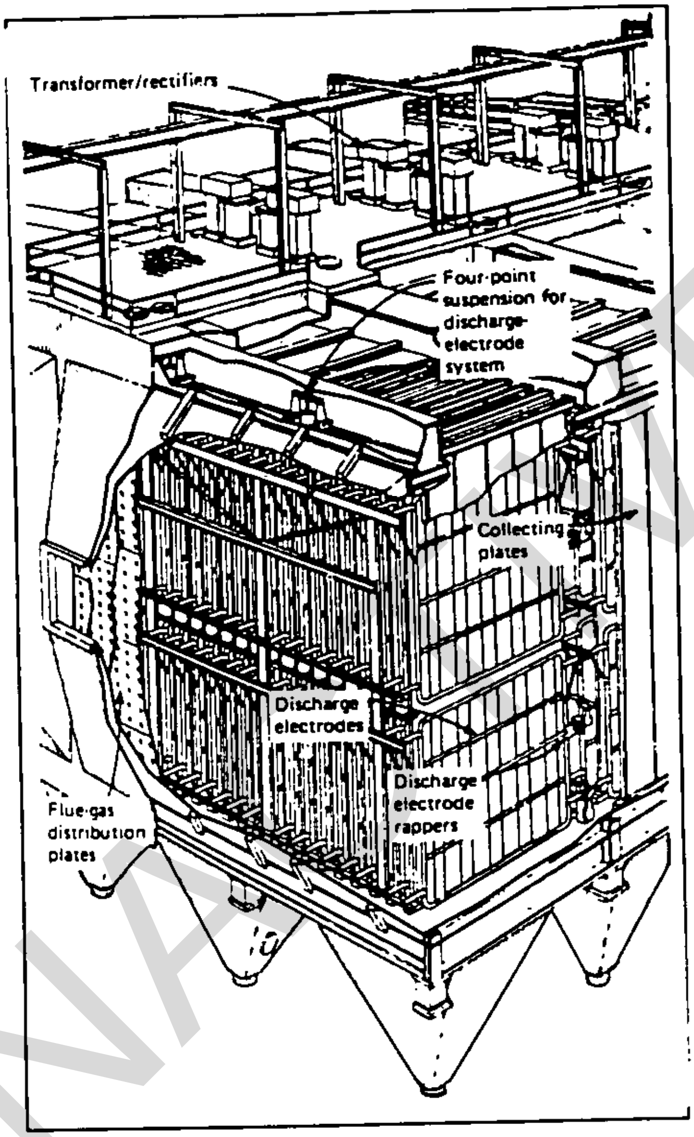


Figure 103
Electrostatic Precipitator

b) Rigid Frame. Some modern precipitators use rigid frame construction. In this type of construction, both the positive and negative electrodes are rigidly mounted at top and bottom to maintain precise alignment. This is somewhat more expensive, but is advantageous when extremely high collection efficiencies are required. It also reduces maintenance costs by minimizing or eliminating electrode wire breakage.

3.5.5.2 Precipitator Location. Precipitators may be located either in hot regions of the flue gas stream, where temperatures are above 600 degrees F, or after the last heat trap, where temperatures are between 300 and 350 degrees F. These two locations are termed hot and cold, respectively.

a) Hot Precipitators. Hot precipitators are generally applied to units designed for low sulfur coal because the characteristics of ash from this type of coal make it difficult to collect in a cold precipitator. Particle resistance to collection decreases at the higher temperature. The ability to remove particles from the plates and hoppers is also increased at these temperatures. Hot precipitators are more expensive, however, because they must be larger to handle the higher specific volume of the gas stream. Material selection, design for proper expansion, and structural considerations also become more critical at higher temperatures. Finally, radiation losses from the precipitator housing increase at higher temperatures, necessitating either more insulation or a reduction in boiler operating efficiency.

b) Cold Precipitators. Cold precipitators are designed to operate at temperatures between 300 to 350 degrees F. They are smaller in construction and therefore cheaper than hot units for the same boiler size. However, they are not as effective in collecting ash from low sulfur coal. In addition, they must be resistant to corrosion due to condensation of sulfuric acid at lower temperatures.

3.5.5.3 Cleaning and Dust Removal. Dust is removed from electrodes by rappers. Rappers can consist of electromagnetic solenoids, motor-driven cams or motor-driven hammers which vibrate or impact upon the tops of the plates and wires. This causes collected dust to slide down the electrode, eventually reaching the dust collection hopper at the bottom of the unit. Once collected in the hoppers, dust is removed by the fly ash removal system.

3.5.5.4 Energy Requirements. The main uses of energy in an electrostatic precipitator are the fan horsepower to move flue gas through the unit and the power required to maintain the electrostatic field. These two power usages are approximately equal. A typical electrostatic precipitator on a 30,000 lb/hr boiler would require about two to three brake horsepower in fan power consumption and two to three kilowatts to maintain the electrostatic field. The rappers and dust removal systems are other sources of power consumption.

3.5.5.5 Application of Electrostatic Precipitators. Electrostatic precipitators can be designed to function efficiently on almost any boiler, either for a new or retrofit installation, if sufficient physical space exists. However, it is important to have a good knowledge of the fuel analysis that will actually be burned, since this has a major effect upon the design of the precipitator. Once the precipitator has been designed and sized for a given fuel, major inefficiencies and operating problems can result from fuel changes.

3.5.6 Wet Scrubbers. A wet scrubber is a device designed to use a liquid to separate particulate contaminants from a flue gas stream. Wet scrubbers have some potential application and advantages over other types of particulate control devices and are thus discussed in this handbook. Most wet scrubber applications to Navy boilers would be of the wet approach venturi type (Figure 104). It is very compact and has the capability to collect particles down to submicron size with about 99 percent efficiency, or even more if necessary. Its principle of operation is somewhat similar to a mechanical collector, but it adds the action of liquid scrubbing to centrifugal and inertial forces. The incoming gas steam accelerates and atomizes the liquid droplets. These atomized droplets then wash dust out of the gas stream in the same manner that a severe rainstorm can wash dust out of the atmosphere. Pressure drop through a wet scrubber increases with decreasing particle size and increasing collection efficiency.

For a venturi scrubber applied to a coal-fired boiler, pressure drop typically ranges from 20 to 25 in water. This creates a significant penalty in fan horsepower requirements and is one of the primary reasons that wet scrubbers are seldom applied to smaller boilers. Other types of scrubbers can lower this horsepower requirement, but their collection efficiencies are also lower. The other major disadvantage of the wet scrubber is its water usage. The cost of pretreating water and the cost and complexity of treating the waste slurry from the scrubber discharge can be significant. The primary advantages of a wet scrubber are its compact size and its tolerance for extremely high gas temperatures. These two characteristics make it potentially useful for retrofit application where other types of control devices might not be applicable due to efficiency or space requirements.

3.6 Auxiliary Equipment

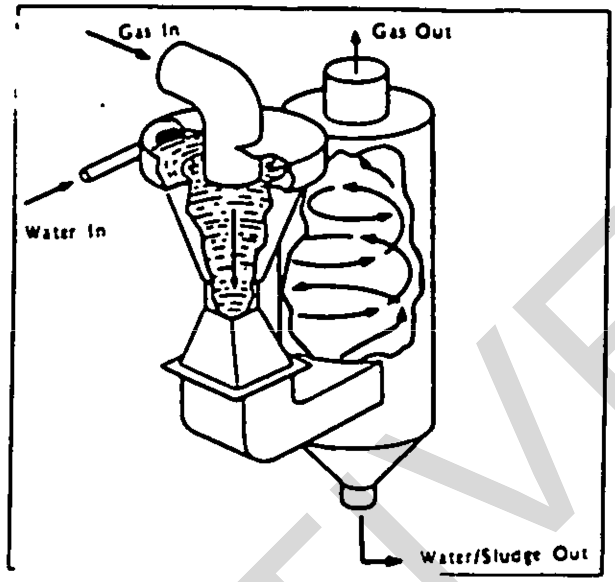


Figure 104
Wet Approach Venturi
Scrubber

3.6.1 Feedwater Heaters. Closed feedwater heaters of the tube and shell type are used to preheat feedwater going to deaerators and hot water boilers as well as for deaerating heating. These closed feedwater heaters can make use of turbine exhaust steam or waste heat generated in the boiler plant to improve overall plant efficiency. Figure 105 illustrates a closed U-tube heat exchanger used for feedwater heating.

3.6.2 Pumps and Injectors. The selection and replacement of pumps require consideration of capacity and pressure requirements, the type and temperature of fluid to be handled, and the type of pump best suited for the job requirements. Performance characteristics vary widely, even among pumps of the same type and capacity. Pumps can be classified into four groups: centrifugal pumps, reciprocating piston pumps, rotary positive displacement pumps, and jet pumps/injectors. The characteristics of these groups are discussed later.

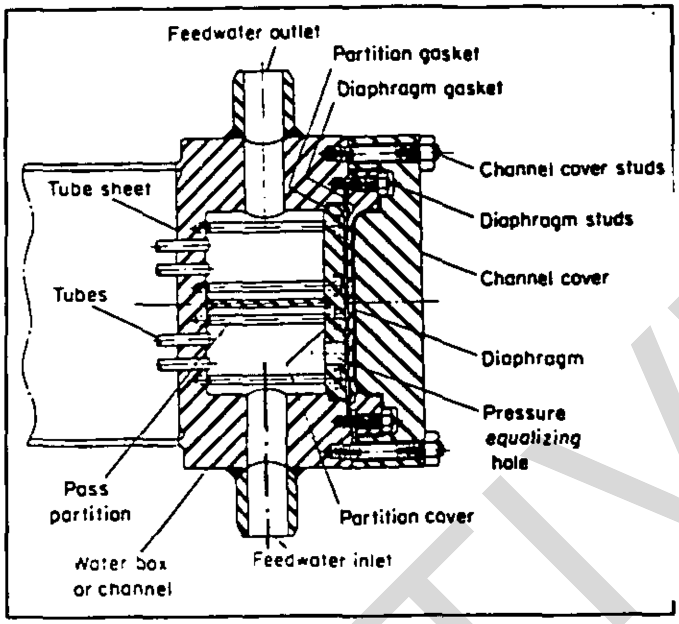


Figure 105
U-Tube Heat Exchanger

3.6.2.1 Installation. Selection of a pump for a particular job involves many considerations, but once the pump is selected, successful performance depends upon details of the installation. This is particularly true where the pump must lift the fluid or when the fluid is heated. Greater care must be exercised in design and installation of the suction line than of the pump discharge. A strainer is required to prevent foreign objects from entering and clogging the pump or piping. The maximum suction lift or minimum suction lift or minimum suction head depends to a great extent upon the temperature of the water and distance of the pump above sea level, as noted in Table 16. The following rules should be observed when installing a suction line to a pump. Disregarding any of the following rules may lead to unsatisfactory operation or complete failure:

a) The line must be tight. A leak in the discharge line may be annoying, but a leak in the suction line may lead to inoperation of the pump.

b) Keep the suction lift, or the vertical distance from the pump to the water supply, as small as possible.

Table 16
Permissible Maximum Suction Lifts and
Minimum Suction Heads in Feet
for Various Temperatures and Altitudes

Altitude	Water Temperature (degrees F)								
	60	80	100	120	140	160	180	200	210
At sea level	-22	-17	-13	-8	-4	+0	+5	+10	+12
2,000 ft above	-19	-15	-11	-6	-2	+3	+7	+12	+15
6,000 ft above	-15	-11	-6	-2	+3	+7	+12	+16	-
10,000 ft above	-11	-7	-2	+2	+7	+11	+16	-	-

Note: (-) indicates maximum suction lift, or distance of pump above water.
(+) indicates suction head, or distance of pump below water.

c) Keep the suction line as short as possible. Keep the number of fittings, such as ells, tees, reducers, and valves to a minimum.

d) To reduce losses caused by pipe friction and high velocity, keep the diameter of the suction line as large as practical.

e) To prevent formation of air pockets, maintain proper slope on horizontal sections of pipe. Slope the line away from the pump for a suction lift and toward the pump for a suction head (Figure 106A).

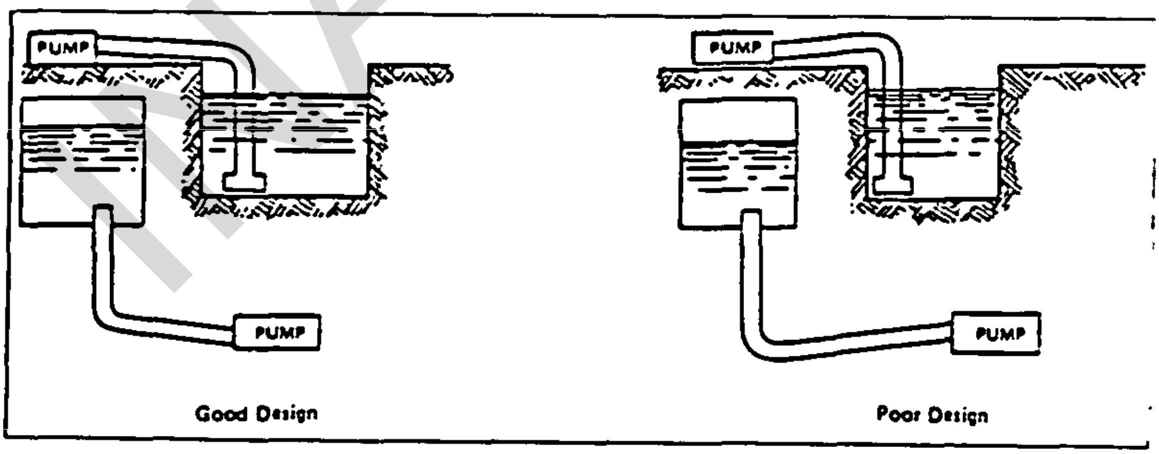


Figure 106A
Maintain Proper Slope to Suction Line

f) Do not use fittings that permit the formation of air pockets (Figure 106B). Note: An air chamber is occasionally used on the suction line of a pump to smooth out pressure fluctuations or surges. These must be carefully designed and installed to ensure proper operation.

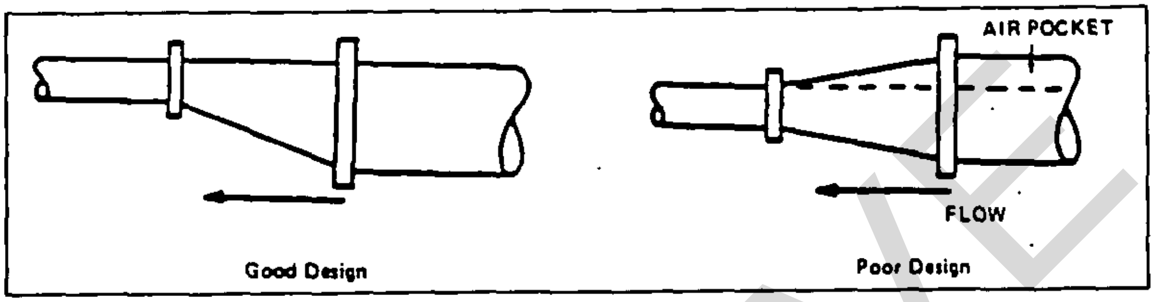


Figure 106B
Suction Line Installation

g) To keep the line and pump full of water when the pump is idle, install a foot valve on the inlet end of a suction line. A foot valve is a special type of check valve made for this purpose. Very little force is required to operate it, and a strainer is usually incorporated. A foot valve has no value when the pump is located below the source of water supply.

h) Properly guard gears, belts, shafts, and other moving parts exposed to hazardous contact, and provide drains from pump bases.

3.6.2.2 Centrifugal Pumps. Centrifugal pumps use a rotating impeller to give velocity and pressure to fluid. This type of pump is widely used in boiler feed and condensate pumping applications. Figure 107 illustrates a horizontal split case type of centrifugal pump. Centrifugal pumps are available in many configurations, including single and double suction, single and double volute, multistage, and vertical. Although these pumps look different, they have basically the same components and operate similarly. They are compact, of simple construction, discharge at a uniform rate of flow and pressure, contain no valves or pistons, operate at a high speed, and can handle dirty water. They have two major disadvantages: comparatively low efficiency, and inability to discharge air or vapor. However, their advantages more than offset the lower efficiency. The inability to discharge air can be overcome by proper installation and operating practices.

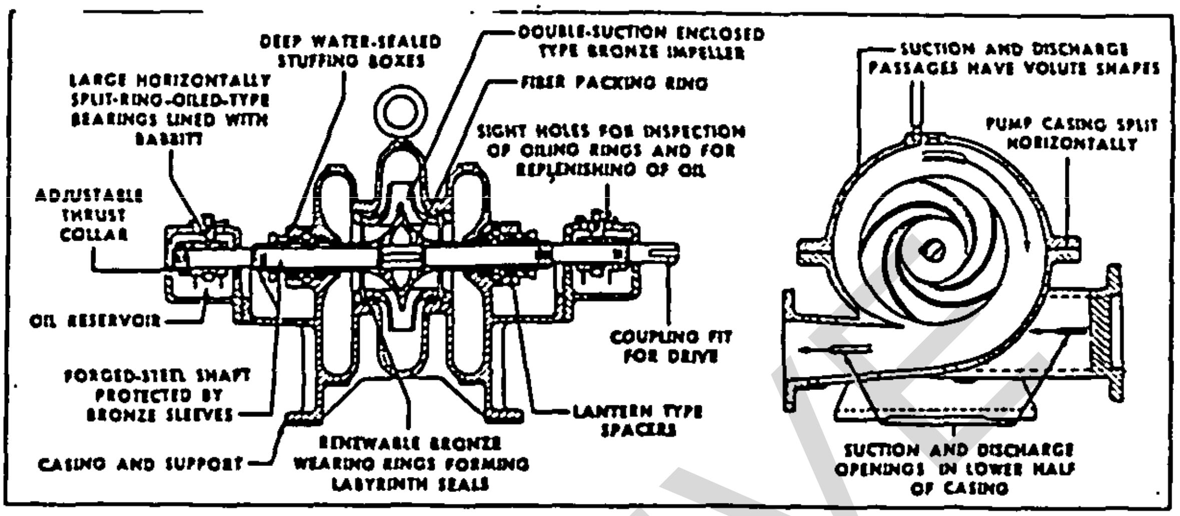


Figure 107
Centrifugal Pump

a) Construction. The pump shown in Figure 107 consists of the rotating element called an "impeller," the casing, shaft, and parts used for sealing the pump against leakage.

(1) The impeller consists of two disks separated by a number of vanes which form passages for water and are connected to the hub. This impeller may be of cast iron, bronze, steel, or other alloys, depending upon the fluid to be handled. Its diameter depends on its operating speed and the difference between suction and discharge pressures. The pressure difference is usually called the "pump head" and is measured in feet. An impeller may be either single or double suction. The one shown is the double suction type, in which water enters from both sides.

(2) The casing is split on the horizontal center line and contains the inlet and outlet passages. Inlet and outlet connections are usually in the bottom half of the casing, permitting disassembly and repair of the pump without disturbing pipe connections or pump alignment. The casing guides water from the inlet connection to the impeller and from the impeller to the discharge connection. The casing, although usually made of cast iron, can be made of other materials if necessary to handle special fluids.

(3) The shaft supports and drives the impeller and is, in turn, supported by bearings. Babbitt-type bearings are used in the pump shown in Figure 107, though many pumps use ball bearings.

(4) The impeller is held firmly by shaft sleeves that also help to seal it against air leakage into the pump. Sleeves are held in place by two nuts, one of which has a right-hand thread and the other a left-hand thread. Packing is sometimes provided between these nuts and the sleeves to ensure a tight seal. Stuffing boxes are provided where the shaft passes through the casing. Stuffing boxes are filled with packing held in place by packing glands. A brass or bronze lantern ring is often inserted between two adjacent rings of packing to provide a channel for the sealing water. The sealing water lubricates and cools the packing and shaft sleeve and helps seal against air leakage into the pump. It may be supplied directly from the pump, as shown, or from an outside source. The casing has renewable rings to reduce leakage from the discharge to the inlet side of the impeller. Renewable bearings are occasionally installed on the impeller.

b) Operation

(1) When the pump is operating, the impeller rotates at high speed, drawing water into its center, near the shaft. The resultant centrifugal force imparts energy to the water, which is forced outward. As this occurs, the partial vacuum produced at the inlet draws additional water. The casing must transform the velocity of water leaving the impeller into pressure with minimum loss. This is done in the pump shown by making the casing in the form of a spiral, called a "volute," and gradually increasing its cross-sectional area from its beginning to the pump discharge. The pump shown is called a "single-stage pump" because water passes through only one impeller. Multistage pumps are used when it is necessary to operate against higher heads. In a multistage pump, water travels through successive impellers or stages until it has reached the desired head.

(2) The output of a centrifugal pump can be controlled by regulating the pump speed, providing a controlled recirculation line, or throttling the discharge. The recirculation line, or bypass, consists of a valved line between the pump discharge and suction. The output of the pump is decreased by opening this valve and recirculating water through the pump. Throttling the discharge increases pressure at the pump outlet, causing some of the fluid to stop and remain in the pump casing. Any of these control methods can be manual or automatic. A centrifugal pump must be equipped with a check valve on the discharge side to prevent backflow of water when the

pump is inoperative. Centrifugal pumps are designed to deliver a given quantity of fluid against a specified discharge pressure or head. Every centrifugal pump has a maximum or shutoff head, above which it is unable to deliver any fluid. This fact should be taken into consideration when an increase in delivery pressure is contemplated. The shutoff head can sometimes be increased by substitution of a larger impeller, although a larger motor may also be required.

3.6.2.3 Reciprocating Piston Pumps. The direct-acting, steam-driven duplex pump is widely used because of its low initial cost, low maintenance, simple operation, and positive action. Simplex pumps are rarely used because of the wide fluctuation in fluid pressure at the pump discharge.

A horizontal duplex piston pump is shown in Figure 108. This type of pump consists of two single-cylinder pumps mounted side by side. The piston rod of one pump operates the steam valve of the other through a system of bell cranks, rocker arms, or links. Pistons move alternately so that the resultant discharge of water is essentially continuous. Steam is admitted for the full stroke and is not used expansively, resulting in high steam consumption for the amount of water handled. Each cylinder has two ports in each end, one of which admits steam while the other discharges it. This minimizes the required valve travel but leaves sufficient bearing surface between the steam ports and the main exhaust port to prevent steam leakage from one to the other. Steam which is trapped in the cylinder when the exhaust stroke nears completion provides a cushion to prevent the piston from striking the cylinder heads. Some pumps also have small hand operated valves on the side of the steam chest to regulate the amount of cushioning by controlling the escape of the steam from the cylinder. Maximum cushioning is desired with the pump operating at high speeds, and is obtained by closing the hand valve.

Valves of a duplex pump do not overlap the edges of the ports with the valve in its mid-position. Valves are held to their seats by the pressure differential acting on the two sides of the valve. Figure 109 shows the relative position of the working parts when the pump and valve are in mid-position. The illustrations indicate that valves are not fastened rigidly to the stem and that there is lost motion between the valve and the stem. This lost motion is provided to force the pump to take a full stroke; otherwise, it would make only about a quarter stroke. The typical operations of the pump are also due to this lost motion. When one piston has completed its stroke, it pauses and goes into reverse only after the second piston has reached the end of its stroke and moved its valve. One piston is always in position to move so that the pump goes into operation as soon as the steam valve is opened.

3.6.2.4 Rotary Positive Displacement Pumps. Rotary positive displacement pumps use gears, screws, or sliding vanes to move a volume of fluid through the pump (Figure 110A and 110B). Rotary positive displacement pumps are most commonly used in boiler plants to pump fuel oil. Very close tolerances are maintained between the pump internals to minimize slippage of fluid. Slippage in a positive displacement pump may be less than 0.5 percent, while slippage of 50 percent or more is common in centrifugal pumps. These pumps can thus operate at high efficiencies and pressures. Rotary positive displacement pumps should be equipped with relief valves to protect against over pressurization. While centrifugal pumps may be controlled by throttled flow, rotary positive displacement pumps are controlled by recirculating a portion of the pumped fluid back to the tank or the pump suction.

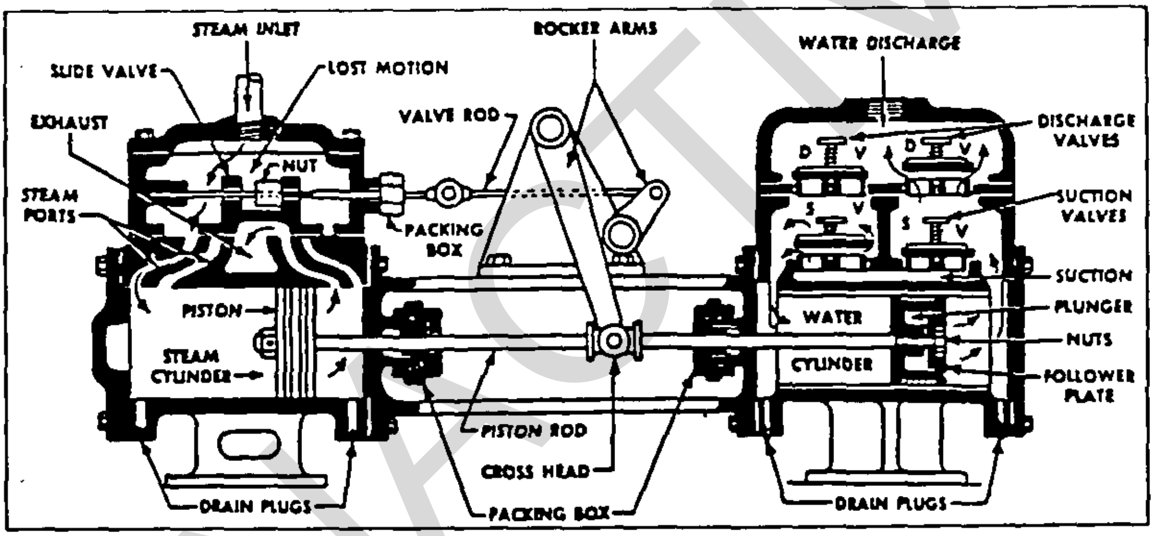


Figure 108
Reciprocating Piston Pump

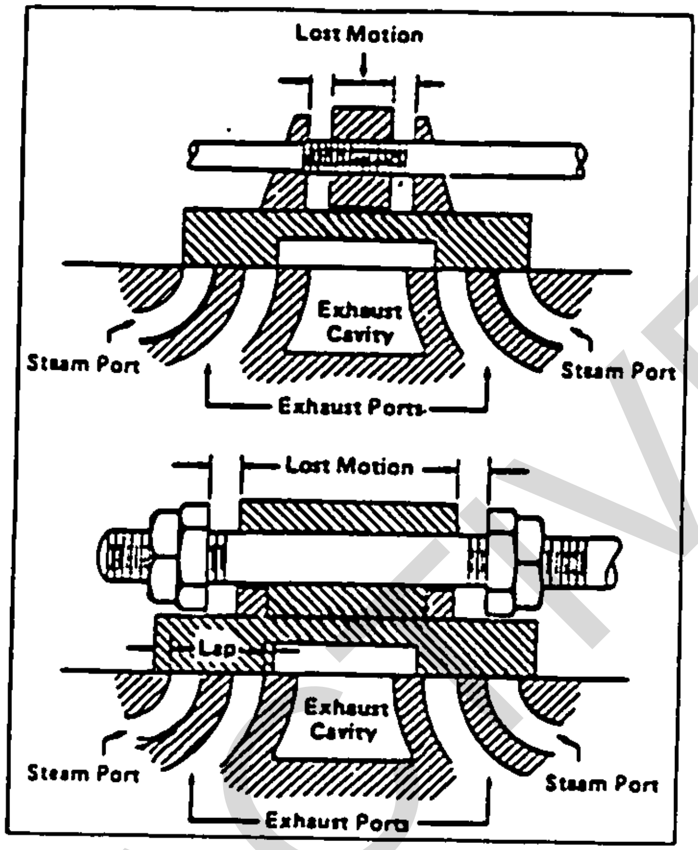


Figure 109
Two Methods of Providing Lost Motion

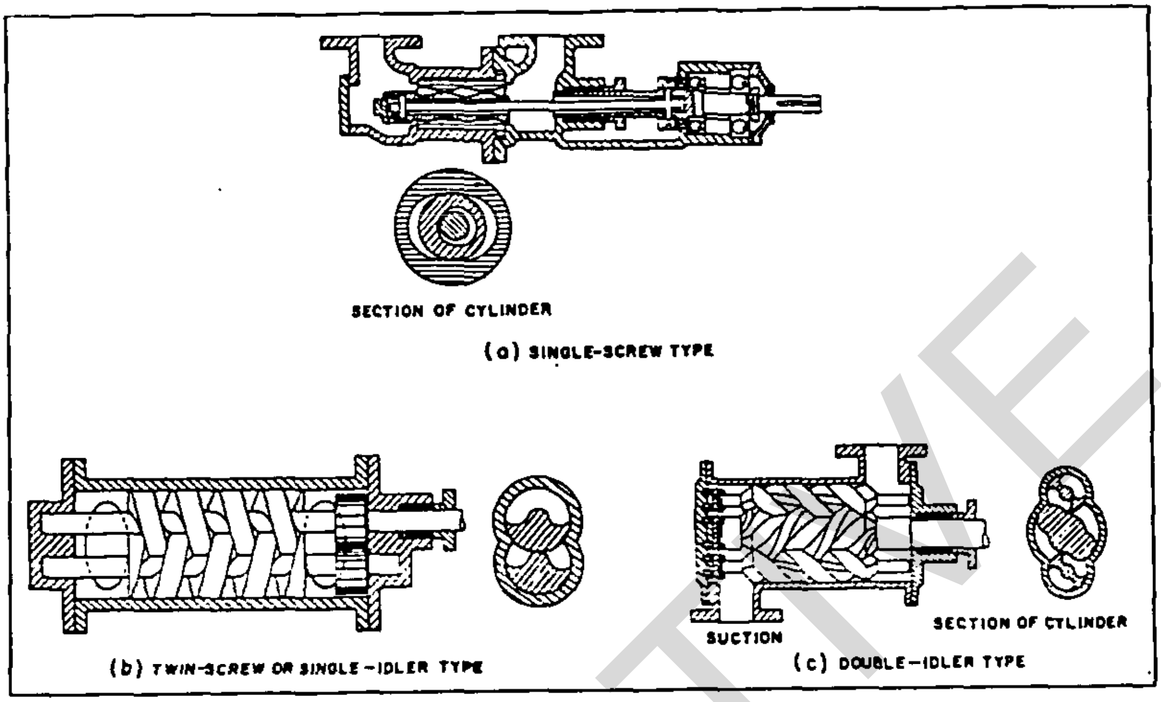


Figure 110A
Rotary Screw Pumps

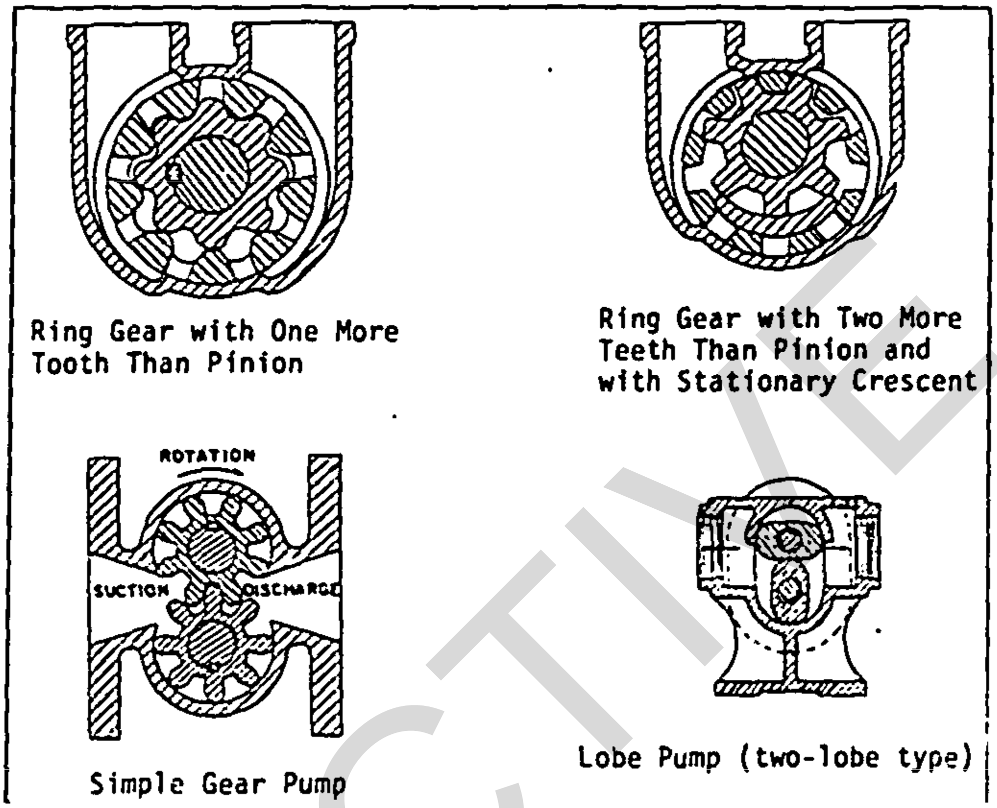


Figure 110B
Rotary Gear Pumps

3.6.2.5 Jet Pumps/Injectors. An injector is a jet pump used to feed water into a boiler, where its high thermal efficiency justifies its use. Most of the heat, in the form of steam, used to operate the pump is returned to the boiler with the water. The injector is convenient, cheap, compact, efficient, and has no moving parts. It delivers warm water into the boiler without preheating, and has no exhaust to dispose of. It cannot be used to pump hot water and can handle a maximum water temperature of about 140 degrees. Excessive preheating of feedwater passing through the injector often causes impurities to drop into the tubes, scaling them so heavily that the injector fails to function.

Essential parts of an injector are the steam tube, combining and delivery tubes, and the necessary casing to guide water to and from these tubes (Figure 111). The shape of the steam tube is designed in the shape of a venturi to increase the velocity of the steam passing through the tube. As a result of this high velocity, air is partially evacuated from the inlet line, causing the water to rise until it contacts steam at the entrance of the combining tube. Steam is condensed and imparts considerable velocity to water. The condensing steam reduces its volume and thus maintains the vacuum. The combining tube further increases the velocity of the moving mass of water, enabling it to cross the opening to the delivery tube. The water velocity opens a check valve and water enters the boiler against the boiler pressure. An overflow is provided to remove water when the injector is started. No water should appear at the overflow if the injector is operating properly. Injectors can be hand starting, automatic, single tube, or double tube. An automatic injector will resume its flow after an interruption without any attention from the operator. The injector operates satisfactorily under a constant load and pressure but becomes unreliable when operating with fluctuating pressure. Due to this fact and to low temperature limitations, injectors are rarely used on modern installations. Injector failures are most often caused by excessive suction lift, hot water, clogged strainer or suction line, and fluctuating pressures.

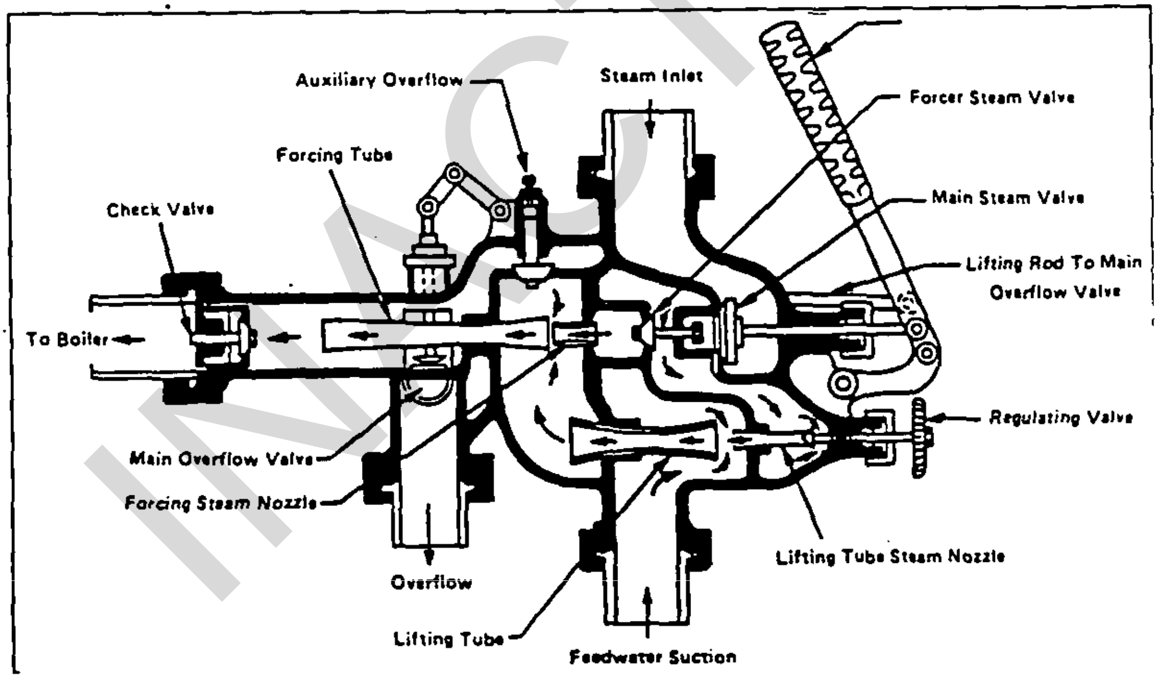


Figure 111
Steam Injector

3.6.2.6 <u>Boiler Feed Pumps</u>. The boiler feed pump is probably the single most important auxiliary in the boiler plant. It must be operated continuously when the boiler is in operation, and at a rate of discharge equal to the rating of the boiler. The ASME Code requires the boiler to have two methods of feeding water, to ensure that an adequate supply is available at all times. Reciprocating and jet pumps can be used for this purpose, but centrifugal pumps are most commonly used in modern stationary practice. Centrifugal pumps have the advantages of small size, high speed, low chance of boiler water contamination with oil, and continuous steady flow.

a) Reciprocating Pump Application. The area of the steam cylinder of a reciprocating pump ranges from two to three times that of the water piston or plunger to allow for friction losses and to permit the pump operation at reduced steam pressures. A boiler feed pump is required to pump against a total head ranging from 1.1 to 1.5 times the boiler pressure. A reciprocating pump must be sized to provide the desired water discharge capacity with the pump operating at approximately one-half the maximum stroke rate. This allows for pump wear and provides a margin in an emergency, such as low water or ruptured tubes. Reciprocating pumps of the direct-acting duplex type are sometimes used for small capacities and moderate pressures. They consume approximately 5 percent of the steam produced by the boiler, but since the exhaust is utilized to heat the feedwater, the net heat consumed by the pump can be less than 1 percent.

b) Centrifugal Pump Application. Centrifugal pumps for boiler feed applications must be sized to develop enough head and capacity to feed the boiler under all conditions. A centrifugal pump may be driven by a steam turbine or a variable- or constant-speed motor. The method used to control output depends primarily on the type of drive used. Any centrifugal pump used to pump hot water must be provided with an adequate flow of water at all times. Centrifugal pumps quickly become steam-bound and stop pumping under certain conditions, and may be damaged if permitted to operate under those conditions for any length of time.

3.6.2.7 <u>Condensate Pumps</u>. Reciprocating, positive-displacement rotary, and centrifugal pumps are used for this service. Heating systems generally use an automatic float-operated centrifugal pump. The condensate drains to a return tank or reservoir, and a float operates a motor switch which starts and stops the centrifugal pump. In one arrangement, the motor is on top of the tank and the pump is at the bottom. In another arrangement, the pump and motor are mounted outside and below the return tank.

3.6.2.8 Vacuum Pumps. Reciprocating, jet, and positive-displacement rotary pumps may be used for vacuum service. A centrifugal pump can be used to supply water to the jet, which actually maintains the vacuum. Reciprocating pumps, arranged to remove both condensate and air at the same time, are called wet vacuum pumps. This is a common arrangement and is used with small condensing turbines or engines. Smaller clearances in the water end characterize pumps used for this service. A pump which removes only air is known as a dry vacuum pump. The vacuum pump in a vacuum return heating system must handle both air and water. One method of doing this is to use a pump with two impellers mounted on a shaft. One impeller handles water and the other air. Condensate flows into the receiver and enters the pump. An automatic control actuated by the water level and pressure in the receiver (which is below atmospheric) starts and stops the pump as required. This arrangement can maintain a vacuum of 10 to 18 inches of mercury in a system which is reasonably free from leaks.

3.6.3 Forced Draft (FD) Fans. FD fans are applied to push combustion air through the burner into the furnace. If an ID fan is not supplied, the FD fans must also push the products of combustion through the boiler to the stack. Both centrifugal and axial fans are used, with centrifugal units being more common. Centrifugal fans include the following blade designs: radial, forward curved, forward curved/backward inclined, backward inclined, and airfoil/backward inclined. Backward inclined and airfoil/backward inclined fans are most commonly used for FD fan service because of their high efficiency, stable operation, and nonoverloading horsepower characteristics. FD fans are required to operate over a load range of approximately 25 to 100 percent capacity. This is accomplished primarily by use of dampers. Three types of dampers are used: inlet dampers, parallel blade outlet dampers, and opposed blade outlet dampers. Figure 112 illustrates a FD fan equipped with inlet vane dampers. Figure 113 illustrates a typical parallel blade outlet damper. Inlet vane dampers control airflow through the fan by prespinning the entering air. Each position of an inlet vane damper in effect creates a new fan and horsepower curve, as shown in Figure 114. This results in improved control range and horsepower savings over outlet damper applications by creating a static pressure on the fan. Increased static pressure reduces flow and causes the operating point to move back up the fan curve (Figure 115). Opposed blade outlet dampers provide a greater control range than parallel blade outlet dampers, which operate best in the 70 to 100 percent capacity range.

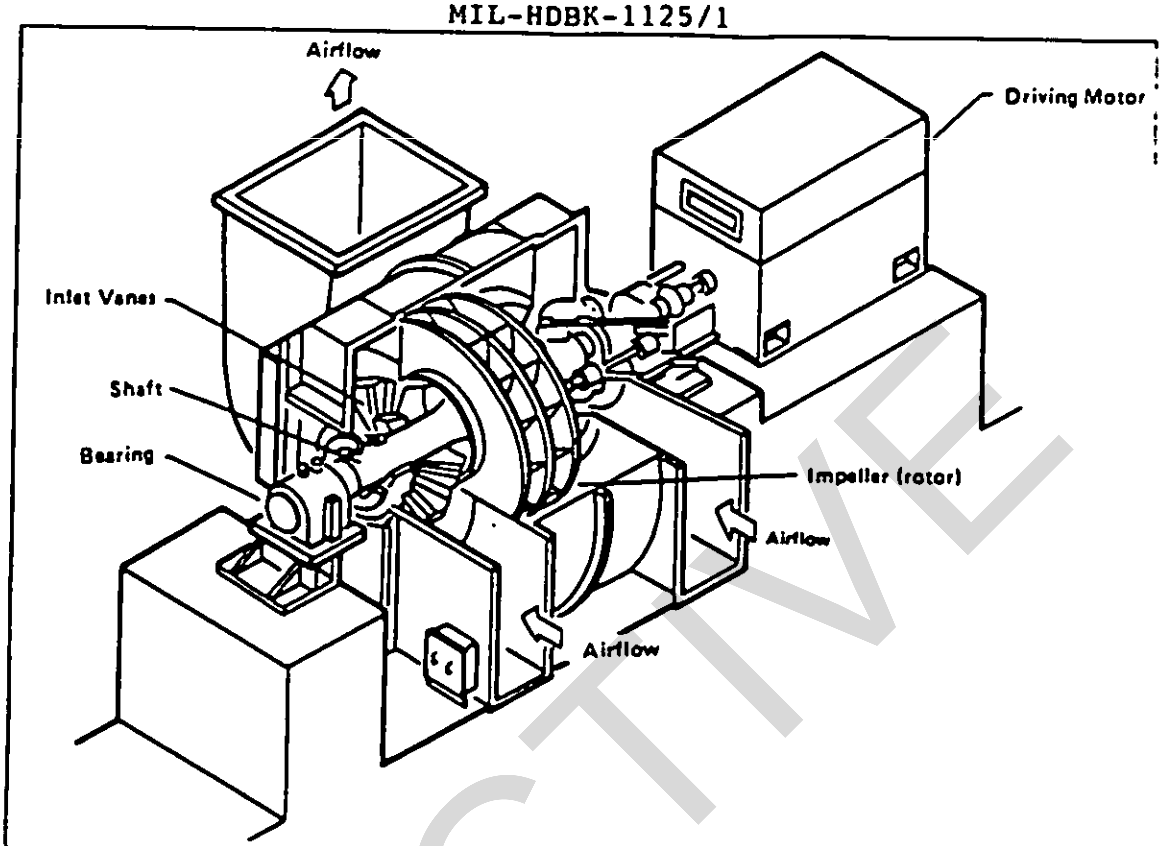


Figure 112
Forced Draft Fan With Inlet Damper

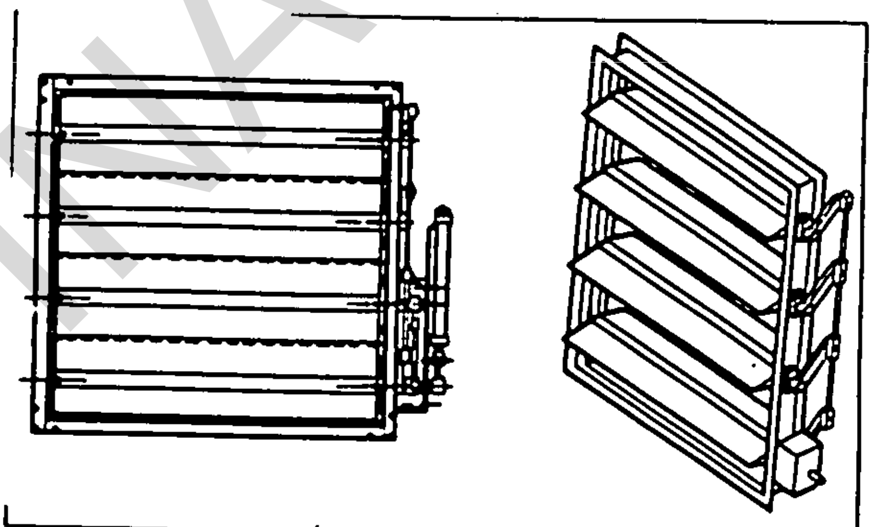


Figure 113
Typical Outlet Fan Dampers

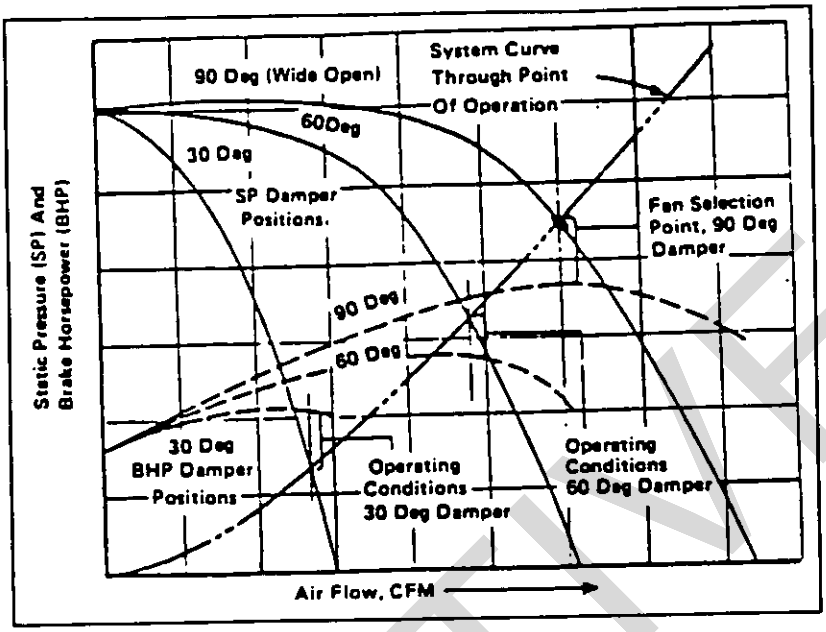


Figure 114
Fan Curves for Different Inlet Vane
Positions

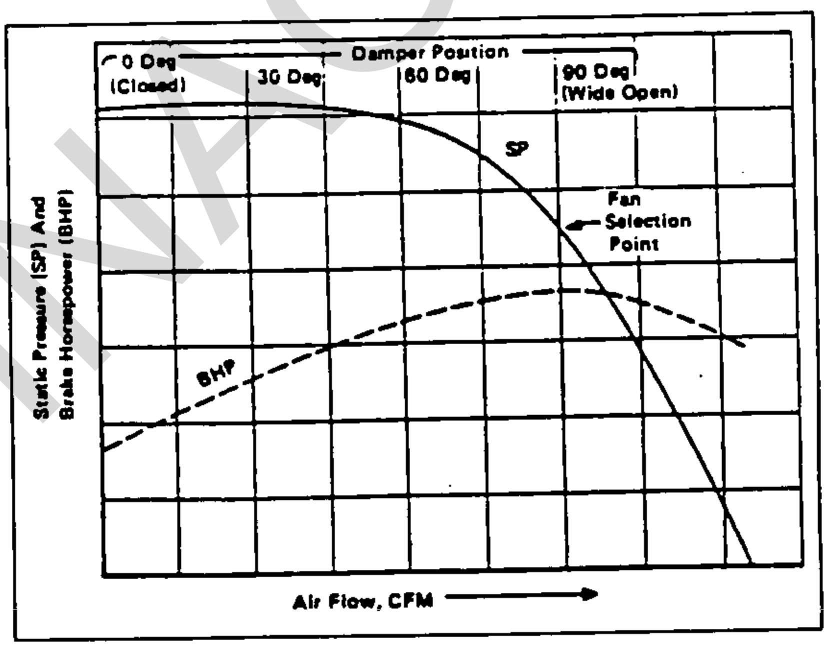


Figure 115
Fan Curve for Fan With Outlet Damper

3.6.4 Induced Draft (ID) Fans. ID fans are used to exhaust the products of combustion from the boiler. Maintaining balanced draft conditions in the furnace improves boiler operation and provides energy to move flue gases at velocities needed for good heat transfer. ID fans are subjected to more severe service conditions than FD fans, because they must handle larger volumes of gas at high temperatures and contain ash particles. Physical characteristics of ID fans must therefore be different from those of FD fans. Airfoil blades are not recommended for ID fan service. Backward inclined fans are acceptable for nonabrasive gas service, while radial or radial tip blades and forward curved/backward inclined fans are recommended for abrasive service. The higher temperature of gases handled by the ID fan sometimes makes it necessary to use water cooled bearings to prevent overheating. Inlet damper controls or variable speed drives are used to control ID fan capacity.

3.6.5 Stacks, Flues, and Ducts. Stacks or chimneys are necessary to discharge the products of combustion at a sufficiently high elevation to prevent nuisance due to low flying smoke, soot, and ash. A certain amount of draft is also required to conduct flue gases through the furnace, boiler, tubes, economizers, air heaters, and dust collectors, and the stack can help to produce part of this draft. The height of the stack necessary to meet the first requirement is often enough to also produce the draft necessary to meet the second requirement. The amount of draft available from a stack depends on the height and diameter of the stack, the amount of flue gas flowing through it, the elevation above sea level, and the difference between temperature of the outside air and average temperature of gases inside the stack. Excessive stack temperatures are undesirable, because they represent a heat loss and efficiency reduction.

3.6.5.1 Stack Construction. Stacks are built of steel plate, masonry, and reinforced concrete. Caged ladders should be installed. Stack guys should be kept clear of walkways and roads and, where subject to hazardous contact, should be properly guarded. Stacks are provided with the means of cleaning ash, soot, or water from their base, the means depending mainly on the size of the stack.

a) Steel. The advantages of steel stacks over masonry or reinforced concrete are reduced construction time, lower weight, smaller wind surface, and lower initial cost. Major disadvantages are higher maintenance cost and shorter life. Steel stacks may be either self-supporting or guyed, single-wall or double-wall construction, and lined or unlined. Unlined guyed stacks usually are used on smaller installations. This type of stack can be supported by the boiler smoke box, the building structure, or a separate foundation. Two sets of four guy wires each are usually used to hold the stack erect. Steel stacks over 72 inches in diameter are normally self supporting. They are typically lined with refractory or insulation to protect the metal from the corrosive attack of flue gases and to improve performance of the stack by minimizing cooling of flue gases. The self-supporting stack is usually mounted on its own foundation or on the building structure framework. Stub and venturi stacks are typically of steel construction and usually extend no more than 20 feet above the boiler. When these stacks are used they contribute little to the draft requirements, which must then be supplied entirely by FD and/or ID fans.

b) Brick. The modern brick chimney built of special radial brick or block is very satisfactory, its major disadvantage being its higher cost. This type of stack is normally lined with fire brick for about one-fifth of its height and must be protected from lightning.

3.6.5.2 Flues and Ducts. Flues are used to interconnect boiler outlets, economizers, air heaters, and stacks. Ducts are used to interconnect forced draft fans, air heaters, and windboxes or combustion air plenums. Flues and ducts are usually made of steel. Expansion joints are provided to allow for expansion and contraction. Flues or ducts carrying heated air or gases should be insulated to minimize radiation losses. Outside insulation is preferred for its maintainability. Flues and ducts are designed to be as short as possible, free from sharp bends or abrupt changes in cross-sectional area, and of adequate cross-sectional area to minimize draft loss at the design flow rates.

3.6.6 Steam Turbines. The reciprocating steam engine with its need for oil lubrication and resulting contaminated steam has been replaced by steam turbines and electric motors. Steam turbine-driven boiler plant auxiliaries are generally economical only if exhaust steam can be used for feedwater or other heating applications. The steam turbine uses a rotating wheel, with buckets or blades uniformly spaced around its circumference to transform the heat energy of steam into mechanical energy or work. Steam, expanding through a nozzle, is directed against these buckets and causes the wheel to turn. Various types of steam turbines differ in the construction and arrangement of the nozzles, steam passages, and buckets. The steam turbine is essentially a high-speed machine; it is best used with direct connection to electric generators, pumps and fans, and with geared connection to low-speed machinery. The common noncondensing turbine operates at an efficiency of only 20 percent. Only special circumstances, such as the necessity for oil-free exhaust steam, can justify use of a small turbine for any purposes other than standby or emergency. Figure 116 shows a single-stage impulse noncondensing steam turbine.

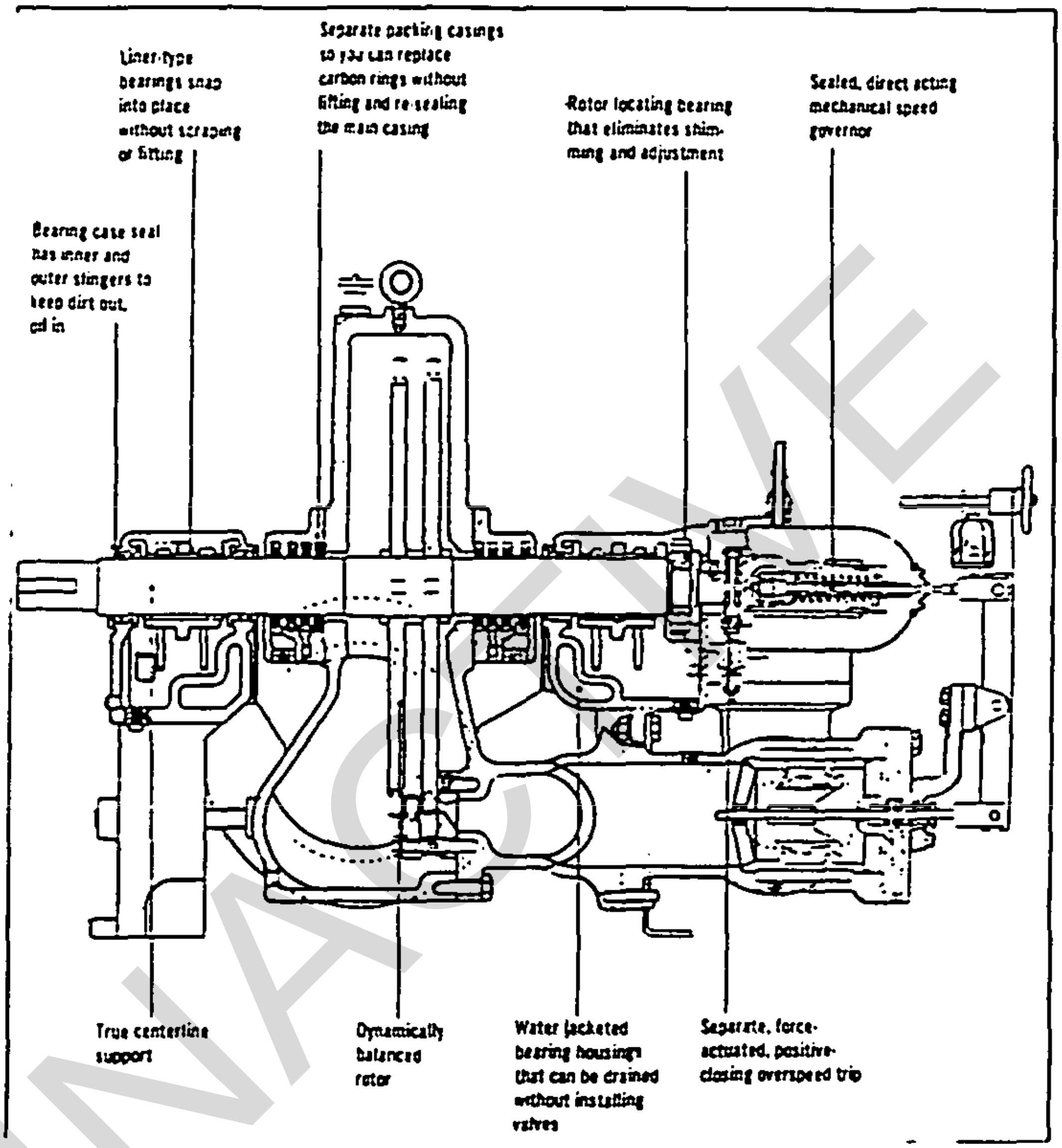


Figure 116
Single-Stage Impulse Noncondensing Turbine

3.6.7 Electric Motors. Electric motors can be grouped into three general classes based on power source. These classes are direct current, single-phase alternating current (AC), and three-phase AC. Three-phase motors are available in squirrel cage, synchronous, and wound rotor. The squirrel cage motor has become dominant because of its low cost, high reliability, high efficiency over a wide load range, and high starting torque, and it is estimated that 90 percent of electric motor energy is consumed by three-phase squirrel cage motors. Not all squirrel cage motors perform equally, however. When the need to replace or install a new motor exists, modern higher efficiency and higher power factor designs should be considered. Economic analysis usually justifies the slightly higher initial cost of high-efficiency motors.

3.6.8 Electrical Equipment. Electrical equipment used in central plants includes motors, motor starters, controls, circuit breakers, switchgear, transformers, fire protection, lighting, conduit, and wiring. Operation of these devices involves use of voltages that are dangerous to life. Operating personnel must observe safety regulations found in NAVFAC P-1060, Electrical Transmission and Distribution Safety Manual.

3.6.9 Variable Speed Drives. Electrical, mechanical, and fluid variable speed drives are available. Electrical drives include multiple speed motors, variable frequency controls, and variable voltage controls. Development of solid state components has allowed the design of variable frequency controls which can operate at high efficiency over a wide load range. Mechanical variable speed drives include belts with adjustable pulleys, gear reducers, and geared transmission. Fluid drives include a variety of hydraulic couplings.

3.6.10 Air Compressors. Three basic types of air compressors are available: reciprocating, rotary, and centrifugal. Air compressors may be further classified as oil free or lubricated. Air compressors used in Navy installations are comparatively small units, with final discharge pressures of approximately 100 psi. They are typically of rotary screw or single- or two-stage reciprocating design. These two types are discussed below. NAVFAC MO-209, Maintenance of Steam, Hot Water and Compressed Air Distribution Systems may be referenced for additional information on compressed air systems.

3.6.10.1 Reciprocating Compressors. The reciprocating compressor is a piston, positive displacement machine. Air volumes can range up to approximately 6,000 cfm. Two-stage compressors are frequently used, because they require less power to compress a given quantity of air than do single-stage machines. Cylinders and intercoolers of two-stage machines may be cooled by either air or water. The need for shielding or baffling structures for noise attenuation requires investigation when reciprocating compressors are to be used.

3.6.10.2 Rotary Screw Compressors. Rotary screw compressors are also classified as positive displacement machines. They operate by passing the inlet air through an inlet valve, and then compressing it through the action of two helical screws rotating against one another. Air volumes can range as high as 3,000 cfm but are more typically in the 100- to 150-cfm range. Packaged units are readily available in sizes up to 500 cfm which incorporate necessary filters, coalescers, and coolers into a single, factory-designed and assembled unit. Liquid sealed rotary screw-type units are available up to about 300 cfm and can provide oil-free air. This type of compressor is recommended in food processing or health care facilities but is not often used in boiler plants. It is more common to provide oil-free air to boiler plants by means of filters and separators in combination with one of the compressor types discussed above.

3.6.10.3 Capacity of Air Compressors. Total air requirement should be based not upon the total of individual maximum requirements but upon the sum of average air consumption of air-operated devices. Compressor capacity should be based upon the calculation procedure explained in NAVFAC MO-209.

3.6.10.4 Aftercoolers. In the process of compressing air, approximately 80 percent of energy delivered by the electric motor becomes heat energy stored in compressed air at elevated temperatures. Aftercoolers are required to cool the air to a more usable temperature. An aftercooler is a heat exchanger which is sized to cool the air below the dew point so as to allow water and oil vapors to condense. A moisture separator is attached to remove condensed vapors. The aftercooler is normally cooled with water, but it may also use air as its heat exchanger medium.

3.6.10.5 Air Dryers. Some compressed air applications require moisture removal in addition to that provided by the aftercooler. Such applications in the boiler plant include pneumatic tools, operation of pneumatic drives on dampers or valves, and instrument air. For these applications, a supplemental dryer is required. Three basic categories exist: refrigeration dryers, regenerative dryers, and deliquescent dryers. Regenerative dryers are the type usually used in boiler plants, and are discussed here. Information on the other types may be obtained from manufacturers or from NAVFAC MO-209. Regenerative dryers are further broken down into three types: heatless desiccant, heat regenerative, and low temperature regenerative.

a) Heatless Desiccant Dryers. Heatless desiccant regeneration passes a quantity of dried (purged) air through the offstream bed. No external heat is applied. This type should be selected with a field-adjustable purge control so that the purge rate (and therefore the pressure dew point) can be adjusted to accommodate seasonal variations in ambient temperature, thereby reducing operating costs. Heatless dryers are capable of providing -150 degrees F pressure dew point. Maintenance costs are low, since there are few moving parts. With adequate prefiltering to remove oil, desiccant replacement requirements are minimal.

b) Heat Regenerative Dryers. Heat regenerative dryers utilize heat from an external source (either electric or steam) in conjunction with purged air to regenerate the offstream tower. By reducing the amount of purged air required to regenerate, the heat regenerative dryer operating costs can be outweighed by maintenance costs and downtime.

c) Low Temperature Regenerative Dryers. Low temperature regenerative (heat pump) dryers utilize thermal energy from the inlet air to heat the offstream tower for regeneration. No electric heaters or steam are used. This type of dryer provides the economy of refrigerated drying and the low pressure dew point capability of desiccant drying. Refrigeration cooling is used to remove most of the incoming moisture and to cool the onstream tower for high adsorption efficiency. This system saves energy, since the heat energy removed from the inlet stream is recycled by the refrigeration compressor and discharged to the offstream tower for regeneration. Stable pressure dew points down to -100 degrees F are realized with this type.

3.6.10.6 Air Receivers. Air receivers are steel pressure vessels, constructed in accordance with the ASME Boiler and Pressure Vessel Code, Section VIII, which are sized to dampen pulsations entering the compressor discharge line, to serve as a reservoir for sudden or unusually heavy demands in excess of compressor capacity, to prevent too frequent loading and unloading of the compressor, and to allow moisture and oil vapor carryover from the aftercooler to precipitate. Drainage valves and piping, safety valves, and pressure gages must be installed in accordance with the Code.

3.6.11 Steam Traps. Steam traps are used to discharge condensate and air but not steam from a pipeline or heat exchanger (refer to NCEL UG-0005, Steam Trap User's Guide). No single type of trap is ideal for every situation. The four major types of steam traps are thermostatic, float and thermostatic, disc/thermodynamic, and inverted bucket. These are discussed below. Orifice or impulse traps are also produced but operate by discharging steam continuously and are therefore not recommended. This waste, as well as the wasting of steam from defective or damaged traps, represents an energy loss that is not acceptable. Proper maintenance of steam traps is discussed in Section 5.

3.6.11.1 Thermostatic Steam Traps. Thermostatic traps can be further subdivided into balanced-pressure thermostatic traps, liquid expansion traps, and bimetallic traps. All three subtypes work by sensing the difference between steam temperature and cooler condensate temperature, utilizing an expanding bellows or bimetal strip to operate a valve head. They usually discharge condensate below steam temperature and therefore require a collecting leg before the trap to allow for some condensate cooling. A balanced pressure thermostatic trap is illustrated in Figure 117. Thermostatic traps are typically used in low and medium pressure applications such as steam radiators, submerged heating coils, and steam tracing lines.

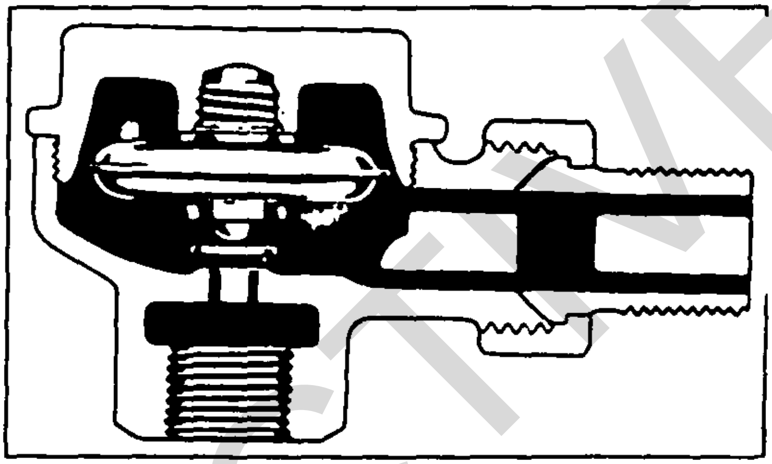


Figure 117
Thermostatic Steam Trap

3.6.11.2 Float and Thermostatic Steam Traps. Float and thermostatic steam traps (Figure 118) are recommended for use wherever possible. Their valve seat is always under water, preventing any steam loss. The discharge is continuous and modulates with the condensing rate, and it is unaffected by changes in inlet pressure. A separate thermostatic air vent independently purges air, giving a fast start-up, and discharges in parallel with the main valve seat without affecting its operation. Typical applications of float and thermostatic traps are air unit heaters, hot water heaters, heat exchangers, and converters.

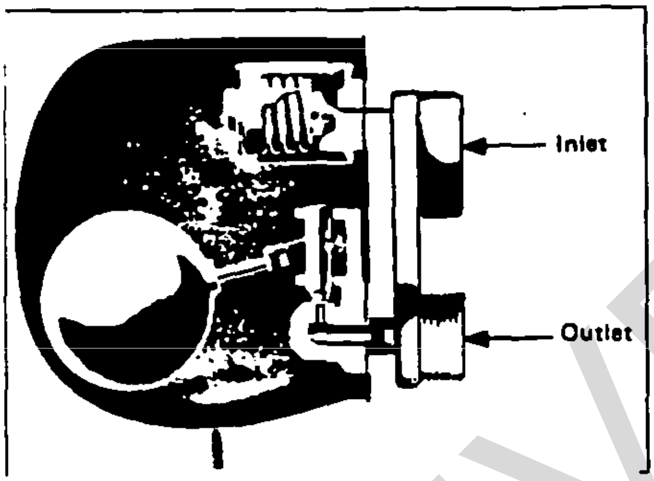


Figure 118
Float and Thermostatic
Steam Trap

3.6.11.3 Disc/Thermodynamic Steam Traps. Disc/thermodynamic traps (Figure 119) are widely used due to their small size, wide pressure range, one moving part, and resistance to water hammer and corrosion. Because operation of each model depends on the manufacturers seat and disc design, results may widely vary. Many are prone to air binding on start-up, operate below steam temperature (causing water logging), have a relatively short life due to soft seat and disc materials, and contain a bleed slot which causes rapid cycling and steam loss. Properly designed disc/thermodynamic traps can overcome these problems and allow effective and efficient operation. They are typically used on high pressure or superheated steam drip legs, steam trace lines, and unit heaters.

3.6.11.4 Inverted Bucket Steam Traps. Inverted bucket traps (Figure 120) have been in existence for many years, and their low initial cost helps keep them popular, although in every application superior results can be obtained with another type of trap. They consume a small amount of steam in operation and can blow fully open if they lose their prime due to oversizing or a rapid drop in inlet pressure. Their discharge is intermittent, not continuous. Typical applications include high pressure indoor steam main drips and submerged heating coils.

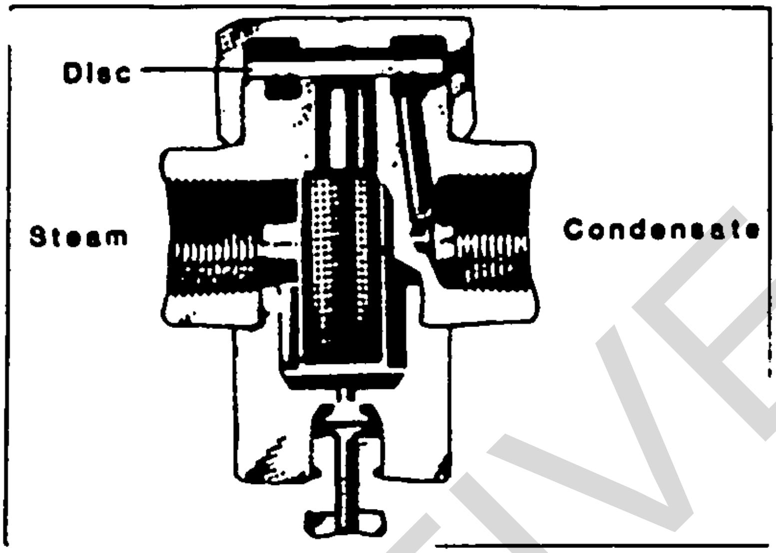


Figure 119
Disc/Thermodynamic Steam Trap

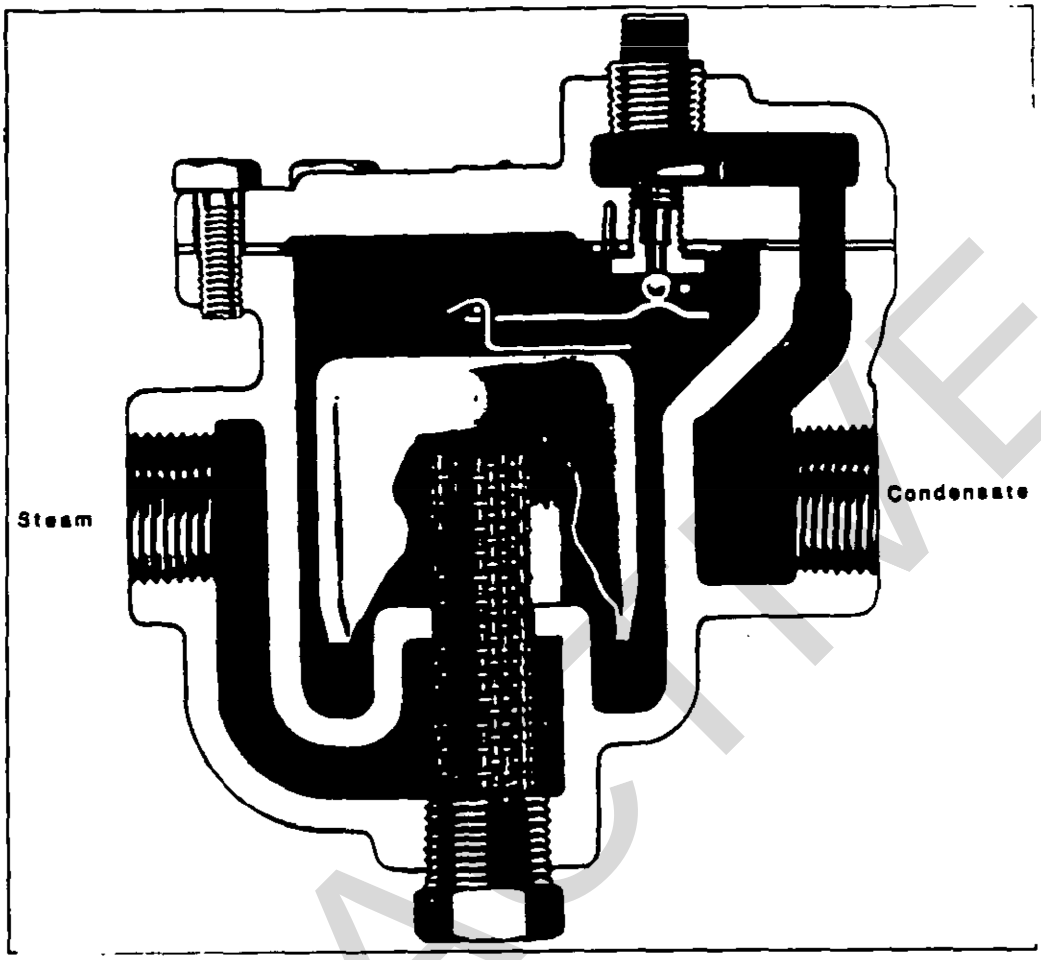


Figure 120
Inverted Bucket Steam Trap

3.6.12 Piping Systems. Piping (and tubing) systems are used in the central boiler plant to transport a wide variety of fluids, including, among others: water, steam, oil, natural gas, and compressed air. The following section is intended to provide a brief overview of some of the components and considerations that are involved in piping and tubing systems. The word "piping" in this handbook can generally be assumed to mean both pipe and tube. Strictly speaking, however, there is a difference between pipe and tube, and this is discussed briefly in par. 3.6.12.3.

3.6.12.1 Design Codes. Design of boiler plant piping is generally governed by design codes and industry standards. The ASME Boiler and Pressure Vessel Code, Section I, which was discussed in par. 3.2.1 as it applies to boilers and accessories, also covers certain portions of the piping around the boiler. Much of the balance of the piping in a boiler plant is covered by the American National Standards Institute (ANSI) B31.1, Power Piping. Some additional design codes and their applicability are given in Table 17. These design codes generally specify materials that may be used within their scope, how piping sizes and thicknesses must be determined, how pipe must be supported, what types of fittings, joints, and accessories may be used, and other provisions. Although these codes are written primarily for the piping designer or engineer, a general knowledge of their provisions is useful to the operator as well.

3.6.12.2 Materials. Piping materials are generally specified by the design code under which the system is built. The most common piping material in the boiler plant is steel. Steel pipe is strong, relatively easily worked, and available in a wide variety of sizes to fit most applications of pressure, temperature, and fluid. Other piping materials which are used for specific applications include copper, stainless steel, cast iron, and plastic. Some common applications of various materials are included in Table 18.

3.6.12.3 Sizing. Standard specification of size is the primary difference between pipes and tubes. Pipe size is specified by nominal pipe size (NPS) and schedule. Tube size is given by outside diameter (OD) and wall thickness.

a) Pipe Size. Nominal pipe size (or NPS) refers to the diameter of the pipe. Nominal pipe sizes range from 1/2 inch up to at least 30 inches, in standard increments. The OD for a given NPS is always the same, while the inside diameter varies depending upon the schedule. Schedule refers to the wall thickness and is generally listed as Schedule 40, Schedule 80, Schedule 160, etc. Earlier practice, which is still used on occasion, was to refer to schedules by designations such as Standard (STD), Extra Strong (XS), or Double Extra Strong (XXS). Dimensions and tolerances corresponding to nominal sizes and schedules are established by ANSI standards. There is no easy way, other than referring to a chart, to determine the actual dimensions of a given nominal pipe size. For instance, 1-inch NPS, Schedule 80 pipe has an outside diameter of 1.315 inches, a wall thickness of 0.179 inches, and an inside diameter of 0.957 inch.

Table 17
Piping Codes and Standards for Boiler Plants

Sponsoring Agency	Identification	Title	Coverage
ASME	Section I	Power Boilers	Rules for construction of power boilers
	Section IV	Heating Boilers	Requirements for heating boilers
	Section VI	Care of Heating Boilers	Recommended rules for the care and operation of heating boilers
	Section VII	Care of Power Boilers	Recommended rules for the care of power boilers
	Section VIII	Pressure Vessels	Rules for construction of pressure vessels
	Section IX	Welding Qualifications	Welding procedures and qualifications
	ASME 4.1	Power Test Codes	Steam generation units
ANSI	B31.1	Power Piping	All boiler plant piping beyond the jurisdiction of ASME BPV I
	B36 Series	Iron and Steel Pipe	Materials and dimensions
	B16 Series	Pipe, Flanges, and Fittings	Materials, dimensions, stresses, and pressure/temperature ratings
	B18 Series	Bolts and Nuts	Bolted connections
ASTM		Testing Materials	Physical properties of materials specified in ASME and ANSI codes
NEMA	TU4 and SM20	Steam Turbines	Allowable reactions and movements on turbines from piping
NFPA	30	Combustion Liquids Code	Flammable and combustible liquids code
	31	Oil Burning Equipment	Standards for the installation of oil burning equipment
	8501	Fuel Oil and Natural Gas	Standards for prevention of furnace explosions in fuel oil and natural gas fired single burner boiler furnaces
	85B	Natural Gas Multiple Burners	Standards for prevention of furnace explosions in natural gas fired multiple burner boiler furnaces
	85D	Fuel Oil Multiple Burners	Standards for prevention of furnace explosions in full oil fired multiple burner boiler furnaces
	85E	Pulverized Coal	Standards for prevention of furnace explosions in pulverized coal fired multiple burner boiler furnaces
	8503	Pulverized Fuel	Standards for the installation and operation of pulverized fuel systems

Table 18
Typical Piping Material Applications

Material	Typical Applications	Typical Joints*
Carbon Steel	High pressure steam, water, fuel oil, compressed air, and natural gas. Almost any fluid, with the exception of certain corrosive types, up to about 750 degrees F	Screwed, socket- or butt-welded, flanged
Low Alloy Steel	Superheated steam, up to 1,000 degrees F	Welded
Stainless Steel	Chemical and corrosive applications**, steam above 1,000 degrees F, instrument tubing	Socket- or butt-welded, flanged; tubing may use flared or compression fittings
Cast Iron	Floor and roof drains; water supply, sanitary piping; low pressure and temperature applications	Bell and spigot, mechanical groove-lock joints
Copper	Plumbing, potable water; instrument tubing	Soldered, flared, or compression fittings
Plastic (PVC, ABS)	Sanitary drains, nonpotable water; miscellaneous low pressure applications	Solvent welded

* Selection of proper joint must be based on design code.
** Extreme care must be used in selection of proper alloys for corrosive service.

b) Tubing Size. Tubing size is specified by OD and wall thickness. Although tubing theoretically is available in almost any diameter, ranging from a few hundredths of an inch up to several feet, in practice, tubing in a boiler plant is limited to sizes of about 1/8 to 1 inch. Tubing in common use in the boiler plant is generally either copper or stainless steel. The major exception to this rule is within the boiler itself. Boiler manufacturers generally use tubing rather than pipe, and for the most part use carbon or low alloy steel.

c) Determination of Proper Size. Piping systems must be sized with regard to a number of criteria, including type and quantity of fluid to be transported, pressure and temperature conditions, allowable velocities, and pressure loss. These calculations can become quite sophisticated and are outside the scope of this handbook. The pertinent design codes should be consulted for guidance.

3.6.12.4 Fittings and Joints. Pipe and tubing may be joined in a variety of ways, including threading, welding, flanges, a variety of mechanical coupling joints, soldering (for copper and brass), and solvent welding (for plastics). These methods are common, and the type used in a particular application is usually specified by the design code. In steel piping, high pressure systems such as steam or boiler feedwater commonly use welded joints, as do systems which are larger than approximately 2 to 3 inches in diameter. Smaller diameter systems in steel pipe may be threaded or socket welded. Flanges are often used when piping must be disassembled periodically, for instance to perform maintenance on valves or other components. Fittings and flanges are available in materials and thicknesses to correspond to pressure and temperature requirements of the piping system.

3.6.12.5 Pipe Supports. Proper support of piping systems requires sophisticated design calculations and is outside the scope of this handbook. Some of the general criteria that must be considered in making these calculations are discussed below.

a) Allowable Stress. The design codes for each application generally provide allowable stress levels for each material. These levels have been determined by experience to have adequate safety margin, and they must be adhered to. Allowable stress for a given material is a function of temperature and decreases at higher temperatures.

b) Expansion/Flexibility. As the temperature of a pipe changes, the pipe moves due to expansion and contraction. Provisions must be made in the piping support system to accommodate this movement by providing piping flexibility through bends, expansion loops, or expansion joints. The required amount of expansion must be determined by calculating the stress level in the pipe and ensuring that it is less than the allowable stress.

c) Anchors and Supports. An almost infinite variety of anchors, hangers, and supports may be seen in central boiler plants. A variety of hanger types has been standardized by the Manufacturers Standardization Society (MSS), and some of these are illustrated in Figure 121. Custom designed supports using structural steel shapes and standard hardware are also common.

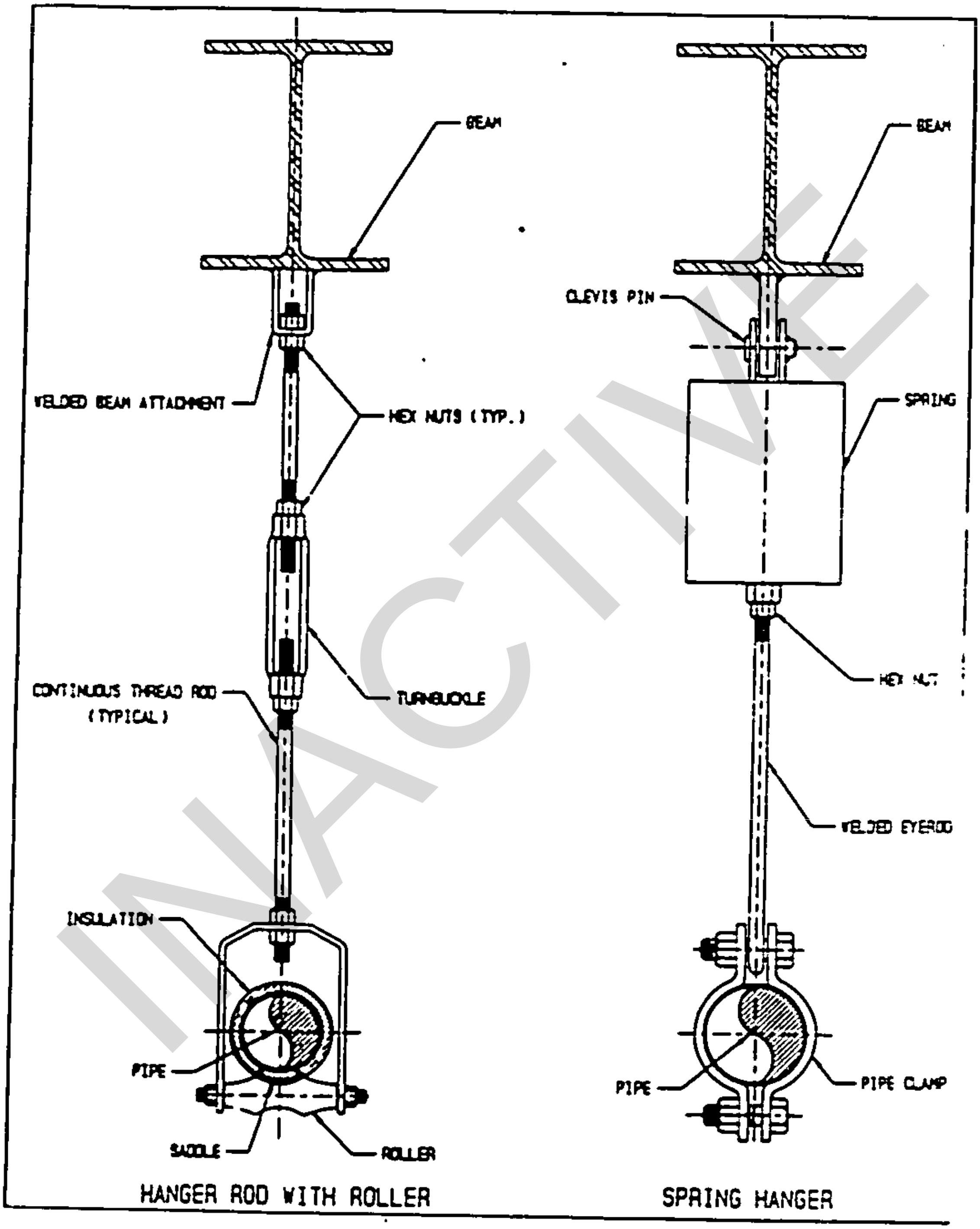


Figure 121
Standard Hanger Types for Piping Systems

3.6.12.6 Valves. Valves are available in a wide variety of types, materials, and pressure/temperature ratings to correspond to the system in which they are used and their purpose in that system. Some types of specialized valves are discussed elsewhere in the manual (gage cocks, par. 3.2.2; safety valves, par. 3.2.5; boiler outlet valves, par. 3.2.6; blowoff valves, par. 3.2.7; control valves, par. 3.4.1). Several additional common types are discussed below. Specific applications should be discussed with the manufacturers representative to ensure the correct body and internal materials, seat design, packing design and material, and other details.

a) Function. Valves can serve many different functions in a piping system. Broad categories of valve function include: isolation (on-off), throttling (control), backflow prevention, pressure relief, and regulation.

b) Gate Valves. The gate valve is the simplest in design and operation and is commonly used in boiler plants. Gate valves are used where minimum pressure drop is important. They are employed where the valve will operate in a wide open or fully closed position and is to be operated infrequently. Gate valves are not designed for throttling operation, and under prolonged use in a partially open position damage to the seat or disc may occur. A solid wedge type of gate valve is illustrated in Figure 122.

c) Globe Valves. The globe valve is used primarily for throttling or positioning to create a definite pressure drop. Globe valves are available in the common partial globe and seat contact type, the small needle type, and numerous variations such as top-guided, post-guided, angle, Y-pattern, fluted, and cage-guided. Because of their inherent ability to exhibit repeatable flow curves, they are the most commonly used type of valve for control valve application. Globe valves can also be used in on-off service where pressure drop in the fully open position is not of primary importance. Normally, globe valves are installed with the flow under the disc, but in certain cases where it is desirable to have line pressure assist in maintaining seat closure, flow may be directed over the disc. In motor- and air-actuated valves, this flow direction is very important in sizing the actuator. A standard single-port globe valve is illustrated in Figure 123.

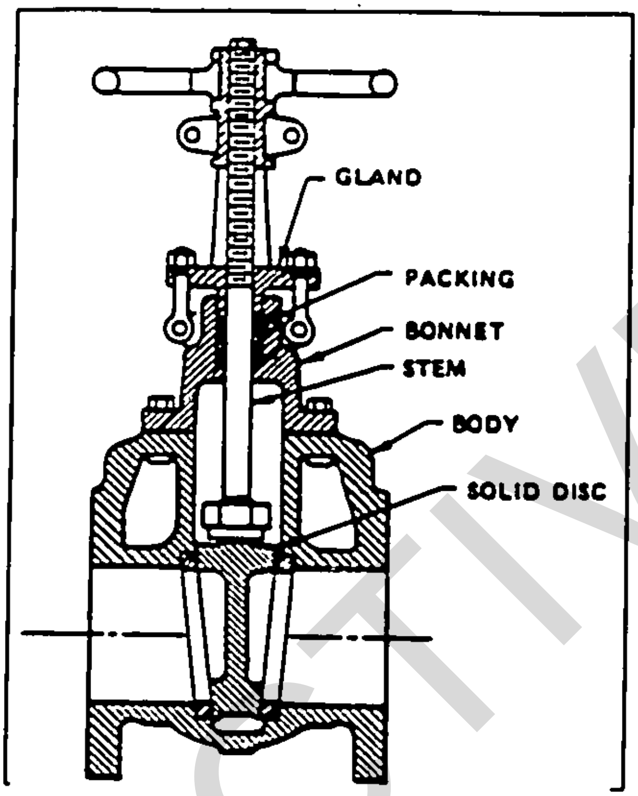


Figure 122
Solid Wedge Disc Gate
Valve

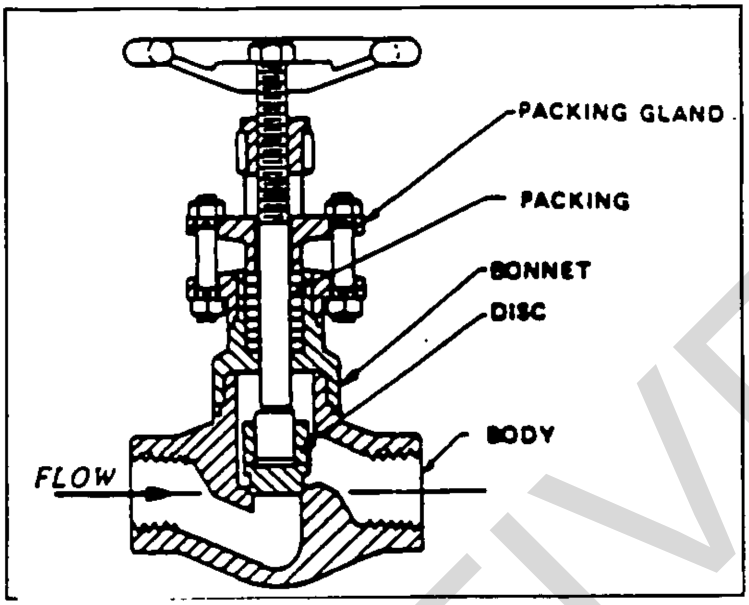


Figure 123
Single-Port Globe Valve

d) Plug Valves. The plug valve is a refinement of the earliest known valve, the spigot. Basically, it is a 90-degree rotation from open to closed position of a tapered inner valve. The downward thrust of the plug taper exerts a compression load on the side wall, thus ensuring a continuous circumferential sealing surface. Like the gate valve, it is used primarily in on-off service only. The plug valve has the added benefit of bubble-tight sealing, thus making it ideal for gaseous service. In addition, because of its large unobstructed flow passage, the plug valve is ideally suited for slurry service. A typical plug valve is illustrated in Figure 124.

e) Butterfly Valves. Butterfly valves have been used in industry for decades, performing well-defined tasks in which they show distinct advantages over other valve types. Some butterfly valve designs can provide dependable bubbletight shutoff, and others are ideally suited for throttling or control applications, having an equal percentage flow characteristic. Butterfly valves are quick opening and highly efficient, can be operated manually or automatically, and can be used in handling a variety of media, including liquids, solids, slurries, gases, and vapor (steam). Figure 125 illustrates a typical butterfly valve.

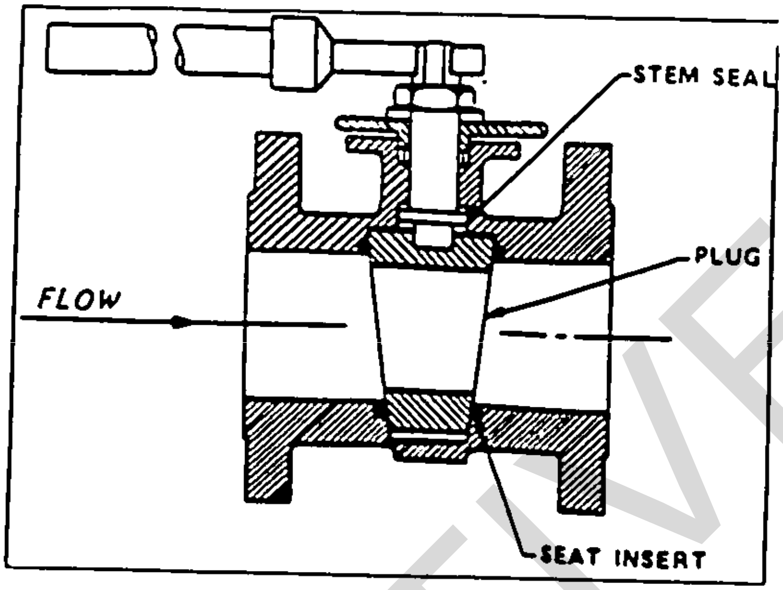


Figure 124
Nonlubricated Plug Valve

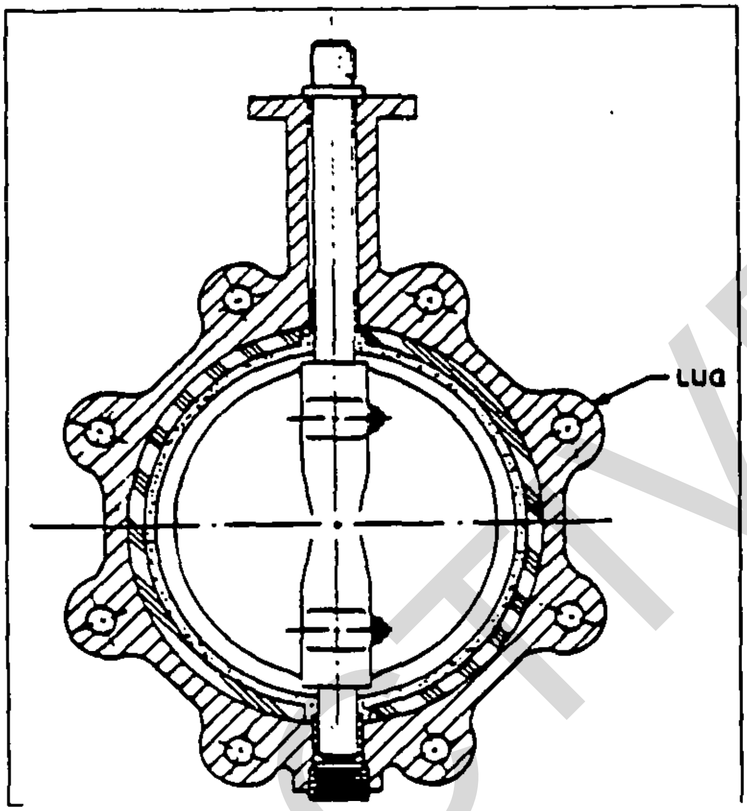


Figure 125
Butterfly Valve

f) Check Valves. Check valves are designed for use in a piping system where protection against the reversal of fluid flow is desired. During operation, liquid or gas pressure will move the disc off the valve seat and allow fluid to flow through the valve with minimum pressure drop. If the fluid flow ceases or reverses direction, the reverse fluid flow and design of the disc assembly will force the disc against the seat to prevent fluid back flow. The disc weight, seat configuration, and internal spring assistance (if provided) contribute to the ease with which the disc opens or closes and to a leak tight seal when in the closed position. Check valves can be obtained in a wide variety of styles to fit specific applications. Two of the more common types (swing check and spring-loaded lift check) are illustrated in Figure 126A and 126B.

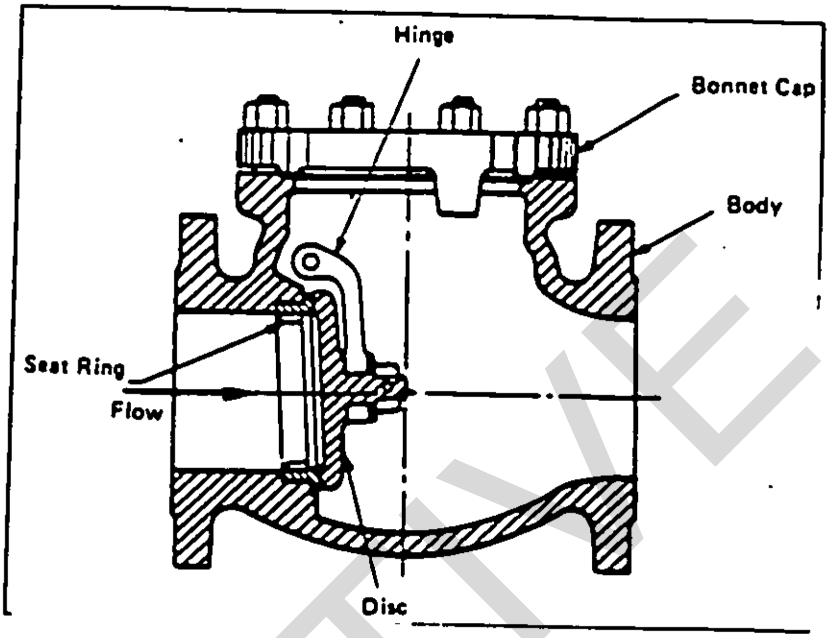


Figure 126A
Swing Check Valve

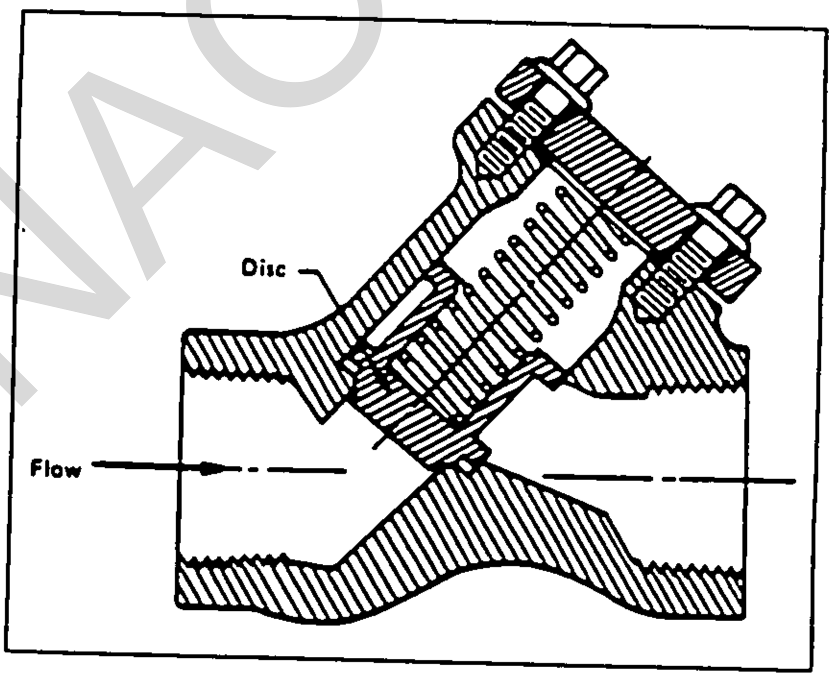


Figure 126B
Y-Type Spring Lift Check Valve

3.6.12.7 Insulation. Insulation is used to reduce heat loss from hot piping, eliminate condensation, reduce heat gain on cold piping, and provide personnel protection. Insulation types typically used in central boiler plant piping systems include fiberglass, mineral wool, and calcium silicate. Jacketing or vapor barrier is usually incorporated over insulation to protect insulation material. Common jacket materials include aluminum, fiberglass cloth, and various other fabrics. Asbestos insulation is no longer used because of potential health hazards. The Navy has been removing and replacing asbestos materials in older plants. Prior to removing any insulation, be sure that it has been certified asbestos-free.

Section 4: OPERATION

4.1 Introduction. This section discusses operation of equipment that has been described in Section 3. Operational recommendations are made for steam and hot water boilers with capacities less than 200,000 pounds per hour of steam or less than 250 million Btu per hour output. Comments are generally based upon steam boilers producing saturated steam, although in some cases, specific differences are noted for hot water boilers. ASME Boiler and Pressure Vessel Code, Section VI or VII, NFPA 85 series standards, ASME CSD-1, and manufacturers operating and maintenance instructions should be carefully considered in addition to the following text. Safe and reliable operation is dependent to a large extent upon the skill and attentiveness of the operation and maintenance personnel. Operating skill requires knowledge of fundamentals, familiarity with equipment, and a suitable background of training and experience.

4.2 Preliminary Operating Procedures

4.2.1 Plant Operation Considerations. Standard operating procedures (SOP's) should be prepared and posted in the boiler room. The SOP should clearly indicate the sequence of actions to be performed for each unusual condition which could create a hazard operational interruption. Examples of such unusual conditions include flame failure, loss of water, tube failure, sudden loss of load, steam line failure, loss of electric power, or control malfunction. The exact order in which each valve, control, and piece of equipment should be operated for a particular type of failure should be stated in the SOP. Valves and equipment should be marked for easy identification. The SOP may also be used to describe normal actions necessary to maximize boiler and plant efficiency.

4.2.1.1 Boiler Plant Operating Logs. Boiler plant operating logs provide a means of recording data and maintaining a history of boiler plant performance. Information should be recorded at specified time intervals. This information should include the following: date, time, operating equipment, relative parameters (pressure, temperature, flow), energy in (fuel), energy out (steam, electricity), water quality, efficiency, equipment problems, and any work performed on equipment. These data should be compiled at the end of each month and reported on a monthly log.

4.2.2 Inspection. A boiler is subject to damage and must be periodically inspected by a qualified inspector to ensure that it is in safe operating condition. Boilers must be inspected as required by MO-324, Inspection and Certification of Boilers and Unfired Pressure Vessels. Details are included in Section 5.

Daily operation requires the operator to be aware of normal operation and to perform daily inspections to ensure that equipment is operating properly and safely. Abnormal operation should be logged and reported.

4.2.3 Applicable Codes. The following codes provide rules and practical guidance for the safe and effective operation of boilers and boiler accessories:

a) ASME Boiler and Pressure Vessel Code, Section VI, Recommended Rules for Care and Operation of Heating Boilers.

b) ASME Boiler and Pressure Vessel Code, Section VII, Recommended Rules for Care of Power Boilers.

c) NFPA National Fire Codes, NFPA 8501.

d) NFPA National Fire Codes, NFPA 8502.

e) NFPA National Fire Codes, NFPA 8503, Standard for Pulverized Fuel Systems.

f) ASME CSD-1.

4.2.4 Preparation for Start-up. Specific plant SOP's should be prepared and followed in preparing for boiler start-up. In general, before lighting fire in a boiler the following steps should be taken.

4.2.4.1 Instrumentation. Check instrumentation. If possible, operate control devices to prove operation, freedom of movement, and function of limit switches. Check that the boiler pressure gage cock is open.

4.2.4.2 Internal Inspection. Check that personnel and tools have been removed from the boiler. Inspect furnace walls, boiler tubes, and flues to confirm that they have been cleared of slag, soot, and deposits which could act as insulation, thus reducing heat transfer and boiler efficiency. Slag, soot, and ash should be removed as discussed in pars. 4.3.5 and 4.3.6. Check that doors and openings are closed.

4.2.4.3 Combustion Equipment. Inspect and test operation of combustion equipment without lighting a fire. Careful inspection of a stoker or burner and their accessories helps to prevent forced outages.

4.2.4.4 Fuel Supply. Check the fuel storage system to ensure that there is enough fuel to meet boiler requirements. For solid fuels, check the fuel level in the hopper, as well as its size and moisture content. For oil, measure the quantity of fuel oil by stick or gage. Ensure that valves are properly aligned, and that necessary pumps and regulating valves are in operation. Check that fuel oil is available at the required pressure and temperature. If atomizing air or steam is required, confirm its availability. For gas fuel, check for correct gas pressure and valve positions, and for any signs of gas leakage from piping or valves.

4.2.4.5 Water Supply. Ensure that an adequate supply of treated feedwater is available at the proper temperature. Check the level and temperature of water storage tanks or deaerator. Check valve alignments and boiler feedwater pump availability.

4.2.4.6 Water Column and Gage Glass. Check operation and close blowoff valves, water column, gage glass drains, and gage cocks. Ensure that the gage glass is clean and well lighted. Open the drum vent and drain valve between header and nonreturn valves. Open feedwater valves and admit water to the boiler slowly until the water level is just above the lowest safe level. Blow down the water column and operate the cock as a further check of water level and to ensure that these appliances are in good working condition. If provided, check the operability of the low-water fuel cutoff. On forced circulation hot water boilers, start the circulating pump and, if a proof of water flow switch is provided, prove switch operating by shutting off and then restarting the pump.

4.2.4.7 Boiler Safety Control. Clean the flame scanner lens when provided. Check limit switches to prove operation.

4.2.4.8 Furnace Purge. The furnace, boiler bank, economizer, air heater, ducts, and pollution equipment must be adequately purged before starting a fire.

CAUTION: Many disastrous explosions are caused by failure to vent the furnace and setting completely before attempting to start a fire. Explosive mixtures of air and gases may accumulate and ignite if a fire is started without first venting the furnace and setting. To avoid this danger, open the stack damper and operate necessary fans and dampers to purge the furnace and attached equipment.

The purge air should be at a sufficient rate to provide adequate velocity to clear dead spots or inactive pockets and sweep the entire unit. Purge airflow rates of 25 to 75 percent and purge time of 3 to 5 minutes, or eight air changes are considered adequate. A boiler must also be purged after an accidental loss of ignition.

4.2.5 Starting Fire. After completing the preparatory steps outlined above, combustion equipment may be started. Manufacturers' recommendations for equipment start-up should be reviewed and carefully followed for each type of equipment and fuel. General recommendations are provided below.

4.2.5.1 Hand Firing Coal. Ensure that ashes and clinkers are removed from grates. If lump coal is available, spread a layer 3 to 6 inches thick on grates to prevent fines from sifting through. When ash content of coal is low (under about 7 percent), spread about an inch of ashes on grate before introducing coal. Spread dry wood, shavings, or live coals from an adjacent boiler on top of coal. Gasoline, naphtha, or other highly flammable liquids should never be used as kindling. Partly open the stack damper and ash-pit doors to induce airflow through the furnace. Light the kindling, leaving the fire door partly open to admit air over the fire and reduce smoke. After the fire is started, regulate the damper and ash-pit doors to maintain a draft and accelerate combustion. Supply additional coal as required and control the rate of combustion by regulating airflow through the fuel bed.

4.2.5.2 Stoker Firing Coal. To start a fire on a mechanical stoker, supply coal to the furnace by operating the feed mechanism or shoveling coal into the furnace. Place enough coal into the furnace to cover the tuyeres of an underfeed stoker to a depth of about 6 inches, or the grates of a spreader stoker to about 2 inches. Place wood, shavings, or kindling on top of the coal, and open the stack damper or operate the induced draft fan. Maintain a slightly negative furnace pressure to remove products of combustion. Light shavings and regulate the draft as required to keep the fire burning. In some plants, fires may also be started with live coals from another furnace. As soon as the coal burns freely, operate the FD fan and regulate airflow to the furnace with the blast gate or damper to control the rate of combustion. If the boiler heats up too rapidly, operate fans at lower ratings or stop them for a short time. Do not add more coal to the furnace until the fire burns freely. When neither steam nor electric power is available to operate the fan and stoker, feed the coal by hand and use natural draft until steam pressure is high enough to operate the auxiliary equipment.

4.2.5.3 Pulverized Coal Firing. When firing pulverized coal, follow the procedures outlined in NFPA 8502 and NFPA 8503, and refer to the plant's specific SOP.

4.2.5.4 Oil Firing. Oil firing procedures vary with the type of burner, controls, and fuel oil. Some plants use No. 2 fuel oil with pressure or steam atomizing burners, automatic controls, and electric spark ignition. Many installations use No. 4, 5, or

6 fuel oils with either air, semiautomatic, or automatic ignition procedures. In every procedure an important step is the purging of the boiler furnace. If ignition is delayed, immediately determine the cause and correct the problems.

a) Preheating the Fuel Oil. Heavy oils (Nos. 5 and 6, and sometimes 4) require heating to reduce the oil viscosity to a point where pumping is practical. Additional heating may also be required to optimize atomization. Pump and burner manufacturer viscosity recommendations should be followed. Steam or electric tank heaters are used to heat oil to a temperature of 90 to 110 degrees F, with oil preheaters supplying additional heat as needed. To determine the amount of preheat temperature necessary for a given oil, consult the burner manufacturer for an initial recommendation. Experimentation is often necessary to determine the temperature that works best for the particular installation. One hundred to 300 Saybolt seconds universal (SSU) viscosity is usually desirable for Nos. 5 and 6 fuel oils. No. 4 may also need some preheating depending on the type of atomizer/burner and the particular oil. No. 2 oil rarely needs preheating, but outside storage in cold climates may necessitate preheating to room temperature.

b) Lighting Burners. Before lighting off a burner, always check for proper oil pressure, temperature, and atomizing air or steam pressure. Purge the unit and establish airflow suitable for light-off.

Gas igniters or pilots are usually used to light off light oil burners. These igniters typically use an electric spark to ignite the gas. If the igniter flame is seen by the flame scanner within a 10-second trial for ignition, the oil safety shut-off valve is opened, either manually or automatically. The oil control valve should be at its low fire position and is often interlocked in this position. Fifteen seconds after the oil shutoff vale is opened, the igniter is shut off. If the flame scanner still sees flame, the burner will continue to operate. If no main flame is seen at this time, the shutoff valve is closed. The boiler should be repurged before a second trial for ignition is made. Loss of main flame or other safety interlock limits as shown on Figures 51 and 52 will result in the safety shutdown of a burner.

4.2.5.5 Gas Firing. The ignition of a gas burner is always accomplished with the use of a gas igniter, flame scanner, and flame safeguard control. Purging the boiler is required before a trial for ignition. Proper gas pressure should be available to both the igniter and main burner, and the gas control valve should be in its low fire position. The semiautomatic or automatic light-off sequence is identical to that for oil burners except the trial for ignition of main flame is only 10 seconds. Loss of flame or boiler and burner limits shown on Figure 52 or Figure 53 will result in the shutdown of a burner. The boiler furnace must be repurged before a new trial for ignition may be attempted.

4.2.6 Warm-Up Time. The time required to bring a boiler up to line pressure or temperature is dependent on many things, including the size and type of boiler, its operating pressure or temperature, the combustion equipment, and whether or not it is equipped with a superheater. Manufacturer's detailed instructions should be followed to minimize thermal stresses as the boiler heats up and expands. In general, boilers out of service long enough to cool down to room temperature require 1/2 to 2-1/2 hours to reach line pressure. If a new boiler or one with extensive repairs to the furnace or setting is being placed in service, sufficient time must be allowed for brickwork to dry out. Operate the boiler on low fire for several days before it is actually placed into service. If the boiler is equipped with a superheater, take extra precautions to prevent it from overheating by firing at a low rate during the warm-up period, and by allowing a small amount of steam to flow through the superheater. Leave the outlet drain from the superheater open so that some steam flows through the tubes as pressure builds up. This steam will help to cool the superheater metal, and prevent tube damage.

4.2.7 Placing a High Pressure Steam Boiler in Service. When water in the drum begins to boil, steam is discharged from the drum vent. When boiler pressure reaches about 25 psig, air will have been removed, and the vent should be closed. If the boiler does not have a vent, use the gage cocks to allow air to escape. Carefully observe the fire while the pressure is increased, and maintain minimum stable firing conditions. If the firing rate is too high on multiple burner boilers, shut off some of the burners. Rotate operation of burners to promote uniform heating. If the firing rate is too high on a stoker-fired boiler, shut off the FD fan for a period and operate on natural or ID only.

4.2.7.1 Control of Water Level. Observe water level frequently during the warm-up period. Increasing temperature and the formation of steam causes the boiler water to expand. To avoid high water levels, start the boiler with the water level just above the lowest safe level. If necessary, open the blowdown valves and remove water to prevent high level conditions.

4.2.7.2 Checking Safety Valves. Safety valves should be tested periodically by hand lifting them. Do this when steam pressure in the boiler is at least 75 percent of the set pressure of the lowest safety valve. Care should be taken to hold the valve open wide and release the hand lever briskly, so that the valve closes with a snap. At intervals, as required by the Authorized Inspector, safety valves must be tested by raising the boiler pressure to the set pressure of the safety valve to ensure that it pops and reseats correctly. When a safety valve fails to operate, do not attempt to free it by striking the body or other parts of the valve. If a safety valve leaks or fails to operate properly, remove the boiler from service immediately and repair or replace the valve. Checking of safety valves by raising pressure on the boiler must be under direct supervision of a designated, qualified employee.

4.2.7.3 Operation of Header Valves. When placing a boiler into service, care must be taken to avoid water hammer and expansion stresses associated with large temperature differentials. When other boilers on a header are already operating, the steam line from the boiler being started must be brought up to temperature by operating the bypass and drain valves to create a flow of steam from the header. When the line is up to temperature and pressure, the header gate valve may be opened wide and the bypass closed. The nonreturn valve should be opened to a 25 percent position until the boiler starts to supply steam to the header, after which it may be fully opened. In the absence of a nonreturn valve, the boiler stop valve should be opened slowly when pressure in the boiler and header are approximately equal. If a boiler is being put into service on a header which is not under pressure, it is desirable to warm up both the boiler and steamline/header together. In this case, open both the stop and nonreturn valves and make sure the steam header drain valves are open to remove any condensate formed.

4.2.7.4 Activate Controls. When the boiler is producing steam and is properly connected to the header, place the feedwater and combustion controls into automatic operation in accordance with the manufacturer's recommendations and instructions.

4.2.8 Placing a Hot Water Boiler in Service. The following general procedures should be followed for placing a single LTW, MTW, or HTW boiler into service. Procedures are also included for placing additional boilers into service on multiple boiler installations.

4.2.8.1 Procedure for a Single Boiler. When starting a boiler after lay up, proceed as follows:

a) Review manufacturer's recommendations for start-up of burner and boiler.

b) Fill boiler and system; vent air at high point in system.

c) Check altitude gage and expansion tank to ensure system is properly filled.

d) Set control switch in "OFF" position.

e) Make sure fresh air to boiler room is unobstructed and manual dampers are open.

f) Check availability of fuel.

g) Vent combustion chamber to remove unburned gases.

h) Clean glass on flame scanner, if provided.

i) Observe proper functioning of water pressure regulator and turn circulator pumps on electrically.

j) Check temperature control(s) for proper setting.

k) Check manual reset button on low water fuel cutoff and high limit temperature control.

l) Set manual fuel oil supply or manual gas valve in "OPEN" position.

m) Place circuit breaker or fuse disconnect in "ON" position.

n) Place boiler emergency switches in "ON" position.

o) Place boiler control starting switch in "ON" or "START" position. (Do not stand in front of boiler doors or breeching.)

p) Do not leave boiler unattended until it reaches the established cutout point to ensure that controls shut off the burner.

q) During temperature and pressure build-up period, walk around the boiler frequently to observe that associated equipment and piping is functioning properly. Visually check burner for proper combustion.

r) Immediately after burner shuts off, inspect water pressure and open the highest vent to determine that system is completely full of water.

s) Enter in log book:

(1) Date and time of start-up.

(2) Any irregularities observed and corrective action taken.

(3) Time when controls shut off burner at established temperature, tests performed etc.

(4) Signature of operator.

t) Check safety relief valve for evidence of leaking. Perform try lever test.

4.2.8.2 Action in Case of Abnormal Conditions. If any abnormal conditions occur during light off or temperature build-up, immediately open emergency switch. Do not attempt to restart the unit until difficulties have been identified and corrected.

4.2.8.3 Placing Additional Boilers into Service. When placing a boiler on the line with other boilers which are already in service, start the boiler using the above procedures, but have its supply and return stop valves closed. Bring the second boiler to the same temperature as the operating boiler and partially open the supply valve(s). If there is no unusual disturbance, such as noise, vibration, etc., continue to open the valve slowly until it is fully open. Open the valve in the return line.

Caution: When the stop valve at the boiler outlet is closed, the stop valve in the return line of that boiler must also be closed.

4.3 Operating Adjustments and Procedures

4.3.1 Boiler Operation. Basic boiler operation consists of supplying fuel to generate steam (or hot water) as required by system demand, and supplying air in the correct proportion to efficiently burn the fuel. The rate of fuel feed used to maintain steam pressure or water temperature may be controlled either manually or automatically. In supplying air to the burner or furnace, both the quantity and its point of application for optimum combustion must be considered. Other facets of boiler operation include feedwater supply, which must be introduced in proportion to quantity of steam discharged, and operation of pumps, fans, dampers valves, controllers and fuel handling equipment, all of which are used to maintain proper flow of materials to and from boiler.

4.3.2 Maintaining Pressure or Temperature. Pressure gages indicate the difference between pressure inside the boiler and atmospheric pressure. Pressure on each square inch of internal surface is expressed as pounds per square inch gage (psig). For steam boilers the pressure gage indicates if the firing rate is properly adjusted. If the rate of steam flow from a boiler increases, the pressure drops because heat is carried away faster than it is being supplied, and the firing rate must be increased. If steam flow decreases, the pressure increases and the firing rate must be decreased. For hot water boilers, the temperature gage is used to indicate the proper firing rate. If the boiler outlet temperature falls below the set point, the firing rate needs to be increased. If the outlet temperature rises above the set point, the firing rate must be decreased. If manual control is being used, the operator notes changes to pressure or temperature and adjusts the fuel and air supply accordingly. Automatic combustion controls, as discussed in par. 3.4.2, sense pressure or temperature changes and automatically adjust fuel and air supplies. Automatic systems relieve the operator of the tedious and continuous adjustment necessary with each change in demand.

4.3.3 Feedwater and Boiler Water Treatment. Feedwater must be supplied to the boiler at an acceptable temperature to avoid thermal shock and excessive stresses on the boiler pressure parts. Water must also be treated to minimize corrosion and scale formation in the boiler and the distribution system and optimize heat transfer and boiler efficiency. Refer to MO-225.

4.3.4 Controlling Feedwater. Hot water boilers operate with constant water flow rates and do not require feedwater controls. Water flow to steam boilers must be regulated so that 1 pound of water replaces each pound of steam generated. The gage glass, try cocks, and other water level indicators are used as guides in controlling water flow to a boiler. Visible water level is not always a true indication of the amount of water in a boiler because steam bubbles, as well as water, are contained in the water space and cause the water to swell. If the steaming rate decreases, the amount of steam bubbles decreases, the water shrinks, and the water level drops. The tendency of water level to vary with steaming rate is known as "swell" and "shrink." Swell and shrink must be taken into consideration in controlling water flow so that the flow varies properly with steam output. The types of feedwater controls available are discussed in par. 3.4.1. Most feedwater controls on small boilers are of the single-element type, and sense only water level. Although they do a very good job on most boilers, they cannot compensate for swell and shrink. Where swell and shrink become a problem, two- and three-element feedwater controls are available to provide improved control.

4.3.5 Boiler Accessories. Operating procedures for water columns, gage glasses, safety valves, blowoff lines, and soot blowers are outlined below.

4.3.5.1 Water Column and Gage Glass. If water level is too low, the boiler may be severely damaged by overheating. If water level is too high, water may be carried out with steam, resulting in damage to engines and turbines and causing deposits to form in piping, valves, and other equipment. A gage glass, try cocks, high- and low-level alarms, and various other indicating and recording devices are used as guides in maintaining proper water level. The gage glass and try cocks are the most reliable and should be used as the final check when the various devices disagree.

a) Removing Sediment. Sediment collects in the water column and, in time, will obstruct the connection so the gage glass and try cocks do not show correct level. To ensure correct indication, the water column and gage glass must be blown down regularly. Once per shift is the recommended interval. Lines from the boiler drum to indicating and recording devices should be blown down daily.

b) Leaks. Promptly repair leaks in pipes, valves, or gage glasses to avoid false water level indication.

c) Valves. Gage glasses have valves at both top and bottom. Hand-operated valves are usually supplied with chain operators so that if the glass breaks, the operator can close valves and avoid danger of burns from escaping steam and hot water. Some gage glass valves are automatically closed by the rush of steam and water if the glass breaks. Determine the type of valves employed on gage glasses and decide in advance what to do in case of breakage.

d) Replacement of Gage Glass. To replace a broken gage glass, remove packing nuts, packing, and broken pieces of glass. Insert new glass and packing. Tighten packing nuts carefully. Turn on upper steam valve first to heat the new glass uniformly. Goggles and wire mesh or canvas screen should be provided when first putting pressure on gage glass.

e) Valves in Water Column Line. If valves are supplied in the lines from the drum to the water column, they must be sealed or locked open.

4.3.5.2 Safety Valves. Safety valves are designed to remain closed under normal operating conditions. If load drops and fuel supply is not readjusted quickly enough, the safety valve opens to relieve the increased pressure. Opening of safety valves causes discharge of steam or hot water into the atmosphere and results in a loss of heat. Although it may be assumed that the original safety valves were of sufficient capacity, larger capacity may be required when a coal-fired boiler is converted to oil or gas firing.

a) Adjustment. Adjustment and sealing of safety valves must be performed only by properly trained and authorized personnel, such as qualified boiler inspectors and factory representatives. A safety valve normally requires two adjustments, popping pressure and blowdown. For boilers operating at pressures of 250 psig or below, the popping pressure can be adjusted over a range of 10 percent above or below the pressure for which the valve is designed, by varying the compression of the valve spring. A new spring must be installed if the desired adjustment exceeds 10 percent. Blowdown is varied by means of an adjusting ring. The ASME Boiler and Pressure Vessel Code requires that safety valves be adjusted to close after blowing down not more than 4 percent of the set pressure but not less than 2 psi. It also requires that the blowdown be not less than 2 percent for pressures between 100 and 300 psig. Lifting levers are provided to lift the valve manually to check its action and blow any dirt away from the seat. When using the lift lever, the boiler pressure should be at least 75 percent of the set pressure. Use these levers to test safety valves at 30-day intervals to ensure that the valve disc does not stick to the seat. Once a year, a test should be made by actually raising the boiler pressure to check the valve setting and blowdown. When the lifting lever is used, raise the valve disc sufficiently to ensure that foreign matter is blown from around the seat. This will help to prevent leakage after the valve is closed.

b) Hydrostatic Test Caution. Testing clamps or gags are often used to hold the valve discs on their seats during hydrostatic tests. When this is done, ensure that the clamps are not over tightened, as damage to the valve stem may occur. Also take every precaution to ensure that the clamps are removed as soon as the test is completed. Never use a test clamp to gag a valve that is leaking.

c) Capacity. The capacity of the safety valve(s) must be sufficient to discharge steam generated by the boiler without allowing pressure to rise more than 6 percent above the maximum allowable working pressure. This capacity may be checked by closing steam outlets and forcing the fire to the maximum. If pressure builds up more than 6 percent, additional valve capacity is needed. Safety valve capacity for each boiler must not be less than the minimum ASME Boiler and Pressure Vessel Code requirements. When changing from coal to oil gas firing, do not overlook the increased safety valve requirements. Capacity checks must be authorized by the Public Works Officer and made under the direct supervision of a designated qualified employee, an authorized insurance inspector, or a factory representative.

4.3.5.3 Blowoff Lines. Boilers are equipped with blowoff lines at the lowest point in the water system. These lines are necessary for draining and also to help control concentration of solids and sludge. This concentration is determined by an analysis of the boiler water and should be a routine part of operating procedure. Blow down a specific quantity of water each time, usually a few inches as measured on gage glass. Frequency of blowdown is based on results of water analysis.

a) Blowdown Procedure. Open the quick-opening valve or cock first. Then open the slow-opening valve fully until the required quantity of water is discharged. Do not open valves too rapidly, as undue stress or damage to blowoff piping and connections may result. Blowdown when the boiler is banked or steaming at low rate is most effective in removing sludge and solids. Bottom blowoff connections must be used to remove sludge.

b) Continuous Blowdown. Surface blowoff connections are also provided on most steam boilers and when used on a continuous basis, are the most effective and economical means of controlling dissolved solids. Recovery of some of the heat from the blowdown water can be accomplished by use of a heat exchanger. If continuous blowdown is used, the bottom blowdown valves should still be used at intervals to prevent them from becoming stuck or otherwise inoperative, and to remove sludge. The quantity and frequency of manual blowdowns are determined by the degree to which sludge accumulates in mud drums and headers.

4.3.5.4 Soot Blowers. Flue gases carry ash and soot that act as insulators and, when deposited on boiler heating surfaces, reduce the rate of heat transfer. The extent of soot deposit depends upon the fuel burned, completeness of combustion, and the rating at which the boiler is operated. When coal-fired boilers are operated at high rating, ash and slag may deposit on tubes to such an extent that gas flow is restricted and draft loss through the boiler increases. Oil-fired boilers seldom build up enough ash to restrict gas flow, but heat transfer efficiency can be affected. Several cleaning methods are discussed below.

a) Swinging-Pipe Soot Blower. Fire tube boilers may be cleaned while in operation by means of steam jets operated from outside the boiler setting. Steam is applied to the pipe of a swinging-pipe soot blower with steam jets directed into the boiler tubes. The soot blower is rotated to direct the jets into each tube. After completing the blowing operation, the soot blower is moved to a position where it is protected from heat or gases. Fire tube boiler tubes should be cleaned daily.

b) Long-Handled Brush. Swinging-pipe soot blowers for fire tube boilers are convenient but are not satisfactory when boiler tubes are long. Soot can be effectively removed from the tubes of fire tube boilers with a long-handled brush. The brush should be just large enough to pass through the tubes. Frequency of cleaning depends upon operating conditions. Goggles and respiratory protection equipment should be used when cleaning boiler tubes.

c) Mechanical Soot Blowers. Many water tube boilers are supplied with mechanical soot blowers. These should be operated once every 8 hours, or an interval dictated by operating experience. To operate a soot blowing system, open the piping system drains first, then slowly open the steam valve to admit steam. Completely preheat and drain the piping system before admitting steam to the soot blower elements, as a small quantity of water introduced into a hot soot blower element can cause serious damage. Drain valves may be throttled but not closed while the elements are being operated. Increase the draft in the boiler and furnace during soot blowing periods to prevent smoke and to carry away material removed from tubes. Soot blower elements are operated by a handwheel or chain or in some cases by an electric motor. As the element is rotated, an automatic valve opens and admits steam. Two rotations of the element are usually sufficient; more rotations only result in wasted steam. Rotate the element slowly for maximum effect. Start the soot blowing sequence near the furnace and progress toward the boiler outlet.

d) Hand Lancing. If mechanical soot blowers are not available or cannot be used, hand lancing must be employed. A practical hand lance can be made from a section of 1/2-inch pipe of suitable length attached to a hose and supplied with 100 psig air pressure. When using a hand lance, care must be exercised to prevent damage to furnace walls and baffles.

4.3.6 Coal Firing Procedures. Procedures for firing coal by hand firing, underfeed stoker, spreader stoker, and traveling grate stoker follow.

4.3.6.1 Hand Firing - Coking. Coking allows time for escape of volatile gases before coal is placed directly on the fuel bed. First, place coal on the dead plate where radiant heat causes the gases to be distilled off. These gases mix with secondary air coming through the damper in the fire door and burn as they pass over the hot fuel bed. Coked coal is later distributed over the fuel bed. Disadvantages of this method are that smoke is produced and the introduction of air causes ash and burning coke to mix and create clinkers, wasting both time and fuel. However, this method of firing may be successfully applied to small furnaces operating at low rating.

4.3.6.2 Hand Firing - Alternate Method. Satisfactory combustion can be obtained by use of an alternate method of firing. A layer of green coal is applied to one side of the furnace. Heat generated by combustion on the opposite side causes volatile gases to be distilled off and accelerates combustion. The ash-pit door should be closed during and immediately after firing to reduce smoke. Keep the fire door open about 1 inch for 1 to 3 minutes to supply sufficient secondary air to allow the volatile gases to burn off. Despite these precautions, gases may still be distilled off more rapidly than they can be burned due to the large surface of green coal exposed.

4.3.6.3 Hand Firing - Spreader Method. Spreader firing consists of distributing coal over the entire fire bed. Thin spots are observed by their bright appearance and additional fuel should be applied to keep the fuel bed uniformly thick. When correctly used, this method permits operation at high ratings. Be sure to supply sufficient overfire air, as volatile gases are quickly liberated. Agitation of the fuel bed causes ash to come into contact with the hot portion of fire, forming clinkers. If coal is properly placed, firing proceeds without resorting to agitation of the fuel bed.

4.3.6.4 Cleaning Hand-Fired Furnaces. Coarse pieces of ash and clinkers that do not fall through the grates must be removed at sufficiently short intervals, or the air passages can become restricted and the rate of combustion reduced. One method of cleaning grates consists of pushing burning coal against the bridge wall, after which ash and clinkers can be removed from the front. This method has the advantage of being quick, but does not remove all ash, as some always remains at the bridge wall. A more complete cleaning is accomplished by the "side" method, which consists of pushing good coal to one side of the furnace and exposing ash and clinkers, which are then readily removed. Burning coal is then moved to the side which has been cleaned and remaining ash and clinkers are removed. When shaking grates are employed, a greater percent of ash can be discharged to the ash pit and the work of cleaning fires is materially reduced.

4.3.6.5 Combustion Rate Regulation in Hand-Fired Furnaces. Rate of combustion is controlled by the quantity of air passing through the fuel bed, while efficiency of combustion is controlled by the quantity and distribution of overfire air. To regulate the rate of combustion, change the furnace draft by controlling the stack damper. The fuel bed must be kept light (6 to 8 inches) so that airflow is not retarded. If holes develop in the fuel bed, air will follow the path of least resistance and pass through the holes rather than the active portion of fuel.

4.3.6.6 Underfeed Stoker Firing. Underfeed stokers admit coal from underneath the burning fuel bed. Gases distilled from the fuel pass up through the bed to accelerate combustion. Single retort underfeed stokers are horizontal, with coal being moved into the furnace and distributed by mechanical motion. Multiple retort underfeed stokers are inclined and coal movement is caused by mechanical motion and force of gravity.

a) Adjusting Feed. Adjust the stoker feeding mechanism (screw or ram) so that coal is fed to meet consumption requirements. If the stoker has an off-and-on control, adjust the fuel and air feed so that the stoker operates most of the time. Adjust the coal distributing mechanism (secondary arm) as necessary to maintain sufficient coal to fill the retort. If the fire burns back, it will damage the stoker. After dumping ashes, cover the ends of the grate bars adjacent to the dump grates with coal. The depth of the fuel bed above the tuyeres of single-retort stokers varies from 8 to 14 inches, and from 12 to 24 inches on high-rating multiple retort stokers. If the fuel bed is too thin, increase coal feed without increasing air until normal conditions are restored. If the fuel bed is irregular, adjust the secondary feeding mechanism or air distributor. Many stokers have dampers that vary the supply of air to different zones. If a hole appears in the fire, the condition may be corrected by reducing the airflow to that area. If the fuel bed is of correct thickness, the rating is changed by varying both air and fuel supply.

b) Ash Removal. The procedure for removing ash depends on whether stationary grates, dumping grates, or clinker grinders are used. In all cases, burn coke thoroughly before dumping refuse into the ash pit. Air must be passed through the coke and ash for some time before discharging. Do not introduce too much air as fuel losses may result. In cleaning the fires, do not remove ashes from the grate bars, instead, let them move down by stoker action for removal at the next cleaning.

c) Agitation and Clinker Formation. Underfeed stokers vary in the amount of agitation given the fuel bed. In some designs, coal is forced into the furnace and passed over stationary tuyeres and grate; in others these parts move and agitate the burning fuel bed. Stokers that supply agitation are best suited for burning coals having extreme coking tendencies as the movement tends to retard coke formation. Burning coal of low ash fusion temperature on these stokers causes clinkers when the ash is pushed into the high temperature zone. Clinkering is greatly accelerated when the stoker is operated at high ratings. Work the fire as little as possible to reduce clinker formation, and remove clinkers that adhere to grates or side walls at once with the least possible agitation of the fuel bed.

d) Air Supply. Underfeed stokers are operated with relatively thick fuel beds and require a FD fan to supply air. The windbox pressure varies from 1 to 7 inches of water. Best results are usually obtained by operating with a slight draft in the furnace. Regulate windbox pressure to supply the required quantity of combustion air and regulate the ID fan or stack damper to produce the necessary draft to overcome resistance of the boiler. This draft regulation is often accomplished automatically.

e) Operation. Lubricate moving parts according to manufacturer's instructions. Keep sufficient coal in the retort to prevent fire from reaching this section of the stoker. Do not permit ashes to fill the ash pit. Inspect windboxes each operating shift and remove any accumulation of siftings. When banking the boiler, feed sufficient coal and renew the coal supply as required during long banking periods. Make frequent inspections of stoker and brickwork and report unusual conditions so that repairs can be made before equipment is seriously damaged.

4.3.6.7 Spreader Stoker Firing. Spreader stokers permit burning of fine coal particles in suspension and the remainder of the coal on grates. This permits faster load response and reduces clinker formation since the fuel bed on the grates is quite thin. Coal inventory in the furnace lasts only a few minutes. Check the thickness of the fuel bed by stopping the coal feed and noting the rate at which fuel on the grates is burned. If ashes are ready to dump after 3 to 5 minutes, the thickness of the fuel bed is correct.

a) Adjusting Spreading Mechanism. Adjust the spreading mechanism for a uniform thickness of fuel over the grates to optimize mixing of fuel and air. At the same time, adjust the rate of fuel and air feed in correct proportions for efficient combustion.

b) Effect of Coal Size on Operation. Spreader stokers are not suitable for burning coal particles larger than 1-1/2 inches, as they hinder operation of the feeding mechanism. The most efficient size of coal is 1/4 inch, with not more than 40 percent passing through a 1/4-inch screen. Satisfactory results can be obtained with sizes up to 1-1/2 inches. The fine coal burns in suspension with larger particles falling to the grates where combustion is completed. Too much coal overloads the grates. In passing through bunkers or chutes, coal sometimes segregates into coarse and fine particles. If this occurs, the stoker will burn practically all "fines" at one time and all coarse at another, resulting in variable and inefficient operation.

c) Ash Removal. Clean the fires at regular intervals, usually twice each operating shift or when ashes are from 3 to 6 inches deep on grates. If the grates are divided, clean one zone at a time. Shut off the coal flow and wait 3 to 5 minutes with the FD fan on for the remaining coal to burn. Do not allow the bed to become too thick or clinkers will form. Remove the ash deposit promptly from the ash pit to prevent fires.

d) Banking Procedures. Allow some accumulation of ash on the grates before banking a spreader stoker. Reduce the air supply and adjust the feeder mechanism to deliver coal to the front of the stoker to build up the fuel bed in that area. Maintain a slight draft in the furnace during the time the furnace is banked.

e) Overfire Draft. The best operating results are usually obtained with an overfire draft from 0.03 to 0.07 inch of water. This reduces air leakage to a minimum without causing overheating of furnace walls, doors, or other parts subjected to heat. Adjust the air supply so that it is just sufficient to prevent smoking. This should result in approximately 11 to 14 percent carbon dioxide in flue gas. Examine the furnace frequently to ensure that it is not overheated. Low carbon dioxide and inability to secure proper draft through the boiler are often due to air leakage through the boiler setting. Maintain flue gas temperature at the minimum level consistent with good operation. Some packaged boilers are operated with positive pressure in the furnace. These boilers should be operated in accordance with the manufacturer's operating instructions.

f) Operation. Examine the windbox periodically and keep it clean. Check the operation of feeding mechanisms to ensure equal distribution. If wet coal sticks in the hopper, push it into the feeder with a rod. Lubricate bearings frequently in accordance with manufacturer's requirements.

4.3.6.8 <u>Traveling Grate Stoker Firing</u>. Traveling grate stokers provide a means of burning very fine coal or coal having a low ash fusion temperature. They are not generally suitable for burning caking or coking coal. Control is obtained by varying the rate of feed either by changing the thickness of coal feed ribbon to the stoker or by changing the rate of grate movement.

The method employed is determined by trial to suit the skill of the individual operator. Adjustment of grate speed must be done with care. The usual speed varies from 2-1/2 to 3-1/2 feet per minute. The fuel must be completely burned before it reaches the end of the grate to prevent excess carbon loss to the ash pit. Excessive burning of link ends is an indication that an appreciable amount of burning combustible is passing over the refuse end of the stoker. However, if the fuel is burned too far before the end of the grate, too much air will be admitted through the uncovered grate and an excessive quantity of heat will be carried away with the flue gases. This condition can be determined by observation and flue gas analysis. Additional regulation of the fuel-bed level is obtained by use of section air control dampers under the stoker. Use these dampers to reduce the supply of air to thin sections. Note that if the ash has a low fusion temperature, excessive agitation of the fuel bed can result in clinker formation.

a) Air Control. Traveling grate stokers are used with either natural or FD boilers, with modern units being almost all FD type. FD is necessary when the use of fine coal increases the resistance of the fuel bed or when the grate openings are small in size. Greater control and high rates of combustion are also obtained with the use of FD. Operation, in either case, remains essentially the same. Draft loss through the fuel bed varies from 0.25 to 0.60 inch of water with natural draft and from 1 to 4 inches with FD.

b) Draft Control. An overfire draft of 0.03 to 0.07 inch of water should be maintained. This minimizes air leakage, overheating of furnace walls, doors, and other parts exposed to heat.

c) Storing Coal. Do not segregate coarse and fine coal in bunkers or hoppers, as this will result in irregular burning and holes in the fuel bed.

d) Adjusting Grate Tension. Adjust tension on the grate with tension screws at the back sprocket bearing. Adjust the screws on both sides until chain or grate bars are tight, then loosen the screws slightly.

e) Ledge-Plate Clearance. Many stokers are supplied with ledge plates on the sides to prevent excessive air leakage. Ensure that ledge plates have approximately 1/8-inch clearance. If proper clearance is not maintained, excess air levels increase and boiler efficiency is reduced.

f) Banking Procedures. To bank fire on a traveling grate stoker, allow the fire to burn down, reducing draft as much as possible. Introduce a bed of coal approximately 1 foot thick. The stoker should be run ahead at hourly intervals during the banked period. Frequency of this operation depends upon the rate of burning. In starting from bank, break up any coke which has formed, introduce air, allow the coke to burn, and wait until furnace walls are heated before resuming normal operation.

4.3.7 Oil-Firing Procedures. Efficient operation of oil-fired burners requires careful oil storage, oil preparation, and burner adjustment.

4.3.7.1 Sludge Control. Good bunkering practices greatly reduce sludge accumulation in storage tanks. However, occasional cleaning is necessary. When sludge reaches the level that it may enter the pump suction line, the tank must be emptied and the sludge removed. The most practical method of reducing sludge formation to a minimum is controlled bunkering. This consists basically of extending the fill, suction, and return lines to within one to two pipe diameters of the tank bottom. Keep the fill line on the opposite end of the tank from the suction and return lines. This piping arrangement helps to prevent heavy sludge deposits by sweeping the bottom of the storage tank. Sludge conditions in storage tanks are aggravated by the following:

a) Return to the tank of overheated oil.

b) Maintaining the oil temperature too high in the storage tank, causing separation of the light and heavy fractions.

c) Leakage of ground water into the tank.

d) Storing oil in tanks for excessively long periods.

4.3.7.2 Air Leakage. A small air leak in a pump suction line can cause a great deal of trouble. Such leaks can occur around valve stems, screwed or flanged fittings, and strainer gaskets. Test for such leakage by applying a small quantity of light oil to the joint or part in question. Oil is drawn into the suction line if leakage is present. If air does get into lines, it should be released from bleed points. If bleed points are not available, check burner operation closely until air is completely cleared. Air coming through the burner may cause fires to go out. If oil flow is then resumed, explosive ignition can occur from the hot furnace walls. Do not allow oil storage tanks to be emptied to the level where the suction line may draw air, except when necessary for annual cleaning.

4.3.7.3 Oil Strainers. Strainers are provided in oil suction and distribution piping to protect pumps and burner atomizers from being damaged or clogged. These strainers remove particulate and sludge from the oil. Strainer baskets should be checked and cleaned on a weekly basis, while daily cleaning may be required for heavy oils.

4.3.7.4 Oil Heating. When heating oil in a storage tank or suction line before transfer to supply pumps, do not heat the oil to a temperature where vapors are given off, since vapor locking of pumps and unpredictable burner operation can result. Day tanks may be effectively used if significant quantities of heated oil are circulated through a distribution header with only a portion of that oil used. When a pumping and heating set is part of an installation, it is important to adjust the pressure control valve to maintain a constant oil supply pressure and recirculate oil to the tank ahead of the heaters. Oil temperature control can often be improved by reducing the steam pressure or water temperature to the oil heater. This is particularly important if oil flows through the heater are less than the design conditions.

4.3.7.5 Oil Temperature at Burner. The best oil temperature for atomization is dependent upon the type of oil and the burner manufacturer's recommendation. The burner manufacturer will recommend a viscosity range in which to operate. Typically, a range of 35 to 150 SSU is recommended for pressure atomizers, 35 to 250 SSU for steam or air atomizers, and 35 to 300 SSU for rotary atomizers. An atomizer for a LEA burner may require an 80 to 120 SSU range for No. 4, No. 5, or No. 6 oil. Refer to par. 2.4.1.2, Table 2, and Table 3 for further information. Figure 127 illustrates typical viscosity limits for various oils as a function of temperature. This chart can be used to plot a viscosity curve for a particular oil. Semi-logarithmic graph paper must be used. If the viscosity at one temperature is known, a curve can be plotted by assuming that the slope of the line is the same as the standard slopes. An example is shown on Figure 127. However, with the blended oils common today, it is best to know the viscosity at two different temperatures and draw a straight line through those two points. When the viscosity-temperature curve is known, the proper operating temperature range can be read from the chart. Maintaining a constant and stable viscosity to the oil control valve is also important if accurate control of oil flow over the burner control range is to be maintained. Most control systems do not compensate for viscosity changes, and fuel/air ratio control becomes difficult if viscosity is not held constant.

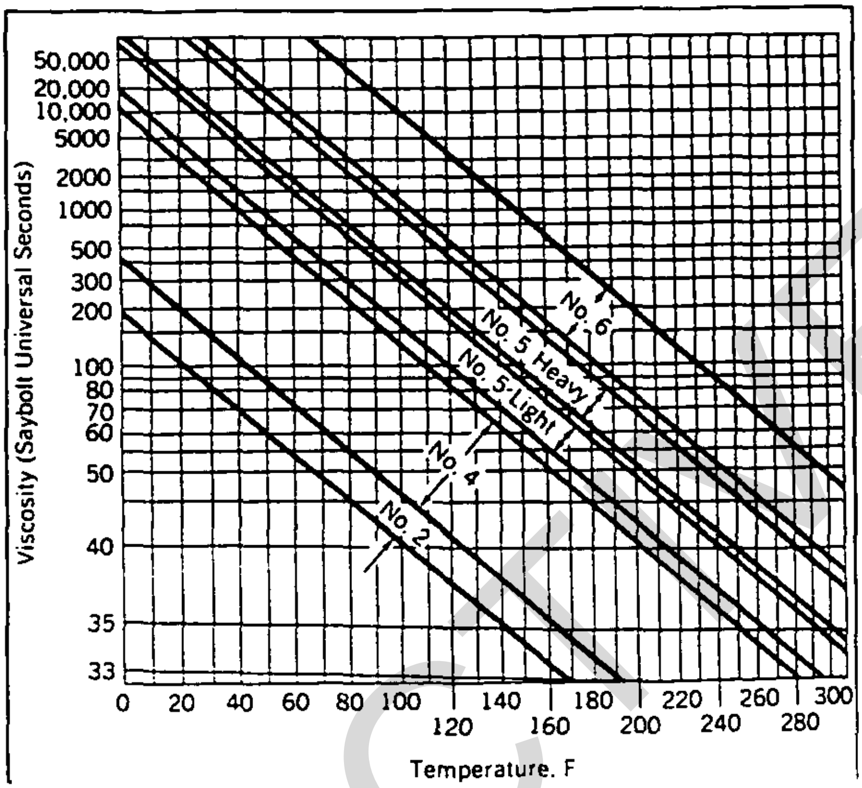


Figure 127
Oil Viscosity Versus Temperature

4.3.7.6 Oil, Atomizing Steam, and Combustion Air at Burner. Oil, atomizing steam (or atomizing air), and combustion air must be supplied to the burner at the pressures recommended by the manufacturer. Oil atomizers using steam or air for atomization normally maintain a differential pressure with the pressure of steam or air being above the oil pressure throughout the firing range. Atomizing steam lines should be well drained and trapped to ensure that no water is delivered with the steam. Combustion air also must be controlled at the pressures and quantities necessary for complete and efficient combustion. The energy in the oil pressure, atomizing steam or air, and combustion air are used to mix fuel and air for efficient combustion.

4.3.7.7 Burner Adjustments. Burner adjustments are necessary to ensure that the atomized fuel and combustion air mix completely and efficiently. The positions of the atomizer, diffuser, and register baffles are adjusted to optimize burner performance. Some control systems change the register positions automatically throughout the firing range to maintain LEA levels. If automatic adjustment is not part of your system and boiler load varies significantly over the year, optimum burner adjustment for the low and high load ranges should be determined and burners and controls adjusted accordingly.

4.3.7.8 Daily Operation. Oil burners should be inspected daily. The atomizer should be removed and cleaned in accordance with manufacturer's recommendations. For No. 6 oil firing, this may be a daily procedure, while for No. 2 oil, a weekly cleaning is usually sufficient. A visual inspection of the burner flame and furnace condition should be made. The flame should be clean, smokeless, and steady with a yellow to yellow-orange color. There should be minimal or no flame impingement on the furnace walls, no smoke or sparklers in the fire, no slanting or laziness in the flame, and no brilliant color. If any of these conditions exist, check the excess air levels, oil pressure and temperature, water in oil, atomizing steam or air differential pressure, burner adjustments, and the atomizer for wear. Take corrective action or request assistance. Fuel/air ratio control is discussed in par. 4.3.9.1.

4.3.8 Gas-Firing Procedures. Efficient operation of gas-fired burners requires proper gas handling and burner adjustment.

4.3.8.1 Pressure Regulation. Gas is supplied under pressure. A strainer, pressure regulating valve, and gas meter are commonly supplied at the inlet of gas service to reduce line pressure and meter the gas. A second gas pressure regulating valve is then supplied to maintain a constant pressure in the distribution piping to the burners. Accurate gas pressure regulation is important for the proper functioning of the gas control valve and for maintaining the proper fuel/air ratio. Gas distribution pressure should be checked each shift. A higher than normal gas pressure reduces the amount of excess air, while a lower pressure increases the excess air.

4.3.8.2 Burner Adjustments. Burner adjustments are required to ensure that the gas and combustion air mix completely and efficiently. Gas burner position (if movable), diffuser position, and register/baffle positions must be adjusted to optimize burner performance in that specific furnace. Some control systems automatically change the register positions throughout the burner firing range to maintain LEA levels. If automatic adjustment is not part of your system and boiler load varies significantly over the year, optimum burner adjustment for the low and high load ranges should be determined and burners and controls adjusted accordingly.

4.3.8.3 Daily Operation. Gas burners should be inspected daily. A visual inspection of the flame and furnace conditions should be made. Traditionally, gas flames have been blue in color with yellow tips. However, modern burners, designed for LEA and/or NO_x control, may vary in color from almost invisible to luminescent yellow. The burner flame should be clean and steady, with minimal impingement on the furnace walls, and no smoke, flaring, instability, brilliance, shortness, or flashback. If any of these conditions exist, check excess air levels, gas pressure, burner adjustments, and furnace pressure. Take corrective action or request assistance, as required. Fuel/air ratio control is discussed in par. 4.3.9.1.

4.3.9 Combustion Controls. Operate combustion controls in the fully automatic mode whenever possible. Review manufacturer's operating instructions to fully understand the operating characteristics of your particular control system. Inspect control drives and linkages daily for smooth operation and tight connections.

4.3.9.1 Fuel/Air Ratio Adjustment. When the amount of excess air observed in flue gas exceeds the amount determined as proper for your system, the fuel/air ratio should be adjusted. To determine the proper fuel/air ratio, the boiler should be operated at four different loads; approximately 20 percent, 40 percent, 70 percent, and full load. Data should be taken at each load, after adjusting the burner for optimum operation. The data should include steam flow or Btu output, fuel flow, fuel valve position, fuel pressure, fuel temperature, atomizing steam or air pressure (of oil), overfire air pressure (if coal), Bacharach or Ringleman smoke density, combustion air pressure, combustion airflow if available, fan damper position(s), furnace pressure, percent oxygen or carbon dioxide in flue gas, and flue gas temperature. At each load, a curve of smoke density versus percent oxygen or carbon dioxide should be developed. Figure 128 illustrates such a curve. When the desired operating positions are known for the four loads, the controllers and linkages should be adjusted to duplicate the settings. When compromise is necessary due to control limitations, the system should be arranged for best control throughout the normal operating range of the boiler.

4.3.9.2 Standard Operating Procedures. Simple biasing of the fuel/air ratio is often possible to allow the operator to compensate for changes in fuel, air, or other operating characteristics. This involves increasing or decreasing the amount of airflow by a fixed amount. Biasing of airflow does not change the basic fuel/air ratio. Figure 129 illustrates fuel/air ratio biasing. When simple biasing of the fuel/air ratio is possible, a Standard Operating Procedure should be developed to detail and authorize actions to be taken by the operator. Each time corrective action is taken, it should be noted in the boiler log.

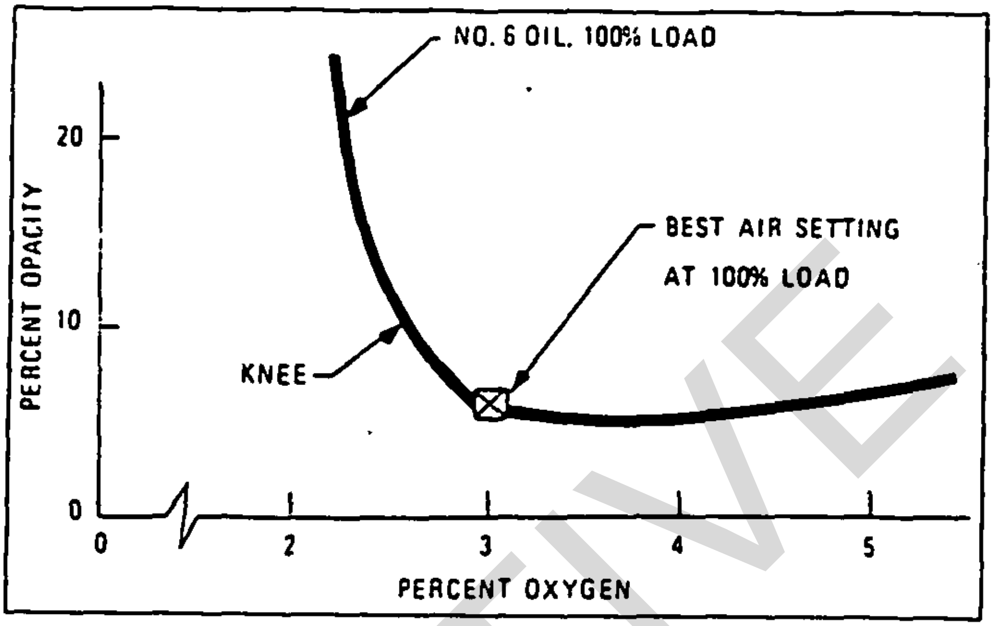


Figure 128
Smoke Density Versus Percent Oxygen

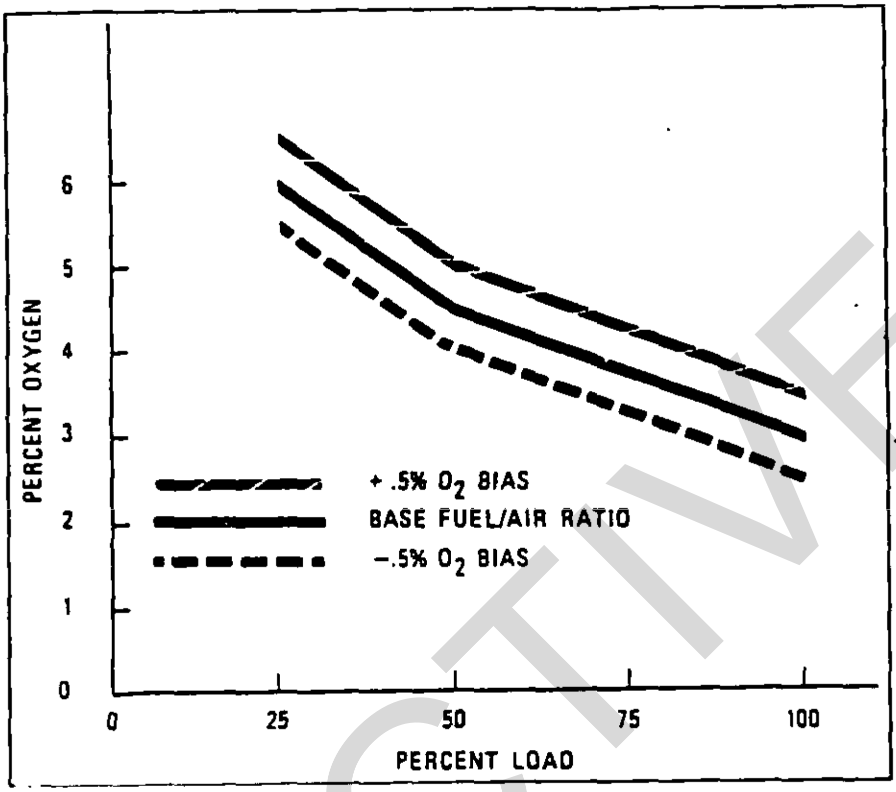


Figure 129
Fuel/Air Ratio Biasing

4.3.10 Boiler Safety Controls. The water column discussed in par. 4.3.5.1 is equipped with a low water cutout switch interlocked to shut down the fuel to the boiler. Historically, this is the most important boiler safety control. Tube rupture failure due to low water level is one of the most common and most dangerous types of failure. The water column must be blown down each shift to improve operation and ensure that sediment does not prevent normal operation. High steam pressure or high water temperature switches, flame scanner function, and other safety switches as shown in Figures 51, 52, or 53 must also be tested periodically. Tests can best be performed during the normal start-up shutdown procedures.

4.3.11 Centrifugal Pumps. Centrifugal pumps are widely used in heating plants and require a minimum of attention. Small, electrically driven centrifugal pumps are started by closing the motor-starting switch. Discharge valves of large pumps should be closed before the pump is started to reduce power required for starting. After the pump has started, slowly open the discharge valve. Pumps can be safely operated for a few minutes with the discharge valve closed, but continued operation without water circulation will cause the pump to overheat. Open casing vents to remove air or gases trapped in the casing. Some centrifugal pumps are driven at constant speed with output controlled by throttling a discharge valve either manually or automatically. When centrifugal boiler feed pumps are used, pump control may consist of the boiler feedwater control valve. In all cases where automatic regulation is employed, be sure to prevent the discharge valve from closing off completely, as this would result in overheating of the pumps. Large hot water distribution pumps are often equipped with variable speed drives to economically control water flow. Centrifugal pumps are built to operate against a given head or discharge pressure for a specified speed. If there is stoppage, or if for any reason discharge pressure becomes higher than the rated value, the pump will stall and a no-flow condition will exist. Immediately investigate and correct the cause of the increased pressure.

4.3.11.1 Operating Centrifugal Pumps in Parallel. If centrifugal pumps are operated in parallel, each pump must have the same characteristic, otherwise the pump with the greatest head will pump all or most of the water. This results in overheating of the low lower head pump. Exercise care in selecting the required number of pumps to meet load conditions.

4.3.11.2 Controlling Leakage. For a pump not using mechanical seal, pack the pump shaft with the recommended packing material to minimize leakage. In tightening the packing, be sure to take it up evenly, but not so tight as to produce excessive friction and cause overheating.

4.3.11.3 Lubrication. If centrifugal pump bearings are lubricated by oil rings, ensure that the oil level is maintained high enough to come up to the rings. Check the rings to see that they are turning. Drain the oil occasionally, flush out the bearings, and add new oil. Centrifugal pumps that have roller bearings packed with grease require infrequent attention. Do not overgrease the bearings as this may result in overheating. When adding grease to a roller bearing, remove the drain plug or use a safety fitting to prevent overgreasing. Inspect pumps daily for proper operation and bearing temperatures.

4.3.12 Direct-Acting Pumps. Direct-acting pumps (duplex and simplex) may be used where steam of 60 psig or more is available and where the exhaust steam may be utilized for heating. These pumps are not economical when exhaust is discharged to the atmosphere. Neglecting leakage, direct-acting pumps deliver a given amount of water per stroke. The maximum pressure which a given pump develops depends on the steam pressure supplied, and it is necessary to regulate the speed of the pump to control output. Regulation is accomplished by controlling the rate of steam flow to the pump with a hand-operated globe valve or a regulating valve actuated by pump discharge pressure. This control varies the pump speed and thereby maintains constant discharge pressure. Some duplex pumps are supplied with cushion valves to regulate the length of stroke; when the pump begins to short-stroke the cushion valve is opened to compensate. If cushion valves are not supplied, the length of stroke is regulated by adjusting the valve-gear lost motion; this adjustment cannot be made during pump operation.

4.3.12.1 Operation. To start a direct-acting steam pump, drain the steam line and ensure that no water is present. Open the drain cocks on the steam cylinders. Ensure that valves on inlet and outlet water lines and exhaust steam lines are open. Admit steam to the pump and allow the cylinder drain cocks to remain open until the pump operates. Adjust cylinder lubricators to feed the required amount of cylinder oil.

4.3.12.2 Lubrication. There are two principal types of lubricators: hydrostatic and mechanical. Hydrostatic lubricators depend upon pressure created by a column of water to force oil into the cylinder against steam pressure. A mechanical lubricator consists of a small plunger pump operated by the reciprocating motion of the pump. Avoid excessive lubrication so that oil does not find its way into the boiler by mixing with the condensate.

4.3.12.3 Leakage. Leakage of packing and valves results in decreased capacity of displacement pumps. Valve leakage is usually accompanied by irregular operation. Replace the packing or repair valves as necessary.

4.3.12.4 Steam or Air Binding. Steam or air binding is a common cause for failure of displacement pumps to deliver water. When suction lift is too great or water too hot, flashing takes place within the suction pipe and pump cylinder, and steam expands and contracts as the piston or plunger operates. To correct this condition, decrease suction lift, or cool the water. If air leaks into the suction line past the packing, the cylinder will become filled with air instead of water. Since air is a compressible gas, its presence prevents the pump from operating. When the pump has a suction line, ensure that the suction pipe is absolutely tight.

4.3.13 Injectors. Injectors used in stationary practice are usually of the self-starting automotive type. To operate, open the water and steam supply valves. Water is first discharged through an overflow. When the injector starts to deliver water, the overflow valve is automatically closed by the vacuum produced. Rate of flow is then controlled by means of either water or steam supply valves. Some of the common difficulties encountered in operation of injectors are:

a) Water too hot.

b) Suction lift too great.

c) Leaks in suction piping.

d) Scale deposits in injector nozzles and body.

e) Worn nozzles caused by impurities in water.

f) Clogged foot valve, strainer, or suction piping.

g) Fluctuating steam pressure.

4.3.14 Fans. In many older plants, natural draft created by a stack was used to move air through the boiler. The need for more positive control and safety resulted in use of FD fans and ID fans.

4.3.14.1 Lubrication. Sleeve bearings are lubricated by oil rings. Oil rings are larger in diameter than the shaft and dip into an oil well under the bearing. Rotation of the shaft causes rings to turn and carry oil to the bearing. It is important that proper oil level in the well be maintained. If the ring fails to touch oil, the bearing will not be lubricated. Roller bearings require less attention than sleeve bearings. Pack roller bearings with grease every 6 months to 1 year, depending on service. Use manufacturer's recommended grease only and use care to prevent overgreasing.

4.3.14.2 Water-Cooled Bearings. For fans handling high temperature air or gases, water-cooled bearings may be required. Ensure that cooling water is maintained on the bearings. A bearing operating temperature of 130 degrees F or less is considered satisfactory.

4.3.14.3 Regulation. Output of a fan can be regulated either by changing its speed or by adjusting inlet or outlet dampers. Damper adjustment is usually employed to avoid the expense of supplying a variable-speed drive for the fan. Dampers may be manually or automatically controlled. In either case, means are provided to regulate airflow to meet system requirements.

4.3.14.4 Common Difficulties. Some common difficulties encountered in fan operation are:

a) Vibration caused by unbalanced rotor.

b) Misalignment resulting in vibration, overheating of bearings, and wear of couplings.

c) Incorrect or insufficient lubrication resulting in failure or overheating of bearings.

d) Improper regulation due to fouled or worn control vanes, dampers, and control mechanisms.

e) Reduced fan efficiency and capacity due to blades fouled with dust, dirt, or grease.

f) Fan rotor and casing erosion due to handling air or gases laden with fly ash and other abrasive material.

4.3.15 Feedwater Heating and Treatment. In the simplest of systems a closed feedwater heater may be used to heat the feedwater to an acceptable temperature, usually 180 to 220 degrees F.

4.3.16 Economizers, Air Heaters, and Pollution Control Equipment. This equipment is located between the boiler outlet and the stack. Gas pressure and temperature through this equipment should be closely monitored, as they are good indicators of performance, both for individual items of equipment and for overall boiler installation. When soot blowers or other cleaning devices are provided they should be operated once a shift or as recommended by the manufacturer. Moving parts such as dampers, linkages or air heater drives should be lubricated as recommended by the manufacturers. Ash hoppers should be emptied daily or more frequently, if required. Care must be taken to maintain gas temperature above the acid dew point (Figure 22) to minimize corrosion. Daily inspection is required. Manufacturer's shutdown instructions should be incorporated into the boiler shutdown procedure. When an economizer or air heater will not be operated for more than 2 days, clean the fire side to minimize corrosion problems.

4.3.17 Emergency Procedure - Abnormal Water Level. Correct water level is maintained either manually or automatically. Automatic control is an aid but cannot always replace the operator for reliability. Low water level can result in burned tubes and boiler plates with the possibility of destructive explosion. High water level causes water to be carried out with the steam and causes damage or destruction to engines, turbines, valves, or piping. Abnormal water level (high or low) can be caused by operator carelessness, failure of a regulator or pumps, broken piping, boiler leaks, failure of an indicating device, or failures in the water circulating system.

4.3.17.1 Low Water Level. If the water level is below the visible range of the gage glass, shut off fuel flow, purge the boiler, and shut off fans. Continue to feed water slowly until normal level is restored. If there is any possibility that the boiler has been damaged, it should be cooled and thoroughly inspected before being put back into service. The underlying cause of the low water condition should be determined and appropriate corrective action taken before attempting to resume normal operation. Water level should be controlled manually until the automatic control is known to be functioning correctly.

4.3.17.2 High Water Level (Steam Boilers). If water is above the visible range of the gage glass, shut off feedwater and fuel, purge the boiler, and shut off combustion air. For hand-fired boilers, smother the fire by covering the grate with green coal or wet ashes. For stoker-fired boilers, shut down the stoker, cut off the air supply, and open the furnace doors. If the water level does not recede into the visible range of the gage glass within 2 minutes, operate the main blowdown valves as required. The underlying cause of the high water should be determined and appropriate corrective action taken before attempting to resume normal operation. Water level should be controlled manually until the automatic control is known to be functioning correctly.

4.3.18 Emergency Procedure - Boiler Tube Failure. If relatively cold water is introduced into the empty drum of a hot boiler, the drum and tube joints are subjected to severe thermal strains which may result in cracks or loosened tubes. Should the water get too low while heat is still applied, serious damage to tubes and boiler structures may result. Leakage may become so great that available water is not sufficient to maintain the required level. If a feedwater regulator is used, it will open wide when the level drops. This results in a large flow of water to that boiler and may cause other boilers on the same header system to develop low water conditions. The correct remedial procedure varies, depending on how rapid the fire can be extinguished.

4.3.18.1 Procedure for Gas- or Oil-Fired Boilers. If the leak is so serious that immediate removal of the boiler is necessary, proceed as follows for gas- or oil-fired boilers:

a) Shut off fuel.

b) Close the steam outlet valves if only one boiler is in operation. Do this quickly to prevent a sudden pressure drop and corresponding temperature drop. For a multiple boiler installation when more than one is in service, the header pressure and the nonreturn valve will automatically isolate the disabled boiler from the header.

c) Shut off the supply of feedwater to the boiler, provided there is not enough hot refractory to cause overheating. In the case of boilers with refractory furnaces, adjust the feedwater flow to the maximum consistent with the protection of supply to other operating boilers. Attempt to maintain a normal water level until the overheating hazard is past, then shut off the feedwater.

d) Maintain minimum airflow through the boiler setting to carry away steam discharged from the leak.

e) After 15 or 20 minutes, shut down the FD fans.

f). Proceed with the normal method of cooling the boiler. Do not drain the unit until the furnace is cool enough to enter.

g). Inspect boiler and pressure parts completely. Repair the boiler, as required. Be sure the boiler is hydrostatically tested and approved by an Authorized Inspector before returning to service.

4.3.18.2 Procedure for Stoker-Fired Boilers. For stoker-fired units, the following procedure is recommended if tube failure occurs:

a). Shut off the fuel feed and gradually reduce airflow as the fuel bed decreases. Also, use whatever means have been predetermined or are available to smother the fire effectively without danger of explosion.

b) Close the steam outlet valves.

c) Adjust the feedwater flow to the maximum permissible and attempt to maintain normal water level. Shut off the feedwater after the setting has cooled to a point where no danger of overheating exists.

d) Adjust airflow to minimum safe level consistent with preventing water or steam from flowing into the boiler room and minimizing the rate of cooling.

e) Inspect the boiler completely and make the necessary repairs. Be sure the boiler is hydrostatically tested and approved by an Authorized Inspector before returning to service.

4.3.19 Emergency Procedure - Fan Failure. The flow of air and gases through the boiler depends upon the action of the FD and ID fans. The greatest difficulty occurs when ID fans stop for any reason. If the combustion system continues to operate when the ID fan fails, smoke, combustion gases, or fire are discharged into the boiler room. The FD fan and fuel feed should be immediately stopped when the ID fan trips. Most boilers are equipped with safety interlocks that do this automatically. Safety interlocks are also normally provided to stop the fuel feed if the FD fan fails. If such interlocks are not provided, the operator must take these actions manually. If the ID fans have tripped for any reason, slowly open dampers in the air and flue gas passages to their wide open position to create as much natural draft as possible to ventilate the setting. Opening the dampers should be timed or controlled to avoid excessive pressure transients during fan coast-down. Maintain this condition for a period that will result in not less than five volume changes, but in any case not less than 15 minutes. At the end of this period, close the flow control dampers and immediately start the fan(s). Gradually increase the airflow to at least 25 percent of full load flow and purge the setting for 5 minutes. These general recommendations should be adhered to unless adequate tests on a specific boiler demonstrate that different values should be used.

4.3.20 Emergency Procedure - Electric System Failure. Auxiliary equipment in some plants is equipped with both steam and electric drivers. In case of the failure of one, the other can be quickly put into service. If auxiliary equipment is electrically driven and there is no gasoline or steam engine backup, or emergency source of auxiliary power, electrical failure causes a complete outage. While power is being restored, prepare the boiler equipment so that operation may be immediately resumed when power is available. Prepare and follow a schedule for testing operation of standby equipment. Some boilers may be operated at reduced rating with natural draft. Steam-driven pumps may be used to supply feedwater. If this is possible, some of the steam service may be able to be maintained. Arrange a schedule so that the least important service is shut off during an emergency. Study the plant and determine how, in case of electric power failure, the following services may be continued:

a) Water supply to the boilers.

b) Operation of ID fan.

c) Fuel supply to the furnace.

d) Combustion air supply.

e) Operation of automatic controls.

f) Operation of valves and safety devices.

4.3.21 Emergency Procedure - Flame Failure. Oil and gas burners are provided with flame scanners and safety controls which will safely shut down a burner within 2 to 4 seconds of flame failure, and post purge the furnace before shutting off the fans. Manual systems require that the operator take these actions. If fans are operating after a safety shutdown, continue the operation. Do not immediately increase the airflow. If the airflow is above 25 percent of full load flow, it should be gradually decreased to this value for a post-firing purge of at least 5 minutes. If the flow is below 25 percent at the time of the shutdown, it should be continued at that rate for 5 minutes, then increased to the 25 percent level, and held there for an additional 5 minutes. Refer to NFPA 85 series or ASME CSD-1, as applicable, for additional information.

4.3.22 Removing a Boiler From Service. When removing a boiler from service, care must be taken to prevent rapid temperature changes and resulting thermal stress. This helps to decrease the possibility of future forced outages and reduces maintenance costs. The procedure for removal is as follows:

a) Reduce the load on the boiler to the minimum stable firing rate.

b) Open the bottom blowdown connection for a sufficient time to remove sludge from the mud drum.

c) With oil or gas firing, the fuel shutoff valve should be tripped at the appropriate time and manual valves at burners closed immediately. With stoker-fired boilers, the stoker hoppers should be emptied and the fuel bed burned out.

d) The setting and boiler should be cooled down without exceeding the maximum rate prescribed by the manufacturer. As a general guide it is advisable to wait until furnace refractory is black before using higher rates of airflow for cooling. Exercise care when using the ID fan for cooling. The ID fan and motor are designed to handle hot gases, and cooler gases, if not controlled, can cause the motor to overload.

e) On high pressure steam boilers, after the feedwater flow ceases and the nonreturn valve has closed, close the feedwater valves and main steam stop valve. Run down the stem on the nonreturn valve to hold the disc on its seat. Where two stop valves are used, open the drain between them to ensure that it is clear and bleeds off any pressure in the line.

f) When steam pressure falls below 25 psig, open the drum vent(s) to prevent formation of a vacuum that might cause subsequent leakage of gasketed joints.

g) On hot water boilers, maintain water circulation until the boiler is sufficiently cooled, then stop circulation, close the inlet and outlet water valves, and open a vent valve.

h) The boiler should be inspected and cleaned in accordance with instructions in par. 5.10.2. Procedures for removing low pressure steam and low temperature water heating boilers from service can be found in ASME Boiler and Pressure Vessel Code, Section VI.

4.4 Optimizing Central Plant Efficiency

4.4.1 Optimizing Combustion Efficiency. With cost of fuel continuously increasing, the need to operate central boiler plants efficiently becomes more important all the time. Procedures for optimizing operating efficiencies are discussed in this section. An operator should review the elementary combustion principles and principles of steam and hot water generation found in Section 2. To optimize boiler efficiency, the combustion efficiency must first be optimized. Combustion efficiency is a function of the type of fuel burned, flue gas temperature, and the amount of excess air in flue gas. For a given fuel, the operator must take action to optimize combustion efficiency by maintaining as low a flue gas temperature and excess air level as is possible.

4.4.1.1 Soot Blowing/Cleaning to Reduce Flue Gas Temperatures. Boilers equipped with soot blowers should be operated as needed to maintain clean heat transfer surfaces. Once a shift is the recommended interval when oil or coal is being fired, although experience may dictate a different interval for a particular unit. Note the flue gas temperature before and after soot blowing. A reduction in temperature of 35 to 40 degrees F corresponds to an efficiency improvement of 1 percent. See Tables 5 through 8 for the specific improvement at the actual temperatures and excess air levels at which you are operating. For fire tube boilers not equipped with soot blowers, a record of flue gas temperatures at the normal firing rate of the boiler should be kept. When flue gas temperature exceeds the clean boiler flue gas temperature by more than 70 degrees F, the boiler should be taken out of service and cleaned. Fire tube boilers should, as a minimum, be cleaned during the quarterly inspection.

4.4.1.2 Water Side Cleaning. Maintaining the water side of a boiler is equally as important as maintaining the fire side. Scale on the water side reduces heat transfer just as soot does, and thereby increases flue gas temperature and reduces efficiency. Quarterly inspection and mechanical cleaning may be required. Chemical cleaning may be required occasionally. The operator should know the flue gas temperature of the boiler at its normal firing rate and excess air level, with the gas and water side clean. Any major change in temperature at those firing conditions indicates a problem, typically dirty gas or water side heat transfer surfaces.

4.4.1.3 Setting Leaks. Air leakage into the boiler system increases excess air levels and reduces efficiency. Any air drawn into the boiler through leaks in the furnace setting, casing, or flues must be heated from room temperature to the flue gas temperature, using heat that could otherwise be transferred to the steam. Normal maintenance should greatly reduce the number and size of leaks (refer to par. 5.10.2). The operator should ensure that doors, ports, and openings into the furnace are tightly closed. The furnace draft should be maintained at a slightly negative level of -0.03 to -0.10 inch of water. This practice helps to minimize air leaks. When the draft is increased for soot blowing, take care to return it to its normal level after soot blowing is complete. The use of a continuous oxygen analyzer to traverse the stack or flue can sometimes help to locate an air leak by showing a higher than normal excess air level.

4.4.1.4 Baffles. To obtain maximum heat absorption, baffles are often used to help direct the hot gases over the tubes. Arrangements vary widely, depending upon tube arrangement. Baffles restrict the flow of gases and affect draft flow required by the boiler. Defective baffles allow gases to short circuit so they do not pass over the entire heating surface. Leaking baffles result in high outlet gas temperature, and decreased efficiency. Leaking baffles can usually be distinguished from fouled heat transfer surfaces by their effect on draft loss: leaking baffles decrease gas loss, while fouled surfaces increase draft loss. Always investigate and report a change in flue gas temperature or draft loss.

4.4.1.5 Fuel/Air Ratio Optimization. Refer to par. 4.3.9.1. Know the proper excess air levels for each firing rate. When proper levels are known, corrective action can be taken if the fuel/air ratio is out of adjustment. Some corrective actions, such as returning the oil header pressure or temperature to the correct operating point, adjusting the stoker feed, returning the furnace draft to the operating point, or biasing the fuel/air ratio may be taken by the operator. If additional corrective action is required, note this in the boiler log and inform the responsible personnel. The optimum fuel/air ratio for a winter load is probably not optimum for a summer load. Determine the optimum ratio over the full load range of the boiler, and post a chart where it can be readily accessed by the operators. Table 19 gives recommended oxygen, carbon dioxide, and excess air levels at full load, 50 percent load, and 25 percent load for typical equipment. Boilers will not be able to operate at these levels, but this level of performance is possible with modern, correctly adjusted equipment. Plant modifications to reach these levels may be economically justified based on fuel savings resulting from improved combustion efficiency.

Table 19
Flue Gas Analysis at 25 Percent,
50 Percent, and 100 Percent Load
for Natural Gas, No. 2 Oil, No. 6 Oil, and Stoker Coal

Fuel	Load (Percent)	Flue Gas (Percent)		
		O_2	CO_2	Excess Air
Natural Gas	25 50 100	4.0 3.0 2.0	9.6 10.1 10.7	21.1 15.1 9.5
No. 2 Oil	25 50 100	5.0 4.0 2.5	11.9 12.6 13.8	29.2 22.0 12.6
No. 6 Oil	25 50 100	5.5 4.5 3.0	12.2 13.0 14.1	33.6 25.8 15.8
Stoker Coal	25 50 100	7.0 6.0 5.0	12.4 13.3 14.2	48.5 38.8 30.3

4.4.2 Optimizing Boiler Efficiency. Boiler efficiency accounts for the energy loss included in combustion efficiency plus energy losses associated with heat radiated from the boiler casing, heat removed with blowdown, and heat lost due to incomplete combustion. Boiler efficiency is affected by the stability of the combustion controls. Boiler efficiency is always less than combustion efficiency.

4.4.2.1 Reduce Radiation Losses. Inspect, maintain, and improve boiler, flue, and pipe insulation. Improved insulation is often available and economically justified. Radiation losses can be minimized by the proper selection of operating and standby boilers, and the temperature at which standby boilers are maintained. For some plants operating with noncritical load, a standby boiler need not be maintained in hot condition. Close the inlet and outlet dampers of any standby boilers. This will help to minimize the natural draft airflow which will cool the boiler.

4.4.2.2 Reduce Blowdown Losses. Blowdown is necessary to control steam boiler water quality and minimize scale formation. Reduced scale formation helps to maintain combustion efficiency near clean boiler levels and reduces water side maintenance. Blowdown is a form of preventive maintenance that should be carefully controlled. Continuous blowdown is recommended for steam boilers because blowdown heat exchangers can be used to recover much of the heat in the blowdown water by preheating makeup water. Automatic control of continuous blowdown is also recommended to improve the accuracy of the blowdown procedure and help minimize losses.

4.4.2.3 Reduce Unburned Carbon Losses. Unburned carbon losses from oil- and gas-fired boilers are usually negligible because the fuels burn easily and excess air levels and smoke are easily controlled. Unburned carbon losses for stoker-fired boilers, however, can be significant. Stokers should be carefully maintained and operated to minimize unburned carbon losses. Ash reinjection systems are an important part of a spreader stoker system which must be maintained in good operative condition. Overfire air is also very important on any stoker system to obtain proper mixing of air and combustion gases. Refer to operation procedures in par. 4.3.6.

4.4.2.4 Stabilize Combustion Controls. The combustion control system must accurately establish the correct fuel/air ratio to optimize combustion efficiency. Combustion controls are designed to regulate fuel and airflows to satisfy load demand, establish correct fuel/air ratio, and minimize the time spent at inefficient firing conditions. Combustion controls are stabilized by making the proper adjustments to the proportional band, integral, and rate settings to best respond to the load conditions. It is common that the best settings for winter load conditions are not best for summer conditions. The assistance of the control manufacturer may be required to determine the best settings. Settings should be changed only by trained and authorized personnel.

4.4.3 Optimizing Central Boiler Plant Efficiency. Overall plant efficiency is always less than boiler efficiency. Refer to par. 2.4.10 for an initial discussion of central boiler plant efficiency. After individual boiler efficiency is optimized, then consideration must be given to proper boiler selection, deaerator control, use of steam-driven auxiliaries, building energy conservation, and modifications or additions to plant equipment.

4.4.3.1 Boiler Selection. The best use of available boilers is necessary to optimize plant efficiency. A curve of efficiency versus load should be developed for each boiler based upon the data obtained when the fuel/air ratios were developed. Figure 130 illustrates such a curve. With this information it is possible to select which boiler or group of boilers is best suited to operate at a given load. For a steam demand of 30,000 pph, operation of boilers No. 1 and No. 2 would be most economical. If efficiency of a particular boiler is good over a very small range, it may be best to baseload that boiler in that range and allow the other boiler(s) to handle load swings. Two boilers operating at partial load may be more efficient than one boiler operating near its design capacity. A SOP should be developed establishing which boilers should operate for a given load.

4.4.3.2 Deaerator Control. Deaerators consume a significant amount of steam to heat and deaerate feedwater. Some of the steam is vented to atmosphere and lost. The amount vented ranges from 1/10 percent to 1 percent of the plant load and is dependent upon both the original design of the deaerator and vent condenser and their proper operation. With poor operation or design, 5 percent or more of the plant load can be vented through the deaerator. If operation alone does not resolve excessive venting, equipment modification or replacement should be considered.

4.4.3.3 Steam-Driven Auxiliaries. Steam-driven fans and pumps may be useful in providing a plant that can be operated in case of electric failure. Care must be taken, however, in utilizing such drives, because they can have a significant effect on plant efficiency. The efficiency of a noncondensing steam turbine is only about 20 percent. Suitable uses for exhaust steam must, therefore, be developed if steam turbines are to be used effectively. Operate steam drives only when a use for low pressure exhaust steam is available.

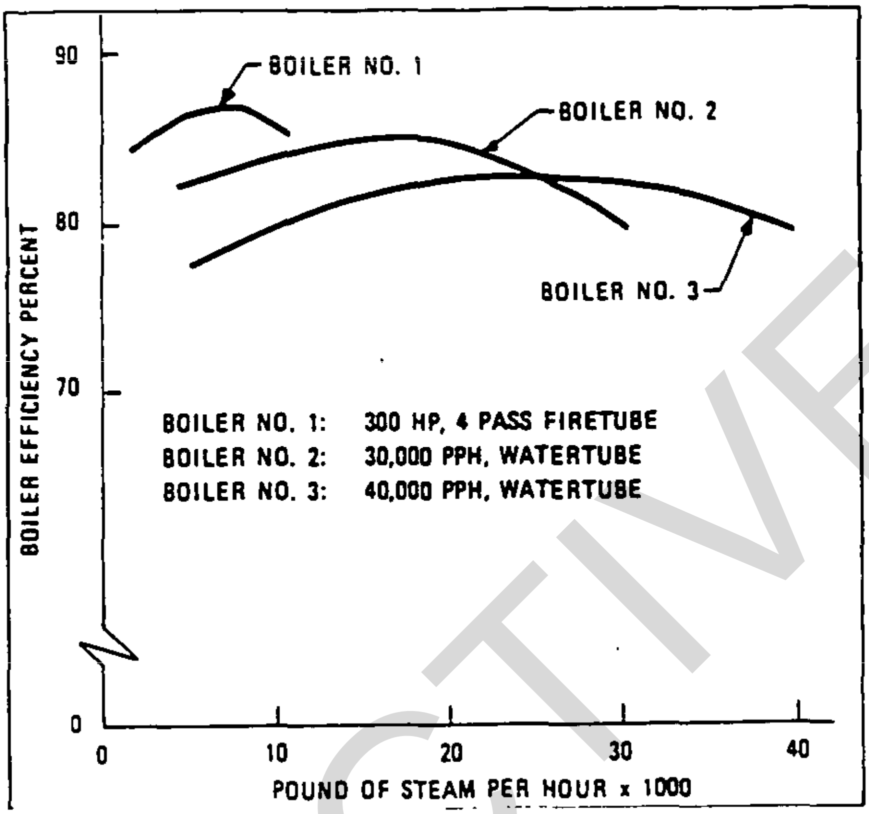


Figure 130
Boiler Efficiency Versus Load

4.4.3.4 Plant Building Conservation. Overall plant efficiency can be improved by minimizing the use of plant-generated energy for building heating. Use waste heat from condensate return, blowdown water, or boiler radiation whenever possible. Insulate the building. Maintain building steam traps and repair water or steam leaks immediately. Provide vent condensers on condensate wells, deaerators or deaerating heaters, and use the minimum steam pressure practical in heat exchangers (refer to par. 2.2.2.1).

4.4.3.5 Equipment Modifications or Additions. Existing equipment that does not operate efficiently should be modified or replaced if economically justified. Consider use of economizers or air heaters for boilers that normally operate with flue gas temperatures above 500 degrees F, if these boilers operate for significant periods of the year. Five percent improvement in boiler efficiency is common and can often economically justify the addition of such equipment. Improvements to external water treatment may be justified if significant reductions in blowdown be realized. Addition of a blowdown heat recovery system should be considered. Also consider use of vent condensers, condensate heat recovery systems, improved steam flow and upgraded boiler combustion controls. The economics of such modifications should be carefully reviewed, but it will often be found that the potential energy savings will quickly pay back the capital investment required.

4.4.3.6 Distribution System Effects on Plant Efficiency. If less water is returned to the central plant than was supplied in the form of steam or hot water, plant efficiency is reduced. Makeup water must be heated from its supply temperature, usually about 60 degrees F, while condensate return water needs only to be heated from its already elevated temperature of 150 to 180 degrees F. It is important to monitor supply and return flows as well as makeup flow and determine if excessive losses occur. Note that temperature compensation is required for accurate flow comparison. If losses are determined to be excessive or other problems develop, appropriate personnel should be alerted so repairs to the distribution system can be made. Distribution system losses should not exceed 5 to 10 percent of supplied flow in a steam system and 1 percent in a hot water system.

Section 5: INSPECTION AND PREVENTIVE MAINTENANCE

5.1 Purpose and Scope. This section is presented to cover general information and provide guidance to those responsible for maintenance of boiler plant equipment. It establishes a system of maintenance assignments and records sufficiently flexible to be applicable to most boiler plant installations. Although this handbook schedules most of the maintenance called for by manufacturers, it is not intended to take the place of manufacturer's instruction sheets. Each plant must maintain for ready reference and use a manufacturer's instruction file on installed equipment.

5.1.1 References. Along with manufacturers' instructions, ASME Boiler and Pressure Vessel Code, Sections VI and VII provide general procedures for care and operation of boilers. NAVFAC Instruction 11300.37, Energy and Utilities Policy, provides Navy policy for maintenance of plant equipment, NAVFAC MO-324 provides guidelines for inspection and certification of boilers and unfired pressure vessels, and the National Board of Boiler and Pressure Vessel Inspectors (NBBI), National Board Inspection Code provides national board inspection codes for construction, repair, and alterations of boilers.

5.2 Types of Maintenance

5.2.1 Breakdown Maintenance. Forced outages for repair or replacement of equipment parts that have failed in service can be, and often are, very costly. Through the application of proper operating procedures and careful inspection, it is possible to increase the length of time over which a boiler can be carried on the line before any repairs are required. This, in turn, will prolong the useful life of the equipment and minimize forced maintenance. The principal causes of forced outages and excessive maintenance are:

a) Sustained and frequent overloading of fuel burning equipment

b) Operating with improper airflow conditions

c) Fouling of external heating surfaces

d) Inadequate water conditioning

e) Improper lubrication

Forced maintenance is outside the scope of this handbook. Normally, forced maintenance and major overhauls are not performed by operating personnel, but rather by assigned maintenance personnel or outside contractors.

5.2.2 Preventive Maintenance. Preventive maintenance can be defined as the systemic and periodic inspection and servicing required to keep equipment in proper operating condition. Maintenance tasks are based on elapsed time or hours of service. Preventive maintenance means fixing things before they break, thus keeping equipment in continuous service or ready for service. The life of boiler plant equipment depends largely upon its maintenance, and the cost of operation in a well maintained plant is consistently lower than in a poorly maintained one. In addition, proper preventive maintenance results in improved working conditions and better employee morale.

5.2.3 Predictive Maintenance. Preventive maintenance has been the mainstay of maintenance practice for decades. No doubt it is better than breakdown maintenance, but with the advent of modestly priced computer systems and software it can be augmented with a more refined procedure known as predictive maintenance. For example, with predictive maintenance, wearing parts of equipment are maintained in step with their actual maintenance needs rather than arbitrary assumptions based on the passage of time or hours of use.

Predictive maintenance can be described as follows: predictive maintenance involves equipment condition monitoring along with data tracking and trending to predict failures. Condition monitoring information is gathered from vibration monitoring, infrared imaging, oil and wear particle analysis, ultrasound detection, visual inspections, and other nondestructive testing. Predictive maintenance information is scanned, by computer analysis software or other methods, and potential problems are diagnosed. A technician tracks the severity of the problems, orders necessary parts, and schedules maintenance accordingly. Depending on the severity, equipment with problems can be scheduled for repairs during the next outage or taken out of service immediately. With this method, breakdown maintenance is avoided.

5.2.3.1 Benefits. A predictive maintenance program used in conjunction with a good preventive maintenance program can reduce machinery cost and improve safety. These savings are realized as follows:

a) Avoid Breakdowns. By monitoring a machine's actual condition, forced outages and the additional problems associated with a catastrophic failure are avoided.

b) Reduced Maintenance Requirements. Maintenance is performed only as needed and not according to assumptions based on passage of time.

c) Reduced Spare Parts Inventory. With the ability to determine what equipment, tools, and labor will be required, spare parts inventories can be reduced.

d) Longer Machine Life. Early detection of incipient machine problems and prevention of catastrophic failures will increase machine life.

e) Verification of New Equipment and Repairs. Equipment can be checked for problems prior to returning to service or accepting contracted services.

5.2.3.2 Vibration Analysis. Vibration analysis is presently the most widely used predictive maintenance technique. It has been used in the Navy, mostly on submarines, since the early 1960's. With the availability of microcomputers and advanced programs, vibration analysis is now cost effective in smaller plants. Vibration analysis products range in complexity from pocket size single point level indicators to continuous on-line diagnostic systems. It is important to understand the available equipment before implementing a program.

5.3 Responsibility. The chief operator or plant supervisor has the ultimate responsibility for boiler plant equipment, its proper operation, and the scheduling and performance of maintenance. The chief operator should assign to himself responsibility for inspection and servicing required for plant safety. He will assign other operating or maintenance personnel the responsibility for maintenance of specific pieces of equipment as required. Some items listed for daily inspection by an assigned individual also require hourly inspections by the operating personnel. These hourly inspections do not relieve the assigned operator of his responsibility to inspect, service, and record the equipment condition.

5.4 Inspection. Inspection is the first step in a preventive maintenance program. The early detection of a problem can greatly reduce the amount of damage, simplify maintenance, and prolong equipment life. The key to effective inspection is a complete understanding of the equipment's operating characteristics. The operator should know the condition, sound, temperature, pressure, speed, vibration, and performance characteristics of each piece of equipment in the plant, and particularly those that are his assigned responsibility. Any change in normal characteristics should be immediately reported, investigated, and corrected.

5.5 Housekeeping. A neat boiler plant generally indicates a well run plant. The boiler plant should be kept free of unnecessary material and equipment. Good housekeeping should be encouraged and procedures established to maintain the desired level of cleanliness. Equipment should be kept clean. Sometimes cleaning is all that is required to keep equipment in trouble-free operation. Moisture, dirt, dust, cobwebs, bugs, and oil in the wrong place are enemies of mechanical and electrical equipment. Stop leaks as soon as they are detected. Leaks not repaired at best represent waste and at worst may cause extensive damage.

5.6 Utilities Inspection and Service Records. Preventive maintenance programs are effective only if careful, accurate, and complete records are kept. In no other way can the maintenance manager ensure that personnel are carrying out their responsibilities and that equipment is being properly maintained. Figures 131 and 132 are examples of the types of log sheets that should be maintained at each plant.

5.6.1 Records. As discussed above, maintaining accurate and complete records is an essential part of a good preventive maintenance program. Record data cards provide an effective method for smaller plants; however, for larger more complex plants, new software programs are available for record keeping. A computerized maintenance management system (CMMS) provides the maintenance department with a method of handling large amounts of data.

5.6.1.1 Computerized Maintenance Management System (CMMS). There are many maintenance software packages available on the commercial market with different options available. A typical CMMS is used to plan scheduling, issue work orders, track costs, and provide inventory control for maintenance tasks. Maintenance personnel perform equipment inspections, maintenance, and functional checks at specified time intervals. The program prints predictive maintenance task sheets specifying work required on the equipment, then updates a history file when the work is complete. Reports provide managers with equipment, maintenance, personnel, and cost information. This exchange of information helps coordinate management and maintenance personnel. Maintenance can also use these programs to track predictive maintenance tasks and history files.

Maintenance, Testing, and Inspection Log Hot Water Heating Boilers	Building: Address:	Month:	Year:
Person(s) to be Notified in Emergency (Name and Telephone No.)		Fuel Type:	
		Boiler No.:	

DAILY CHECKS

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
(1) Record Pressure																															
(2) Record Boiler Water Temperature																															
(3) Record Flue Gas Temperature																															

WEEKLY CHECKS (Enter Date)

	WEEK 1	WEEK 2	WEEK 3	WEEK 4
(1) Observe Flame Condition				
(2) Observe Circulating Pumps				

MONTHLY CHECKS (Enter Date)

(1) Manual Lift Relief Valve				
(2) Review Condition of or Test Each Item	(A) Flame Detection Devices		(F) Refractory	
	(B) Limit Controls		(G) Stop Valves	
	(C) Operating Controls		(H) Check Valves	
	(D) Floor Drains		(I) Drain Valves	
	(E) Fuel Piping		(J) Linkages	
(3) Observe Gage Glass on Expansion Tank				
(4) Combustion Air Adequate/Unobstructed				

General Comments:

INSTRUCTIONS

I. Fill in the name of the building, its location, boiler number, fuel type used, and the year. Name the person to be contacted in an emergency or malfunction.

II. Daily Checks

(1) Record pressure (see ASME Section VI — 8.35)
(2) Record temperature (see ASME Section VI — 8.05)
(3) Record the flue-gas temperature. (This should be read with the boiler running and at pressure.)

III. Weekly Checks (Record the date the test or check was completed.)

(1) Observe flame condition
(2) Observe circulating pumps for proper operation

IV. Monthly Checks (Record the date the test or check was completed.)

(1) Lift try lever to full open and release it to snap shut (see ASME Section VI — Exhibit C IV A)
(2) Review the condition of or test each item:
(A) Test flame detection devices (see ASME Section VI — 8.07H)
(B) Test limit controls
(C) Test operating controls
(D) Test floor drains to be sure they are draining properly
(E) Check fuel piping for leakage
(F) If possible without opening boiler, check the refractory for cracking and deterioration
(G) Check stop valves
(H) Inspect check valves
(I) Check drain valves
(J) Check linkages for damage or disconnection
(3) Observe water level of gage glass on expansion tank. (Optional)
(4) Check combustion air supply for obstructions and adequacy of air flow

V. Log Retention

Retain this log for at least 1 year (see ASME Section VI — 8.09C)

Figure 131
Hot Water Heating Boiler Log

Maintenance, Testing, and Inspection Log Steam Heating Boilers	Building:	Month:	Year:
	Address:	Fuel Type:	
Person(s) to be Notified in Emergency (Name and Telephone No.)		Boiler No.:	

DAILY CHECKS

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
(1) Observe Water Level																															
(2) Record Pressure																															
(3) Record Flue Gas Temperature																															

WEEKLY CHECKS (Enter Date)

	WEEK 1	WEEK 2	WEEK 3	WEEK 4
(1) Test Low Water Cutoff				
(2) Test Gage Glass				
(3) Observe Flame Condition				

MONTHLY CHECKS (Enter Date)

(1) Manual Lift Safety Valve				
(2) Review Condition of or Test Each Item	(A) Linkages		(F) Floor Drains	
	(B) Damper Controls		(G) Flame Detection Device	
	(C) Stop Valves		(H) Limit Controls	
	(D) Refractory		(I) Operating Controls	
	(E) Flue-Chimney Breeching			
(3) Inspect Fuel Piping				
(4) Combustion Air Adequate/Unobstructed				

General Comments:

INSTRUCTIONS

I Fill in the name of the building, its location, boiler number, fuel type used, and the year. Name the person to be contacted in an emergency or malfunction.

II Daily Checks

(1) Observe water level in the water column sight glass (see ASME Section VI — 7.05A)
(2) Record boiler pressure indicated by the gage at the boiler
(3) Record the flue gas temperature. (This should be read with the boiler running and at pressure.)

III Weekly Checks (Record the date the test or check was completed.)

(1) Drain float chamber while boiler is running to determine if the control will shut down the boiler (see ASME Section VI — 7.05H)
(2) Close the lower gage gas valve, then open drain cock which is on the bottom of this valve and blow the glass clear. Close the drain cock and open lower gage glass valve. Water should return to the gage glass immediately (see ASME Section VI — 7.05A(2))
(3) Observe flame condition

IV Monthly Checks (Record the date the test or check was completed.)

(1) Lift try lever to full open and release it to snap shut (see ASME Section VI — Exhibit C [illegible])
(2) Review the condition of or test each item
(A) Check linkages for damage or disconnection (see ASME Section VI — 7.0[illegible])
(B) Watch damper controls during operation to be sure they operate properly
(C) Check stop valves
(D) If possible without opening boiler, check the refractory for cracking and deterioration.
(E) Check the flue-chimney breeching for signs of leakage, damage, or deterioration
(F) Test floor drains to be sure they are draining properly
(G) Test flame detection device
(H) Test limit controls
(I) Test operating controls
(3) Inspect fuel piping for leakage and damage

V Log Retention

Retain this log for at least 1 year (see ASME Section VI — 6.09C)

Figure 132
Steam Heating Boiler Log

5.6.1.2 Data Entry. Whether using a CMMS or record cards, care is required when initially filling in entry data. The following outlines basic information that should be included when establishing maintenance records:

a) Equipment Number. The equipment number is made up of three separate parts separated by dashes. The first part is the boiler plant building or location number. The second and third parts are equipment classification codes used to distinguish between similar pieces of equipment.

b) Description. Describe equipment briefly but in enough detail so that it can be readily identified.

c) Preventive Maintenance To Be Done By. Show the job title and name of the person responsible for maintenance; this should normally be the person who actually operates the equipment. He is also responsible for reminding the chief operator, superintendent, or other supervisor of any special semiannual or annual inspections required, and for ensuring that the supervisor makes the appropriate entry on the card after the inspection is completed.

d) Work To Be Done. Study the handbook and the equipment manufacturer's manual, noting inspection and service required. Enter in this space the paragraph or subparagraph heading describing the operation. Add any operations not covered in the manual but needed to maintain the unit. Ensure that necessary inspections and services are shown on the record card. List operations in order of frequency of performance, with daily service first.

e) Item Number. Identify each operation with the proper item number. Usually the item number is the subparagraph number unless an item number is noted. Where the same item number is used to identify more than one operation, differentiate between them by adding a letter to one of the numbers; thus, if "1" is used twice, write one of them as "1a."

f) Reference. Insert paragraph numbers to facilitate reference to the appropriate manual.

g) Frequency. Record frequency of operations, as shown in Time-Schedule columns. Modify suggested frequencies as required to fit local conditions.

h) Time. Show specific day or month when service is due. Stagger quarterly, semiannual, and annual inspections so as to minimize rush periods and schedule conflicts. Choose the season when the work can be best accomplished.

i) Tab Index. Mark an "X" at the top of the form alongside each month during which work is to be done or a report submitted. This helps to schedule operations, since overall work required in a given month can be quickly determined by reference to the tab index.

j) Service Record. On the back of the card, record the date and item number whenever maintenance is performed, and initial. If service is required beyond the ability or authority of the inspector, he must request the proper help and enter the request in the Work Done column. For example, if inspection of a motor reveals a grooved commutator, the entry would read "Electrician needed to complete Item 51 - commutator grooved." The work order number is entered under the column headed Signed and is initialed. When spaces on the Service Record are filled in, a blank card should be stapled to the original.

5.6.2 Assignment of Work. Only general rules covering assignment of preventive maintenance work are given here. Actual assignments will necessarily depend upon the specific plant and the qualifications of operating personnel. Work loads of personnel should be substantially equal, and duties assigned must be in keeping with the qualifications of the individual. A coal handler, for example, may inspect the stack and breeching for fly-ash accumulations, and examine guy wires, coal bunkers, elevators, and conveyors. He should not be expected to maintain and adjust flow meters or combustion controls.

5.6.2.1 Chief Operator/Supervisor. The chief operator is charged with overall responsibility for the plant. Therefore, inspections having to do with safety of operation or the possibility of serious damage to equipment are assigned to him. These items must be checked at frequent intervals. Likewise, items of major importance such as internal inspection of boilers and furnaces should be under his personal supervision.

5.6.2.2 Regular Operators. Shift operators, firemen, or other qualified personnel usually have maintenance duties in addition to their regular assignments. The man to whom a given piece of equipment is assigned should perform the required maintenance during whatever shift he happens to be working on a given day. During this man's time off, the relief operator or the chief operator performs the scheduled maintenance. Maintenance activity can sometimes be assigned entirely to day shift operators. This arrangement necessitates close supervision to guard against neglect, but maintenance work during daylight hours is more pleasant and frequently more effective.

5.6.2.3 Maintenance Men. In plants where regular maintenance men are available, assignment of preventive maintenance work is simplified. Here day-shift work is usual. However, certain special items should still be assigned to skillful operators.

5.7 Tools. Proper preventive maintenance requires proper tools and instruments. Review the operations listed on the maintenance cards and determine the tools required for each operation. There is no single list of tools which will apply to all plants. However, each plant should be equipped with a workbench with a pipe vise, a machinist's vise, and a tool board.

5.7.1 Special Tools. Some maintenance operations require tools that would be used too infrequently to justify their purchase for the central boiler plant. If possible, such tools should be borrowed from other departments on the base; otherwise, requisition them. Indicate on the maintenance card the department from which they may be borrowed.

5.7.2 Care of Tools. Maintain tools in first class condition. Take defective tools out of service immediately and repair or replace them. Use tools properly. If the proper tool for an operation is not available, immediate arrangements should be made for its procurement.

5.7.3 Tool Board. Keep tools on a well planned tool board or tool box, not in bins, benches, or drawers. Keeping tools on a tool board helps prevent loss and makes them instantly available when required. Locate the tool board in a conspicuous place, convenient to the majority of operators. Space should be provided on the board for additions to the tool supply. The shape or size of a tool should not prevent its being installed on the tool board. Extension cords, oil cans, flashlights, and electric drills can be installed on the board by use of special brackets. The outline of each tool should be painted on the board in a contrasting color to assist in replacing tools in their proper place and to serve as a ready check on missing tools.

5.8 Spare Parts. Preventive maintenance requires an adequate stock of spare parts. Service conditions, the importance of the part to service continuity, and the ease of procurement help to determine the kind and number of spare parts kept in stock. Examine the equipment requirements in the plant and prepare a spare parts inventory. Do not neglect to include small parts such as nuts, bolts, shear pins, steam traps, gaskets, valve seats, packing, and cotter pins.

5.9 Special Supplies. Lubricants and cleaning solvents are needed for proper equipment operation and long life. Clean, properly lubricated equipment is required for successful plant operation.

5.9.1 Lubricants. Lubricants are frequently referred to in par. 5.10. Because of the extreme variations in equipment and service conditions, the types of lubricants required for a given plant must be determined locally. Determine lubricant requirements from the equipment manufacturers instructions, or advice from lubricant manufacturers.

5.9.2 Cleaning Solvents. Cleaning solvents such as mineral spirits, kerosene, and Varsol can be used in central boiler plants. Petroleum derivatives such as naphtha and gasoline present an explosion and fire danger and must never be used. Benzene especially must never be used, as it not only has a low flashpoint, but is also extremely toxic. Follow the precautions for use and storage that are provided with the solvents. Material Safety Data Sheets must be readily available to employees in accordance with OSHA Regulation 29 CFR 1910.1200. When using cleaning solvents, be sure the solvent is completely evaporated before placing the equipment back into service. When using solvents for cleaning electrical equipment, first remove loose dirt and dust, then dip a rag into the solvent and wipe the insulation. When spraying solvents, extra precautions against fire or health hazards must be observed. When cleaning bearings or machined parts, place the cleaned parts on clean rags or paper, allow them to dry and immediately dip them in oil or apply lubricant. Do not allow rust-susceptible parts to remain exposed to air after cleaning.

5.10 Scheduled Preventive Maintenance

5.10.1 Scheduling and Use of the Information. The following sections provide suggested preventive maintenance schedules for many types of central boiler plant equipment. The subparagraph designates the frequency for preventive maintenance: daily, weekly, monthly, quarterly, semiannually, and annually. The second subparagraph numbers are numbered consecutively and can be used as index numbers on the record cards. The lists of inspection and work presented here should not be considered to be complete. Review the manufacturer's operating and maintenance instructions and add additional required items. Review the applicable section of the ASME Boiler and Pressure Vessel Code and the NBBI National Board Inspection Code, along with NAVFAC

MO-324 for additional requirements and suggestions. Other equipment will be found which is not discussed in this section. Such equipment should be researched with the manufacturer and appropriate record cards prepared. The frequency suggested here is based on good practice. Modify the suggested frequency to best match local conditions and experience.

5.10.2 Boilers. The successful operation and maintenance of a boiler is greatly dependent on the operation and maintenance of its auxiliaries. Boiler operation and boiler preventive maintenance involve inspection of the boiler operating conditions.

a) Daily

(1) Check the following conditions and take action as required:

(a) Water level.

(b) Steam pressure or water temperature stability.

(c) Flue gas temperature at two loads, compared to clean boiler temperatures.

(d) Flue gas oxygen or carbon dioxide levels at two loads, compared with baseline data.

(e) Water or steam leaks.

(f) Air leaks in casing, ducts, or setting.

(2) Take water samples and perform necessary tests. Adjust internal treatment and continuous blowdown.

(3) Blow down steam boilers through the bottom blowdown connection to remove sludge.

(4) Clean boiler exterior.

b) Monthly

(1) Lever test safety valves (refer to par. 5.10.6).

(2) Check boiler drain valves for proper opening and closing.

(3) Check boiler room floor drains for proper function.

c) Quarterly. One of the quarterly inspections should be timed to coincide with the annual inspection by the Authorized Inspector.

(1) Internally and externally inspect the boiler. Refer to semiannual and annual procedures.

(2) Clean the fire side of the boiler.

d) Semiannually. Semiannually or as required by NAVFAC MO-324, an external inspection of the boiler by an Authorized Inspector is required. With the boiler operating, inspect for the following:

(1) Any evidence of steam or water leakage.

(2) Pressure gage accuracy and function.

(3) Safety or safety relief valves.

(4) Water level gage function.

(5) Pressure controls function.

(6) Low water fuel cutoff and level control function.

(7) Steam, water, and blowdown piping for leakage, vibration, proper rating, and freedom to expand.

(8) Review the boiler log, maintenance records, and water treatment records to ensure that regular and adequate tests have been made.

e) Annually. Annual inspections are required by NAVFAC MO-324. Boiler inspections are to be made in accordance with rules for inspections in Section VII of the ASME Boiler and Pressure Vessel Code. An Authorized Inspector is required. Preparation for an annual inspection is discussed in the next subparagraph. The most recent copy of Boiler Inspection Report, NAVFAC Form 9-11014/32 (3/67), must be posted for each boiler in the plant.

(1) Inspect the boiler for the following; clean and repair as required:

(a) Water side of tubes for deposits caused by water treatment, scale, or oil. Remove excessive deposits by mechanical or chemical means.

(b) Stays and stay bolts. Repair or replace as required.

(c) Water side of tubes and boiler for corrosion, grooving, and cracks.

(d) Manholes, internals, and connections to the boiler for cracks, corrosion, erosion and clean passages.

(e) Fusible plugs. Replace annually.

(f) Tube sheets, tube ends and drums for signs of thinning, leaking, corrosion, or cracks.

(g) Boiler supports and setting for freedom of expansion.

(h) Fire side of tubes for bulging, blistering, leaks, corrosion or erosion.

(i) Setting for cracks, settlement, loose bricks, spalling, and leakage.

(j) Safety valves and their connections and piping. Test the safety valves.

(k) Baffles.

(l) Blowdown piping.

(m) Boiler appliances.

(n) When required by the Authorized Inspector, hydrostatically test the boiler.

(o) Review past inspection reports and plant records.

(p) Make any other inspection required by the ASME Boiler and Pressure Vessel Code or NBBI National Board Inspection Code.

(2) Preparation for an annual inspection. Make the following preparations for annual inspection. Other preparations may also be required by the ASME Boiler and Pressure Vessel Code or NBBI National Board Inspection Code.

(a) Where soot blowers are installed, blow soot before reducing boiler load below 50 percent.

(b) Shut down the boiler in accordance with par. 4.3.22. Shut off fuel supply lines and lock when possible. Sufficiently cool the boiler before draining the water. Internally wash the boiler to remove sludge deposits, suspended solids sediment, and loose scale. Do not clean drums or tubes until after the inspection unless prior agreement has been reached with the Authorized Inspector.

(c) Before opening or entering any part of the boiler, ensure that the nonreturn and stop valves are closed, tagged, and preferably padlocked and drain valves between the two are opened. The feed and check valves must be closed, tagged, and padlocked and drain valves between the two must be opened. After draining the boiler blowoff valves must be closed and padlocked. Drain and vent lines should be opened.

(d) Proper low voltage lighting should be provided for internal inspection.

(e) The fire side walls, baffles, and tubes should be thoroughly swept and ash and soot removed.

(f) If the installation burns coal, remove the grate bars, and clean the firebox plates along the grate line until the bare metal is exposed. Take care not to damage the metal during the cleaning.

(g) Have available a supply of gaskets for manholes and hand holes, and suitable wrenches for removing and replacing covers.

(h) Replace fusible plugs.

(i) If insulation conceals manufacturers inscribed data, remove the lagging and clean the surface carefully so that die-cut letters and figures can be easily read.

(j). Assign a qualified boiler plant operator to assist the Inspector throughout the tests.

(k) Be prepared to run a hydrostatic pressure test. A hand pump should be provided for this test if required. Provide gags to prevent safety valves from lifting when test pressure is applied. If hydrostatic pressure tests on more than one boiler are contemplated, sufficient gags should be provided for the boilers. If boiler gages and controls are not designed for the proposed test pressure, be prepared to isolate or remove them and plug the openings.

(l) Have boiler records available.

f) Taking a Boiler Out of Service. Whenever a boiler is to be out of service for more than 2 days, thoroughly clean the fire side of the boiler, flues, economizer and air heater. Ash and soot deposits must be removed. Dry ash and soot are not corrosive but moisture in combination with the ash and soot of sulfur bearing fuel is. To avoid acid attack and corrosion of the metal, ash and soot must be removed.

5.10.3 Economizers. Refer to par. 3.1.7.

a) Daily. Inspect for leaks in piping, valves, packings, gasketed joints, hand-hole openings, casing, etc. Make repairs as required.

b) Monthly. Check the following under identical load conditions:

(1) Water pressure drop through the economizer.

(2) Draft losses across the economizer.

(3) Gas temperature drop across the economizer. An increase in draft loss and a decrease in gas temperature drop normally indicates a fouling condition.

c) Annually. During the annual boiler overhaul, clean and inspect the economizer.

(1) Externally look for signs of overheating, leakage, wear, or corrosion in pressure parts. Check the baffles and tubes in the area of soot blowers for signs of abrasion caused by fly ash or steam cutting. Check the elements of the soot blower.

(2) Internally look for corrosion, erosion, scale, sludge deposits, or oil in tubes and headers.

5.10.4 Air Heaters. Refer to par. 3.1.8.

a) Daily

(1) Inspect the air heater for gas or air leaks in duct, casing, gasketed joints, etc.

(2) Inspect for abnormal air or gas temperatures.

(3) Inspect for mechanical drive problems on rotary air heaters, if supplied.

(4) Establish a lubrication schedule for rotary air heaters in accordance with manufacturer's recommendations.

b) Monthly. Check the following under identical load conditions:

(1) Air and gas side draft losses.

(2) Gas temperature drop through the air heater.

(3) Inspect for mechanical drive problems on rotary air hanging heaters, if supplied.

(4) Establish a lubrication schedule for rotary air heaters in accordance with manufacturer's recommendations.

(5) Air temperature rise through the air heater. An increase in gas side draft losses combined with a decrease in air temperature rise indicates excessive soot deposits in the tubes or gas passages.

(6) Make an oxygen analysis of flue gas at the air heater inlet and outlet. The difference in total air content between the analyses indicates air leakage. Repair if leakage is excessive.

c) Annually

(1) During the boiler overhaul, clean and inspect the air heater. Look for indications of corrosion, erosion, leakage, and wear.

(2) In rotary regenerative air heaters, inspect the motor drive, speed reducer, auxiliary air motor if provided, lubricating system, cooling system, bearings, rotor seals, etc.

(3) Check the condition of soot blowers and washing equipment.

5.10.5 Water Columns. Refer to par. 3.2.3.

a) Daily

(1) Blow down and inspect water columns, gage glasses, level indicators, and level alarm devices for leaks, correct operation, correct level indication, and adequate lighting. Repair leaks immediately.

(2) Check to see that valves between boiler and gage glass are free and operational.

(3) When provided, test high and low automatic alarm to ensure that it is in perfect order. Repair when faulty.

b) Annually. During annual boiler overhaul, or more often if necessary, dismantle, clean, and inspect parts such as valves, alarm linkages, floats, chains, alarms, glasses, diaphragms, or electrodes. Replace or repair damaged or worn parts as required to ensure proper functioning.

5.10.6 Safety Valves. Refer to par. 3.2.5.

a) Daily

(1) Check for steam leakage indicating damaged seat, defective parts or lodged scale. Immediately correct such faults as leaking, simmering, or chattering.

(2) Check supports and anchors of discharge pipe.

(3) Check the drain line from safety valve outlet to ensure that it is open and will function when needed.

b) Monthly. Check each safety valve by raising the valve off the seat by lifting the lever. Keep the valve wide open for at least 10 seconds to blow dirt and scale clean from the seat. Close the valve by suddenly releasing the lever.

c) Annually. Before and after the annual steam generator inspection and overhaul, test the operation of safety valves. Testing is also required whenever the spring or blow back ring has been reset or adjusted.

5.10.7 Fusible Plugs. Refer to par. 3.2.8. These items should be put on the boiler record card where applicable.

a) Quarterly. Inspect fusible plugs during boiler inspections. Scrape the surface clean and bright. Replace if the metal does not appear sound.

b) Annually. Replace fusible plugs at least once a year.

5.10.8 Soot blowers. Refer to par. 3.2.9.2.

a) Daily

(1) Check for leaks. Repair if required.

(2) Check for correct operation of the system components.

b) Semiannually

(1) During the boiler outages, inspect the following items and repair if required:

(a) Defective elements (warped, corroded, eroded, or otherwise damaged).

(b) Worn, loose, or defective nozzles.

(c) Incorrect blowing and adjustment.

(d) Incorrect location of elements or nozzles.

(e) Alignment and tightness of the supporting bearings.

(f) Defective chains, control valves, and control system components.

(g) Condition of soot blower piping system.

(h) Evidence of abrasion caused by impingement of the jet.

(2) Repack and adjust glands to prevent leakage.

5.10.9 Stokers. Refer to par. 3.3.1.1.

a) Daily

(1) Clean exposed parts of the stoker.

(2) Inspect accessible parts. Pay special attention to bolts and connections in shear pins or safety release mechanisms. Be sure there is no binding that may keep protective devices from functioning. Operating personnel should inspect the following items hourly:

(a) Hot bearings.

(b) Foreign material in coal.

(c) Mechanical linkages.

(d) Damaged, overheated, or burned out parts.

(e) Oil leaks.

(f) Proper oil level and condition of hydraulic systems.

(g) Correct oil pressures and oil temperature.

(h) Clinkers.

(3) Establish lubrication requirements and a schedule in accordance with manufacturer's requirements.

b) Quarterly. Make the following general inspection and overhaul whenever a boiler is removed from service.

(1) Inspect the complete stoker. Check for wear on surfaces of feeder-box sides, conveyor areas, and moving parts. Check alignment and condition of the grates. Replace broken, warped, or distorted parts promptly. Check the following:

(a) Clearances between grate elements.

(b) Tightness of nuts, bolts, and holding parts.

(c) Drive mechanism and drive unit. Clean and repair any damage to gears and other components.

(d) Bearings of drive unit. Lubricate as required.

(e) Electrical controls and connections.

(f) Fan and its bearings. Check and lubricate bearings.

(g) Fly-ash reinjection system. Look for worn areas and plugged lines. Repair if required.

(h) Air seals. Repair if required.

(2) Remove slag from furnace walls adjacent to stoker or fuel bed surface. Take care to avoid injury to the brickwork.

5.10.10 Pulverized Coal Equipment. Preventive maintenance procedures for pulverized coal equipment are as follows.

5.10.10.1 Lubrication. Establish a definite lubrication schedule for pulverizer installations and assign definite responsibility for the periodic lubrication. Frequency of lubrication and lubricants used should be approved by both the pulverizer and lubricant manufacturers.

5.10.10.2 Ball Mills

a) Daily. The operator shall inspect the installation daily for the following:

(1) Unusual noise or vibration.

(2) Driver overload.

(3) Correct lubricating oil pressures, temperatures, and levels.

(4) Hot bearings.

(5) Correct cooling water temperatures.

(6) Correct coal level in mill.

(7) Proper operation of coal feeder and controls.

(8) Correct mill outlet temperature.

(9) Proper operation of exhauster.

b) Annually. Once a year, or as required, depending upon the severity of service, inspect the mill for the following:

(1) Liner bolts for tightness.

(2) Mill liner for wear.

(3) Exhauster blades and liners for erosion.

(4) Correct ball charge.

(5) Bearings for wear and dirt.

(6) Gear drives for wear.

(7) Coal valves and lines for wear and dirt accumulations.

(8) Check coupling alignment.

c) General

(1) Add to ball charge as required.

(2) Tighten mill liner bolts frequently.

(3) Repair or replace worn or defective parts.

(4) Thoroughly clean and flush lubricating oil system annually.

(5) Repair or replace worn or damaged coal valves.

5.10.10.3 Bowl Mills

a) Daily. The operator shall inspect the mill installation daily for the following:

(1) Hot bearings.

(2) Motor overheating.

(3) Unusual noise or vibration.

(4) Correct lubricating oil levels, pressures and temperatures.

(5) Proper operation of exhauster.

(6) Correct roll pressure.

(7) Proper setting of classifier deflector valves.

(8) Correct mill outlet temperature.

b) Annually. Once a year, or as required, depending upon the severity of service, inspect for the following:

(1) Rolls and grinding rings for wear.

(2) Mill liners for wear.

(3) Exhauster blades, deflectors, and air-directional vanes for erosion and damage.

(4) Bearings and gears for wear. Check setting of gears.

(5) Coal valves and lines for wear and dirt accumulations.

(6) Check bolts for tightness.

(7) Check coupling alignment.

c) General. Worn or defective mill liners, deflectors, and air-directional vanes should be repaired or replaced as required. Do not leave finished surfaces beaded when building up worn surfaces with weld metal. Lips resulting from wear to rolls and grinding rings may be trimmed, making it possible to use either the trimmed rolls with the trimmed ring, the trimmed rolls with a new ring, or new rolls with the trimmed ring. Rolls are made of chilled cast iron, chilled to a depth of about 1 inch. Should the wear on the roll have progressed below the chill, nothing can be gained by trimming the lip. Trimming must be done by melting with a 1/2-inch to 3/4-inch carbon electrode at 300 to 400 amperes, using reverse polarity on the machine. It is not necessary to obtain a smooth surface. The grinding ring can be trimmed using an acetylene torch. This cut also does not have to produce a smooth finish. Trimming can be accomplished by fastening the torch in a suitable fixture and setting the torch to cut the lip at the desired angle. The bowl can be turned by turning the mill shaft. An alternate method is to trim the lip by hand burning, the bowl being turned intermittently as required.

5.10.10.4 Ball-Race Pulverizer

a) Daily. The operator shall inspect the pulverizer installation daily for the following:

(1) Unusual noise and vibration.

(2) Hot bearings.

(3) Motor overheating.

(4) Correct lubricating oil levels, pressures, and temperatures.

(5) Correct spring loading on grinding elements.

(6) Proper operation of blower.

(7) Proper setting of classifier vanes, if adjustable.

(8) Correct mill outlet temperature.

(9) Proper operation of coal feeder and controls.

b) Annually. Once a year, inspect the installation for the following:

(1) Balls and grinding rings for wear.

(2) Classifier vanes for erosion and wear.

(3) Blower for wear.

(4) Bearings and gears for wear.

(5) Check bolts for tightness.

(6) Check coupling alignment.

c) General. Renew worn balls and races as required. It is good practice in this type of pulverizer to wear down two complete sets of balls with one set of grinding rings to obtain maximum life of the grinding elements. When new balls and races are installed, allow the ball diameter to reduce 1/4 inch and then replace with a second set of balls. Allow the second set to wear down 1/2 inch and then change to the first set and allow them to wear an additional 1/2 inch. By following this procedure, the balls are kept within 1/4 inch of each other in diameter and close to the contour of the races. If one set of balls is allowed to wear to the minimum size, the effect on the races will be such that the races will have to be replaced prematurely. The maximum permissible ball wear is 7-1/2-inch balls worn to 5 inches, 9-1/4-inch balls worn to 6-1/4 inches, or 10-1/2-inch balls worn to a 7-inch diameter. Extra or fill-in balls should be added as wear increases, but the addition of a ball must not reduce the average clearance between balls to less than 5/8 inch. Grinding rings may be worn to a thickness of from 1 inch to 1-3/4 inches. New top and bottom grinding rings should be installed at the same time so as to provide mating ring surfaces for proper ball contact.

5.10.10.5 Attrition Pulverizer

a) Daily. The operator shall inspect the installation daily for the following:

(1) Hot bearings.

(2) Driver overload.

(3) Unusual noise or vibration.

(4) Proper lubricating oil levels, pressures and temperatures.

(5) Correct mill outlet temperature.

(6) Proper operation of coal feeder and controls.

(7) Check rpm on turbine driven machines.

b) Annually

(1) Inspect stationary pegs, hammer, and moving pegs for erosion and wear.

(2) Check housing liners for wear.

(3) Inspect rejector arms for erosion and damage.

(4) Inspect fan blades for wear.

(5) Check bearings for wear and dirt.

(6) Check coupling alignment.

(7) Check bolts for tightness.

c) General. Replace stationary peg bases when bolts that hold peg tips are exposed and in danger of being cut off. Replace stationary peg tips when approximately 1 inch has been worn off the total length. Replace moving pegs when approximately one-third of the face area has been chipped or worn away. Replace rotor wearing plates when it appears that continued operation might result in failure. Fan blades can be kept in service until the blades are cut through at the tip. Pulverizer liners should be replaced when it appears that continued operation will result in coal cutting through to the housing.

5.10.11 Coal-Handling Equipment. Refer to par. 3.3.2.

a) Daily

(1) Inspect for the following hourly:

(a) Unusual noise or vibration.

(b) Motor overheating.

(c) Hot bearings.

(d) Coal accumulation. Clean as required.

(e) Correct chain or belt tension.

(f) Damaged or loose drag flights or buckets.

(g) Damaged chain, chain sprockets, or belts.

(h) Proper operating conditions.

(i) Oil or water leaks. Repair as required.

(j) Proper lubricant levels.

(2) Establish lubrication requirements and schedule as required by manufacturer's instructions.

(3) Inspect scales for zero load balance.

b) Monthly. Inspect for the following:

(1) Gear boxes, sheaves, rollers, shafts for proper lubrication, freedom of movement, and bearing play.

(2) Screens for holes or plugging. Repair or clean as required.

(3) Structural frame for broken or bent parts and loose or damaged joints.

(4) Proper alignment of pulleys and other parts.

(5) Proper operation of control and safety devices.

c) Semiannually. Inspect for the following:

(1) Corrosion or erosion of hoppers, chutes, and gates.

(2) Damage of lining and protective coatings.

(3) Wear or damage of scale levers, knife edges, and bearings. Repair or replace as required.

(4) Cracks or other damage of concrete structures.

d) Annually. Prepare applicable metal surfaces and repaint.

5.10.12 Ash-Handling Equipment. Refer to par. 3.3.3.

a) Daily

(1) Inspect for the following:

(a) Piping leaks. Repair immediately.

(b) Proper operation of steam or mechanical exhauster.

(c) Proper operation of air washer, if provided.

(d) Proper operation of ash gates and clinker grinders.

(e) Proper operation of automatic steam valves and automatic controls, including maintenance of correct steam pressure.

b) Quarterly

(1) Inspect conveyor piping, especially at elbows, for accumulated ash and erosion. Rotate, repair, or replace as necessary.

(2) Inspect steam exhauster for corrosion and erosion.

(3) Inspect washer internals for wear, ash accumulation, and nozzle condition. Clean and repair as necessary.

5.10.13 Oil Burners. Refer to pars. 3.3.4 and 4.3.7.

a) Daily

(1) Inspect for the following hourly:

(a) Oil, steam, or air leaks. Repair immediately.

(b) Unburned oil deposits and overheating of burner parts.

(c) Burner flame for proper shape, color and stability.

(d) Proper operating pressures and temperatures.

(2) Remove and clean the oil atomizer.

(3) Clean burner exterior.

(4) Follow the established schedule for cleaning burner strainers.

b) Annually

(1) Completely remove and clean the burner and igniter.

(2) Inspect air register and burner parts for freedom of movement, warpage, and wear. Repair or replace as required. Adjust parts for proper operation. The services of a burner serviceman may be required.

(3) Replace atomizer tips or nozzles that have been in normal service with new tips or nozzles.

(4) Calibrate burner pressure and temperature gages.

5.10.14 Oil-Handling Equipment. Refer to pars. 3.3.5 and 4.3.7.

a) Daily

(1) Inspect for the following:

(a) Oil, steam, water, or air leaks. Repair immediately.

(b) Proper operation of traps, controls, and instrumentation.

(c) Proper operating pressures, temperatures, and levels.

(2) Clean equipment as required.

(3) Establish a schedule for cleaning strainers.

(4) Inspect and maintain pumps as outlined in pars. 5.10.25, 5.10.26, and 5.10.27.

b) Annually

(1) Inspect and clean heaters and tanks internally and externally. Inspect carefully for corrosion, erosion, pitting, plugged tubes, damaged baffles, sludge deposits, water accumulations, and scale deposits.

(2) Inspect for damage to protective coatings, or paint. Repair or repaint as required.

(3) Test relief valve settings and operation.

(4) Clean, inspect, and calibrate controls and instrumentation.

5.10.15 Gas Burners. Refer to pars. 3.3.6 and 4.3.8.

a) Daily. Inspect for the following hourly:

(1) Gas or air leaks. Repair immediately.

(2) Proper gas and air pressures.

(3) Burner flame for proper shape, color, and stability.

(4) Overheating or binding of burner parts.

b) Annually

(1) Completely remove and clean the burner and igniter.

(2) Inspect burner parts for freedom of movement, warpage, and wear. Inspect gas nozzles. Repair or replace as required. Adjust parts for proper operation. The services of a burner serviceman may be required.

(3) Calibrate burner pressure gages.

5.10.16 Feedwater/Drum Level Controls. Refer to par. 3.4.1.

a) Daily

(1) Inspect for water leaks. Repair immediately.

(2) Observe operation of control devices. Report and repair any malfunctions immediately.

(3) Establish a calibration schedule for components in the control system in accordance with manufacturer's recommendations.

b) Annually

(1) During the boiler overhaul, or more often if necessary, clean and inspect control components. Look for signs of corrosion, erosion, or wear and for deposits, leaks, and defective parts. Repair as required.

(2) Check settings, adjustments, and operation of components.

5.10.17 Combustion Controls. Refer to pars. 3.4.2 and 4.3.9.

a) Daily

(1) Inspect for air, oil, gas, and water leaks. Repair immediately.

(2) Blow down compressed air drip legs and filters.

(3) Check jack shafts, dampers and linkages for slippage and freedom of movement.

(4) Inspect for stable and proper operation.

(5) Clean exterior of controls.

(6) Establish lubrication requirements and schedule in accordance with manufacturer's instructions.

b) Monthly. Replace or clean system filters.

c) Annually

(1) Inspect and completely clean control devices internally. Replace any worn, corroded, or damaged parts.

(2) Test for correct calibration. Adjust as required.

(3) Test control settings under operating conditions. Optimize control function to improve plant efficiency.

(4) Obtain the assistance of a fully trained combustion control service engineer as required to calibrate, clean and adjust the controls.

5.10.18 Boiler Safety Controls. Refer to pars. 3.4.3 and 4.3.10.

a) Daily

(1) Inspect safety controls for leaks and cleanliness. Repair and clean immediately.

(2) Blow down the water column, gage glass, and low water fuel cutoff each shift. Test function.

b) Monthly

(1) Inspect safety controls for such problems as dirty switch contacts, defective diaphragms or sensing elements, loose wires, dirty flame scanner lens, or flame rod. Clean or repair immediately.

(2) Test safety controls for proper calibration and operation.

5.10.19 Instrumentation. Refer to par. 3.4.4.

a) Daily

(1) Inspect for leaks. Repair immediately.

(2) Check for proper operation. Report any malfunction. Only trained personnel should place in service, remove from service, calibrate, or maintain instruments.

(3) Inspect for undue vibration, broken glass, lighting, and readability.

b) Annually. Once a year, or more often if necessary, make a thorough inspection of instruments and gages for corrosion, deposits, or other defects. Inspect carefully for the following:

(1) Ruptured or distorted pressure parts.

(2) Incorrect calibrations or adjustments.

(3) Badly worn pins or bushings.

(4) Damaged or burned thermocouple wire insulation.

(5) Leaking or damaged diaphragms, bellows, and gaskets.

(6) Mercury separations in thermometers.

(7) Loose pointers.

(8) Broken balance-arm screws.

(9) Plugged piping or tubing.

(10) Broken or damaged adjustment assemblies.

(11) Defective clockwork mechanism or electric motor operation.

5.10.20 Mechanical Collectors. Refer to par. 3.5.3.

a) Daily

(1) Observe draft gage readings and compare with normal readings for that operating condition.

(2) Check dust level in hopper to ensure hoppers are being emptied on a regular basis.

b) Quarterly. At the time of boiler outage, inspect for the following:

(1) Check gasketed joints for leaks. Replace damaged or defective gaskets as required.

(2) Check the interior of dust collector for caked deposits, corrosion, erosion, loose parts, and other damage. Clean and repair as required.

(3) Check the exterior of dust collector for damaged parts, paint, corrosion, etc. Clean and repair as required.

c) Annually. Paint the entire assembly.

5.10.21 Stacks. Refer to par. 3.6.5.

a) Daily. Inspect for possible defects, leaks, damage, deterioration of lining, cracks, or settlement in foundation. Report promptly any such observation.

b) Quarterly

(1) Make a more thorough examination of the chimney exterior using high powered binoculars quarterly or after every severe storm to look for cracks, spalls, corrosion, loose guy wires (if provided), damaged lightning rod and connectors, loose parts, etc.

(2) Remove soot and fly-ash accumulation from base of stack.

(3) Clean accumulation of soot and fly ash from connecting flues and inspect them for corrosion, erosion, and moisture. If moisture is found, clean more frequently. Remove the cause of water formation if possible.

c) Semiannually. Carefully examine stack supports for corrosion, cracking, or movement of anchor blocks, and proper guy wire tension. Check for corrosion of the ladder.

d) Annually. Clean and inspect the stack internally and externally. Inspect lightning rod tips and ground connections. Paint.

5.10.22 Zeolite Water Softeners

a) Daily

(1) Check for the following:

(a) Flow rates. Service, backwash, regenerant solution, and rinse rates should be carefully maintained.

(b) Adherence to manufacturers instructions for length of time for backwash, regeneration, and rinse operations.

(c) Proper operation of flow regulators, meters, pressure gages, temperature indicators.

(d) Chemical or water leaks.

(e) Hardness of water leaving softener to determine when to regenerate.

(f) Density of brine.

(g) Sump for zeolite carryover.

(2) Establish lubrication requirements and schedule in accordance with manufacturers recommendations.

b) Semiannually

(1) Inspect ion exchange vessel, valves, and piping for corrosion, rust, and peeling of paint.

(2) Drain and internally inspect the ion exchange vessel for loss of resin, dirt, slime, or oil fouling of the bed, uneven bed, or corrosion or erosion in distributor piping.

c) Annually. Calibrate instruments annually or more often as required.

5.10.23 Hot Lime-Soda Softeners

a) Daily

(1) Check for the following:

(a) Alkalinity and hardness several times each day to determine proper chemical additions.

(b) Chemical feed pump for operation.

(c) Plugging of feed lines.

(d) Chemical proportioner for operation.

(e) Temperature of water in reaction tank to verify heater function. Temperature should be greater than 212 degrees F at sea level.

(f) Heater vent for proper venting.

(g) Live steam makeup valve for operation and pressure control.

(h) Pressure differential across filters to determine necessity of backwashing.

(i) Chemical solution tank. Add chemicals as required.

(j) Lines and valves for leakage. Repair or replace immediately.

(2) Blow down reaction tank daily or more often according to sludge accumulation.

(3) Lubricate motors and pumps according to manufacturer,s directions and schedule.

b) Monthly

(1) Clean chemical solution tank. Clean outlet strainer.

(2) Clean and flush chemical feed pump.

(3) Lubricate and adjust chemical proportioner.

c) Semiannually

(1) Open and clean heater. Level and adjust trays and spray nozzles. Clean and drain vent condenser. Repack and reseat live steam regulator valve. Check diaphragm in regulator and replace if worn. Adjust regulator. Repack and reseat water inlet control valve.

(2) Open, examine, clean, and recharge filters in accordance with manufacturer's recommendations.

d) Annually

(1) Drain, open, and clean reaction tank. Repair or replace damaged insulation. If corrosion is excessive on interior of tank, scrape thoroughly and apply protective paint or other similar coating. If exterior is exposed, paint after thoroughly cleaning.

(2) Dismantle, clean, overhaul, and repack pumps.

(3) Repack valves.

(4) Paint exposed surfaces.

5.10.24 Deaerating Heaters and Deaerators

a) Daily

(1) Check for correct operation of relief valve, steam pressure reducing valve, overflow, controls, alarms, and steam pressure and temperature indicators. Report any malfunctions immediately.

(2) Inspect for steam and water leaks. Repair immediately.

b) Annually. Once a year, or more often under severe service conditions, clean the unit and inspect the following:

(1) Spray valves for corrosion, erosion, scaling, and proper seating.

(2) Water discharge nozzles for clogging, corrosion, and wear.

(3) Trays (on tray type units). Remove and inspect for corrosion, warping, and scaling.

(4) Oil separator. Inspect interior of heater for evidence of oil, corrosion, or scaling.

(5) Condition of relief, steam pressure reducing, float, vent, and overflow valves.

(6) Condition of gage glass, controls, alarms, and instruments.

(7) Condition of piping and valves.

(8) Vent condenser. Open and check for corrosion, wear, clogging of tubes, and scaling.

(9) Condition of insulation. Check for cracks and peeling.

5.10.25 Pumps. Refer to par. 3.6.2.

a) Daily. Inspect for the following hourly:

(1) Unusual noise or vibration.

(2) Electric motors for overheating.

(3) Hot bearings.

(4) Abnormal suction or discharge pressures.

(5) Hot stuffing box.

(6) Abnormal leakage through glands/seals.

b) Monthly. Inspect external gear and bearing housings for correct lubricant condition. Establish lubrication requirements and schedule in accordance with manufacturer's recommendations.

c) Annually. Completely disassemble, clean, and inspect the pump. Check for the following:

(1) Excessive clearances.

(2) Hot and cold alignment.

(3) Corrosion or erosion of parts.

(4) Excessive wear of shafts, sleeves, bearings, and seals.

(5) Cracks, scrapes, wastage, or corrosion of gear teeth if provided.

5.10.26 Centrifugal Pumps. Refer to par. 3.6.2.2.

a) Daily. Inspect for the following hourly:

(1) Abnormal vibration and noise.

(2) Abnormal pressure and flow conditions.

(3) Excessive or inadequate packing leakage.

(4) Hot bearings.

(5) Hot stuffing box.

b) Semiannually

(1) Check alignment of pump and driver with the unit at stand-still and normal operating temperature.

(2) Check shaft sleeves for scoring.

(3) Replace packing if required.

(4) Drain the oil from oil-lubricated bearings, flush, and refill with clean oil.

(5) Check grease-lubricated bearings. Do not overgrease the bearings. When adding grease, remove drain plug or use a safety fitting to prevent overgreasing.

c) Annually. Completely disassemble, clean, and inspect the pump. Check for the following:

(1) Wearing ring clearances according to manufacturer's instructions. Diametric clearance between 0.005 and 0.025 inch is usual.

(2) Bearing wear and clearances. Overhaul if required, according to manufacturer's instructions.

(3) Shaft for scoring, corrosion, or wear at seals, and alignment.

(4) Impellers for corrosion, erosion, or excessive wear.

(5) Calibrate pressure gages, thermometers, and flow meters.

(6) Suction and discharge strainers for cleanliness.

5.10.27 Reciprocating Pumps. Refer to par. 3.6.2.3.

a) Daily

(1) Inspect for the following hourly:

(a) Abnormal speed.

(b) Improper stroke length.

(c) Defective operation of lubricator.

(d) Ineffective operation of governor.

(e) Improper action of the air chamber.

(f) Steam and water leaks.

(2) Establish lubrication requirements and schedule in accordance with manufacturer's instructions.

b) Monthly. Inspect for the following:

(1) Scoring of piston rods.

(2) Binding of valve operating mechanism.

(3) Lost motion.

(4) Tilted glands in stuffing boxes.

(5) Defective condition of strainers.

c) Annually

(1) Dismantle the pump once a year or more often if required; clean and inspect the pump.

(2) Check the following in the liquid end:

(a) Condition of valves, springs, and retaining bolts.

(b) Condition of cylinder liner.

(c) Piston rings or packings.

(d) Piston rod packing.

(e) Relief valve, if used, and setting.

(f) Alignment.

(g) Strainers, if used.

(3) Also look for corrosion, erosion, or excessive wear of paints, and for transmission of strains from piping to pump.

(4) Check the following in the steam end:

(a) Condition of pistons and piston rings, slide valves and seals.

(b) Alignment.

(c) Clearance between piston and cylinder liner.

(d) Lubricator.

(e) Governor.

(5) Check for plugged steam passages in steam chest, scoring of shoulders or cylinders, corrosion, erosion, and excessive wear of parts.

(6) Calibrate instruments.

(7) Replace packings.

5.10.28 Steam Injectors. Refer to par. 3.6.2.5.

a) Daily

(1) Inspect for steam and water leaks. Repair as required.

(2) Check for correct feedwater flow.

(3) Check for correct temperature and pressure readings.

(4) Check for erratic overflow.

b) Annually. Dismantle injector. Clean and inspect for the following:

(1) Injectors for corrosion, erosion, excessive wear, and clogging passages. Pay particular attention to nozzles.

(2) Valves for corrosion, excessive wear, and leakage. Check packing.

(3) Piping for corrosion, scaling, and erosion.

(4) Insulation.

5.10.29 Steam Turbines (Noncondensing). Refer to par. 3.6.6. Institute preventive maintenance schedule in accordance with manufacturer's recommendations. The following program is suggested for a single-stage impulse noncondensing steam turbine typically used to drive auxiliary equipment.

a) Daily

(1) Inspect for the following:

(a) Proper oil levels, pressures, and temperatures.

(b) Hot bearings.

(c) Dirty or emulsified oil.

(d) Unusual noise or vibration.

(e) Steam, water, and oil leaks. Repair as necessary.

(f) Proper operation of governor under varying load.

(g) Proper operation of instruments, gages, and throttle valve.

(2) Establish lubrication requirements and schedule in accordance with manufacturer's instructions.

b) Weekly

(1) Blow down steam strainer connection.

(2) Lubricate governor and overspeed trip linkages.

(3) Trip emergency valve by hand trip lever to check its operability.

c) Monthly

(1) Change bearing oil and clean reservoir.

(2) Make visual inspection of governor parts, bearings, and linkage for lost motion.

(3) Check coupling for looseness, wear, and alignment.

d) Annually. Make a thorough inspection of the unit after the first year of operation. Subsequent internal inspection intervals should be based upon operating conditions and the operating record of the machine. Follow manufacturer's recommendations for such inspections. The following may be adopted as guidelines for an annual overhaul:

(1) Dismantle speed governor and check and rectify play in linkage.

(2) Check overspeed trip governor for proper operation. Repair if necessary.

(3) Clean and examine governor valve, bushing, valve stem, etc. Replace stem packing.

(4) Check thrust bearing for end play.

(5) Clean and examine turbine blades and shrouds for cracks, damage, erosion, and debris.

(6) Clean steam strainer.

(7) Clean and inspect packing rings for damage and axial rubs.

(8) Inspect turbine bearings. Change if necessary.

5.10.30 Air Compressors. Refer to par. 3.6.10.

a) Daily

(1) Inspect for the following:

(a) Unusual noise or vibration.

(b) Abnormal temperature and pressure of compressed air, cooling water, or lubricating oil.

(c) Proper operation of unloader.

(d) Hot bearings and stuffing box.

(e) Correct lubricating oil level and oil consistency.

(2) Establish lubrication requirements and schedule in accordance with manufacturer's recommendations.

b) Quarterly. Inspect for the following:

(1) Compressor valves for wear, dirt, and improper seating.

(2) Operation of safety valves.

(3) Belts for tension, wear, and deterioration.

(4) Cleanliness of air intake filter.

(5) Tightness of cylinder head bolts and gaskets.

c) Annually

(1) Check cylinders for wear, scoring, corrosion, and dirt.

(2) Inspect pistons and rings for leakage, wear, scoring, security to the piston rod, and head clearances.

(3) Inspect crank shaft and crank shaft bearings for wear and proper operation.

(4) Check alignment of the compressor with respect to the driver.

5.10.31 Steam Traps. Refer to par. 3.6.11. Establish a comprehensive and coordinated maintenance and inspection program for steam traps, strainers, and separators. As a minimum, the following must be done for central boiler plants.

a) Daily. Inspect the traps, strainers, and separators for the following:

(1) Piping leaks. Repair as necessary.

(2) Correct operation.

(3) Abnormal pressure drop across strainers.

(4) Unusual accumulations of foreign matter in strainer baskets.

(5) Unusual and excessive discharge of condensate and oil from separators.

(6) Damage to insulation at traps. Repair as necessary.

b) Monthly

(1) Blow down steam trap to eliminate dirt accumulations.

(2) Open the air vents on float traps to vent accumulated air.

(3) Test traps for correct operation.

c) Annually

(1) Completely disassemble steam traps and inspect them carefully for the following:

(a) Cracked, corroded, broken, loose, or worn parts.

(b) Excessive wear, grooving, and wire drawing of valves and seats.

(c) Defective bellows, buckets, or floats.

(2) Replace or repair defective gaskets, linkages, and orifices.

(3) Reassemble and test for proper operation.

5.10.32 Electric Motors. Refer to par. 3.6.7.

a) Daily

(1) Inspect for the following:

(a) Cleanliness.

(b) Overheating.

(c) Hot bearings.

(d) Correct lubrication.

(e) Proper operation of instruments and controls.

(f) Unusual noise or vibration.

(g) Continuous or excessive sparking at commutator or brushes.

(h) Loose belts, if provided.

(2) Establish lubrication and motor maintenance in accordance with manufacturer's recommendations.

b) Annually

(1) Inspect squirrel cage rotors for broken or loose bars. Check for loose or broken fan blades.

(2) Thoroughly inspect ball, roller, and sleeve bearings for wear and dirt.

(3) Check and record insulation resistance.

(4) Check windings for dirt, moisture, cracks, and loose wedges.

(5) Check coupling alignment.

5.10.33 Forced Draft (FD) and Induced Draft (ID) Fans. Refer to pars. 3.6.3 and 3.6.4.

a) Daily

(1) Inspect for the following:

(a) Abnormal noises.

(b) Abnormal vibrations.

(c) Overheating of drive.

(d) Abnormal bearing temperature.

(e) Condition of oil and bearing oil level.

(f) Proper flow and temperature of bearing cooling water.

(g) Freedom of damper motion.

(2) Establish lubrication requirements and schedule in accordance with manufacturer's recommendations.

b) Quarterly

(1) Examine water cooling system for corrosion and clogging.

(2) Clean rotor and casing and inspect for corrosion, erosion, and damage. Check clearances between rotor and casing.

(3) Check alignment of shaft and coupling; inspect coupling.

(4) Check condition of foundation and tightness of bearing and foundation bolts. Defective foundation or loose bolts may promote heavy vibration.

(5) Inspect bearings.

c) Annually. Annually, or more often if required, inspect and perform the following maintenance work:

(1) Completely overhaul bearings.

(2) Clean and flush cooling system.

(3) Repair or replace fan blades, as required. After replacing blades, rebalance rotor.

(4) Repair or replace defective parts.

(5) Repair insulation.

5.10.34 Command Inspections. Command inspections are a function of commanding officers. They are made to determine the general condition and effective use of central boiler plant equipment, causes of neglect or carelessness, and need for additional instruction or training of operating personnel. Command inspections may be formal, informal, or spot checks.

5.10.34.1 Procedure. Command inspections are made on accessible central boiler plant equipment at any time that causes the least possible interference with boiler plant routine. Equipment, accessories, and connections are checked during formal inspections; equipment is selected at random for informal inspections and spot checks. Inspectors look for the following:

a) Cleanliness of equipment, pipes, walks, floors, walls, and instruments.

b) Any leaks from water, steam, oil, or air equipment.

c) Neat and orderly storage tools, spare parts, supplies, and fuel.

d) Deficiencies of equipment, working order of parts.

e) Methods and procedures used in hazardous operations.

5.10.34.2 Follow-up. After inspections have been completed, personnel are advised of the deficiencies and irregularities noted.

5.10.35 Technical Inspection. Technical inspections are made to determine the general condition of boiler plant equipment, effectiveness of preventive maintenance, and need for additional instruction or training of maintenance personnel.

5.10.35.1 Procedure. Boiler plant equipment is selected at random and inspected without previous notification so that the overall condition of equipment and efficiency of maintenance personnel can be determined. Technical inspections are preferably made while equipment is being dismantled for routine inspection. In thoroughness, the technical inspection should equal inspections made by insurance or other authorized inspecting agencies. The following are checked at each piece of boiler plant equipment inspected:

a) Items included in command inspections (refer to par. 5.10.34).

b) Adequacy of preventive maintenance as it is being performed.

5.10.35.2 Follow-up. On completion of the technical inspection, the Public Works Officer will take the steps necessary to correct indicated deficiencies in preventive maintenance inspection and service procedures. He will arrange to have any indicated maintenance work done at once.

APPENDIX A

HEAT BALANCE CALCULATIONS

A.1 <u>100-psig Steam Heat Balance</u>. See Figure A-1. (Note that this figure is a duplicate of Figure 1.)

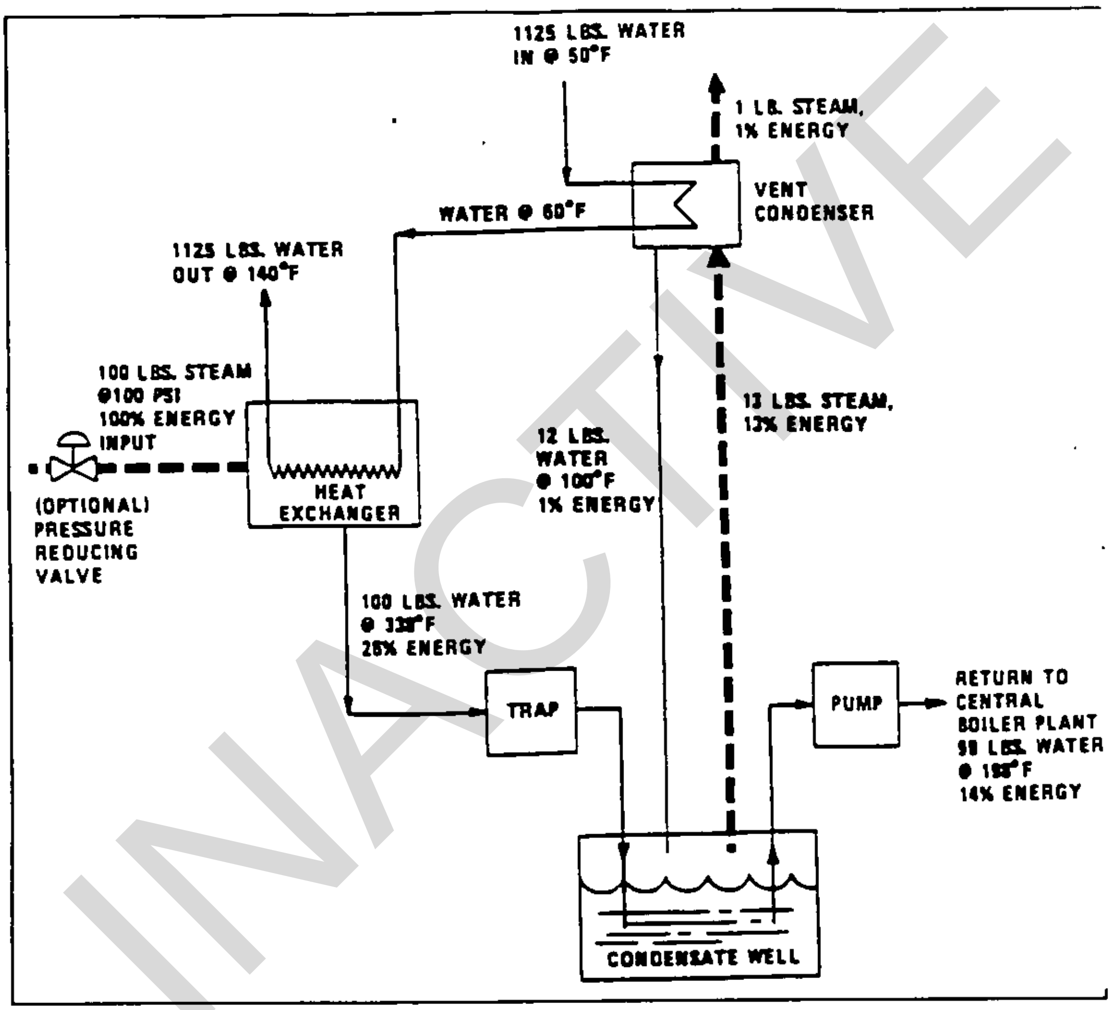


Figure A-1
100-psi Steam Heat Balance

a) The following assumptions have been made:

(1) 100 lb of steam at 100 psig saturated conditions will heat water from 50 to 140 degrees F.

(2) Percent energy is based on the energy in the steam input to the heat exchanger.

(3) Negligible heat is lost from the insulated piping, heat exchanger, vent condenser, or condensate tank.

(4) The vent condenser condenses 91 percent of the flash steam and cools the condensate to 100 degrees F.

(5) The amount of flash steam released is not affected by the water returned from the vent condenser. With this assumption, our example serves to establish flash steam losses for systems without vent condensers.

b) The following steam table enthalphies in Btu/lb have been utilized:

(1) For 100 psig steam hg100 = 1189.7 and hf100 = 309.0

(2) For 0 psig steam hg0 = 1150.4 and hf0 = 180.0

(3) For water at 50 degrees F hf50 = 18.0

(4) For water at 100 degrees F hf100 = 68.0

(5) For water at 140 degrees F hf140 = 107.9

(6) For water at 198 degrees F hf198 = 166.0

c) Percent energy in saturated water at the heat exchanger outlet is calculated as follows:

(1) Base Energy = M x hg100 = 100 lb x 1189.7 Btu

(2) Energy at heater exchanger outlet = M x hf100 = 100 lb x 309.0 Btu/lb = 30,900 Btu

(3) Percent energy at heat exchanger out = (energy at heat exchanger outlet divided by base energy) x 100 = (30,900 divided by 118,970) x 100 = 26 percent

d) Energy from the 100-psig saturated water at 309 Btu/lb and 338 degrees F reaches a new equilibrium after it exits the steam trap at 0 psig, 180 Btu/lb, and 212 degrees F by flashing a portion of its mass to steam at 0 psig. The pounds of flash steam Fs released is calculated as follows:

(1) M x hf100 = Fs x hg0 + (M-Fs) x hf0

(2) 100 lb x 309.0 Btu/lb = Fs = (100 lb-Fs 1150 Btu/lb) = (100 lb-Fs) x 180 Btu/lb

(3) 30,900 Btu 1150 Btu/lb x fs + 18,000 Btu + 180 Btu/lb x Fs

(4) 12,900 Btu = 970 Btu/lb x fs

(5) 13.3 lb = Fs. Use Fs = 13 lb for Figure A-1.

e) Percent energy in flash steam is calculated as follows:

(1) Energy in flash steam = MF x hgO = 13.3 lb x 1150 Btu/lb = 15,295 Btu

(2) Percent energy in flash steam = (energy in flash steam divided by base energy) x 100 (15,295 Btu divided by 118,970 Btu) x 100 = 12.86 percent

(3) Use 13 percent in Figure A-1.

f) Pounds of flash steam lost = 0.09 x 13.3 lb = 1.2 lb. Use 1 lb.

g) Percent energy in flash steam lost = (MFlost x hgO divided by base energy) x 100 = (1.2 lb x 1150 Btu/lb divided by 118,970 Btu) x 100 = 1.16 percent. Use 1 percent.

h) Pound of condensate returned from vent condenser 0.91 x 13.3 lb = 12.1 lb. Use 12 lb.

i) Percent energy in condensate return from vent condenser = (MCR x hf100 divided by base energy) x 100 = 12.1 lb x 68 Btu/lb divided by 118,970 Btu) x 100.69 percent. Use 1 percent.

j) Condensate return to the central boiler plant will have characteristics calculated as follows:

(1) The mass flow to the plant will equal (water in - flash steam out = condensate returned from the vent condenser) = 100 lb - 13.3 lb = 12.1 lb = 98.8 lb. Use 99 lb.

(2) The energy in the condensate well will equal the energy in the 86.7 lb of condensate from the heat exchanger at 180 Btu/lb and 212 degrees F = 12.1 lb of condensate from the vent condenser at 68 Btu/lb and 100 degrees F = (86.7 lb x 180 Btu/lb = 12.1 lb x 68 Btu/lb) = (15,606 + 823) = 16,428 Btu.

(3) The temperature of the condensate can be calculated from the energy of the condensate and the steam tables. Energy in condensate divided by lb of condensate = (16,428 Btu divided by 98.8 lb) = 166.3 Btu/lb. This corresponds to 198 degrees F.

(4) Percent energy in the condensate return is (energy in condensate divided by base energy) x 100 = (16,428 Btu divided by 118,970 Btu) x 100 = 13.8 percent. Use 14 percent.

k) The amount of water heated from 50 to 140 degrees F in the heat exchanger and vent condenser is calculated as follows:

(1) The energy available for heating the water equals the energy in the incoming steam (base energy) minus the energy lost by vented steam (subpar. f) minus energy return (subpar. i) = (118,970 Btu - 1,380 Btu - 16,428 Btu) = 101,162 Btu.

(2) The energy required to heat water from 50 to 140 degrees Fis (hf140 - hf50) = (107.9 Btu/lb) - 18 Btu/lb = 89.9 Btu/lb.

(3) The pounds of water heated is (101,162 Btu divided by 89.9 Btu/lb) = 1,125 lb.

l) The temperature at the outlet of the vent condenser is calculated:

(1) MFcond. x (hg0-hf0) divided by Mw = 12.1 lb x (1150.4 Btu/lb - 180 Btu/lb) divided by 1125 lb = 10.44 Btu/lb.

(2) h50 + 10.44 = 18 Btu/lb + 10.44 Btu/lb = 28.44 Btu/lb. From the steam tables this corresponds to a temperature of 60 degrees F.

A.2 <u>15-psig Steam Heat Balance</u>. See Figure A-2. (This figure is a duplicate of Figure 2.) This heat balance is based on the same assumptions listed in par. A.1 except now 15-psig saturated steam is utilized for heating water.

a). The following steam table enthalphies in Btu/lb have been utilized:

(1) For 15 psig steam hg15 = 1164.0 and hf15 = 219.0

(2) For water at 50 degrees F hf50 = 18.0

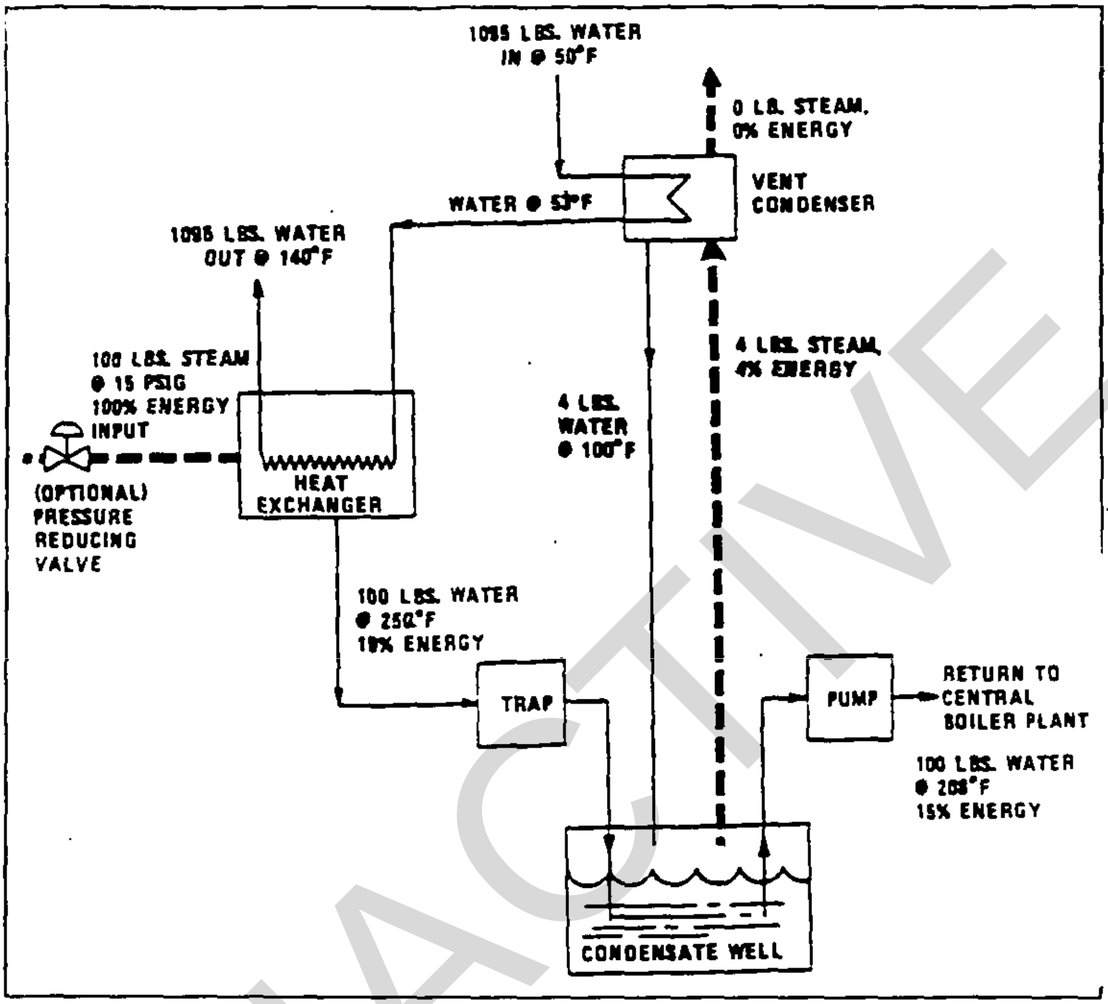


Figure A-2
15-psi Steam Heat Balance

(3) For water at 140 degrees F hf140 = 107.9

(4) For water at 208 degrees F hf208 = 176.0

b) Percent energy in saturated water at the heat exchanger outlet is calculated as follows:

(1) Base Energy = M x hg15 = (100 lb x 1164.0 Btu/lb = 116,400 Btu

(2) Energy at heat exchanger outlet = M x hf15 = (100 lb x 219.0 Btu/lb) = 21,900 Btu

(3) Percent energy at heat exchanger outlet = (Energy at heat exchanger outlet divided by base energy) x 100 = (21,900 divided by 116,400) x 100 = 18.8 percent. Use 19 percent.

c) Energy from the 15-psig saturated water at 219 Btu/lb and 250 degrees F reaches a new equilibrium after it exits the steam trap at 0 psig, 180 Btu/lb, and 212 degrees F by flashing a portion of its mass to steam at 0 psig. The pounds of flash steam Fs released is calculated as follows:

(1) M x hf15 = Fs x hg0 + (M-Fs) x hf0

(2) 100 lb x 219.0 Btu/lb = Fs x 1150 Btu/lb = (100 lb - Fs) x 180 Btu/lb

(3) 21,900 Btu = 1150 Btu/lb x Fs + 18,000 Btu - 180 Btu/lb x F

(4) 3,900 Btu = 970 Btu lb x Fs

(5) 4.0 lb = Fs

d) Percent energy in flash steam is calculated as follows:

(1) Energy in flash steam = MF x hg0 = 4.0 lb x 1150 Btu/lb =4,600 Btu

(2) Percent energy in flash steam = (energy in flash steam divided by base energy) x 100 = (4,600 Btu divided by 116,400 Btu) x 100 = 4.0 percent.

e) Pounds of flash steam lost = 0.09 x 4.0 lb = 0.36 lb.

f) Percent energy in flash steam lost = (Flost x hg0 divided by base energy) x 100 = (.36 lb x 1150 Btu/lb divided by 116,400 Btu) x 100 = 0.36 percent.

g) Pound of condensate returned from vent condenser = 0.91 x 4.0 lb = 3.64 lb. Use 3.6 lb.

h) Percent energy in condensate return from vent condenser = (MMCR x hf100 divided by base energy) x 100 = 3.64 lb x 68 Btu/lb divided by 116,400 Btu) x 100 = 0.21 percent

i) Condensate return to the central boiler plant will have characteristics calculated as follows:

(1) The mass flow to the plant will equal (water in - flash steam out = condensate returned from the vent condenser) = 100 lb - 4.0 lb + 3.6 lb = 99.6 lb. Use 100 lb.

(2) The energy in the condensate well will equal the energy in the 96.0 lb of condensate from the heat exchanger at 180 Btu/lb and 212 degrees F + 3.6 lb of condensate from the vent condenser at 68 Btu/lb and 100 degrees F = (96.0 lb x 180 Btu/lb + 3.6 lb x 68 Btu/lb) + (17,280 + 245) = 17,525 Btu.

(3) The temperature of the condensate can be calculated from the energy of the condensate and the steam tables. Energy in condensate divided by pounds of condensate = (17,525 Btu divided by 99.6 lb) = 176 Btu/lb. This corresponds to 208 degrees F.

(4) Percent energy in the condensate return is (energy in condensate divided by base energy) x 100 = (17,525 Btu divided by 116,400 Btu) x 100 = 15 percent.

j) The amount of water heated from 50 to 140 degrees F in the heat exchanger and vent condenser is calculated as follows:

(1) The energy available for heating the water equals the energy in the incoming steam (base energy) minus the energy lost by vented steam (subpar. f) minus energy return (subpar. i) = (116,400 Btu - 414 Btu - 17,525 Btu) = 98,461 Btu.

(2) The energy required to heat water from 50 to 140 degrees F is ($hf140$ - $hf50$) = (107.9 Btu/lb - 18 Btu/lb) = 89.9 Btu/lb.

(3) The pounds of water heated is (98,461 Btu divided by 89.9 Btu/lb) = 1,095 lb. Use 1,100 lb.

k) The temperature at the outlet of the vent condenser is calculated:

(1) MFcond. x ($hg0$ - $hf0$) divided by Mw = 3.64 lb x (1150.4 Btu/lb - 180 Btu/lb) divided by 1,095 lb = 3.22 Btu/lb.

(2) $hf50$ + 3.22 = 18 Btu/lb + 3.22 Btu/lb = 21.22 Btu/lb. From the steam tables this corresponds to a temperature of 53 degrees F.

A.3 <u>High Temperature Water (HTW) Heat Balance</u>. See Figure A-3 (identical to Figure 3).

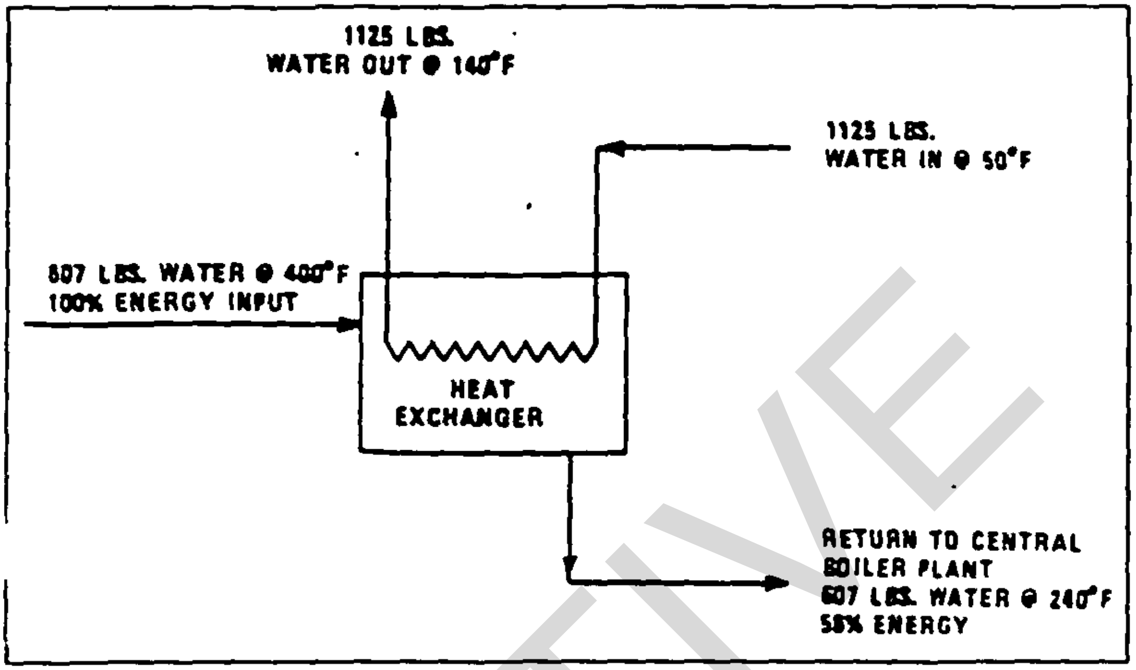


Figure A-3
High Temperature Water (HTW) Heat Balance

a) The following assumptions are made so we can compare the HTW system with the 100-psig steam system:

(1) 1126 lb of water will be heated from 50 to 140 degrees F.

(2) The heat exchanger will be designed to heat the water with a 400 degrees F inlet and 240 degrees F outlet HTW.

(3) Negligible heat is lost from the insulated piping an heat exchanger.

b) The following steam table enthalphies in Btu/lb have been utilized:

(1) For water at 50 degrees F hf50 = 18.0

(2) For water at 140 degrees F hf140 = 107.9

(3) For water at 240 degrees F hf240 = 208.3

(4) For water at 400 degrees F hf400 = 375.0

c) Energy added to water is calculated: Mw x (hf140 - hf50) = 1125 lb x (107.9 Btu/lb - 18.0 Btu/lb) = 101,138 Btu.

d) High temperature water (HTW) flow rate is calculated by the following energy balance:

(1) Energy added = Energy released by HTW

(2) 101,138 Btu = MHTW x (hf400 - hf240) = MHTW x (375.0 Btu/lb - 208.3 Btu/lb)

(3) MHTW = 606.7 lb. Use 607 lb.

e) Percent energy in water returned to the central boiler plant is calculated as follows:

(Energy in water returned divided by energy in water supplied) x 100 = (MHTW x hf400) x 100 = 606.7 lb x 208.3 Btu/lb divided by 606.7 lb x 375 Btu/lb) x 100 = 55.5 percent. Use 56 percent.

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NOTE: THE FOLLOWING REFERENCED DOCUMENTS FORM A PART OF THIS HANDBOOK TO THE EXTENT SPECIFIED HEREIN. USERS OF THIS HANDBOOK SHOULD REFER TO THE LATEST REVISIONS OF CITED DOCUMENTS UNLESS OTHERWISE DIRECTED.

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NFPA 8503	Standard for Pulverized Fuel Systems.

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GLOSSARY

Abatement. The reduction in degree of intensity of pollution.

Absolute pressure. Pressure above zero pressure, the sum of the gage and atmospheric pressures.

AC. Alternating current.

Actual cubic foot. A cubic foot referring to the actual temperature and pressure of the gas. Usually abbreviated ACF.

Actual volume. The volume of a gas at its actual temperature and pressure. In the United States, this is normally expressed as actual cubic feet.

Actuating signal. A signal which causes a control element to function or position itself accordingly.

Adiabatic temperature. The theoretical temperature that would be attained by the products of combustion provided the entire chemical energy of the fuel, the sensible heat content of the fuel, and combustion air above the datum temperature were transferred to the products of combustion. This assumes:

1. Combustion is complete.
2. There is no heat loss.
3. There is no dissociation of the gaseous compounds.
4. Inert gases play no part in the reaction.

Aeration. To circulate oxygen through a substance.

Afterburner. An air pollution control device that removes undesirable organic gases by incineration.

Aftercooler. A device used for lowering the temperature of a fluid. Typically used on air compressors or to reduce the temperature of boiler blowoff discharge before it enters the building drain.

Agglomerating. A caking characteristic of a coal.

Air atomizing oil burner. A burner for firing oil in which the oil is atomized by compressed air which is forced into and through one or more streams of oil, breaking the oil into a fine spray.

Air blast. The flow of air at a high velocity, usually for a short period.

Air-cooled wall. A refractory wall of hollow construction through which air passes.

Air deficiency. Insufficient air in an air-fuel mixture to supply the oxygen theoretically required for complete combustion of the fuel.

Air dried. Condition of coal after sample has been exposed to 85 to 95 degrees F air until weight is constant.

Air-fuel ratio. The ratio of the weight, or volume of air to fuel.

Air infiltration. The leakage of air into a setting, furnace, boiler, or duct.

Air moisture. The water vapor suspended in the air.

Air monitoring. See Monitoring.

Air pollution. The presence of contaminant substances in the air that do not disperse properly and interfere with human health.

Air port. An opening through which air passes.

Air preheater or air heater. A heat exchanger that transfers heat from a high temperature medium such as hot gas, or steam, to an incoming air stream.

Air-puff blower. An automatically controlled soot blower removing ash, refuse, or soot from heat-absorbing surfaces.

Air purge. The removal of undesired matter by replacement with air.

Air quality control region. An area designated by the Federal Government in which communities share a common air pollution problem, sometimes involving several states.

Air quality standards. The level of pollutants prescribed by law that cannot be exceeded during a specified time in a defined area.

Air resistance. The opposition offered to the passage of air through any flow path.

<u>Air vent</u>. A valved opening for venting air from the top of the highest drum of a boiler or pressure vessel.

<u>Alarm</u>. A suitable horn, bell, light or other device which when operated will give suitable notice of malfunction or off-normal condition.

<u>Allowable working pressure</u>. The maximum pressure for which the boiler was designed and constructed; the maximum gage pressure on a complete boiler and the basis for setting of the pressure relieving devices protecting the boiler.

<u>Ambient air</u>. The air that surrounds the equipment.

<u>Ambient temperature</u>. The temperature of the air surrounding the equipment.

<u>Analysis, proximate</u>. Analysis of a solid fuel determining moisture, volatile matter, fixed carbon and ash expressed as percentage of the total weight of sample.

<u>Analysis, ultimate</u>. Chemical analysis of a fuel determining carbon, hydrogen, sulfur, nitrogen, chlorine, oxygen, and ash as percentages of the total weight of sample.

<u>Anthracite</u>. ASTM coal classification by rank: dry fixed carbon 92 percent or more and less than 98 percent; and dry volatile matter 8 percent or less and more than 2 percent on a mineral-matter-free basis.

<u>Aquifer</u>. An underground bed or layer of earth, gravel, or porous stone that contains water.

<u>Area source</u>. In air pollution, any small individual fuel combustion source, including vehicles. A more precise legal definition is available in Federal Regulations.

<u>Arch-furnace</u>. A substantially horizontal structure extending into the furnace, to serve as a deflector of the gases.

<u>As-fired fuel</u>. Fuel in the condition as fed to the fuel burning equipment.

<u>Ash</u>. The incombustible solid matter in fuel.

<u>Ash bed</u>. A layer of refuse left on grates or deposited on a furnace floor after the fuel is burned.

Ash-free basis. The method of reporting fuel analysis whereby ash is deducted and other constituents are recalculated to total 100 percent.

Ash gate. A gate or valve through which refuse is removed from an ash pit or soot hopper.

Ash sluice. A trench or channel used for transporting refuse from ash pits to a disposal point by means of water.

Aspect ratio. The ratio of width to depth in a rectangular duct or elbow. Used in calculating resistance to flow.

Aspirating air. Compressed air supplied at pressures sufficiently above furnace pressure to prevent flow of combustion gases from escaping the boiler.

Aspirating burner. A burner in which the fuel in a gaseous or finely divided form is burned in suspension, the air for combustion being supplied by bringing into contact with the fuel air drawn through one or more openings by the lower static pressure created by the velocity of the fuel stream.

Atmosphere. The body of air surrounding the earth.

Atmospheric pressure. The barometer reading of pressure exerted by the atmosphere; at sea level, 14.7 pounds per square inch or 29.92 inches of mercury.

Atomizer. A device by means of which a liquid is reduced to a very fine spray.

Attemperator. Apparatus for reducing and controlling the temperature of a superheated vapor or of a fluid. Also called desuperheater.

Automatic controller. A device which causes the difference between a measured property and its set point to diminish.

Automatic lighter or igniter. A means for starting ignition of fuel without manual intervention. Usually applied to liquid, gaseous or pulverized fuel (see Igniter).

Auxiliary air. Additional air, either hot or cold, which may be introduced into the exhauster inlet or burner lines to increase the primary air at the burner.

Available draft. The draft which may be utilized to cause the flow of air for combustion or the flow of products of combustion.

Availability factor. The fraction of the time during which the unit is in operable condition.

Axial fan. Consists of a propeller or disc wheel within a cylinder discharging the air parallel to the axis of the wheel.

Background level. In air pollution, the level of pollutants present in ambient air from natural sources.

Backing ring. A ring of steel or other material placed behind the welding groove when joining tubes or pipes by welding, to confine the weld metal.

Bacharach number. See Smoke Spot Number.

Baffle. A plate or wall for deflecting gases or liquids.

Bag. 1. A deep bulge in the bottom of the shell or furnace of a firetube boiler.

2. A single fabric filter unit in a baghouse.

Baghouse. An air pollution abatement device used to trap particulates by filtering gas streams through large fabric bags usually made of glass fibers.

Balanced draft. The maintenance of a fixed value of draft in a furnace at combustion rates by control of incoming air and outgoing products of combustion.

Banking. Burning solid fuels on a grate at rates sufficient to maintain ignition only.

Banking (live). Operating boilers at combustion rates just sufficient to maintain normal operating pressure under conditions of no load demand.

Bare tube wall. A furnace wall having bare tubes.

Barometric pressure. Atmospheric pressure as determined by a barometer. Usually expressed in inches of mercury.

Base load. The term applied to that portion of a boiler plant load that is essentially constant for long periods.

Battery setting. A type of setting in which two or more boilers share common division walls.

Beaded tube-end. The rounded end of a rolled tube when the tube metal is formed over against the sheet in which the tube is rolled.

Belled tube-end. See Flared Tube-End.

Bellows seal. A seal in the shape of a bellows used to prevent air or gas leakage.

Bin system. A system in which fuel is pulverized, stored in bins, and subsequently withdrawn through feeders to the burners in amounts sufficient to satisfy load demands.

Bituminous coal. ASTM coal classification by rank on a mineral-matter-free basis and with bed moisture only.

1. Low volatile: dry fixed carbon 78 percent or more, and less than 86 percent; and dry volatile matter 22 percent or less, and more than 14 percent.

2. Medium volatile: dry fixed carbon 69 percent or more, and less than 78 percent; and dry volatile matter 22 percent or less, and more than 31 percent.

3. High volatile:

(a) Dry fixed carbon less than 69 percent, and dry volatile matter more than 31 percent Btu value equal to or greater than 14,000 moist, mineral- matter-free basis.

(b) Btu value 13,000 or more and less than 14,000 moist, mineral-matter-free basis.

(c) Btu value 11,000 or more and less than 13,000 moist, mineral-free basis commonly agglomerating, or 8,300 to 11,500 Btu agglomerating.

Blank head. A head, without a manhole, at the end of a boiler drum.

Blind nipple. A nipple, or a short piece of pipe or tube, closed at one end.

Blister. A raised area on the surface of solid metal produced by pressure thereon while the metal is hot and plastic due to overheating.

Block. Usually a rectangular-shaped casting of metal or of high heat-conducting material made to fit closely on or cast to furnace side walls. Also a refractory shape used as a furnace lining and cooled by air.

Blowback. The difference between the pressures at which a safety valve opens and closes, usually about 3 percent of the opening pressure.

Blow down valve. A valve generally used to continuously regulate concentration of solids in the boiler (not a drain valve).

Blower. A fan used to force air under pressure. Typically used to force air through a pulverizer or to force primary air through an oil or gas burner register.

Blowhole. A local area in a burning fuel bed through which a disproportionately large quantity of air passes.

Blowoff separator. A vented and drained container equipped with baffles or an apparatus for the purpose of separating moisture from flash steam as it passes through the vessel.

Blowoff valve. A specially designed, manually operated, valve connected to the boiler for the purpose of reducing the concentration of solids in the boiler or for draining purposes.

Boiler. A closed vessel in which water is heated, steam is generated, steam is superheated, or any combination thereof, under pressure or vacuum by the application of heat. The term does not include such facilities that are an integral part of a continuous processing unit but does include units supplying heating or vaporizing liquids other than water where these are separate from processing systems and are complete within themselves.

1. High pressure - a boiler furnishing steam at pressures in excess of 15 pounds per square inch or hot water at temperatures in excess of 250 degrees F or at pressures in excess of 160 pounds per square inch.

2. Low pressure - a boiler furnishing hot water at pressures not exceeding 160 pounds per square inch or at temperatures not more than 250 degrees F or steam at pressures not more than 15 pounds per square inch.

3. High temperature water (HTW) - a water heating boiler operating at a pressure exceeding 160 psig or temperatures exceeding 250 degrees F.

4. Water tube - a boiler in which the tubes contain water and steam, the heat being applied to the outside surface.

5. Bent tube - a water tube boiler consisting of two or more drums connected by tubes, practically all of which are bent near the ends to permit attachment to the drum shell on radial lines.

6. Horizontal - a water tube boiler in which the main bank of tubes are straight and on a slope of 5 to 15 degrees from the horizontal.

7. Sectional header - a horizontal boiler of the longitudinal or cross drum type, with the tube bank comprised of multiple parallel sections, each section made up of a front and rear header connected by one or more vertical rows of generating tubes and with the sections or groups of sections having a common steam drum.

8. Box heater - a horizontal boiler of the longitudinal or cross drum type consisting of a front and rear inclined rectangular header connected by tubes.

9. Cross drum - a sectional header or box boiler in which the axis of the horizontal drum is at right angles to the center lines of the tubes in the main bank.

10. Longitudinal drum - a sectional header or box header boiler in which the axis on the horizontal drum or drums is parallel to the tubes in a vertical plane.

11. Low head - a bent tube boiler having three drums with relatively short tubes in a vertical plane.

12. Firetube - a boiler with straight tubes, which are surrounded by water and steam and through which the products of combustion pass.

13. Horizontal return tubular - a firetube boiler consisting of a shell, with tubes inside the shell attached to both end closures. The products of combustion pass under the bottom half of the shell and return through the tubes.

14. Locomotive - a horizontal firetube boiler with an internal furnace the rear of which is a tube sheet directly attached to a shell containing tubes through which the products of combustion leave the furnace.

15. Horizontal firebox - a firetube boiler with an internal furnace the rear of which is a tube sheet directly attached to a shell containing tubes. The first-pass bank of tubes is connected between the furnace tube sheet and the rear head. The second-pass bank of tubes, passing over the crown sheet, is connected between the front and rear end closures.

16. Refractory lined firebox - a horizontal firetube boiler, the front portion of which sets over a refractory or water-cooled refractory furnace, the rear of the boiler shell having an integral or separately connected section containing the first-pass tubes through which the products of combustion leave the furnace, then returning through the second-pass upper bank of tubes.

17. Vertical - a firetube boiler consisting of a cylindrical shell, with tubes connected between the top head and the tube sheet which forms the top of the internal furnace. The products of combustion pass from the furnace directly through the vertical tubes.

18. Submerged vertical - the same as the vertical type above, except that by use of a water leg construction as part of the upper tube sheet, it is possible to carry the waterline at a point above the top ends of the tubes.

19. Scotch boiler - a cylindrical steel shell with one or more cylindrical internal steel furnaces located generally in the lower potion and with a bank or banks (passes) of tubes attached to both end closures.

In Stationary Service, the boilers are either of the dry-back, or wet-back type (see Boiler Dry-Back and Boiler Wet-Back). In Marine Service, the boilers are generally of the wet-back type.

<u>Boiler blowoff piping</u>. The piping connections from the boiler to the blowoff valves.

<u>Boiler blowoff tank</u>. A vented and drained container into which water is discharged above atmospheric pressure from a boiler blowoff line. Also called flash tank.

<u>Boiler convection bank</u>. A group of two or more rows of tubes forming part of a water boiler circulatory system and to which heat is transmitted mainly by convection from the products of combustion.

<u>Boiler dry-back</u>. The baffle provided in a firetube boiler joining the furnace to the second pass. Constructed to be separate from the pressure vessel and constructed of heat-resistant material (generally refractory and insulating material).

<u>Boiler efficiency</u>. The ratio of the net energy output of the boiler fluid divided by the input of the primary energy source(s).

<u>Boiler horsepower</u>. The evaporation of 34-1/2 pounds of water per hour from a temperature of 212 degrees F into dry saturated steam at the same temperature. Equivalent to 33,472 Btu/hr.

<u>Boiler wet-back</u>. A completed water-cooled baffle provided in a firetube boiler or water leg construction covering the rear end of the furnace and tubes. The products of combustion leaving the furnace are turned in this area and enter the tube bank.

<u>Bond</u>. A retaining or holding high-temperature cement for making a joint between brick or adjacent courses of brick.

<u>Bone coal</u>. Coal from that part of a seam which has a very high ash content. In connection with anthracite, any material which has between 40 and 75 percent fixed carbon.

<u>Booster fan</u>. A device for increasing the pressure of flow of a gas (see Blower).

<u>Boss</u>. A raised portion of metal of small area and limited thickness on flat or curved metal surfaces.

<u>Bottom air admission</u>. A method of introducing air to a chain or traveling grate stoker under the stoker.

<u>Breeching</u>. A duct for the transport of the products of combustion between parts of a steam generating unit or to the stack.

<u>Bridgewall</u>. A wall in a furnace over which the products of combustion pass.

<u>Bridging</u>. The accumulation of noncombustible matter and slag partially or completely blocking spaces or orifices between heat absorbing tubes.

British thermal unit. The mean British thermal unit is 1/180 of the heat required to raise the temperature of 1 pound of water from 32 to 212 degrees F at a constant atmospheric pressure. It is about equal to the quantity of heat required to raise 1 pound of water 1 degree F (abbreviated Btu).

Broken coal. Anthracite coal size - through 4-3/8 inches, over 3-1/4-inch round mesh screen.

Brown coal. A former coal classification according to rank now included in Lignite B.

Buckstay spacer. A spacer for separating a pair of channels which are used as a buckstay.

Buckwheat. Anthracite coal size:

1. Number 1 (Buckwheat) - through 9/16-inch, over 5/16-inch round mesh screen.

2. Number 2 (Rice) - through 5/15-inch, over 3/16-inch round mesh screen.

3. Number 3 (Barley) - through 3/16-inch, over 3/32-inch round mesh screen.

4. Number 4 - through 3/32-inch, over 3/64-inch round mesh screen.

5. Number 5 - through 3/64-inch, round mesh screen.

Bulge. A local distortion or outward swelling caused by internal pressure on a tube wall or boiler shell while overheated. Also applied to similar distortion of a cylindrical furnace due to external pressure when overheated provided the distortion is of a degree that can be driven back.

Bump. A raised or flattened portion of a boiler drum head or shell formed by fabrication, generally used for nozzle or pipe attachments.

Bunker C oil. Residual fuel oil (No. 6 fuel oil) of high viscosity commonly used in marine and stationary steam power plants.

Burner. A device for the introduction of fuel and air into a furnace at the desired velocities, turbulence, and concentration to establish and maintain proper ignition and combustion of the fuel.

1. Automatic burner - a burner that stops and starts automatically.

2. Burner, automatically ignited - one where main burner fuel is automatically turned on and ignited.

3. Burner, manually ignited - one where fuel to the main burner is turned on only by hand and ignited under supervision.

4. Burner, forced draft - a burner where air for combustion is supplied above atmospheric pressure.

5. Burner, natural draft type - a burner which depends principally upon the natural draft to induce into the burner the air required for combustion.

Burner windbox. A plenum chamber around a burner in which air pressure is maintained to ensure proper distribution and discharge of secondary air.

Burner windbox pressure. The air pressure maintained in the windbox or plenum chamber.

Buttstrap. A narrow strip of boiler plate overlapping the joint of two butted plates, used for connecting by riveting.

Bypass. A passage for a fluid, permitting a portion or all of the fluid to flow around certain heat-absorbing surfaces over which it would normally pass.

Caking. Property of certain coals to become plastic when heated and form large masses of coke.

Calorific value. The number of heat units liberated per unit of a fuel burned in a calorimeter under prescribed conditions.

Calorimeter. Apparatus for determining the calorific value of a fuel.

Capacity. The manufacturer's stated output rate over a period of time for which the boiler is designed to operate.

Capacity factor. The total output over a period of time divided by the product of the boiler capacity and the time period.

Carbon. An element. The principal combustible constituent of most fuels.

<u>Carbon conversion efficiency</u>. An indictor of the degree to which the fuel carbon compounds are oxidized to CO_2.

<u>Carbonization</u>. The process of converting coal to carbon by removing other ingredients.

<u>Carbon loss</u>. The loss representing the unliberated thermal energy occasioned by failure to oxidize some of the carbon in the fuel.

<u>Carbon residue</u>. The carbon residue of a fuel is a measure of the carbonaceous material left after the volatile compounds are vaporized in the absence of air.

<u>Casing</u>. A covering of sheets of metal or other material such as fire-resistant composition board used to enclose all or a portion of a steam generating unit.

<u>Centrifugal collector</u>. A mechanical system using centrifugal force to remove aerosols from a gas stream or to dewater sludge.

<u>Centrifugal fan</u>. A type of fan using a rotor or wheel within a scroll type housing and discharging the air at a right angle to the axis of the wheel.

<u>Chain grate stoker</u>. A stoker which has a moving endless chain as a grate surface, onto which coal is fed directly from a hopper.

<u>Checker work</u>. An arrangement of alternately spaced brick in a furnace with openings through which air or gas flows.

<u>Chemical feed pipe</u>. A pipe inside a boiler drum through which chemicals for treating the boiler water are introduced.

<u>Chimney lining</u>. The material which forms the inner surface of the chimney.

<u>Cinder</u>. Particles of partially burned fuel from which volatile gases have been driven off, which are carried from the furnace by the products of combustion.

<u>Circular burner</u>. A liquid, gaseous, or pulverized fuel burner having a circular opening through the furnace wall.

<u>Circulator</u>. A pipe or tube to pass steam or water between boiler drums or headers. Also used to apply to tubes connecting headers of horizontal water tube boilers with drums.

<u>Class</u>. Rank of coal.

Cleanout door. A door placed so the accumulated refuse may be removed from a boiler setting, flue or chimney.

Clinker. A hard congealed mass of fuel matter fused in the furnace, usually slag.

Clinker chill. Any water-cooled wall surface, the major portion of which is in contact with the edges of the fuel bed.

Clinkering. The formation of clinkers.

CMMS. Computerized Maintenance Management System.

Coal. Solid hydrocarbon fuel formed by ancient decomposition of woody substance under conditions of heat and pressure.

Cogeneration. The production of steam (or hot water) and/or electricity for use by multiple users generated from a single source.

Coking. The conversion by heating carbonaceous fuel, particularly certain bituminous coals, in the absence or near absence of air to a coherent, firm, cellular carbon product known as coke.

Coking plate. A plate adjacent to a grate through which no air passes and on which coal is placed for distilling the volatiles before the coal is moved onto the grate.

Combustible. The heat producing constituents of a fuel.

Combustible in refuse. Combustible matter in the solid refuse resulting from the incomplete combustion of fuel. It may occur in the flue dust discharge from the stack or collected in hoppers, as well as in ash-pit refuse.

Combustible loss. The loss representing the unliberated thermal energy occasioned by failure to oxidize completely some of the combustible matter in the fuel.

Combustion. The rapid chemical combination of oxygen with the combustible elements of a fuel resulting in the production of heat.

Combustion chamber. The space in which combustion takes place. Also called a furnace.

Combustion efficiency. A measure of the completeness of oxidation of fuel compounds. It is usually quantified as the ratio of actual heat release by combustion to the maximum heat of combustion available.

Combustion (flame) safeguard. A system for sensing the presence or absence of flame and indicating, alarming or initiating control action.

Compartment. One of two or more air chambers in a windbox or under the stoker from which air can be passed in controlled quantities.

Complete combustion. The complete oxidation of the combustible constituents of a fuel.

Conduction. The transmission of heat through and by means of matter unaccompanied by any obvious motion of the matter.

Conductivity. The amount of heat (Btu) transmitted in one hour through one square foot of a homogeneous material 1-inch thick for a difference in temperature of 1 degree F between the two surfaces of the material.

Constant ignition. A pilot, usually gas, that remains lighted at full volume whether the main burner is in operation or not.

Continuous blowdown. The uninterrupted removal of concentrated boiler water from a boiler to control total solids concentration in the remaining water.

Control. Any manual or automatic device for the regulation of a machine such as a boiler, to keep it at normal operation. If automatic, the device is motivated by variations in temperature, pressure, water level, time, light, or other influences.

Control element. A device (usually a valve or damper) which produces a physical change according to an actuating signal.

Control, limit. An automatic safety control responsive to changes in liquid level, pressure, or temperature or position for limiting the operation of the controlled equipment.

Control, safety. Control (including relays, switches, and other auxiliary equipment used in conjunction therewith to form a safety control system) which is intended to prevent unsafe operation of the controlled equipment.

Control unit. A device designed to regulate the fuel, air, water, or electrical supply to the controlled equipment. It may be automatic, semi-automatic, or manual.

Control valve. A valve used to control the flow of air, oil, or gas.

Convection. The transmission of heat by the circulation of a liquid or a gas such as air. Convection may be natural or forced.

Corner firing. A method of firing liquid, gaseous, or pulverized fuel in which the burners are located in the corners of the furnace. Also called tangential firing.

Corrosion. The wasting away of metals due to chemical action in a boiler usually caused by the presence of oxygen, carbon dioxide, or an acid.

Cracking. The thermal decomposition of complex hydrocarbons into simpler compounds or elements.

Cricket. A wedge-shaped member of refractory or other construction used to subdivide a channel into hopper-shaped pockets.

Criteria. The standards that the Environmental Protection Agency (EPA) has established for certain pollutants, which not only limit the concentration, but also set a limit to the number of violations per year.

Crown sheet. In a firebox boiler, the plate forming the top of the furnace.

Cross limiting. A feature of some full metering systems which, by means of high-low select controls, prevents fuel flow from exceeding airflow under conditions of load changes or flow changes of either air or fuel.

Crude oil. Unrefined petroleum.

Crusher. A machine to reduce lumps of solid fuel to a desired maximum size.

Cyclone. A device which uses centrifugal action for separation of materials of different densities.

Cyclone collector. A device that uses centrifugal force to pull large particles from polluted air.

Damper. A device for introducing a variable resistance for regulating the volumetric flow of gas or air.

1. Butterfly type - a single blade damper pivoted about its center.

2. Curtain type - a damper, composed of flexible material, moving in a vertical plane as it is rolled.

3. Flap type - a damper consisting of one or more blades each pivoted about one edge.

4. Louvre type - a damper consisting of several blades each pivoted about its center and linked together for simultaneous operation.

5. Slide type - a damper consisting of a single blade which moves substantially normal to the flow.

Dead plate. A grate or plate through which no air passes (see Coking Plate).

Deaeration. Removal of air and gases from boiler feedwater prior to its introduction to a boiler.

Deflector. A device for changing direction of a stream of air or of a mixture of pulverized fuel and air.

Degasification. Removal of air and gases from boiler feedwater prior to its introduction to a boiler.

Degree of superheat. The number of degrees between steam temperature and saturated temperature corresponding to the steam pressure.

Delayed combustion. A continuation of combustion beyond the furnace (see also Secondary Combustion).

Demineralizer. An ion exchange device used to remove solids from water.

Derivative (rate) controller. A controller in which the output signal level is directly proportional to the rate of change of the error. This type of control is rarely used without integral and/or proportional control modes. Derivative control tends to be hypersensitive to noise and other high frequency disturbances.

Design load. The load for which steam generating unit is designed, usually considered the maximum load to be carried.

Design pressure. The pressure used in the design of a boiler for the purpose of determining the minimum permissible thickness or physical characteristics of the different parts of the boiler.

Design steam temperature. The temperature of steam for which a boiler, superheater, or reheater is designed.

De-slag. The removal of slag which has adhered to heat-absorbing surfaces.

Desuperheater. See Attemperator.

Dew point. The temperature at which condensation starts.

Diagonal stay. A brace used in firetube boilers between a flat head or tube sheet and the shell.

Diaphragm. A partition of metal or other material placed in a header, duct, or pipe to separate portions thereof.

Differential (on/off control). The difference between "cut-in" and "cut-out" points.

Diffuser. A device used to distribute airflow within the burner to promote stable ignitions and/or enhance fuel/air mixing. Also called impeller.

Direct-fired circulating system. A system in which fuel is pulverized in proportion to the load demand and conveyed directly from the pulverizers to the burners.

Digital control. A control system that utilizes a microprocessor or computer to process and determine control decisions. Analog signals are converted to digital words, processed, and then converted to analog signals to ultimately be transmitted to final control elements.

Dissociation. The process by which a chemical compound breaks down into simpler constituents.

Dissolved gases. Gases which are in solution in water.

Dissolved solids. Those solids in water which are in solution.

Distillate oil. Light fraction of oil which has been separated from crude oil by fractional distillation.

Distillation zone. The region, in a solid fuel bed, in which volatile constituents of the fuel are vaporized.

Distilled water. Water produced by vaporization and condensation with a resulting higher purity.

Distributed digital control. A control system, characterized by the integration of a central digital control area with one or more remote digital control areas that are partially dedicated to perform specified control, within their realm of operation. Specified levels of communication and operation may be controlled from the central area or any remote area. The concept of distributed digital control is to prevent complete system failure due to a failure in any one area.

Double inclined grate. A grate consisting of two parts, so placed and inclined to form a Figure "V."

Downcomer. A tube or pipe in a boiler or waterwall circulating system through which fluid flows downward. See Supply Tube.

Draft. The difference between atmospheric pressure and some lower pressure existing in the furnace or gas passages of steam generating unit.

Draft control, barometric. A device that controls draft by means of a balanced damper which bleeds air into the breeching on changes of pressure to maintain a steady draft.

Draft differential. The difference in static pressure between two points in a system.

Draft gage. A device for measuring draft, usually in inches of water.

Draft loss. The drop in the static pressure of a gas between two points in a system, both of which are below atmospheric pressure, and caused by resistance to flow.

Draft regulator. A device which functions to maintain a desired draft in the appliance by automatically controlling the chimney draft to the desired value.

Drag plate. A plate beneath a traveling or chain grate stoker used to support the returning grates.

Drag seal. In a chain grate stoker the hinged plate resting against the returning chain and used to seal the air compartments.

Drain. A valved connection at the lowest point of the boiler or piping system for the removal of water.

Drier. An apparatus for the removal of part or all of the water or moisture from fuel or air.

Drum. A cylindrical shell closed at both ends designed to withstand internal pressure.

Drum baffle. A plate or series of plates or screens placed within a drum to divert or change the direction of the flow of water or water and steam.

Drum head. A plate closing the end of a boiler drum or shell.

Drum internals. Apparatus within a drum.

Drum operating pressure. The pressure of the steam maintained in the steam drum or steam-and-water drum of a boiler in operation.

Dry air. Air with which no water vapor is mixed. This term is used comparatively, since in nature there is always some water vapor included in air, and such water vapor, being a gas, is dry.

Dry ash. Noncombustible matter in the solid state, usually in granular dust form.

Dry, ash free basis. The method of reporting fuel analysis with ash and moisture eliminated and remaining constituents recalculated to total 100 percent.

Dry-bulb temperature. The temperature of the air indicated by thermometer not affected by the water vapor content of the air.

Dry, fuel basis. The method of reporting fuel analysis with moisture eliminated and other constituents recalculated to total 100 percent.

Dry gas. Gas containing no water vapor.

Dry gas loss. The loss representing the difference between the heat content of the dry exhaust gases and their heat content at the temperature of ambient air.

Dry limestone process. An air pollution control method that uses limestone to absorb the sulfur oxides in furnaces and stack gases.

Dry, mineral-matter-free basis. The method of reporting fuel analysis with moisture and ash, plus other mineral matter eliminated and remaining constituents recalculated to total 100 percent.

Dry steam. Steam containing no moisture. Commercially dry steam is usually said to contain not more than one-half of 1 percent moisture.

Duct. A passage for air or gas flow.

Dump grate stoker. One equipped with movable ash trays, or grates, by means of which the ash can be discharged at any desirable interval.

Dump plate. An ash supporting plate from which ashes may be discharged by rotation from one side of the plate.

Dust. Fine grain particles light enough to be suspended in air.

Dutch oven. A furnace that extends forward of the wall of a boiler setting. It is usually of refractory construction with a low roof, although in some cases the roof and side walls are water cooled.

Economizer. A heat recovery device designed to transfer heat from the products of combustion to boiler feedwater.

Ejector. A device which utilizes the kinetic energy in a jet of water or other fluid to remove a fluid or fluent material from tanks or hoppers.

Electric boiler. A boiler in which electric heating means serve as the source of heat.

Electronic control. A control system which primarily uses electronic signals and solid state control devices.

Electrostatic precipitator (ESP). An air pollution control device that imparts an electrical charge to particles in a gas stream causing them to collect on an electrode.

Embrittlement cracking. A form of metal failure that occurs in steam boilers at riveted joints and at tube ends, the cracking being predominantly intercrystalline in nature.

Emission factor. The relationship between the amount of pollution produced and the amount of fuel burned or raw material processed.

Emission inventory. A listing, by source, of the amounts of air pollutants discharged into the atmosphere of a community daily. It is used to establish emission standards.

Emission standard. The maximum amount of discharge legally allowed from a single source, mobile or stationary.

Entrainment. The conveying of particles of water or solids from the boiler water by the steam.

Environment. The sum of external conditions affecting the life, development, and survival of an organism.

Environmental impact statement. A document required of Federal agencies by the National Environmental Policy Act for major projects or legislative proposals. They are used in making decisions about the positive and negative effects of the undertaking, and list alternatives.

E/P transducer. A transducer used to convert a voltage signal into a pneumatic signal.

Equalizer. Connections between parts of a boiler to equalize pressures.

Erosion. The wearing away of refractory or of metal parts, typically by the action of slag or fly ash.

Error. The difference between a measured property and its set point. This error calculation is usually an integral part of an automatic controller.

Evaporated makeup. Distilled water used to supplement returned condensate for boiler feedwater.

Evaporation rate. The number of pounds of water evaporated in a unit of time.

Evase stack. An expanding connection on the outlet of a fan or in an airflow passage for the purpose of converting kinetic energy to potential energy, i.e., velocity pressure into static pressure.

Excess air. Air supplied for combustion in excess of that theoretically required for complete oxidation.

Exhauster. A fan used to withdraw air or gases under suction.

Exhaust steam. Steam discharged from a prime mover.

Expanded joint. The pressure-tight joint formed by enlarging a tube end in a tube seat.

Expansion joint. A joint to permit movement due to expansion without undue stress.

Explosion. Uncontrolled combustion which proceeds so rapidly that a high pressure is generated suddenly.

Explosion door. A door in a furnace or boiler setting designed to be opened by predetermined gas pressures.

Extended surface. Heating surface in the form of fins, rings, or studs, added to heat absorbing elements.

External treatment. Treatment of boiler feedwater prior to its introduction into the boiler.

Fan. A machine consisting of a rotor and housing for moving air or gases at relatively low pressure differentials.

Feedback. A signal produced by a measuring device which is proportional to the magnitude of a controlled variable or position of a control element. When combined with a set point signal, the required amount of control of a variable is indicated and serves as an input to an automatic controller.

Feed pipe. A pipe through which water is conducted into a boiler.

Feedwater. Water introduced into a boiler during operation. It includes makeup and return condensate.

Feedwater treatment. The treatment of boiler feedwater by the addition of chemicals to prevent the formation of scale or eliminate other objectionable characteristics.

Ferrule. A short metallic ring rolled into a tube hole to decrease in diameter or rolled inside of a rolled tube end. Also a short metallic ring for making up handhole joints.

Filter. Porous material through which fluids or fluid and solid mixtures are passed to separate matter held in suspension.

Filtration. Removing particles of solid materials from fluids.

Fin. Usually a strip of steel welded longitudinally or circumferentially to a tube.

Fineness. The percentage by weight of a standard sample of a pulverized material which passes through a standard screen of specified mesh when subjected to a prescribed sampling and screening procedure (ASTM D197).

Fines. Sizes below a specific range.

Fin tube. A tube with one or more fins.

Fin tube wall. Spaced waterwall tubes on which flat metal extensions are welded in a plane parallel to the wall.

Firebox. The equivalent of a furnace. A term usually used for the furnaces of locomotives and similar types of boilers.

Fire crack. A crack starting on the heated side of a tube, shell, or header resulting from excessive temperature stresses.

Fired pressure vessel. A pressure vessel in which steam or hot water is generated by the application of heat resulting from the combustion of fuel.

Fire tube. A tube in a boiler having water on the outside and carrying the products of combustion on the inside.

Firing door. A door in a furnace through which coal or other solid fuel is introduced into the furnace.

Firing rate control. A pressure or temperature flow controller which controls the firing rate of a burner according to the deviation from pressure or temperature set point.

Fixed ash. The portion of the ash derived from the original vegetation including intimately contained minerals.

Fixed carbon. A component of the proximate analysis of a solid fuel. The carbonaceous residue less the ash remaining in the test container after the volatile matter has been driven off.

Fixed grate. A grate which does not have movement.

Flame detector. A device which indicates if fuel is burning or if ignition has been lost. The indication may be transmitted to a signal or to a control system.

Flame forming. The technique of shaping the geometry of a flame.

Flame impingement. The substantially continuous contact upon a surface by flame which results in formation of hard carbonaceous deposits and which may result in localized incomplete combustion. Flame impingement is a condition of firing which may cause failure and/or excessive maintenance of combustion chamber wall surfaces.

Flammability. Susceptibility to combustion.

Flammability limits. The limiting (upper and lower) homogeneous composition of a combustible mixture of gas and air beyond which the mixture will not ignite and continue to burn. The lower limit represents the smallest proportion of gas in air that can burn without the continuous application of heat. The higher limit represents the largest proportion of gas in air that can burn without the continuous application of heat.

Flared tube end. The projecting end of a rolled tube which is expanded or rolled to a conical shape.

Flashing. Steam produced by discharging water at saturation temperature into a region of lower pressure.

Flash point. The flash point of a liquid is an indication of the maximum temperature at which it can be stored and handled without serious fire hazard.

Flash tank. See Boiler Blowoff Tank.

Flue. A passage for products of combustion.

Flue dust. The particles of gas-borne solid matter carried in the products of combustion.

Flue gas. The gaseous products of combustion in the flue to the stack.

Flue gas recirculation. The reintroduction of part of the combustion gas at a point upstream of the removal point in the furnace for the purpose of controlling steam temperature or for NO_x control.

Fluidized bed combustion. A process where a fuel is burned in a bed of granulated particles which are maintained in a mobile suspension by the forward flow of air and combustion products.

Fly ash. Suspended ash particles carried in the flue gas.

Fly ash collector. A device designed to remove fly ash in dry form from flue gas.

Foaming. The continuous formation of bubbles which have sufficiently high surface tension to remain as bubbles beyond the disengaging surface.

Forced draft (FD) fan. A fan supplying air under pressure to the fuel burning equipment.

Forced draft (FD) stoker. A stoker in which the flow of air through the grate is caused by a pressure produced by mechanical means.

Fouling. The accumulation of solid matter in gas passages or on heat absorbing surfaces which results in undesirable restrictions to the flow of gas or heat.

Free moisture. See Surface Moisture.

Friability. The tendency of a coal to crumble or break into small pieces.

Front discharge stoker. A stoker so arranged that refuse is discharged from the grate surface at the same end as the coal feed.

Fuel. A substance containing combustible matter, and used for generating heat.

Fuel-air ratio. The ratio of the weight or volume of fuel to air.

Fuel bed. Layer of burning fuel on a furnace grate.

Fuel bed resistance. The static pressure differential across a fuel bed.

Fuel oil. Any hydrocarbon oil as defined by ASTM D396.

Fuel oil grades. 1. Grade No. 1 is a light distillate intended for use in burners of the vaporizing type in which the oil is converted to a vapor by contact with a heated surface or by radiation. High volatility is necessary to ensure that evaporation proceeds with a minimum of residue.

2. Grade No. 2 is a heavier distillate than grade No. 1. It is intended for use in atomizing type burners which spray the oil into a combustion chamber where the tiny droplets burn while in suspension. This grade of oil is used in most domestic burners and in many medium capacity commercial-industrial burners where its ease of handling and ready availability sometimes justify its higher cost over the residual fuels.

3. Grade No. 4 (light) is usually residual but it sometimes is a heavy distillate. It is intended for use both in pressure-atomizing commercial-industrial burners not requiring higher cost distillates and in burners equipped to atomize oils of higher viscosity. Its permissible viscosity range allows it to be pumped and atomized at relatively low storage temperatures.

4. Grade No. 4 is usually a light residual, but it is a heavy distillate. It is intended for use in burners equipped with devices that atomize oils of higher viscosity than domestic burners can handle. Its permissible viscosity range allows it to be pumped and atomized at relatively low storage temperatures. Thus, in all but extremely cold weather, it requires no preheating for handling.

5. Grade No. 5 (light) is residual fuel of intermediate viscosity for burners capable of handling fuel more viscous than grade No. 4 without preheating. Preheating may be necessary in some types of equipment for burning and in colder climates for handling.

6. Grade No. 5 (heavy) is a residual fuel more viscous than grade No. 5 (light) and is intended for use in similar service. Preheating may be necessary in some types of equipment for burning and in colder climates for handling.

7. Grade No. 6, sometimes referred to as "Bunker C," is a high-viscosity oil used mostly in commercial and industrial heating. It requires preheating in the storage tank to permit pumping, and additional preheating at the burner to permit atomizing. The extra equipment and maintenance required to handle this fuel usually preclude its use in small installations.

Full metering. Combustion control system in which air-to-fuel ratios are maintained by measuring both air and fuel with a flow measuring device. Full metering systems can contain many other features such as cross limiting or oxygen trim.

Furnace. See Combustion Chamber.

Furnace draft. The draft in a furnace, measured at a point immediately in front of the furnace outlet.

Furnace liberation rate. The total quantity of thermal energy above a fixed datum introduced into a furnace by the fuel, considered to be the product of the hourly fuel rate, and its high heat value, divided by furnace volume, expressed in Btu per hour per cubic foot of furnace volume.

Furnace release rate. The heat available per square foot of heat absorbing surface in the furnace. That surface is the projected area of tubes, and extended metallic surfaces on the furnace side including walls, floor, roof, partition walls, and platens and the area of the plane of the furnace exit which is defined as the entrance to the convection tube bank.

Furnace slag screen. A screen formed by one or more rows of tubes arranged across a furnace gas outlet, serving to create an ash cooling zone for the particles suspended in the products of combustion leaving the furnace.

Furnace volume. The cubic contents of the furnace or combustion chamber.

Fused slag. Slag which has coalesced into a homogenous solid mass by fusing.

Fusible plug. A hollowed threaded plug having the hollowed portion filled with a low melting point material, usually located at the lowest permissible water level.

Fusibility. Property of slag to fuse and coalesce into a homogeneous mass.

Fusion. The melting of a solid material such as ash.

Gage cock. A valve attached to a water column or drum for checking water level.

Gage glass. The transparent part of a water gage assembly connected directly or through a water column to the boiler, below and above the water line, to indicate the water level in the boiler.

Gage pressure. The pressure above atmospheric pressure.

Gag, safety valve. A clamp designed to prevent a safety valve from lifting while applying a hydrostatic test at higher pressure than the safety valve setting.

Gas analysis. The determination of the constituents of a gaseous mixture.

Gas burner. A burner for use with gaseous fuel.

Gasification. The process of converting solid or liquid fuel into a gaseous fuel such as the gasification of coal.

Gas ring. A circular device with multiple openings or orifices arranged to admit or distribute gaseous fuels into a burner throat.

Generating tube. A tube in which steam is generated.

Grade. Coal classification according to quality.

Grain loading. The rate at which particles are emitted from a pollution source; measurement is made by the number of grains per cubic foot of gas emitted. Also called particulate loading.

Granular ash. Small particles of dry ash.

Grate. The surface on which fuel is supported and burned, and through which air is passed for combustion.

Grate bars. Those parts of the fuel supporting surface arranged to admit air for combustion.

Gravity. 1. Weight index of fuels: liquid petroleum products expressed either as specific or API (American Petroleum Institute) gravity.

2. Weight index of gaseous fuels as specific gravity related to air under specific conditions.

3. Weight index of solid fuels as specific gravity related to water under specific conditions.

Grooved tube seat. A tube seat having one or more shallow grooves into which the tube may be forced by the expander.

Group. A subclassification of coal by rank.

Hand auto station (H/A station). A device for routing a control signal to a final control element. The signal can be from a control system (auto position) or be entered manually to any desired level (manual position).

Hand fired grate. A grate on which fuel is placed manually, usually by means of a shovel.

Handhole. An opening in a pressure part for access, usually not exceeding 6 inches in longest dimension.

Handhole cover. A handhole closure.

Hand lance. A manually manipulated length of pipe carrying air, steam, or water for blowing ash and slag accumulations from heat absorbing surfaces.

Hardness. A measure of the amount of calcium and magnesium salts in boiler water. Usually expressed as grains per gallon or ppm as $CaCo_2$.

<u>Hard water</u>. Water which contains calcium or magnesium in an amount which requires an excessive amount of soap to form a lather.

<u>Header</u>. A chamber for the collection and/or distribution of fluid to or from a multiplicity of parallel flow parts.

<u>Heat available</u>. The thermal energy above a fixed datum that is capable of being absorbed for useful work. In boiler practice, the heat available in the furnace is usually taken to be the higher heating value of the fuel for combustion corrected by subtracting radiation losses, unburned combustible, latent heat of the water in the fuel or formed by the burning of hydrogen, and adding sensible heat in the air, all above ambient temperatures.

<u>Heat balance</u>. An accounting of the distribution of the heat input and output.

<u>Heat exchanger</u>. A vessel in which heat is transferred from one medium to another.

<u>Heating surface</u>. That surface which is exposed to the heating medium for absorption and transfer of heat to the heat medium.

<u>Heat recovery boiler</u>. See Waste Heat Boiler.

<u>Heavy metals</u>. Metallic elements such as mercury, chromium, cadmium, arsenic, and lead, with high molecular weights. They can damage living things at low concentrations and tend to accumulate in the food chain.

<u>High gas pressure switch</u>. A switch to stop the burner if the gas pressure is too high.

<u>Higher heating value (HHV)</u>. The total heat obtained from the combustion of a specified amount of fuel which is at 6 degrees F when combustion starts, and the combustion products of which are cooled to 60 degrees F before the quantity of heat released is measured (see also Calorific Value and Lower Heat Value).

<u>Hopper</u>. A changer or bin used for holding solid fuel or refuse.

<u>Hopper bottom furnace</u>. A furnace bottom with one or more inclined sides forming a hopper for the collection of ash and for the easy removal of same.

Horizontal firing. A means of firing liquid, gaseous or pulverized fuel, in which the burners are so arranged in relation to furnace as to discharge the fuel and air into the furnace in approximately a horizontal direction.

HRT. Horizontal return tubular.

Hydrocarbon. A chemical compound of hydrogen and carbon.

Hydrostatic test. A strength and tightness test of a closed pressure vessel by water pressure.

Igniter. A burner smaller than the main burner, which is ignited by a spark or other independent and stable ignition source, and which provides proven ignition energy required to light off the main burner.

Ignition. The initiation of combustion.

Ignition arch. A refractory arch or surface located over a fuel bed to radiate heat and the rapidity of ignition. Usually used with a low volatile fuel such as anthracite coal.

Ignition period. See Trial for Ignition.

Ignition temperature. Lowest temperature of a fuel at which combustion becomes self sustaining.

Ignition torch. See Lighting-Off Torch.

Incomplete combustion. The partial oxidation of the combustible constituents of a fuel.

Induced draft (ID) fan. A fan exhausting hot gases from the heat absorbing equipment.

Inert gaseous constituents. Incombustible gases such as nitrogen which may be present in a fuel.

Inhibitor. A substance which selectively retards a chemical action.

Injector. A device utilizing a steam jet to entrain and deliver feedwater into a boiler.

Inlet boxes. An integral part of a fan enclosing the fan inlet or inlets to permit attachment of the fan to the duct system.

<u>Inspection door</u>. A small door in the outer enclosure so that certain parts of the interior of the apparatus may be observed.

<u>Insulation</u>. A material of low thermal conductivity used to reduce heat losses.

<u>Integral (reset) controller</u>. A controller in which the rate of change of the output is directly proportional to the error. An integral controller will always attempt to drive the error to zero. The units of the constant of proportionality are usually expressed either in repeats per minute or minutes per repeat.

<u>Interlock</u>. A device to prove the physical state of a required condition and to furnish that proof to the primary safety control circuit.

<u>Intermittent blowdown</u>. The blowing down of boiler water at intervals.

<u>Intermittent ignition</u>. An igniter which burns during light-off and while the main burner is firing, and which is shut off with the main burner.

<u>Internal-mix oil burner</u>. A burner having a mixing chamber in which high velocity steam or air impinges on jets of incoming liquid fuel. The fuel is then discharged in a completely atomized form.

<u>Internal treatment</u>. The treatment of boiler water by introducing chemicals directly into the boiler.

<u>Interrupted ignition</u>. An igniter which burns during light-off, and which is shut off (interrupted) during normal operation of the main burner.

<u>Intertube burner</u>. A burner which terminates in nozzle discharging between adjacent waterwall tubes.

<u>Ion</u>. A charged atom or radical which may be positive or negative.

<u>Ion exchange</u>. A reversible process by which ions are interchanged between solids and a liquid, with no substantial structure changes of the solid.

<u>Jumper tube</u>. A short tube connection for bypassing, routing, or directing the flow of fluid as desired.

<u>Lagging</u>. A covering, usually metallic to protect insulating material, on boilers, pipes, or ducts.

Lance door. A door through which a hand lance may be inserted for cleaning heating surfaces.

Latch switch. A control to prevent fuel valve opening if the burner is not secured in the firing position.

LEA. Low excess air.

Leakage. The uncontrolled quantity of fluid which enters or leaves through the enclosure of air or gas passage.

Ligament. The minimum cross section of solid metal in a header, shell, or tube sheet between two adjacent holes.

Lighting-off torch. A torch used for igniting fuel from a burner. The torch may consist of asbestos wrapped around an iron rod and saturated with oil or may be a small oil or gas burner.

Lignite A. A coal of low ASTM classification by rank with calorific value limits on a moist, mineral-matter-free basis between 6,300 and 8,300 Btu per pound.

Lignite B. A coal of lowest ASTM classification by rank with calorific value limits on a moist, mineral-matter-free basis less than 6,300 Btu per pound.

Lining. The material used on the furnace side of a furnace wall. It is usually high grade refractory tile or brick or plastic refractory material.

Link. An element of the chain of a chain grate stoker.

Live steam. Steam which has not performed any of the work for which it was generated.

Load. The actual instantaneous output rate of a boiler.

Long flame burner. A burner from which the fuel emerges in such a condition, or one in which the air for combustion is admitted in such a manner, that the two do not readily mix, resulting in a comparatively long flame.

Low draft switch. A control to prevent burner operation if the draft is too low. Used primarily with mechanical draft.

Lower heat value (LHV). The higher heating value (HHV) minus the latent heat of vaporization of the water formed by the oxidation of hydrogen bearing compounds in the fuel and the vaporization of water in the fuel.

Low-fire start. The firing of a burner with controls in a low-fire position to provide safe operating condition during light-off.

Low gas pressure switch. A control to stop the burner if gas pressure is too low.

Low oil temperature switch (cold oil switch). A control to prevent burner operation if the temperature of the oil is too low.

Low water cutoff. A device to stop the burner on unsafe water conditions in the boiler.

LPG. Liquefied petroleum gas.

LTW. Low temperature water.

Lug. Any projection used for supporting or grasping.

Luminosity. Emissive power with respect to visible radiation.

Makeup. The water added to boiler feed to compensate for that lost through exhaust, blowdown, leakage, etc.

Manhead. The head of a boiler drum or other pressure vessel having a manhole.

Manhole. The opening in a pressure vessel of sufficient size to permit a man to enter.

Manifold. A pipe or header for collecting a fluid from, or the distributing of a fluid to a number of pipes or tubes.

Measuring device. Any device used to indicate the magnitude of a property (such as flow rate).

Mechanical atomizing oil burner. A burner which uses the pressure of the oil for atomizing.

Mechanical draft. The negative pressure created by mechanical means.

Mechanical efficiency. The ratio of power output to power input.

Mechanical stoker. A device consisting of a mechanically operated fuel feeding mechanism and a grate, used for the purpose of feeding solid fuel into a furnace, distributing it over a grate, admitting air to the fuel for the purpose of combustion, and providing a means for removal or discharge of refuse.

1. Overfeed stoker - a stoker in which fuel is fed onto grates above the point of air admission to the fuel bed. Overfeed stokers include:

(a) Front feed, inclined grate - a stoker in which fuel is fed from the front onto a grate inclined downwards toward the rear of the stoker.

(b) Side feed, double inclined grate - a stoker in which fuel is fed from both sides onto grates inclined downwards towards the centerline of the stoker.

(c) Chain or traveling grate - a stoker having a moving endless grate which conveys fuel into and through the furnace where it is burned, after which it discharges the refuse.

(d) Vibragrate - an inclined vibrating stoker in which fuel is conveyed into and through the furnace where it is burned, after which it discharges the refuse.

2. Spreader stoker - a stoker that distributes fuel into the furnace from a location above the fuel bed with a portion of the fuel burned in suspension and a portion on the grates. Spreader stokers include:

(a) Stationary grate - a stoker in which fuel is fed onto a fixed position grate.

(b) Dump grate - a stoker in which fuel is fed onto a nonmoving grate which is arranged to allow intermittent discharge of refuse through tilting action of the grate bars.

(c) Continuous ash discharge or traveling grate - a stoker in which fuel is fed onto a moving endless grate which conveys the fuel into and through the furnace where it is burned, after which it discharges the refuse.

3. Underfeed stoker - a stoker in which fuel is introduced through retorts at a level below the location of air admission to the fuel bed. Underfeed stokers are divided into three general classes, as follows:

(a) A side ash discharge underfeed stoker is a stoker having one or more retorts which feed and distribute fuel onto side tuyeres or a grate through which air is admitted for combustion, and over which the ash is discharged at the side parallel to the retorts.

(b) A rear discharge underfeed stoker is a stoker having a grate composed of transversely spaced underfeed retorts, which feed and distribute solid fuel to intermediate rows of tuyeres through which is admitted air for combustion. The ash is discharged from the stoker across the rear end.

(c) A continuous ash discharge underfeed stoker is one in which the refuse is discharged continuously from the normally stationary stoker ash tray to the ash pit, without the use of mechanical means other than the normal action of the coal feeding and agitating mechanism.

Meta-anthracite. Highest coal classification according to rank. Dry fixed carbon 98 percent or more and dry volatile matter 2 percent or less, on a mineral-matter-free basis.

Microprocessor control. Utilizes a small microcomputer chip to perform requirements of a system control package. The microprocessor containers support chips to store necessary control system instructions in what is called memory. Usually, changes in system logic can be performed without any rewiring or component changes.

Mineral matter-free basis. The method of reporting coal analysis whereby the ash plus other minerals which are in the original coal are eliminated and the other constituents recalculated to total 100 percent.

Moisture. Water in the liquid or vapor phase.

Moisture and ash free basis. Method of reporting coal analysis. See Dry, Ash Free Basis.

Moisture in steam. Particles of water carried in steam. Usually expressed as the percentage by weight.

Moisture loss. The loss representing the difference in the heat content of the moisture in the exit gases and that at the temperature of the ambient air.

Monitoring. Periodic or continuous sampling to determine the level of pollution.

Monolithic baffle. A baffle of poured or rammed refractory material.

MSS. Manufacturers Standardization Society.

MTW. Medium temperature water.

MW. Molecular weight.

Mud or lower drum. A pressure chamber of a drum or header type located at the lower extremity of a water-tube boiler convection bank which is normally provided with a blowoff valve for periodic blowing off of sediment collecting in the bottom of the drum.

Multifuel burner. A burner by means of which more than one fuel can be burned either separately or simultaneously, such as pulverized fuel, oil, or gas.

Multi-pass arrangement. Heat absorbing surfaces so baffled as to provide two or more passes in series.

Multiple retort stoker. An underfeed stoker consisting of two or more retorts, parallel and adjacent to each other, but separated by a line of tuyeres, and arranged so that the refuse is discharged at the ends of the retorts.

Multiport burner. A burner having a number of nozzles from which fuel and air are discharged.

Natural circulation. The circulation of water in a boiler caused by differences in density; also referred to as thermal or thermally induced circulation.

Natural draft stoker. A stoker in which the flow of air through the grate is caused by the difference of pressure between the furnace and the atmosphere.

Natural gas. Gaseous fuel occurring in nature.

NDIR. Non-dispersive infrared.

Net fan requirements. The calculated operating conditions for a fan excluding tolerances.

Neutral atmosphere. An atmosphere which tends neither to oxidize nor reduce immersed materials.

NO_x. A notation meaning oxides of nitrogen.

NO_x port air. Air that is added downstream of the primary combustion zone to achieve off-stoichiometric combustion and reduce NO_x emissions.

Nozzle. A short flanged or welded neck connection on a drum or shell for the outlet or inlet of fluids; also a projecting spout for the outlet or inlet of fluids; also a projecting spout through which a fluid flows.

NPS. Nominal pipe size.

Nut. Anthracite coal designation through 1-5/8-inches over 15/16-inch round mesh screen. Bituminous coal size designation by some chosen screen mesh size as 2 inches by 3/4 inch.

Nut and slack. A combination of nut and slack coal, such as 2 inches by 3/4 inch nut plus 3/4 inch by slack (see Slack).

OD. Outside diameter.

Oil burner. A burner for firing oil.

Oil cone. The cone of finely atomized oil discharged from an oil atomizer.

Oil heater. A heat exchanger utilizing steam, hot water, or electricity to heat oil to the desired viscosity.

Oil heating and pumping set. See Pump and Heater Set.

Opacity. The degree to which emissions reduce the transmission of light and obscure the view of an object in the background. Usually defined as a number between 0 and 100 percent. At 0 percent, light is completely unobstructed and at 100 percent, light is completely obstructed (opacity numbers with respect to boiler emissions are not intended to include the effect of condensing water vapor). See Smoke Number, Ringlemann and Smoke Spot Number, Bacharach.

Open furnace. A furnace, particularly as applied to chain or traveling grate stoker containing essentially no arches.

Organic matter. Compounds containing carbon often derived from living organisms.

Orifice. 1. The opening from the whirling chamber of a mechanical atomizer or the mixing chamber of a steam atomizer through which liquid fuel is discharged.

2. A device inserted into a pipeline to create a pressure drop to be used for the purpose of measuring fluid flow.

Orsat. A gas-analysis apparatus in which certain gaseous constituents are measured by absorption in separate chemical solutions.

Overfire air. Air for combustion admitted into the furnace at a point above the fuel bed.

<u>Overfire air fan</u>. A fan used to provide air to a combustion chamber above the fuel bed.

<u>Oxidant</u>. A substance containing oxygen that reacts chemically in air to produce a new substance.

<u>Oxidation</u>. Chemical combination with oxygen.

<u>Oxidizing atmosphere</u>. An atmosphere which tends to promote the oxidation of immersed materials.

<u>Oxygen attack</u>. Corrosion or pitting in a boiler caused by oxygen.

<u>Packaged steam generator</u>. A boiler equipped and shipped complete with fuel burning equipment, mechanical draft equipment, automatic controls and accessories.

<u>Packed tower</u>. A pollution control device that forces dirty air through a tower packed with loose pellet-like material of various shapes or a fixed grid type material, while liquid is sprayed over the packing material. Pollutants in the air stream either dissolve or chemically react with the liquid.

<u>Pad</u>. See Boss. A pad is larger than a boss and is attached to a pressure vessel.

<u>Parallel flow burner</u>. A type or class of burners which includes the venturi burner. The burner is characterized by the lack of register spin louvers and normally has a venturi section to straighten, balance, and in some cases, meter airflow. The flame is stabilized by either a diffuser, spinner, or bluff body.

<u>Parallel positioning</u>. Fuel and air control elements have separate actuators responding to the same load signal simultaneously. At least one of the actuators has a positioner to set air-fuel ratio with load.

<u>Particulates</u>. Fine liquid or solid particles such as dust, smoke, mist, fumes, or smog found in the air or emissions.

<u>Pass</u>. A confined passageway through which a fluid, gas, or products of combustion flows in essentially one direction.

<u>Pea</u>. Anthracite or bituminous coal size. In anthracite through 13/16 inch over 9/16 inch round hole screen; in bituminous 3/4 inch by 3/8 inch.

<u>Peak load</u>. The maximum load carried for a stated period of time.

Peep hole. A small hole in a door covered by a movable cover.

Petroleum. Naturally occurring mineral oil consisting predominately of hydrocarbons.

pH. A measure of the acidity or alkalinity of a material, liquid, or solid. pH is represented on a scale of 0 to 14 with 7 being a neutral state, 0 most acid and 14 most alkaline.

Pilot. See Igniter.

Pilot flame establishing. The length of time fuel is permitted to be delivered to a proved pilot before the flame-sensing device is required to detect pilot flame.

Pilot, proved. A pilot flame which has been detected by flame failure controls.

Pilot stabilization period. A time interval synonymous on most systems today with timed trial for pilot ignition. Modern programmers prevent main valve operation for a specified number of seconds after commencement of trial for pilot ignition even though pilot is immediately proved.

Pitting. A concentration attack by oxygen or other corrosive chemicals on a boiler, producing a localized depression in the metal surface.

Plenum. An enclosure through which gas or air passes at relatively low velocities.

Pneumatic control. Utilizes gas pressure (usually air) as the primary motive force for control elements, and as the signal between control devices. The maximum and minimum pressures are usually 3 and 15 psig, but can be other values as well.

Pneumatic conveying. The transportation of fuel through a conduit by air.

Popping pressure. The pressure at which a safety valve opens.

Port. An opening through which fluid passes.

Position indicator. A device which provides means for determining a control element position.

Pour point. An indication of the lowest temperature at which liquid fuels can be stored and still be capable of flowing under gravitational forces.

Power input. The energy required to drive auxiliary equipment, expressed in brake horsepower delivered to shaft or kilowatts to drive motor.

Parts per million. A method of expressing tiny concentrations. In air or flue gas, usually a volume/volume ratio; may also be used as a weight/weight or a weight/volume ratio (abbreviated ppm).

Precipitate. To separate materials from a solution by the formation of insoluble matter by chemical reaction. The material which is removed.

Precipitator. An ash separator and collector of the electrostatic type.

Preheated air. Air at a temperature exceeding that of the ambient air.

Pressure drop. The difference in pressure between two points in a system.

Products of combustion. The gases, vapors, and solids resulting from the combustion of fuel.

Programmable controller. Similar to microprocessor control, but utilizing a simplified method of entering instructions into memory (abbreviated PC).

Program timer. A timing device which actuates a series of switches in programmed sequence.

Projected grate area. The horizontal projected area of the stoker grate.

Proportional control. A mode of control in which there is a continuous linear relation between value of the controller variable and position of the final control element (modulating control).

Proportional controller. A controller in which the position of the output is directly proportional to the error. The constant of proportionality is called gain and usually expressed in percent. In practice, proportional controllers are usually combined with integral action to eliminate residual error (see Integral (Reset) Controller).

Puff. A minor combustion explosion within the boiler furnace or setting.

<u>Pulsation</u>. Rapid fluctuations in furnace pressure.

<u>Pulverizer</u>. A machine which reduces a solid fuel to a fineness suitable for burning in suspension.

<u>Pumps and heater set</u>. Assembled unit consisting of oil heater, fuel pump, strainer, valve, and piping and temperature controls. May be either simplex or duplex arrangements.

<u>Pump, automatic oil</u>. A pump which automatically pumps oil from the supply tank and delivers the oil under a constant head to an oil-burning appliance.

<u>Pump, oil transfer</u>. An oil pump, automatically or manually operated, which transfers through continuous piping from a supply tank to an oil burning appliance or to an auxiliary tank.

<u>Purge</u>. To introduce air into the furnace and the boiler flue passage in such volume and manner as to completely replace the air or gas-air mixture contained therein.

<u>Purge meter interlock</u>. A flow meter so arranged that an airflow through the furnace above a minimum amount must exist for a definite time interval before the interlocking system will permit an automatic igniter to be placed in operation.

<u>Purge, post</u>. A method of scavenging the furnace and boiler passes to remove combustible gases after flame failure controls have sensed pilot and main burner shutdown and safety shutoff valves are closed.

<u>Purge, preignition</u>. A method of scavenging the furnace and boiler passes to remove combustible gases before the ignition system can be energized.

<u>Purity</u>. The degree to which a substance is free of foreign materials.

<u>Pusher</u>. A device for giving motion to fuel bed by reciprocating motion, such as moving block in the bottom of a retort.

<u>Pyrites</u>. A compound of iron and sulfur naturally occurring in coal.

<u>Radiation loss</u>. A comprehensive term used in a boiler unit heat balance to account for the conduction, radiation, and convection heat losses from the settings to the ambient air.

<u>Ram</u>. A form of plunger used in connection with underfeed stokers to introduce fuel into retorts. See also Pusher.

Rank. Method of coal classification based on the degree of progressive alteration in the natural series from lignite b to meta-anthracite. The limits under classifications according to rank are on a mineral-matter-free basis.

Rate of blowdown. A rate normally expressed as a percentage of the incoming water.

Raw water. Water supplied to the plant before treatment.

Rear discharge stoker. A stoker so arranged that refuse is discharged from the grate surface at the end opposite the coal fuel.

Reciprocating grate. A grate element which has reciprocating motion, usually for the purpose of fuel agitation.

Recirculating line. Piping and connections on a heat exchanger through which fluid is returned from the outlet to the inlet.

Reducing atmosphere. An atmosphere which tends to promote the removal of oxygen from immersed materials.

Reduction. Removal of oxygen from a chemical compound.

Refractory. Material that will withstand temperatures above 50 degrees F without distortion or deterioration.

Register burner. A type or class of burner. Air is admitted through one or multiple zones of adjustable louvers which impart a rotary motion to the air. The flame is stabilized by the swirling air from the register louvers and internal eddies generated downstream of the diffuser and external eddies generated downstream of the throat exit.

Register retort. A trough or channel in an underfeed stoker, extending within the furnace, through which fuel is forced upward into the fuel bed.

Regulator, gas pressure. A spring-loaded, dead-weighted or pressure-balanced device which will maintain a nearly constant gas pressure to the burner supply line.

Relative humidity. The ratio of the weight of water vapor present in a unit volume of gas to the maximum possible weight of water vapor in unit volume of the same gas at the same temperature and pressure.

Relay control. Utilizes electro-mechanical relays to perform logic function (on/off status) as burner sequencing and/or safety control. A relay control system usually incorporates timers and/or motor-driven program timers in addition to relays.

Residual oils. Oils which are too heavy to be evaporated in any normal evaporation or distillation process and are thus left over from that process. Such oils are frequently cracked (high temperature fractionation) or catalytically cracked (fractionation in presence of alumina-silica catalyst).

Retarder. A straight or helical strip inserted in a firetube primarily to increase the turbulence and improve heat transfer. Also called turbulator.

Retractable blower. A soot blower in which the blowing element can be mechanically extended into and retracted out of the boiler.

Return flow oil burner. A mechanical atomizing oil burner in which part of oil supplied to the atomizer is withdrawn and returned to storage or to the oil line supplying the atomizer.

Rice. Anthracite coal size, otherwise known as No. 2 Buckwheat - through
5/16 inch over 3/16 inch round mesh screen.

Ringlemann chart. A series of four rectangular grids of black lines of varying widths printed on a white background, used as a criterion of blackness for determining smoke density.

Ringlemann number. See Smoke Number, Ringlemann.

Riser tube. A tube through which steam and water passes from an upper waterwall header to a drum.

Rolled joint. A joint made by expanding a tube into a hole by a roller expander.

Rotary oil burner. A burner in which atomization is accomplished by feeding oil to the inside of a rapidly rotating cup.

RTD. Resistance temperature device.

Run of mine. Unscreened bituminous coal as it comes from the mine.

Saddle. A casting, fabricated chair, or member used for the purpose of support.

Safety shutdown. The action of shutting off fuel and ignition energy to the burner by means of safety control or controls such that restart cannot be accomplished without operator action.

Safety valve. A spring loaded valve that automatically opens when pressure attains the valve setting. Used to prevent excessive pressure from building up in a boiler.

Sampling. The removal of a portion of a material for examination or analysis.

Saturated air. Air which contains the maximum amount of water vapor that it can hold at its temperature and pressure.

Saturated steam. Steam at the pressure corresponding to its saturation temperature.

Saturated water. Water at its boiling point.

Saturation temperature. The temperature at which evaporation occurs at a particular pressure.

Scale. A hard coating or layer of chemical materials on internal surfaces of boiler pressure parts.

Screen. A perforated plate, cylinder or mesh fabric, usually mounted on a frame for separating coarser from finer parts.

Screening. The undersized coal from a screen process (often -3/4 inch or smaller, bituminous).

Screw feed. A means of introducing fuel by rotation of a screw.

Seal. A device to close openings between structures to prevent leakage.

Sealing air. Air at a pressure slightly exceeding boiler internal gas pressures used to prevent flow of combustion gases from escaping the boiler, usually taken from a FD fan.

Seal weld. A weld used primarily to obtain tightness and prevent leakage.

Seam. The joint between two plates welded or riveted together.

Seam. A continuous tubular deposit of vegetal or sedimentary origin bedded between parallel strata of sandstone, shale, or clay.

Secondary combustion. Combustion which occurs as a result of ignition at a point beyond the furnace (see also Delayed Combustion).

Sediment. Matter in water which is in suspension and can be removed by gravity or mechanical means. Noncombustible solid matter which settles out at the bottom of an oil tank; a small percentage is present in residual fuel oils.

Semi-anthracite. A coal classification according to rank. Dry fixed carbon 85 percent or more and less than 92 percent and dry volatile matter 14 percent or less and more than 8 percent, on a mineral matter-free basis.

Semi-bituminous. A former coal classification according to rank, including low volatile bituminous.

Semi-fused slag. Hard slag masses consisting of particles which have partly fused together.

Separator. A device for separating solid matter from a conveying fluid; an electromagnetic device for the removal of magnetic ores or tramp iron from coal.

Service water. General purpose water which may or may not have been treated for a special purpose.

Set point. A control reference point which represents a desired value of a measured property.

Shaking grate. A grate from which refuse is removed by motion of the grate causing the refuse to sift through openings in or between the grate.

Shell. The joint between two plates welded or riveted together.

Side air admission. Admission of air to the underside of a grate from the sides of a chain or traveling grate stoker.

Side dump stoker. A stoker so arranged that refuse is discharged from a dump plate at the side of the stoker.

Sieve. A laboratory apparatus with meshes through which the finer particles of a substance are passed to separate them from the coarser particles.

Siftings. Fine particles of solid fuel which sift through a grate.

Signal. A continuous level of information, transmitted to or from control devices, from which there exists a maximum and minimum value defined by the transmission method and control interpretation. For example, an electronic signal may be based on 4 to 20 milliamperes (mA) of which 4 mA = the minimum or 0 percent and 20 mA = the maximum or 100 percent.

Silt. Finely divided anthracite obtained as a residue from cleaning process.

Single point positioning. Fuel and air control elements are mechanically linked to a common actuator which modulates the two control elements as a unit in response to load. Fuel air ratio is varied with firing rate by means of a mechanical cam arrangement.

Single retort stoker. An underfeed stoker using one retort only in the assembly of a complete stoker.

Skin casing. Casing located in direct contact with boiler tubes used to maintain an airtight envelope.

Slack. Screening, or fine coal; maximum top size seldom above 2-1/2 inches.

Slacking. Breaking down of friable coals due to changes in moisture contents.

Slag. Molten or fused solid matter.

Sleeve. A tubular member through a wall to permit passage of pipe or other connections.

Slip seal. A seal between members designed to permit movement of either member by slipping or sliding.

Slug. A large "dose" of internal chemical treatment applied intermittently to a steam boiler. Also sometimes used instead of "priming" to denote a discharge of water from a boiler steam outlet in relatively large intermittent amounts.

Smog. Air pollution associated with oxidants.

Smoke. Small gas-borne particles of carbon or soot, less than 1 micron (0.001 mm) in size, resulting from incomplete combustion of carbonaceous materials and in sufficient number to be observable.

Smoke number, Ringlemann. An integer between 0 and 5 that is used to describe the "darkness density" or degree of blackness of a visible stack plume. The technique involves comparing standard Ringlemann charts to the stack plume visually. A smoke number of 0 indicates complete nonblack and a 5 indicates complete black.

Smoke spot number, Bacharach. An integer between 0 and 9 that is used to indicate the relative smoke density of stack flue gas. The technique is to draw a specified amount of stack gas through filter paper and compare the "smoke spot" to standard shaded smoke spots.

Softening. The act of removing scale-forming calcium and magnesium impurities from water.

Soft water. Water which contains little or no calcium or magnesium salts, or water from which scale-forming impurities have been removed or reduced.

Solid state control. Utilizes solid state semiconductor components in a hardwired system to perform logic and sequencing control and/or process control. Any changes in system logic usually require rewiring, relocation/replacement of components, addition of components, or any combination thereof.

Soot. Carbon dust formed by incomplete combustion.

Soot blower. A mechanical device for discharging steam or air to clean heat absorbing surfaces.

SOP. Standard operating procedure.

SO_x. A notation meaning oxides of sulfur.

Spalling. The breaking off of the surface refractory material as a result of internal stresses resulting from an excessive temperature gradient.

Specific heat. The quantity of heat, expressed in Btu, required to raise the temperature of 1 pound of a substance 1 degree F.

Splash plate. An abrasion-resistant metal plate, forming the back of an elbow in a pulverized fuel and air line, against which the fluidized material strikes and is dispersed for the purpose of obtaining uniform distribution in the succeeding line or burner.

Splitter. Plates spaced in an elbow of a duct so disposed as to guide the flow of fluid through the elbow with uniform distribution and to minimize pressure drop.

Sponge ash. Accumulation of dry ash particles into soft structures having a spongy appearance.

Spontaneous combustion. Ignition of combustible material following slow oxidation without the application of high temperature from an external source.

Spray angle. The angle included between the sides of the cone formed by liquid fuel discharged from mechanical, rotary atomizers, and by some forms of steam or air atomizers.

Sprayer plate. A metal plate used to atomize the fuel in an atomizer of an oil burner.

Spray nozzle. A nozzle from which a liquid fuel is discharged in the form of a spray.

Spray tower. A duct through which liquid particles flow counter-current to a column of gas: a fine spray is used when the object is to concentrate the liquid, a coarse spray when the object is to remove solids and objectionable materials from gases.

Spud burner. A type of gas burner consisting of several pipes with orifices.

Spun ends. The ends of hollow members closed by rolling members rigidly in position.

SSU. Saybolt seconds universal.

Stack. A vertical conduit to discharge combustion products to the atmosphere. Also called chimney.

Stack effect. Hot gases, as in a chimney, that move upward because they are warmer than the surrounding atmosphere.

Standard cubic foot. A standard cubic foot is referred to 60 degrees F and 14.696 pounds per square inch pressure. A dry cubic foot of air at these conditions weighs 0.0763 pound and has a specific gravity of 1.00. Usually abbreviated SCF.

Standard temperature and pressure. Conditions at which a standard volume of gases is defined. Sometimes abbreviated as STP.

1. Boilers (U.S.) - Standard temperature is 60 degrees F, standard pressure is 14-7 psia.

2. Air pollution control (U.S.) - Standard temperature is 70 degrees F, standard pressure is 14.7 psia.

3. Other - standard temperature is 32 degrees F, standard pressure is 14.7 psia.

Standard volume. The volume of a gas at standard temperature and pressure. In the U.S., this is normally expressed as standard cubic feet.

Stationary grate. A grate having no moving parts.

Stay. A tensile stress member to hold material or other members rigidly in position.

Staybolt. A bolt threaded through or welded at each end, into two spaced sheets of a firebox or box header to support flat surfaces against internal pressure.

Steam. The vapor phase of water substantially unmixed with other gases.

Steam and water drum. A pressure chamber located at the upper extremity of a boiler circulatory system in which the steam generated in the boiler is separated from the water and from which steam is discharged at a position above a water level maintained therein.

Steam atomizing oil burner. A burner for firing oil which is atomized by steam. It may be of the internal or external mixing type.

Steam-cooled wall. A wall partly or completely covered with superheater or reheater tubes.

Steam dome. A receptacle riveted or welded to the top sheet of a firetube boiler through and from which the steam is taken from the boiler.

Steam dryer. A series of screens, wires, or plates through which steam is passed to remove entrained moisture.

Stem gage. A gage for indicating the pressure of steam.

Steam quality. The percent by weight of vapor in a steam and water mixture.

Steam separator. A device for removing the entrained water from steam.

Stoichiometric combustion. The complete oxidation of the combustible constituents of a fuel, utilizing the exact, theoretically required amount of oxygen.

Stoker. See Mechanical Stoker.

Stoker gate. An element of a stoker, placed at the point of entrance of fuel into the furnace and by means of which the depth of fuel on the stoker grate may be controlled. It is generally used in connection with chain or traveling grate stokers and has the form of guillotine.

Stoker grate. That part of the stoker within the space defined by the walls of the furnace at the fuel bed level which forms the bottom of the furnace and supports the fuel bed. On a chain or traveling grate stoker, the fuel bed is considered to be supported only to the center line of the rear shaft or its equivalent.

Strainer, oil. A device, such as filter, to retain solid particles allowing a liquid to pass.

Strength weld. A weld capable of withstanding a design stress.

Stringer support tube. Vertical tubes containing water or steam which act as supports for horizontally oriented convection surface.

Stub tube. A short tube welded to a pressure part for field extension.

Stud. A projecting pin serving as a support or means of attachment.

Stud tube. A tube having short studs welded to it.

Stud tube wall. A tube wall covered with refractory which is held in place by stud anchors attached to the tubes.

Sub-bituminous coal. Coal classification according to rank:

1. Moist Btu 10,500 or more and less than 11,500

2. Moist Btu 9,500 or more and less than 10,500

3. Moist Btu 8,300 or more and less than 9,500

Superheat. To raise the temperature of steam above its saturation temperature. The temperature in excess of its saturation temperature.

Superheated steam. Steam at a higher temperature than its saturation temperature.

Superheater. A group of tubes which absorb heat from the products of combustion to raise the temperature of the vapor passing through the tubes above its saturation temperature.

Supply tube. A tube which carries water to the inlet water header.

Surface blowoff. Removal of water, foam, etc., from the surface at the water level in a boiler. The equipment for such removal.

Surface moisture. That portion of the moisture in the coal which comes from external sources as water seepage, rain, snow, condensation, etc.

Surge. The sudden displacement or movement of water in a closed vessel or drum.

Suspended solids. Undissolved solid in boiler water.
Sweat. The condensation of moisture from a warm saturated atmosphere on a cooler surface.

Swell. A slight weep in a boiler joint, not in sufficient amount to form drops.

Swinging load. The sudden increase in the volume of the steam in the water-steam mixture below the water level.

Tempering moisture. A load that changes at relatively short intervals. Water added to certain coals which, as received, have insufficient moisture content for proper combustion on stokers.

Tertiary air. Air for combustion supplied to the furnace to supplement the primary and secondary air.

Theoretical air. The quantity of air required for perfect combustion. Also called stoichiometric air.

Therm. A unit of heat applied especially to gas. One therm = 100,000 Btu.

Thermal sleeve. A spaced internal sleeve lining of a connection for introducing a fluid of one temperature into a vessel containing fluid at a substantially different temperature, used to avoid abnormal stresses.

Throat. Burner exit, geometrically designed to provide the proper air-fuel expansion for flame shaping and flame stabilization, sometimes referred to as the quarl.

Through stay. A brace used in firetube boilers between the heads or tube sheets.

Tie bar. A structural member designed to maintain the spacing of furnace waterwall tubes.

Tie plate. A plate, through which a bolt or tie rod is passed, to hold brick in place.

Tie rod. A tension member between buckstays or tie plates.

Tile. A preformed burner refractory, usually applied to shapes other than standard brick.

Tile baffle. A baffle formed of preformed burner refractory shapes.

Total air. The total quantity of air supplied to the fuel and products of combustion. Percent total air is the ratio of total air to theoretical air expressed as percent.

Total moisture. The sum of inherent moisture and surface moisture in coal.

Total solids concentration. The weight of dissolved and suspended impurities in a unit weight of boiler water, usually expressed in ppm.

Transducer. A device to convert information from one form to another. The usual application is converting physical states such as pressure, temperature, etc., into a pneumatic or electronic signal.

Traveling grate stoker. A stoker similar to a chain grate stoker with the exception that the grate is separate from, but supported on, and driven by, chains. Only enough chain strands are used as may be required to support and drive the grate.

Treated water. Water which has been chemically treated to make it suitable for boiler feed.

Trial for ignition. That period of time during which the programming flame failure controls permit the burner fuel valves to be open before the flame sensing device is required to detect the flame.

Tube. A hollow cylinder for conveying fluids.

Tube cleaner. A device for cleaning tubes by brushing, hammering, or by rotating cutters.

Tube door. A door in a boiler or furnace wall through which tubes may be removed or new tubes passed.

Tube hole. A hole in a drum, header, or tube sheet to accommodate a tube.

Tube seat. That part of a tube hole with which a tube makes contact.

Tube sheet. The plate containing the tube holes.

Tube-to-tube wall. A waterwall in which the tubes are substantially tangent to each other with essentially no space between the tubes.

Tube turbining. The act of cleaning a tube by means of a power-driven rotary device which passes through the tube.

Turbidity. The optical obstruction to the passing of a ray of light through a body of water, caused by finely divided suspended matter.

Turbulator. See Retarder.

Turbulent burner. A burner in which fuel and air are mixed and discharged into the furnace in such a manner as to produce turbulent flow from the burner.

Tuyeres. Forms of grates, located adjacent to a retort, through which air is introduced.

Ultimate analysis. See Analysis, Ultimate.

Unaccounted for loss. That portion of a boiler heat balance which represents the difference between 100 percent and the sum of the heat absorbed by the unit and the classified losses expressed as percent.

Unburned combustible. The combustible portion of the fuel which is not completely oxidized.

Unburned combustible loss. See Combustible Loss.

Unfired pressure vessel. A vessel designed to withstand internal pressure, neither subjected to heat from products of combustion nor an integral part of a fired pressure vessel system.

Use factor. The ratio of hours in operation to the total hours in that period.

Valve, fuel control. An automatically or manually operated device consisting essentially of a regulating valve and an operating mechanism. It is used to regulate fuel flow.

Vane. A fixed or adjustable plate inserted in a gas or air stream used to change the direction of flow (see also Splitter).

Vane control. A set of movable vanes in the inlet of a fan to provide regulation of air or gas flow.

Vaporization. The change from liquid or solid phase to the vapor phase.

Vapor plumes. Flue gases that are visible because they contain water droplets.

Vent. An opening in a vessel or other enclosed space for the removal of gas or vapor.

Vertical firing. An arrangement of a burner such that air and fuel are discharged into the furnace, in practically a vertical direction, either up or down.

Viscosity. The measure of the internal friction of a fluid or of its resistance to flow. In fuel oil, it is highly significant since it indicates both the relative ease with which the oil will flow or may be pumped, and the ease of atomization.

Vitreous slag. Glassy slag.

Volatile matter. Those products given off by a material as gas or vapor, determined by definite prescribed methods.

Volatilization. See Vaporization.

Wall blower. A short retractable blower for cleaning adjacent waterwall heat absorbing surfaces.

Wall box. A structure in a wall of a steam generator through which apparatus, such as soot blowers, extend into tile setting.

Waste heat. Sensible heat in noncombustible gases, such as gases leaving furnaces used for processing metals, ores, or other materials.

Waste heat boiler. A boiler that recovers normally unused energy and converts it to usable heat.

<u>Water and sediment</u>. Moisture and foreign matter in liquid fuel. Appreciable amounts of water and sediment tend to cause fouling of handling equipment.

<u>Water back</u>. One or more horizontal water tubes located over and laterally across the ash discharge end of a stoker to prevent ash adhesion to the wall and to reduce air leakage from the ash pit into the furnace.

<u>Water column</u>. A vertical tubular member connected at its top and bottom to the steam and water space respectively of a boiler, to which the water gage, gage cocks, and high and low level alarms may be connected.

<u>Water cooled baffle</u>. A baffle composed essentially of closely spaced boiler tubes.

<u>Water cooled burner throat</u>. Burner throat water cooled by waterwall tubes bent to conform to the throat and covered by refractory.

<u>Water cooled stoker</u>. A stoker having tubes in or near the grate surface through which water is passed for cooling the grates.

<u>Water cooled wall</u>. A furnace wall containing water tubes.

<u>Water gage</u>. The gage glass and its fittings for attachment.

<u>Water hammer</u>. A sudden increase in pressure of water due to an instantaneous conversion of momentum to pressure.

<u>Water leg</u>. A vertical or nearly vertical box header, sectional header, or water cooled sides of an internal firebox composed of flat or circular surfaces.

<u>Water level</u>. The elevation of the surface of the water in a boiler.

<u>Water seal</u>. A seal against leakage of air into a furnace consisting of a metal sheet, the lower edge of which is submerged in a trough containing water.

<u>Water tube</u>. A tube in a boiler having the water and steam on the inside and heat applied to the outside.

<u>Water vapor</u>. A synonym for steam, usually used to denote steam of low absolute pressure.

<u>Weathering</u>. Same as slacking.

Weep. A term usually applied to a minute leak in a boiler joint which forms droplets (or tears) of water very slowly.

Welded wall. A furnace closure wall made up of closely spaced waterwall tubes welded to each other or to an intermediate fin to form a continuous airtight structure.

Wet bulb temperature. The lowest temperature which a water wetted body will attain when exposed to an air current. The temperature of adiabatic saturation.

Wetness. A term used to designate the percentage of water in steam. Also used to describe the presence of a water film on heating surface interiors.

Wet steam. Steam containing moisture.

Wetting. The process of supplying a water film to the water side of a heating surface.

Wide range mechanical atomizing oil burner. A burner having an oil atomizer with a range of flow rates greater than that obtainable with the usual mechanical atomizers (see also Return Flow Oil Burner).

Windbox. A chamber below the grate or surrounding a burner, through which air under pressure is supplied for combustion of the fuel.

Windbox pressure. The static pressure in the windbox of a burner, firing system or stoker.

Wrapper sheet. The outside plate enclosing the firebox in a firebox or locomotive boiler. Also the thinner sheet in the shell of a two thickness boiler drum.

Zone control. The control of airflow into individual zones of a stoker.

Zones. Divisions of the stoker windbox in which air can be maintained at different and controllable pressures.

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3. DOCUMENT TITLE
MAINTENANCE AND OPERATION OF CENTRAL HEATING PLANTS

4. NATURE OF CHANGE *(Identify paragraph number and include proposed rewrite, if possible. Attach extra sheets as needed.)*

5. REASON FOR RECOMMENDATION

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a. NAME *(Last, First, Middle Initial)*	b. ORGANIZATION	
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