TM 5-650

TECHNICAL MANUAL

CENTRAL BOILER PLANTS

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HEADQUARTERS, DEPARTMENT OF THE ARMY
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		Paragraph	Page
CHAPTER 1.	GENERAL CONSIDERATIONS		
Section I.	Introduction		
	Purpose	1-1	1-1
	Central Boiler Plants	1-2	1-1
	Equipment	1-3	1-5
Section II.	Elementary Combustion Principles		
	Fossil Fuels	1-4	1-6
	Combustion	1-5	1-6
	Combustion of Coal	1-6	1-8
	Combustion of Oil	1-7	1-13
	Combustion of Natural Gas	1-8	
	Soot and Smoke	1-9	1-13
	Flue Gas Analysis and Temperature	1-10	1-15
	Combustion Efficiency	1-11	1-15
	Boiler Efficiency.	1-12	1-17
	Central Boiler Plant Efficiency	1-13	1-17
Section III.	Principles of Steam and Hot Water Generation		
	Basic Principles	1-14	1-23
	Heat Transfer	1-15	1-23
CHAPTER 2.	DESCRIPTION OF EQUIPMENT		
Section I.	Boilers and Heat Exchangers		
	Boiler Classifications	2-1	2-1
	Boiler Design Requirements 2-2	2-1	
	Fabrication	2-3	2-1
	Fire Tube Boilers	2-4	2-2
	Water Tube Boilers	2-5	2-2
	Hot Water Generators	2-6	2-13
	Economizers	2-7	2-13
	Air Heaters	2-8	2-13
Section II.	Boiler Accessories and Fittings		
	ASME Requirements	2-9	2-19
	Gage Glass, Gage Cocks	2-10	2-19
	Water Columns	2-11	2-19
	Pressure Gage, Temperature Gage	2-12	2-19
	Safety Valves	2-13	2-24
	Boiler Outlet Valves	2-14	2-27
	Blowoff Valves and Piping.	2-15	2-27
	Fusible Plugs	2-16	2-27
	Sootblowers	2-17	2-31
Section III.	Fuel- Handling and Combustion Equipment		

This Manual Supersedes TM 5-650, dated August 1962 and rescinds TM 5-651, dated December 1946.

Figure No.	Title	Page
1-4	Combustion of Oil	1-12
1-5	Combustion of Coal	1-14
1-6	Combustion Efficiency Motor	1-16
1-7	Elementary Boiler	1-24
1-8	Water Circulation	1-28
1-9	Effects of Soot and Scale on Heat Transfer	1-29
2-1	Tube Expander	2-3
2-2	Flared and Beaded Tubes	2-3
2-3	Scotch Boiler	2-3
2-4	Two, Three, and Four Pass Scotch Boiler Designs	2-4
2-5	Horizontal Return Tubular Boiler	2-5
2-6	Four Drum Water Tube Boiler	2-6
2-7	Refractory Expansion Joints	2-8
2-8	Water Wall Construction	2-9
2-9	Steam Drum Internals	2-10
2-10	Superheater in Two Drum Boiler	2-11
2-11	Package Boiler Configurations	2-12
2-12	D Package Boiler	2-12
2-13	Hot Water Generator	2-14
2-14	Hot Water End Uses	2-15
2-15	Hot Water Distribution	2-16
2-16	Bare Tube Economizer	2-17
2-17	Extended Surface Economizer	2-17
2-18	Cold End Corrosion - Minimum Metal Temperatures	2-18
2-19	Tubular Air Heater	2-20
2-20	Regenerative Air Heater	2-21
2-21	Water Gage Glass	2-22
2-22	Water Column	2-23
2-23	Safety Valve Installation	2-25
2-24	Huddling Chamber Safety Valve	2-26
2-25	Outside Screw and Yoke Gate Valve	2-28
2-26	Non-ReturnValve	2-29
2-27	Slow-Opening Blowdown Valve Set	2-30
2-28	Fire Tube Cleaning System	2-32
2-29	Fixed Position Mechanical Sootblower	2-33
2-30	Underfeed Stoker	2-355
2-31	Power Dump Grate Spreader Stoker	2-37
2-32	Underfeed Spreader	2-38
2-33	Traveling Chain Grate Stoker	2-33
2-34	Vibrating Grate Stoker	2-34
2-35	Fluidized Bed Fire Tube Boiler	2-42
2-36	Coal Handling System	2-44
2-37	Types of Bucket Elevators	2-46
2-38	Weigh Larry	2-47
2-39	Pneumatic Ash Handling System	2-48
2-40	Hydraulic Ash Handling System	249
2-41	Steam Atomizer	2-51
2-42	Rotary Atomizer	2-52
2-43	Register Burner	2-54
2-44	Low Excess Air Burner	2-55
245	Arrangement of Above-Ground Fuel Oil Tank	2-56
2-46	Underground Fuel Oil Storage Tank	2-57

Figure No.	Title	Page
2-47	Fuel Oil Pumping and Heating Equipment	2-58
2-48	Safety Equipment Oil-Fired Water Tube Boiler	2-59
2-49	Safety Equipment Oil- or Gas-Fire Tube Boiler	2-60
2-50	Safety Equipment Gas-Fired Water Tube Boiler	2-62
2-51	Positive Displacement Feedwater Regulator	2-63
2-52	Vapor-Generator/Thermohydraulic Feedwater Regulator	2-64
2-53	Thermostatic/Metal Expansion Feedwater Regulator	2-66
2-54	Two Element Feedwater Controls	2-67
2-55	Control Valve with Pneumatic Actuator	2-69
2-56	Control Valve with Pneumatic Actuator and Positioner	2-70
2-57	Steam Pressure Control System	2-71
2-58	Proportional Control	2-71
2-59	Proportional Response	2-72
2-60	Proportional Plus Integral Response	2-72
2-61	Basic Pneumatic Controller	2-74
2-62	Pneumatic Booster Relay	2-74
2-63	Parallel Positioning Control System	2-75
2-64	Series/Parallel Control	2-77
2-65	Jackshaft Control System	2-77
2-66	Parallel Metering System	2-78
2-67	Oxygen Trim Control System	2-79
2-68	Electronic Programming Control in a Boiler Panel	2-81
2-69	Float/Magnet Low-Water Fuel Cutoff	2-82
2-70	Electrode Type Low-Water Fuel Cutoff	2-83
2-71	Bourdon-Tube Pressure Switch	2-83
2-72	Diaphragm Pressure Switch	2-84
2-73	Temperature Switch	2-84
2-74	U-V Flame Scanner	2-85
2-75	Annunciator	2-85
2-76	Air-Flow Steam-Flow Meter	2-86
2-77	Direct-Acting Temperature Regulator	2-88
2-78	Pilot-Operated Temperature Control Valve	2-89
2-79	Pilot-Operated Prssure-Reducing Valve	2-90
2-80	Diaphragm Actuator Pressure-Reducing Valve	2-91
2-81	Self-Contained Diaphragm Pressure-Reducing Valve	2-92
2-82	Differential Pressure-Reducing Valve	2-94
2-83	Steam Differential Pressue-Reducing Valve	2-95
2-84	Orifice, Flow Nozzle, and Venturi	2-96
2-85	Steam Flow Recorder	2-97
2-86	Pneumatic Differential Pressure Transmitter	2-98
2-87	Rotameter	2-99
2-88	Positive Displacement Meter	2-100
2-89	Turbine Meter	2-101
2-90	Bourdon-Tube Pressure Gage	2-102
2-91	Opposed Bellows Differential Pressure Gage	2-103
2-92	Inclined U-Tube Manometer	2-105
2-93	Diaphragm Draft Gage	2-106
2-94	Zirconium Oxide Oxygen Analyzer	2-107
2-95	Recording Thermometer	2-108
2-96	Strip Chart Recorder	2-109
2-97	Medium Efficiency Cyclone Configuration	2-116

		Paragraph	Page
	Coal Combustion Equipment	2-18	2-34
	Coal-Handling Equipment	2-19	2-43
	Ash-Handling Equipment	2-20	2-45
	Oil-Firing Equipment	2-21	2-50
	Oil Storage and Handling	2-22	2-53
	Gas-Firing Equipment	2-23	2-53
	Liquified Petroleum Gas	2-24	2-62
Section IV	Controls and Instrumentation		
	Feedwater-Drum Level Controls	2-25	2-62
	Combustion Controls	2-26	2-65
	Boiler Safety Control	2-27	2-76
	Additional Controls and Instrumentation	2-28	2-89
	Water Treatment Control	2-29	2-110
Section V.	Pollution Control Equipment		
	Pollution Regulations	2-30	2-110
	Types of Pollutants and Control Methods	2-31	2-110
	Mechanical Collectors	2-32	2-112
	Fabric Filters	2-33	2-120
	Electrostatic Precipitators	2-34	2-123
	Wet Scrubbers	2-35	2- 125
Section VI.	Auxiliary Equipment		
	Feedwater Heaters	2-36	2- 125
	Pumps and Injectors	2-37	2-125
	Forced Draft Fans	2-38	2-135
	Induced Draft Fans	2-39	2-137
	Stacks, Flues, and Ducts	2-40	2-137
	Steam Turbines.	2-41	2- 140
	Electric Motors	2-42	2-140
	Electrical Equipment	2-43	2- 140
	Variable Speed Drives	2-44	2- 140
	Air Compressors	2-45	2- 142
	Steam Traps	2-46	2- 142
	Piping Systems.	2-47	2-145
CHAPTER 3.	OPERATION		
Section I.	Preliminary Operating Procedures		
	Plant Operation Considerations	3-1	3-1
	Standing Operating Procedures	3-2	3-1
	Daily and Monthly Boiler Plant Operating Logs.	3-3	3-1
	Inspection	3-4	3-1
	Applicable Codes	3-5	3-1
	Basis for Comments	3-6	3-1
	Preparation for Startup	3- 7	3-4
	Starting Fire	3-8	3-4
	Warm-up Time	3-9	3-5
	Placing a High Pressue Steam Boiler in Service	3-10	3-6
	Placing a Hot Water Boiler in Service	3-11	3-7
Section II.	Operating Adjustments and Procedures		
	Boiler Operation.	3-12	3-8
	Maintaining Pressure or Temperature	3-13	3-8
	Feedwater and Boiler Water Treatment	3-14	3-8

		Paragraph	Page
	Controlling Feedwater	3-15	3-8
	Boiler Accessories	3-16	3-8
	Coal Firing Procedures	3-17	3-10
	Oil Firing Procedures	3-19	3-13
	Combustion Controls	3-20	3-15
	Boiler Safety Controls	3-21	3-15
	Centrifugal Pumps	3-22	3-16
	Direct-Acting Pumps	3-23	3-16
	Injectors	3-24	3-18
	Fans	3-25	3-18
	Feedwater Heating and Treatment	3-26	3-18
	Economizers, Air Heaters and Pollution Control Equipment	3-27	3-19
	Emergency Procedure-Abnormal Water Level	3-18	3-19
	Emergency Procedure-Boiler Tube Failure	3-29	3-19
	Emergency Procedure - Fan Failure	3-30	3-20
	Emergency Procedure - Electric System Failure	3-31	3-20
	Emergency Procedure - Flame Failure	3-32	3-21
	Removing a Boiler from Service	3-33	3-21
Section III.	Optimizing Central Plant Efficiency		3-22
	Optimizing Combustion Efficiency	3-34	3-22
	Optimizing Boiler Efficiency	3-35	3-24
	Optimizing Central Boiler Plant Efficiency	3-36	3-24
CHAPTER 4.	WATER TREATMENT FOR BOILER PLANTS		
Section I.	Introduction		4-1
	Objectives of Water Treatment	4-1	4-1
	Impurities in Water	4-2	4-1
	Results and Reactions of Boiler Water Impurities	4-3	4-5
	Controlling Impurities	4-4	4-6
	Treatment Requirements	4-5	4-8
Section II.	Equipment and Chemicals		4-10
	External Treatment Equipment	4-6	4-10
	Internal Treatment	4-7	
	Blowdown	4-8	
Section III.	Operation		4-33
	Boiler Water Treatment Operating Log	4-9	4-33
	Procurement of Standard and Special Treatment Chemicals	4-10	4-33
	Care and Mixing of Treatment Chemicals	4-11	4-37
	Initial Flushing and Cleaning	4-12	4-37
	Flushing and Cleaning of Scaled and Corroded Boilers	4-13	4-38
	Sampling	4-14	4-38
	Chemical Analysis	4-15	4-40
	General Operation of External Treatment Equipment	4-16	4-41
	General Operation of Internal Treatment Equipment	4-17	4-51
	Safety Precautions	4-18	4-56
	Care of Idle Steel Boilers	4-19	4-56
CHAPTER 5.	INSPECTION AND PREVENTIVE MAINTENANCE		
Section I.	Introduction		5-1
	Purpose and Scope	5-1	5-1
	Types of Maintenance	5-2	5-1

		Paragraph	Page
	Responsibility	5-3	5-1
	Inspection	5-4	5-1
	Housekeeping	5-5	5-1
	Utilities Inspection and Service Records	5-6	5-1
	Tools	5-7	5-3
	Spare Parts	5-8	5-3
	Special Supplies	5-9	5-3
Section II.	Scheduled Preventive Maintenance		5-5
	Scheduling and Use of The Information	5-10	5-5
	Boilers	5-11	5-5
	Economizers	5-12	5-8
	Air Heaters	5-13	5-9
	Water Columns	5-14	5-9
	Safety Valves	5-15	5-9
	Fusible Plugs	5-16	5-10
	Sootblowers	5-17	5-10
	Stokers	5-18	5-10
	Pulverized Coal Equipment	5-19	5-10
	Coal Handling Equipment	5-20	5-10
	Ash Handling Equipment	5-21	5-11
	Oil Burners	5-22	5-11
	Oil Handling Equipment	5-23	5-11
	Gas Burners	5-24	5-11
	Feedwater Drum Level Controls	5-25	5-11
	Combustion Controls	5-26	5-12
	Boiler Safety Controls	5-27	5-12
	Instrumentation	5-28	5-12
	Mechanical Collectors	5-29	5-12
	Stacks	5-30	5-12
	Zeolite Water Softeners	5-31	5-13
	Hot Lime-Soda Softeners	5-32	5-13
	Deaerating Heaters and Dearators	5-33	5-13
	Pumps	5-34	5-14
	Centrifugal Pumps	5-35	5-14
	Reciprocating Pumps	5-36	5-14
	Steam Injectors	5-37	5-15
	Steam Turbine (Non-Condensing)	5-38	5-15
	Air Compressors	5-39	5-15
	Steam Traps	5-40	5-16
	Electric Motors	5-41	5-16
	Forced-Draft and Induced-Draft Fans	5-42	5-16
	Command Inspections	5-43	5-17
	Technical Inspection	5-44	5-17
	Major Army Command Inspections	5-45	5-17
APPENDIX A.	REFERENCES	A-1	A-l
APPENDIX B.	CHEMICAL ANALYSIS PROCEDURES		
	External Treatment Plants	B-l	A-3
	Boiler Water	B-2	A-4
	Miscellaneous Tests	B-3	A-10

		Paragraph	Page
APPENDIX C.	HEAT BALANCE CALCULATIONS		
	100 PSIG Steam Heat Balance	C-l	A-11
	15 PSIG Steam Heat Balance	C-2	A-13
	High Temperature Water Heat Balance	C-3	A- I5
APPENDIX D.	BOILER WATER CALCULATIONS		
	Boiler Blowdown Calculations	D-I	A-17
	Determining Feedwater Requirements	D-2	A-17
	Determining Makeup Requirements	D-3	A-17
	Determining Chemical Treatment Requirements	D-4	A- 19

LIST OF TABLES

Table No.	Title	Page
l-l	Classification of Coals	1-7
1-2	Standard Specification for Fuel Oils	1-9
1-3	Fuel Oil Characteristics	1-10
1-4	Combustion Efficiency for Natural Gas	1-18
1-5	Combustion Efficiency for Number 2 Oil	I-19
1-6	Combustion Efficiency for Number 6 Oil	1-20
1-7	Combustion Efficiency for Coal, 3.5 Moisture, Bituminous	1-21
1-8	Combustion Efficiency for Coal, 9.0% Moisture, Bituminous	1-22
1-9	Water/ Steam Characteristics	1-25
1-10	Water/ Steam Mixtures	1-27
2-l	Typical Point Source Emission Levels for Various Pollutants	2-110
2-2	Comparison of NOx Reduction Techniques	2-111
2-3	Performance Characteristics of Flue-Gas &sulfurization Systems	2-113
2-4	Performance Characteristics of Particulate Control Devices	2-114
2-5	Characteristics of Mechanical Dust Collectors	2-118
2-6	Removal Efficiencies of Uncontrolled Particulate Emissions from Combustion Process	2- 120
2-7	Permissible Maximum Suction Lits and Minimum Suction Heads in Feet for Various Temperatures and Altitudes	2-128
2-8	Piping Codes and Standards for Boiler Plants	2- 148
2-9	Typical Piping Material Applications	2- 149
3-1	Flue Gas Analysis at 25%, 50%, and 100% Load for Natural Gas, No. 2 Oil, No. 6 Oil, and Stoker Coal	3-23
4-1	Common Cations and Anions	4-1
4-2	Water pH	4-5
4-3	Guide for Selection of External Treatment Equipment	4-11
4-4	Common Sodium Phosphates	4-30
4-5	Deaerator Temperature Versus Pressure	4-48
5-1	Lubricating Oils, Greases, and Preservatives	5-6
5-2	Lubricating Oil and Grease Uses	5-7

LIST OF FIGURES

Figure No.	Title	Page
l-l	100 psig Steam Heat Balance	1-2
1-2	15 psig Steam Heat Balance	1-3
1-3	High Temperature Water Heat Balance	1-4

Figure No.	Title	Page
2-98	Multicyclone Configuration	2-117
2-99	Cyclone Fractional Efficiency Curve	2-119
2-100	Reverse Flow Baghouse	2- 121
2-101	Pulse Jet Baghouse	2-122
2-102	Weighted Wire Type Electrostatic Precipitator	2-124
2-103	Wet Approach Venturi Scrubber	2-126
2-104	Tube and Shell Heat Exchanger	2-127
2-105a	Maintain Proper Slope to Suction Line	2-129
2-105b	Suction Line Installation	2-129
2-106	Centrifugal Pump	2- 130
2-107	Reciprocating Piston Pump	2-132
2-108	Two Methods of Providing Lost Motion	2-133
2-109a	Rotary Screw Pump	2-134
2-109b	Rotary Gear Pump	2- 134
2-110	Steam Injector	2-136
2-111	Forced Draft Fan with Inlet Damper	2-138
2-112	Typical Outlet Fan Dampers	2-138
2-113	Fan Curves for Different Inlet Vane Positions	2-139
2-114	Fan Curve for Fan with Outlet Damper	2- 139
2-115	Single-Stage Impulse Non-Condensing Turbine	2-141
2-116	Thermostatic Steam Trap	2- 143
2-117	Float and Thermostatic Steam Trap	2-144
2-119	Disc/ Thermodynamic Steam Trap	2-146
2-119	Inverted Bucket Steam Trap	2-147
2-120	Standard Hanger Types for Piping Systems	2-151
2-121	Sdid Wedge Disc Gate Valve	2-152
2-122	Single Port Globe Valve	2- 152
2-123	Non-Lubricated Plug Valve	2-154
2-124	Butterfly Valve	2-154
2-125a	Swing Check Valve	2- 155
2-125b	Y-Type Spring Lift Check Valve	2-155
3-1	Daily Boiler Plant Operating Log	3-2
3-2	Monthly Boiler Plant Operating Log	3-3
3-3	Gil viscosity versus Temperature	3-14
3-4	Smoke Density versus Percent Oxygen	3-17
3-5	Fuel/Air Ratio Biasing	3-17
3-6	Boiler Efficiency versus Load	3-25
4-1	Condensate Pipe Corrosion	4-2
4-2	Boiler Tube Failure Caused by Scale	4-2
4-3	Superheater Tube Showing Carryover Deposits	4-3
4-4	Effects of Treatment on Raw Water	4-12
4-5	Sodium Zedite Softener	4-13
4-6	Hot Process Lime Soda Softener	4-15
4-7	Hot-Lime Hot-Sodium Zedite Softener	4-16
4-8	Hydrogen and Sodium Zeolite Softeners Operating in Parallel	4-17
4-9	Hydrogen Zeolite with Alkaline Neutralization	4-17
4-10	Degasifier/ Decarbonating Tower	4-18
4-11	Sodium Zedite-Chloride Ion Exchanger System	4-20
4-12	Dcmineralizer	4-21
4-13	Tray Deaerator	4-23
4-14	Spray Deaerator	4-24
4-15	Type I Deaerator Installation	4-25

Figure No.	Title	Page
4-16	**Type** II Deaerator Installation	4-27
4-17	Type III Deaerator Installation	4-28
4-18	Blowdown System with Flash Tank and Heat Exchanger	4-32
4-19	Automatic Continuous Blowdown Controls	4-34
4-20	Conductivity Meter	4-35
4-21	Boiler Water Treatment Operating Log	4-36
4-22	Water Cooled Sample Cooler	4-39
4-23	Condensate Corrosion Tester	4-42
4-24	Zeolite Softener Water Flows	4-43
4-25	Effect of Excessive Water Flow Bates	4-44
4-26	Zeolite Bed Inspection Points	446
4-27	Solubility of Oxygen in Water	4-49
4-28	Pressure Pot Feeder	4-52
4-29	Automatic Proportioning Feeder	4-53
4-30	Chemical Mixing Tank with Chemical Feed Pump	4-54
4-31	Chemical Feed Pump Plunger/ Diaphragm Type	4-55
4-32	Eyewash Station	4-57
4-33	Safety Shower	4-58
4-34	Wet Storage Method	**4-60**
5-1	Record Card Example	5-4
C-l	100 psig Steam Heat Balance	
c-2	15 psig Steam Heat Balance	
c-3	High Temperature Water Heat Balance	
D-l	Example of Boiler Feedwater, Steam Generation and Blowdown	
D-2	Example of Boiler Calculations	

CHAPTER 1
GENERAL CONSIDERATIONS

SECTION I. INTRODUCTION

1-1. PURPOSE

The purpose of this manual is to provide information and guidance on the installation, operation, and maintenance of U.S. Army Central Boiler Plant equipment. Efficient plant operation becomes more important with each increase in the cost of fuel and equipment. The Central Plant operator has an important job in achieving and maintaining maximum efficiency of plant operation. The information and guidance in this manual should be reviewed as a first step toward achieving efficient plant operation.

1-2. CENTRAL BOILER PLANTS

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 for recycle.

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

Low Temperature Water	LTW (up to 250° F, less than 160 psig)
Medium Temperature Water	MTW (251° F to 350° F)
High Temperature Water	HTW (351° F to 450° F)
Low Pressure Steam	LPS (up to 15 psig)
High Pressure Steam	HPS (above 15 psig)

The type of Central Boiler Plant built depends upon the requirements of the specific installation. For applications involving only space heating and domestic water, a low temperature water 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 high temperature water system to those of a steam system. Such an evaluation usually shows the high temperature water plant to be more economical. The following paragraphs provide a brief comparison of the major types of central heating plant systems.

b. Comparison of High Temperature Water and Steam. The major advantages of high and medium temperature water systems result from the closed-loop distribution system. The closed loop system recycles the unused energy in the water and 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. The advantages of high and medium temperature water systems are further discussed in the following paragraphs.

(1)**Energy Losses from a Steam System.** Figures 1-1 and 1-2 illustrate the heat balance at a heat exchanger for 100 psig and 15 psig steam/condensate system, respectively. When 100 psig steam is supplied to a heat exchanger, the condensed water is at a temperature of 338° F and contains 26 percent of the energy originally supplied in the steam. When the condensate discharges from the trap, 13 percent of the water flashes to steam and the remaining condensate is at a temperature of 212° F. When 15 psig steam is supplied, the condensed water contains 19 percent of the original energy at a temperature of 250° F. When the condensate discharges from the trap, 4 percent of the water flashes to steam. The 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) **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, the flash-off steam is lost. If a portion of the condensate is not returned to the central boiler plant for any reason, the portion of the energy remaining in the condensate is lost. For example, if a 100 psig system has 20 percent condensate loss, 5.2 percent (.20 x .26 = .052) of the total energy produced is wasted. In addition, 20 percent treated make-up water is needed to keep the system operating. Procedures for monitoring and controlling condensate losses are further discussed in paragraph 3-2.

(3) **Heat Balance for an HTW System.** Figure 1-3 illustrates a heat balance for a high temperature water system at a heat exchanger. It is informative to compare the high temperature water system with 100 psig steam system. In both cases, 1125 lbs of water is heated from 50° F to 140° F by the heat exchanger. The high temperature

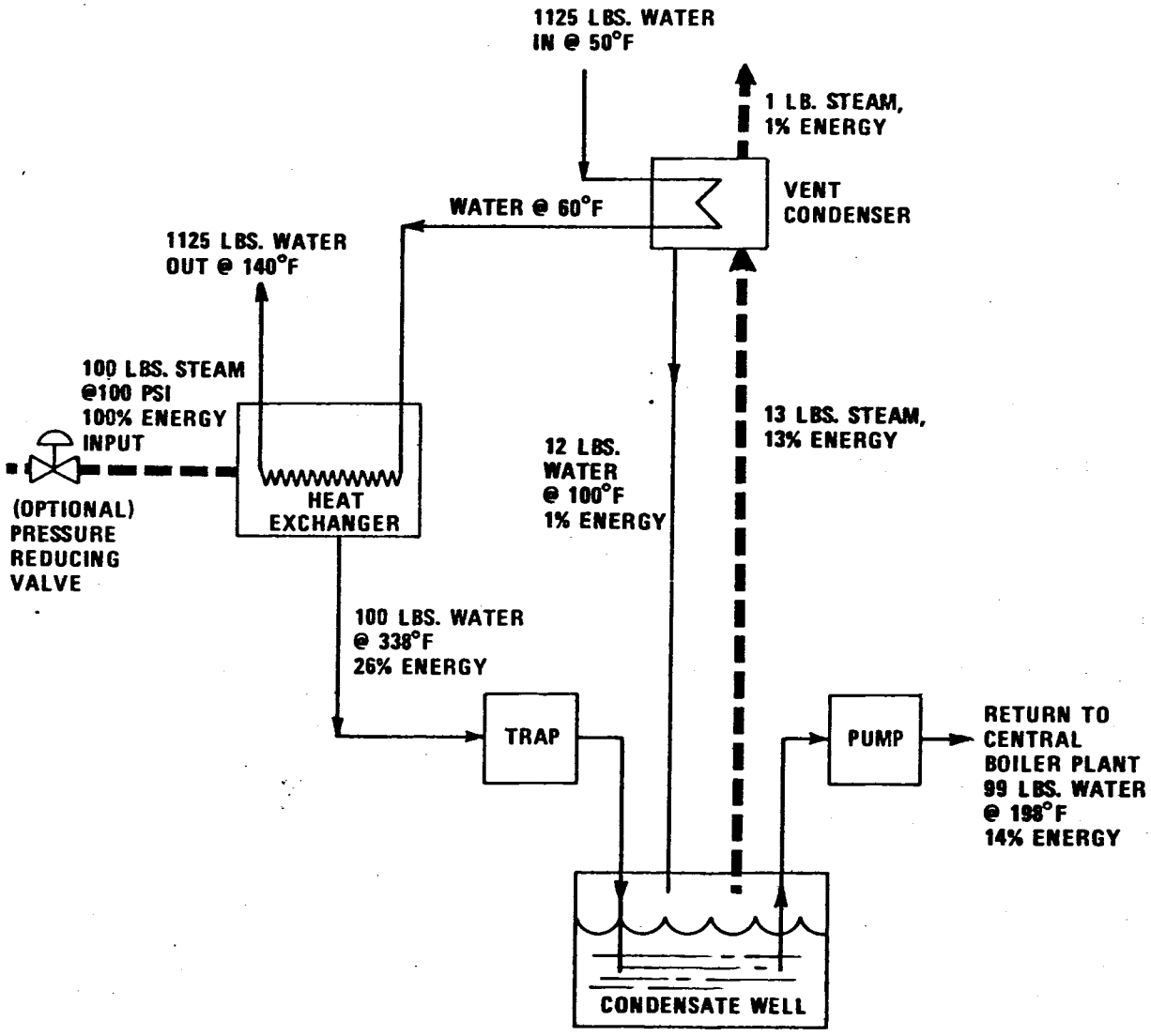


FIGURE 1–1. 100 PSI STEAM HEAT BALANCE

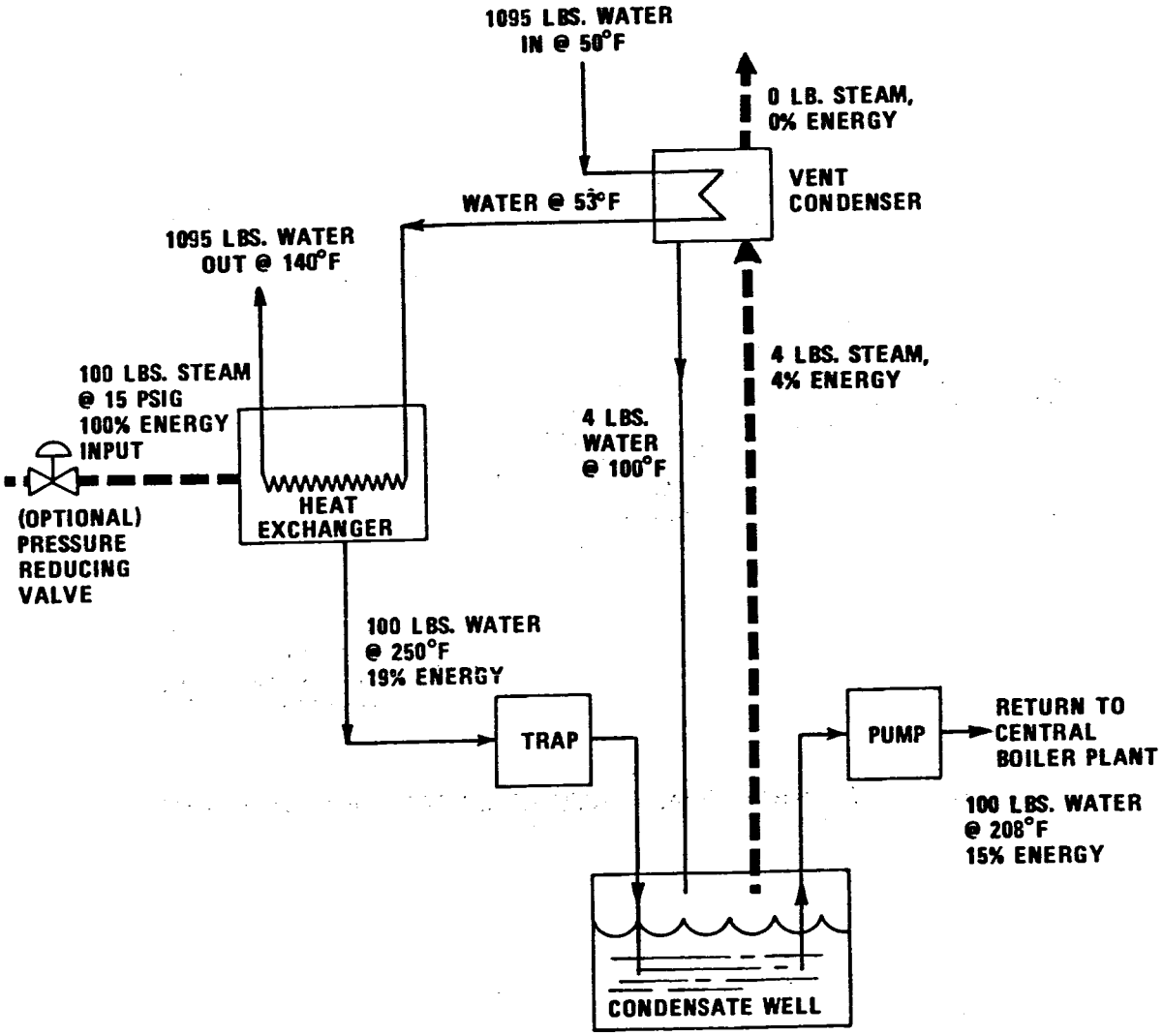


FIGURE 1–2. 15 PSI STEAM HEAT BALANCE

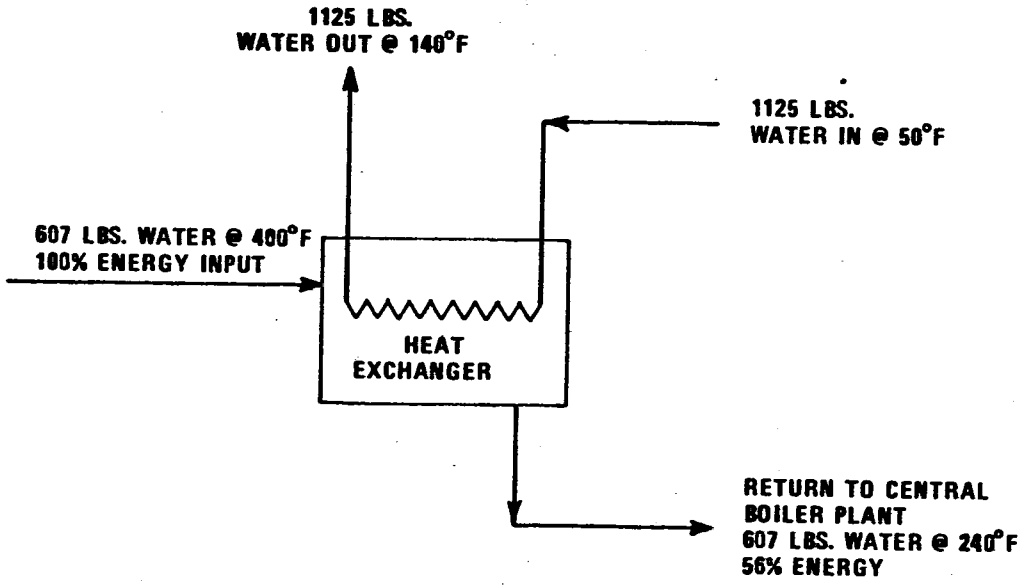


FIGURE 1–3. HIGH TEMPERATURE WATER HEAT BALANCE

water system returns 56 percent of the energy input to the heat exchanger while the steam system returns 14 percent. The high temperature water 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 the process requirements of the system are such that it is applicable. Appendix C provides Heat Balance Calculations explaining these numbers.

(4) **Corrosion.** A major advantage of the high temperature water 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.

(5) Stored Thermal Energy. The large amount of stored thermal energy in an HTW and MTW distribution system 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 the stored thermal capacity in the system.

(6) **Safety.** High and medium temperature water systems are safer than steam. In the event of a line rupture, the 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° F water occurs, ending one to two feet from the rupture. The amount of energy exiting a ruptured high temperature water line is only 5 to 10 percent of the energy exiting a ruptured steam line of the same size.

(7) **Water Treatment.** Due to the 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 a 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. Blowdown is less or not required at all in a hot water boiler.

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

c. Low Temperature Water. Low temperature water plants have all the basic advantages of HTW and MTW 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.

1-3. EQUIPMENT

A Central Boiler Plant is comprised of ten major categories of equipment, as described below.

a. Heat-Absorbing Equipment. Heat (energy) from the combustion of fuel is transferred to the 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 the boiler flue gases (products of combustion) and transfer it to the feedwater. Heat from the flue gases can also be absorbed by air heatings for transfer to the combustion air before it enters the furnace through the burner or stoker grate. Plant efficiency is closely related to the ability of the boiler, economizer, or air heater to absorb heat from the products of combustion.

b. Fuel-Handling Equipment. Coal-burning plants require facilities for storage of coal, and equipment for moving the coal to storage and reclaiming and transferring it at the boiler. Provisions are usually made to move the 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 the burners will be required and oil heaters may be required depending upon the oil used. Ash removal equipment may be required in some cases. Gas-burning plants will have a gas pressure reducing station (shut-off valve, strainer, pressure reducing valve, safety-relief valve, and gas meter) to reduce the incoming line pressure required in the distribution piping and burners.

c. Combustion Equipment. Combustion equipment for oil and gas firing consists of safety shut-off valves, safety devices or interlocks, control valves, and burner(s). The function of the burner is to ignite and burn the 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.

d. Air-Handling Equipment. In order 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 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 fans are used to pull the flue gas from the furnance through the boiler bank and any ductwork, economizer, air heater, or dust collector provided.

e. 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 the fuel and air flow to maintain efficient combustion. The high price of boiler fuel which justifies improved combustion controls also justifies the use of recorders and meters to monitor combustion and ensure optimum plant operation.

f. Pollution Control Equipment. The combustion of fuel may generate a variety of pollutants in excess of limits set by regulatory agencies. The major pollutant emissions of present concern are particulate, oxides of sulfur (SOx), and oxides of nitrogen (NOx). The use of a fuel lower in ash or surfur content and modifications to the combustion process can be effective in reducing these emissions. If these fuels are too expensive or combustion modifications only partially effective, pollution control systems can also be used to bring emissions within acceptabe limits. Typical pollution control systems are mechanical collectors, fabric filters, electrostatic precipitators, wet scrubbers, and tall stacks.

g. Water Treatment Systems. Proper water treatment prevents scale formation on the internal surfaces of the boiler and reduces boiler and distribution system corrosion. Water treatment often involves 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 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.

h. Water Supply Equipment. Feedwater is supplied to steam boilers by means of centrifugal or reciprocating pumps. Centrifugal pumps are also typically used to circulate water through high temperature water boilers and their associated distribution systems.

i. Distribution Systems. The 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, weatherproof pipelines, valve pumps, regulators, and heat exchangers. Steam systems also include traps and condensate handling of equipment.

j. Miscellaneous. Each central boiler plant has its own unique set of maintenance tools and spare parts inventory. Also unique to a given plant is its electric power distribution system, air compressors, and emergency generator sets.

SECTION II. ELEMENTARY COMBUSTION PRINCIPLES

1-4. FOSSIL FUELS

Fossil fuels are derived from the 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 the original carbohydrates and other organic materials were buried and converted to the hydrocarbon or fossil fuels we use today. These fossil fuels are found in solid, liquid, and gaseous form.

a. Coal. Coal is a solid fossil fuel. Coal's characteristics are directly affected by its 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. Considering the cost of coal today, it is worth thinking of coal as young diamonds.

(1) 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 twent-eight 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 1-1 outlines the classification of coals as given by ASTM D 388. This standard establishes ranges for fixed carbon, volatile matter, and heating value for each class and group of coals.

(2) Coal is a highly complex fuel. Most of its heating value exists in the form of carbon, which is present

Table 1-1. 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. Semianthracite	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	13 000
						10 500	11 500
III Subbituminous	1. Subbituminous A coal	--	--	--	--	10 500	11 500
	2. Subbituminous B coal	--	--	--	--	9 500	10 500
	3. Subbituminous C coal	--	--	--	--	8 300	9 500
IV Lignitic	1. Lignite A	--	--	--	--	6 300	8 300
	2. Lignite B	--	--	--	--	--	6 300

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 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 occasionlly on a moisture and ash free basis. Coal is also analyzed for heating value, in 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.

b. Oil. Oil is a liquid fossil fuel, normally found far underground (to a depth of five miles or more). Oil and natural gas are as old or older than coal and are the products of marine plants and organisms which were buried and transformed by bacteria and chemical action into complex hydrocarbons. The oil and gas thus formed 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 the oil and gas are found, the higher their age and quality. The 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 pressure to separate the light ends (straight run No. 1 and No. 2 oil) from the heavier residual oil. The 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 the paraffinic and naphthenic hydrocarbons found in straight run oil. The "Standard Specification for Fuel Oils" is defined in ASTM D 396. Table 1-2 "Detail Requirements for Fuel Oils" establishes limits for many of the key properties of fuel oil for the various standard grades. Table 1-3 relates API gravity to specific gravity, density, and higher heating value of fuel oils. 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 the different components. Fairly recent problems have been related to No. 4 oil refined from imported parafin base crude. Paraffin wax from the oil can plate out and clog strainers, even though the oil is fluid. Heating the oil to 90 to 100° 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 chapter 3.

c. Natural Gas. Natural gas was formed by the same processes which produced oil. Compared with coal and oil, natural gas is a simple fuel consisting primarily of methane (CH_4, 77% to 90% by volume) and ethane (C_2H_6, 5% to 15% 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% to 9% 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 the piping exist, the 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.

d. 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 the consumption of coal, oil, or gas. This trend will undoubtedly continue and accelerate.

1-5. COMBUSTION

Combustion can be defined as the 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 the fuel, oxygen, and heat so that the fuel is completely burned and the maximum use is made of its energy. To achieve controlled and efficient combustion three factors must be considered: TIME, TEMPERATURE, and TURBULENCE. Although the oxidation is rapid, several seconds may be required to start and complete the combusion process. Temperature varies during the combusion process with minimum temperatures occurring at the beginning and end. Turbulence is necessary to allow the fuel to be intimately mixed with the oxygen.

a. Chemical Reactions. The following general chemical reactions occur as the 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 cabon dioxide (CO_2-MW = 44), water (H_2O-MW

Table 1-2. Standard Specification for Fuel Oils

Grade of Fuel	Flash Point °C (°F)	Pour Point °C (°F)	Water and Sediment Vol %	Carbon Residue on 10% Bottoms, %	Ash Weight %	Distillation Temperatures, °C (°F)			Saybolt Viscosity, s				Specific Gravity 60/60°F (Degree API)	Copper Strip Corrosion	Sulfur %
						10% Point	90%	Point	Universal at 38°C (100°F)		Fuel at 50°C (122°F)				
	Min	Max	Max	Max	Max	Max	Min	Max	Min	Max	Min	Max	Max	Max	Max
No. 1 Distillate	38 (100)	-18 (0)	0.05	0.15	--	215 (420)	--	288 (550)	--	--	--	--	0.8499 (35 min)	No. 3	0.5
No. 2 Distillate	38 (100)	-6 (20)	0.05	0.35	--	--	282 (540)	338 (640)	32.6	37.9	--	--	0.8762 (30 min)	No. 3	0.5
No. 4 Light Residual	55 (130)	-6 (20)	0.50	--	0.10	--	--	--	45	125	--	--	--	--	--
No.5 Light Residual	55 (130)	--	1.00	--	0.10	--	--	--	125	300	--	--	--	--	--
No. 5 Heavy Residual	55 (130)	--	1.00	--	0.10	--	--	--	300	900	23	40	--	--	--
No. 6 Heavy Residual	60 (140)	--	2.00	--	--	--	--	--	900	9000	45	300	--	--	--

Table 1-3. Fuel Oil Characteristics

API Gravity	Specific Gravity	Density lb/gal	Higher Heating Value	
			Btu/lb	Btu/gal
5	1.037	8.633	17,980	155,470
10	1.000	8.328.	18,260	152,280
15	0.966	8.044	18,500	149,030
20	0.934	7.778	18,740	145,880
25	0.904	7.529	18,940	142,820
30	0.876	7.273	19,130	139,660
35	0.850	7.076	19,300	136,720
40	0.825	6.870	19,450	133,760
45	0.802	6.675	19,590	130,910

API Gravity ranges for the fuel oil grades are: No. 1 Oil-46 to 41, No. 2 Oil-39 to 30, No. 4 Oil-28 to 24, No. 5 Oil-22 to 18, No. 6 Oil-17 to 9.

= 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 H2 + 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

(1) 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

(2) In some cases, the oxygen 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 be formed 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 British Thermal Units (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 U.S. is to use higher heating value in combustion calculations, while lower heating value 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 efficienty.

b. Air Requirements. The air we breathe is 76.7% nigrogen and 23.3% oxygen by weight or 79% nitrogen and 21% oxygen by volume. We use air to obtain oxygen for the combustion process. Each pound of air contains .233 pounds of oxygen. To obtain one pound of oxygen requires 4.29 pounds of air. This is calculated as follows:

$$4.29\ lb\ air \times \frac{0.233\ lb\ oxygen}{1.0\ lb\ air} = 1.0\ lb oxygen$$

Each 4.29 pounds of air contains 1 pound of oxygen and 3.29 pounds of nitrogen. The nitrogen is not chemically active in the combustion process; however, it lowers the flame temperature by absorbing heat and carrying it away from the boiler in the 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, the 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.

c. Excess Air Example. Combustion of one 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:

.87 lb C x 2.66 lb O_2/ lb C	= 2.31 lb O_2
.12 lb H_2 x 7.94 lb O_2/ lb H_2	= 0.95 lb O_2
.005 lb S x 1.00 lb O_2/ lb S	= 0.01 lb O_2
Theoretical Oxygen	= 3.27 lb O_2

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. The total combustion air per pound of fuel required thus becomes:

14.0 lb air + (14.0 lb air x .20) = 16.8 lb air.

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

14.0 lb. air +1 (14.0 lb air x .50) = 21.0 lb. air.

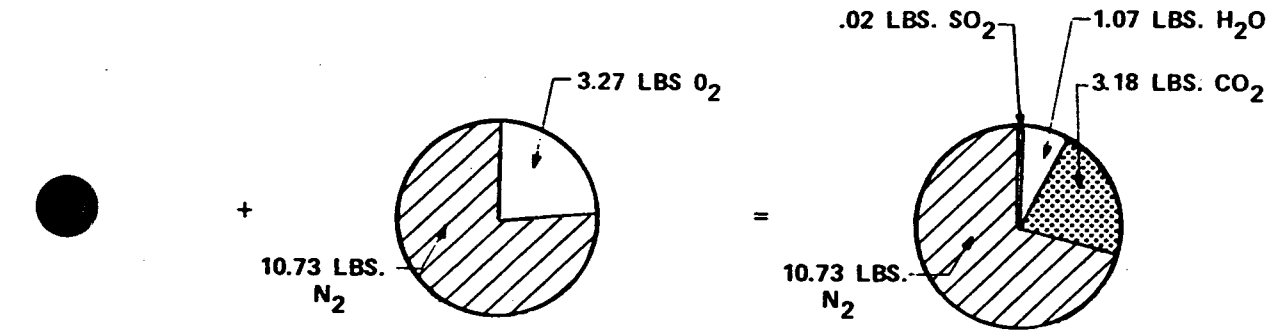
Figure 1.4 illustrates these relationships and the combustion products.

d. Higher Heating Values. Higher heating values of fuels are best determined by calorimeter test. If the ultimate analysis of an oil or coal is known, Dulong's formula may be used to determine HHV of a liquid or solid fuel. Dulong's formula is given below and may be considered accurate to within 2 or 3 percent.

$$HHV = 14{,}544C + 62{,}028\ (H_2 - O_2/8) + 4050\ S$$

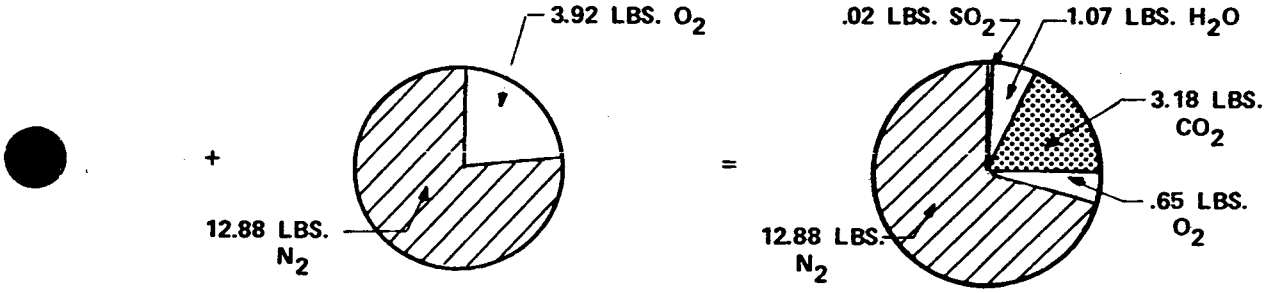
The carbon, hydrogen, oxygen, and sulfur come from the ultimate analysis and are expressed in percent by weight. The coefficients represent the approximate heating values of the constituents in Btu/lb and the result obtained is also in Btu/lb. The $O_2/8$ is a correction applied to the hydrogen in the 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

COMBUSTION WITH THEORETICAL AIR



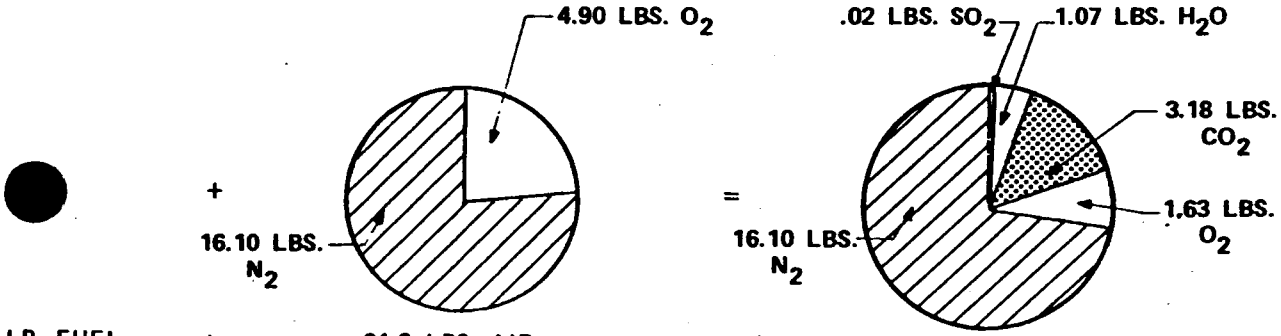
1 LB. FUEL + 14.0 LBS. AIR = 15 LBS. FLUE GASES

COMBUSTION WITH THEORETICAL AIR + 20% EXCESS AIR



1 LB. FUEL + 16.8 LBS. AIR = 17.8 LBS. FLUE GASES

COMBUSTION WITH THEORETICAL AIR + 50 % EXCESS AIR



1 LB. FUEL + 21.0 LBS. AIR = 22.0 LBS. FLUE GASES

FIGURE 1–4. COMBUSTION OF OIL

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 lower heating value 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 1-3 provides a comparison of the API gravity, specific gravity, Btu/lb, and Btu/gallon for ranges of fuel oils.

1-6. COMBUSTION OF COAL

The fundamentals of coal combustion are illustrated in figure 1-5 which represents hand-fired grate burning. A uniform fuel bed eight 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. The 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 the raw coal in the oxygen-deficient reducing zone at the top of the bed. The 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 the 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 the 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 the practrical excess air levels that can be maintained and completeness of combustion. The rate of combustion is controlled by the underfire combustion air. The efficienty of combustion is determined by the 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 the coal combustion. In some stokers, a portion of the coal may be burned in suspension before it falls onto the grate. In underfeed stokers, the 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. The pulverized coal is completely burned in suspension. The principles of coal combustion remain the same for any of these variations. Moisture and volatile matter must be driven off before the fixed carbon can be burned and combustion air must be effectively mixed with the volatile vapors to efficiently complete combustion.

1-7. COMBUSTION OF OIL

The combustion of fuel oil occurs after the liquid oil is varporized. 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. The heavy hydrocarbons crack, as described in paragraph 1-9, to give the oil flame its yellow color. The burner must supply additional air to mix with the 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 all boiler loads.

1-8. COMBUSTION OF NATURAL GAS

Natural gas consists mainly of the 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 as described in paragraph 1-9, 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 vill 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 buildup of such concentrations, safety shut-off 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.

1-9. SOOT AND SMOKE

Understanding the causes of soot and smoke is the first step in their prevention.

a. Soot. Soot is unburned carbon from the fuel. The

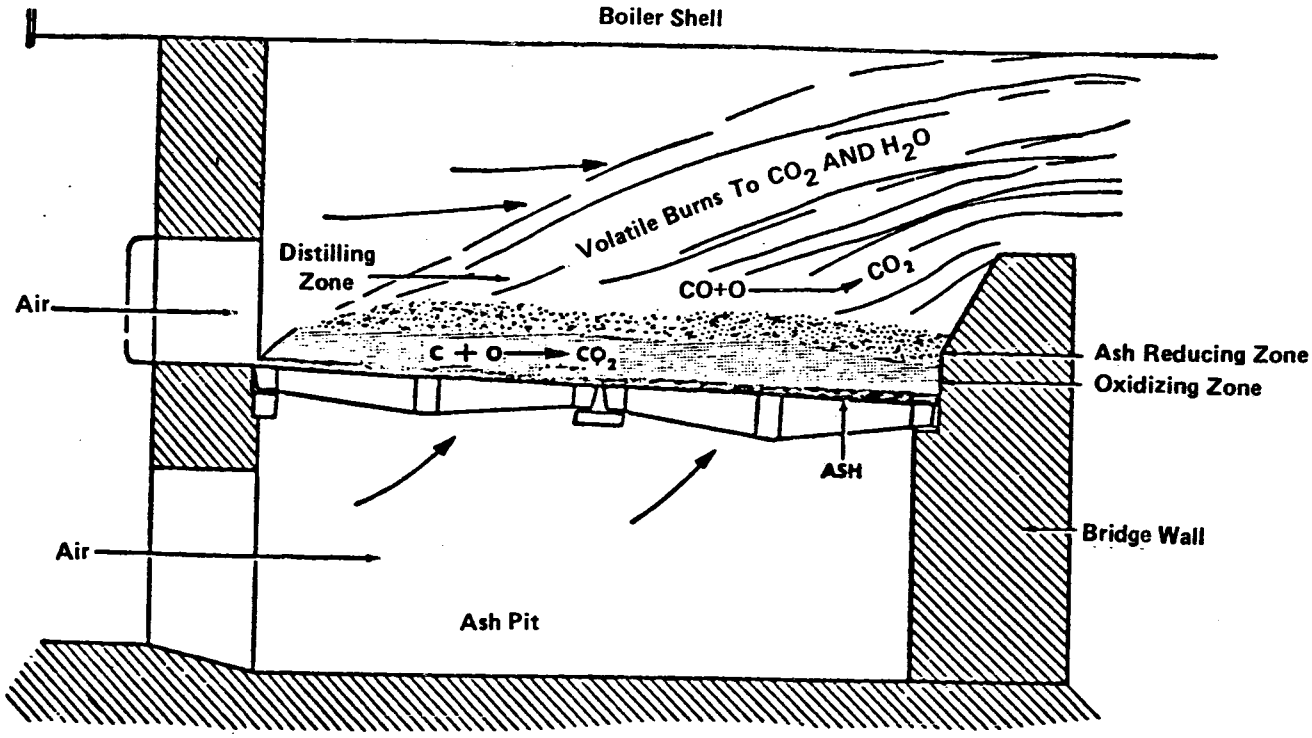


FIGURE 1-5. COMBUSTION OF COAL

finely divided soot particles give flue gases a black color when present. In the refining oil, heavy hydrocarbons are cracked into simpler hydrocarbons, carbon, and hydrogen. This cracking (thermal decomposition) process is also one of the reactions which occur 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. The methane is oxidized without cracking and several intermediate carbon/hydrogen/oxygen compounds are formed. However, if the methane is heated quickly, the gas is cracked into hydrogen and carbon. The carbon particles glow when burnt, giving off a yellow color. If this yellow flame comes in contact with a boiler tube, the 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 the 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.

b. 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 the more rapid cracking of their complex hydrocarbons. While the 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 buildup in the furnace and convection passes. Such buildups can result in large efficiency losses associated with reduced heat transfer and higher boiler exit gas temperatures. Smoke of colors 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 airs no smoke will be visible and finally, at still lower excess air levels, black smoke will occur. Coal-fired often generate white smoke related to the ash in the coal.

c. 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.

1-10. FLUE GAS ANALYSIS AND TEMPERATURE

The performance of a burner and boiler can largely be determined by analysis and temperature of the flue gas. The 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 the flue gas. This analysis is generally on a dry basis by volume since the water vapor is condensed before analysis. Given the type of fuel being burned and the oxygen or carbon dioxide level, tables 1-4 through 1-8 can be used to determine the percent of excess air in the flue gas for natural gas, No. 2 oil, No. 6 oil, and coal. Gas absorption analyzers like the Orsat and "FYRITE" CO_2 bottle are occasionally used to monitor system efficiency. These two analyzers are adequate for monitoring steady boiler loads if care is used in obtaining samples and maintaining the analyzer. Continuous analyzers are also available using either a fuel cell or zirconium oxide element to monitor oxygen levels. The technology of these analyzers is advancing rapidly and many of the current models are accurate, easy to maintain, and will provide a continuous record of the flue gas analysis. By using a continuous monitor an operator can immediately observe the results of firing rate changes and can see how the oxygen level changes at different points in the flue. Monitoring different points in a flue can help to determine if the boiler setting is leaking. Figure 1-6 illustrates an efficiency monitor which includes an oxygen analyzer, carbon monoxide analyzer, smoke tester, thermocouple, and digital readouts for the various measurements. Combustibles analyzers are also available and are particularly valuable for natural gas fired boilers. Smoke density or opacity monitors are commonly used for tuning and monitoring boiler operation.

1-11. 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. The loss of heat in the flue gas, on a percentage basis, is subtracted from 100 percent to provide the percentage combustion efficiency. The heat lost with the flue gas is

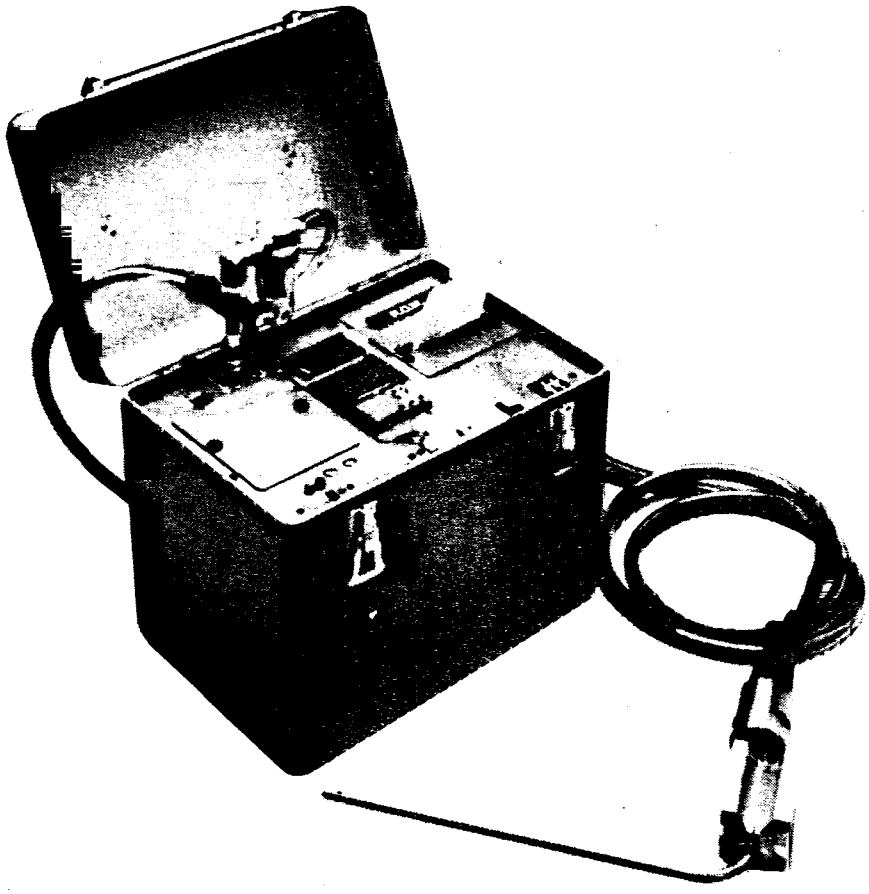


FIGURE 1-6. COMBUSTION EFFICIENCY MONITOR

determined by its temperature and chemical analysis. The amounts of excess air and water vapor are most important in determining their loss. Water is contained in the flue gas in its vapor state. Each pound of water vapor requires 970 Btu of the energy supplied to the boiler to maintain it in its vapor state. In addition to this 970 Btu/lb, water vapor also contains 80% more energy per pound than the 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 than oil and thus has more water in the flue gas. Using table 1-4 and 1-6, at 15% excess air, 70° F combustion air temperature, and 530° F stack temperature, the combustion efficiency of a natural gas fired boiler is 78.9° as compared with 83.4° for a No. 6 oil-fired boiler. Tables 1-4 through 1-8 are Combustion Efficiency Tables for natural gas, No. 2 oil, No. 6 oil, coal with 3.5° moisture, and coal with 9.0° moisture respectively. The combustion efficiency for No. 4 oil may be considered the average of the combustion efficiencies for No. 2 oil and No. 6 oil. Expanded versions of the tables presented here may be found in the Boiler Efficiency Institute book entitled "Boiler Efficiency Improvement."

1-12. BOILER EFFICIENCY

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

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

Boiler efficiency must always be less than combustion efficiency. Typical boiler efficiencies range from 75 to 85 percent. The main boiiler loss is the heat lost in the 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:

- — Minimize excess air to reduce stack losses.
- — Clean the gas side and water side of the boiler tubes to ensure maximum absorption of heat and reduced stack temperatures.
- — Minimize blowdown to reduce blowdown losses.
- — Perform maintenance on burners and controls to minimize unburned fuel.

A more detailed discussion of boiler efficiency is provided in chapter 3.

1-13. CENTRAL BOILER PLANT EFFICIENCY

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

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

Boiler selection, deaerator control, steam trap maintenance, use of steam driven auxiliaries, and plant building energy conservation are all 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. The use of steam driven auxiliaries reduces the amount of energy sent out of the central plant and steam losses can result if the exhaust steam cannot be used in the deaerator or building heating system. Distribution system losses should also be monitored and reported from the Central Boiler Plant. While strictly speaking they are not a part of central plant efficiency, distribution system losses greatly affect the efficiency of the system. Any makeup water required to replace distribution losses must be heated to the feedwater temperature. This requires additional steam to be generated by the boilers, thus using additional fuel and lowering plant efficiency. More information is provided in chapter 3.

Table 1-4. Combustion Efficiency for Natural Gas

% Excess Air	% O_2	% CO_2	Percent Combustion Efficiency Flue Gas Temperature Minus Combustion Air Temperature, Deg F											
			180	220	260	300	340	380	420	460	500	540	580	620
0.0	0.0	11.8	86.1	85.3	84.5	83.6	82.8	81.9	81.0	80.1	79.3	78.4	77.5	76.6
4.5	1.0	11.2	86.0	85.1	84.2	83.4	82.5	81.6	80.7	79.8	78.9	77.9	77.0	76.1
9.5	2.0	10.7	85.8	84.9	84.0	83.1	82.2	81.2	80.3	79.4	78.4	77.5	76.5	75.5
12.1	2.5	10.4	85.7	84.8	83.9	83.0	82.0	81.1	80.1	79.1	78.2	77.2	76.2	75.2
15.0	3.0	10.1	85.7	84.7	83.8	82.8	81.8	80.9	79.9	78.9	77.9	76.9	75.9	74.9
18.0	3.5	9.8	85.6	84.6	83.6	82.6	81.7	80.7	79.7	78.7	77.6	76.6	75.6	74.6
21.1	4.0	9.6	85.5	84.5	83.5	82.5	81.5	80.5	79.4	78.4	77.4	76.3	75.3	74.2
24.5	4.5	9.3	85.4	84.3	83.3	82.3	81.3	80.2	79.2	78.1	77.1	76.0	74.9	73.8
28.1	5.0	9.0	85.2	84.2	83.2	82.1	81.1	80.0	78.9	77.8	76.7	75.6	74.5	73.4
31.9	5.5	8.7	85.1	84.1	83.0	81.9	80.8	79.7	78.6	77.5	76.4	75.3	74.1	73.0
35.9	6.0	8.4	85.0	83.9	82.8	81.7	80.6	79.5	78.3	77.2	76.0	74.9	73.7	72.5
40.3	6.5	8.2	84.9	83.7	82.6	81.5	80.3	79.2	78.0	76.8	75.6	74.5	73.3	72.0
44.9	7.0	7.9	84.7	83.5	82.4	81.2	80.0	78.8	77.6	76.4	75.2	74.0	72.8	71.5
49.9	7.5	7.6	84.5	83.4	82.2	80.9	79.7	78.5	77.3	76.0	74.8	73.5	72.2	71.0
55.3	8.0	7.3	84.4	83.1	81.9	80.7	79.4	78.1	76.9	75.6	74.3	73.0	71.7	70.4
67.3	9.0	6.7	84.0	82.7	81.4	80.0	78.7	77.3	76.0	74.6	73.2	71.8	70.4	69.0
81.6	10.0	6.2	83.5	82.1	80.7	79.3	77.8	76.4	74.9	73.4	71.9	70.4	68.9	67.4
98.7	11.0	5.6	83.0	81.5	79.9	78.3	76.8	75.2	73.6	72.0	70.4	68.8	67.1	65.5
119.7	12.0	5.1	82.3	80.6	78.9	77.2	75.5	73.8	72.0	70.3	68.5	66.7	64.9	63.1
145.8	13.0	4.5	81.5	79.6	77.7	75.8	73.9	72.0	70.1	68.1	66.2	64.2	62.2	60.2
179.5	14.0	3.9	80.4	78.3	76.2	74.0	71.9	69.7	67.5	65.3	63.1	60.9	58.7	56.4
224.3	15.0	3.4	79.0	76.6	74.1	71.7	69.2	66.7	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-.8%. The higher heating value is 21,700 Btu/lb.

Table 1-5. Combustion Efficiency for Number 2 Oil

% Excess Air	% O_2	% CO_2	Percent Combustion Efficiency Flue Gas Temperature Minus Combustion Air Temperature, Deg F											
			180	220	260	300	340	380	420	460	500	540	580	620
0.0	0.0	15.6	90.4	89.6	88.8	88.0	87.1	86.3	85.5	84.7	83.8	83.0	82.1	81.3
4.7	1.0	14.9	90.2	89.4	88.6	87.7	86.9	86.0	85.2	84.3	83.4	82.5	81.6	80.7
9.9	2.0	14.1	90.1	89.2	88.3	87.4	86.6	85.7	84.8	83.9	82.9	82.0	81.1	80.2
12.6	2.5	13.8	90.0	89.1	88.2	87.3	86.4	85.5	84.6	83.6	82.7	81.8	80.8	79.9
15.6	3.0	13.4	89.9	89.0	88.1	87.1	86.2	85.3	84.3	83.4	82.4	81.5	80.5	79.5
18.7	3.5	13.0	89.8	88.9	87.9	87.0	86.0	85.1	84.1	83.1	82.2	81.2	80.2	79.2
22.0	4.0	12.6	89.7	88.7	87.8	86.8	85.8	84.9	83.9	82.9	81.9	80.9	79.8	78.8
25.5	4.5	12.3	89.6	88.6	87.6	86.6	85.6	84.6	83.6	82.6	81.6	80.5	79.5	78.4
29.2	5.0	11.9	89.5	88.5	87.4	86.4	85.4	84.4	83.3	82.3	81.2	80.2	79.1	78.0
33.2	5.5	11.5	89.3	88.3	87.3	86.2	85.2	84.1	83.0	82.0	80.9	79.8	78.7	77.6
37.4	6.0	11.2	89.2	88.1	87.1	86.0	84.9	83.8	82.7	81.6	80.5	79.4	78.3	77.1
41.9	6.5	10.8	89.1	88.0	86.9	85.8	84.6	83.5	82.4	81.3	80.1	79.0	77.8	76.6
46.8	7.0	10.4	88.9	87.8	86.6	85.5	84.4	83.2	82.0	80.9	79.7	78.5	77.3	76.1
52.0	7.5	10.0	88.7	87.6	86.4	85.2	84.1	82.9	81.7	80.4	79.2	78.0	76.7	75.5
57.6	8.0	9.7	88.6	87.4	86.2	84.9	83.7	82.5	81.2	80.0	78.7	77.5	76.2	74.9
70.2	9.0	8.9	88.2	86.9	85.6	84.3	83.0	81.6	80.3	79.0	77.6	76.2	74.9	73.5
85.0	10.0	8.2	87.7	86.3	84.9	83.5	82.1	80.6	79.2	77.8	76.3	74.8	73.3	71.8
102.9	11.0	7.4	87.1	85.6	84.1	82.6	81.0	79.5	77.9	76.3	74.7	73.1	71.5	69.9
124.7	12.0	6.7	86.5	84.8	83.1	81.4	79.7	78.0	76.3	74.5	72.8	71.0	69.2	67.4
152.0	13.0	6.0	85.6	83.7	81.9	80.0	78.1	76.2	74.3	72.3	70.4	68.4	66.4	64.4
187.0	14.0	5.2	84.5	82.4	80.3	78.2	76.0	73.8	71.7	69.5	67.3	65.0	62.8	60.5
233.7	15.0	4.5	83.0	80.6	78.2	75.7	73.2	70.7	68.2	65.7	63.1	60.6	58.0	55.4

This table is based on the following fuel anaysis (% by weight): carbon-86.7%, hydrogen-12.4%, nitrogen-.1%, sulfur-.8%. The higher heating value is 19,500 Btu/lb.

Table 1-6. Combustion Efficiency for Number 6 Oil

% Excess Air	% O_2	% CO_2	Percent Combustion Efficiency Flue Gas Temperature Minus Combustion Air Temperature, Deg F											
			180	220	260	300	340	380	420	460	500	540	580	620
0.0	0.0	16.5	91.2	90.4	89.6	88.8	87.9	87.1	86.3	85.4	84.6	83.7	82.9	82.0
4.7	1.0	15.7	91.0	90.2	89.4	88.5	87.7	86.8	85.9	85.1	84.2	83.3	82.4	81.5
10.0	2.0	14.9	90.9	90.0	89.1	88.2	87.3	86.4	85.5	84.6	83.7	82.8	81.8	80.9
12.8	2.5	14.5	90.8	89.9	89.0	88.1	87.2	86.3	85.3	84.4	83.4	82.5	81.5	80.6
15.8	3.0	14.1	90.7	89.8	88.9	87.9	87.0	86.1	85.1	84.1	83.2	82.2	81.2	80.2
18.9	3.5	13.8	90.6	89.7	88.7	87.8	86.8	85.8	84.9	83.9	82.9	81.9	80.9	79.9
22.3	4.0	13.4	90.5	89.5	88.6	87.6	86.6	85.6	84.6	83.6	82.6	81.6	80.5	79.5
25.8	4.5	13.0	90.4	89.4	88.4	87.4	86.4	85.4	84.3	83.3	82.3	81.2	80.2	79.1
29.6	5.0	12.6	90.3	89.2	88.2	87.2	86.2	85.1	84.1	83.0	81.9	80.9	79.8	78.7
33.6	5.5	12.2	90.1	89.1	88.0	87.0	85.9	84.8	83.8	82.7	81.6	80.5	79.4	78.2
37.9	6.0	11.8	90.0	88.9	87.8	86.8	85.7	84.6	83.4	82.3	81.2	80.0	78.9	77.7
42.4	6.5	11.4	89.8	88.7	87.6	86.5	85.4	84.2	83.1	81.9	80.8	79.6	78.4	77.2
47.3	7.0	11.0	89.7	88.6	87.4	86.3	85.1	83.9	82.7	81.5	80.3	79.1	77.9	76.7
52.6	7.5	10.6	89.5	88.3	87.2	86.0	84.8	83.6	82.3	81.1	79.9	78.6	77.4	76.1
58.2	8.0	10.2	89.3	88.1	86.9	85.7	84.4	83.2	81.9	80.6	79.4	78.1	76.8	75.5
71.0	9.0	9.4	88.9	87.6	86.3	85.0	83.7	82.3	81.0	79.6	78.2	76.8	75.4	74.0
86.0	10.0	8.6	88.5	87.0	85.6	84.2	82.7	81.3	79.8	78.3	76.9	75.4	73.9	72.3
104.1	11.0	7.9	87.9	86.3	84.8	83.2	81.7	80.1	78.5	76.9	75.2	73.6	72.0	70.3
126.1	12.0	7.1	87.2	85.5	83.8	82.1	80.3	78.6	76.8	75.0	73.3	71.5	69.6	67.8
153.7	13.0	6.3	86.3	84.4	82.5	80.6	78.6	76.7	74.7	72.8	70.8	68.8	66.8	64.7
189.1	14.0	5.5	85.2	83.0	80.9	78.7	76.5	74.3	72.1	69.8	67.6	65.3	63.0	60.7
236.4	15.0	4.7	83.7	81.2	78.7	76.2	73.6	71.1	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-.7%. The higher heating value is 18,300 Btu/lb.

Table 1-7. Combustion Efficiency for Coal, 3.5% Moisture, Bituminous

% Excess Air	% O_2	% CO_2	Percent Combustion Efficiency Flue Gas Temperature Minus Combustion Air Temperature, Deg F											
			180	220	260	300	340	380	420	460	500	540	580	620
0.0	0.0	18.4	92.0	91.2	90.3	89.5	88.6	87.7	86.8	85.9	85.0	84.1	83.1	82.2
4.8	1.0	17.6	91.9	91.0	90.1	89.2	88.3	87.3	86.4	85.5	84.5	83.6	82.6	81.6
10.2	2.0	16.7	91.7	90.8	89.8	88.9	87.9	86.9	86.0	85.0	84.0	83.0	82.0	81.0
16.2	3.0	15.8	91.5	90.5	89.5	88.5	87.5	86.5	85.5	84.5	83.4	82.4	81.3	80.3
22.8	4.0	14.9	91.3	90.2	89.2	88.2	87.1	86.0	85.0	83.9	82.8	81.7	80.6	79.5
26.4	4.5	14.5	91.1	90.1	89.0	87.9	86.9	85.8	84.7	83.6	82.4	81.3	80.2	79.0
30.3	5.0	14.0	91.0	89.9	88.8	87.7	86.6	85.5	84.4	83.2	82.1	80.9	79.7	78.6
34.4	5.5	13.6	90.9	89.8	88.6	87.5	86.3	85.2	84.0	82.9	81.7	80.5	79.3	78.1
38.8	6.0	13.2	90.7	89.6	88.4	87.2	86.1	84.9	83.7	82.5	81.3	80.0	78.8	77.6
43.5	6.5	12.7	90.6	89.4	88.2	87.0	85.8	84.5	83.3	82.1	80.8	79.5	78.3	77.0
48.5	7.0	12.3	90.4	89.2	87.9	86.7	85.4	84.2	82.9	81.6	80.3	79.0	77.7	76.4
53.9	7.5	11.9	90.2	88.9	87.7	86.4	85.1	83.8	82.5	81.1	79.8	78.5	77.1	75.7
59.7	8.0	11.4	90.0	88.7	87.4	86.1	84.7	83.4	82.0	80.6	79.2	77.9	76.5	75.0
65.9	8.5	11.0	89.8	88.4	87.1	85.7	84.3	82.9	81.5	80.1	78.6	77.2	75.8	74.3
72.7	9.0	10.5	89.6	88.2	86.7	85.3	83.9	82.4	81.0	79.5	78.0	76.5	75.0	73.5
80.1	9.5	10.1	89.3	87.9	86.4	84.9	83.4	81.9	80.4	78.8	77.3	75.7	74.2	72.6
88.1	10.0	9.7	89.0	87.5	86.0	84.4	82.9	81.3	79.7	78.1	76.5	74.9	73.3	71.6
106.6	11.0	8.8	88.4	86.8	85.1	83.4	81.7	80.0	78.2	76.5	74.7	73.0	71.2	69.4
129.2	12.0	7.9	87.7	85.8	84.0	82.1	80.2	78.3	76.4	74.5	72.6	70.6	68.7	66.7
157.5	13.0	7.0	86.7	84.6	82.6	80.5	78.4	76.3	74.2	72.0	69.9	67.7	65.5	63.3
193.8	14.0	6.1	85.5	83.1	80.8	78.4	76.0	73.6	71.2	68.8	66.4	63.9	61.4	58.9
242.2	15.0	5.3	83.8	81.1	78.4	75.7	72.9	70.1	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 higher heating value of this Class II Group 3 bituminous coal is 13,750 Btu/lb.

Table 1-8. Combustion Efficiency for Coal, 9.0% Moisture, Bituminous

% Excess Air	% O_2	% CO_2	Percent Combustion Efficiency Flue Gas Temperature Minus Combustion Air Temperature, Deg F											
			180	220	260	300	340	380	420	460	500	540	580	620
0.0	0.0	18.4	91.0	90.1	89.2	88.3	87.4	86.5	85.6	84.7	83.7	82.8	81.8	80.9
4.8	1.0	17.6	90.8	89.9	89.0	88.1	87.1	86.2	85.2	84.2	83.2	82.3	81.3	80.3
10.2	2.0	16.7	90.7	89.7	88.7	87.7	86.8	85.8	84.8	83.7	82.7	81.7	80.6	79.6
16.2	3.0	15.8	90.5	89.4	88.4	87.4	86.4	85.3	84.3	83.2	82.1	81.1	80.0	78.9
22.8	4.0	14.9	90.2	89.2	88.1	87.0	85.9	84.8	83.7	82.6	81.5	80.3	79.2	78.1
26.4	4.5	14.5	90.1	89.0	87.9	86.8	85.7	84.6	83.4	82.3	81.1	80.0	78.8	77.6
30.3	5.0	14.0	90.0	88.8	87.7	86.6	85.4	84.3	83.1	81.9	80.7	79.6	78.3	77.1
34.4	5.5	13.6	89.8	88.7	87.5	86.3	85.2	84.0	82.8	81.6	80.3	79.1	77.9	76.6
38.8	6.0	13.2	89.7	88.5	87.3	86.1	84.9	83.6	82.4	81.2	79.9	78.7	77.4	76.1
43.5	6.5	12.7	89.5	88.3	87.1	85.8	84.6	83.3	82.0	80.7	79.5	78.2	76.8	75.5
48.5	7.0	12.3	89.3	88.1	86.8	85.5	84.2	82.9	81.6	80.3	79.0	77.6	76.3	74.9
53.9	7.5	11.9	89.1	87.8	86.5	85.2	83.9	82.5	81.2	79.8	78.4	77.1	75.7	74.3
59.7	8.0	11.4	88.9	87.6	86.2	84.9	83.5	82.1	80.7	79.3	77.9	76.4	75.0	73.5
65.9	8.5	11.0	88.7	87.3	85.9	84.5	83.1	81.6	80.2	78.7	77.3	75.8	74.3	72.8
72.7	9.0	10.5	88.5	87.0	85.6	84.1	82.6	81.1	79.6	78.1	76.6	75.1	73.5	71.9
80.1	9.5	10.1	88.2	86.7	85.2	83.7	82.1	80.6	79.0	77.5	75.9	74.3	72.7	71.0
88.1	10.0	9.7	88.0	86.4	84.8	83.2	81.6	80.0	78.4	76.7	75.1	73.4	71.7	70.1
106.6	11.0	8.8	87.3	85.6	83.9	82.1	80.4	78.6	76.9	75.1	73.3	71.5	69.6	67.8
129.2	12.0	7.9	86.5	84.6	82.7	80.8	78.9	77.0	75.0	73.0	71.1	69.1	67.0	65.0
157.5	13.0	7.0	85.6	83.4	81.3	79.2	77.0	74.9	72.7	70.5	68.3	66.1	63.8	61.6
193.8	14.0	6.1	84.3	81.9	79.5	77.1	74.6	72.2	69.7	67.2	64.7	62.2	59.7	57.1
242.2	15.0	5.3	82.6	79.8	77.1	74.3	71.5	68.6	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 higher heating value of this Class II Group 4 bituminous coal is 12,050 Btu/lb.

SECTION III. PRINCIPLES OF STEAM AND HOT WATER GENERATION

1-14. BASIC PRINCIPLES

The generation of steam occurs as a result of two separate processes: combustion, the release of heat by burning fuel, and heat transfer, the absorption of heat into the 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 1-7. The boiler system can be represented as a container equipped with an outlet pipe and valve, a pressure gage, and a thermometer immersed in the water. If a fire is built under the unit and water at 32° F is put into the container with the valve left open, the water temperature will rise steadily as the fire burns until a temperature of approximately 212° 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, all the water will be evaporated. If the heat content of the fuel source is accurately measured, it can be demonstrated that to raise the temperature from 32° 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 all the water. This additional heat is called the latent heat of vaporization and represents the heat required to convert the small volume of liquid into a large volume of steam. With the valve in a closed position and using another batch of water, repeat the process and allow pressure to build up to 100 psig, then throttle the valve so that pressure is maintained at 100 psig. The temperature in the container will now be approximately 338° F. This is called the saturation temperature for 100 psig pressure. The heat input required to raise one pound of water from 32° F up to this saturation temperature is 309 Btu. The energy expended in boiling one pound of water from 338° F at 100 psig is 880.6 Btu. The temperature required to boil the water increases as the 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 the pressure increases. Table 1-9 provides a summary of saturation temperatures, energy in water, energy in steam, and latent heat of vaporization for pressures from zero to 300 psig.

1-15. 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 the hot flue gases. Heat received by the heating surface travels through the metal by conduction. Heat is then transferred from the metal to the water by convection. Each of these methods is discussed in more detail below.

a. Radiation. Radiation is the most important method of heat transfer in the furnace. The amount of heat transfer depends on the area of the heating surfaces and hot surfaces in the furnace, the difference of the fourth powers 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 the transfer of radiant heat:

— Heat is transmitted in straight lines
— Heat can be reflected and refracted
— Heat is radiated in all directions

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

b. Conduction. In conduction, heat is transferred through a material in which the 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 the 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. The material of which it is made 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. The amount of heat transmitted also varies with the length of the path, the contact area, and the temperature difference.

c. Convection. Transfer of heat by convection can be compared to a bucket brigade in which each man carries the water from a supply point to a tank. In this example the medium is represented by the men and the heat is represented by the water. In convection, the gas or liquid medium receives heat from the source, expands, and is pushed away by colder, heavier particles of the medium. The fluid which receives heat then transfers the heat to a new location, losing some heat in the process. It may or may not return to its source to repeat the cycle. 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.

d. Gas Flow Considerations. In most boilers, a large

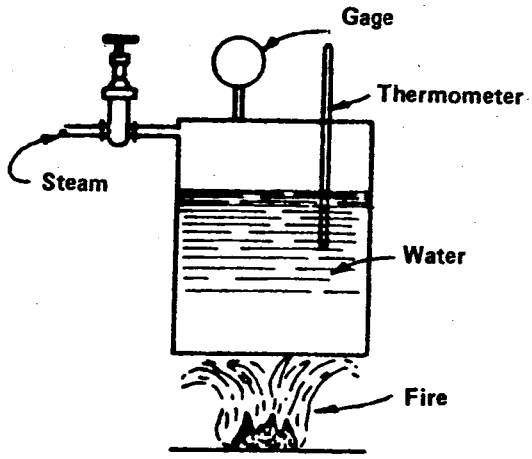


FIGURE 1-7. ELEMENTARY BOILER

Table 1-9. Water/Steam Characteristics

Pressure (psig)	Saturation Temp (°F)	Energy in Water (Btu/lb)	Energy in Steam (Btu/lb)	Latent Heat of Vaporization (Btu/lb)
0	32*	0	-	-
0	60*	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

* 32°F and 60°F are not saturation temperatures of water at 0 psig.

part of the absorbed heat is given up by hot flue gases which sweep over the heat-absorbing surfaces. Heat transfer takes place by convection. The quantity of heat transferred can be varied by controlling the temperature or quantity of the flue gases. Usually both are controlled. The ability of materials to resist the 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. 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 the flowing gases, and cross-sectional area and length of the gas passage. Draft loss increases with the square of the velocity and directly with the length of the passage. Thus, force required to maintain the proper flow increases by a factor of four when velocity is doubled, and by a factor of two when the passage length is doubled. It is important to keep velocity at a minimum, consistent with the requirements of good convective heat transfer, if the 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 the quantity of gas flow which in turn depends on the quantity of air supplied to burn the fuel. A minimum air supply consistent with good combustion practice therefore minimizes draft loss and helps to maximize heat transfer and boiler output.

e. Water Circulation Considerations. Water circulates in a steam boiler because the density of water is greater than the density of the water/steam mixture. Reference figure 1-8. Within the boiler the more dense water falls while the less dense mixture rises. Table 1-10 illustrates the relationships of water and steam mixtures at 15 psig, 100 psig, and 400 psig. As noted in table 1-10, the volume ratios become smaller as pressures increase. Natural circulating forces are thus reduced as the operating pressure of a boiler increases, and increased as the percent of steam in the mixture increases. Hot water boilers normally use pumps to force the circulation of water through the boiler, because the density difference between cold and hot water is not large enough to cause natural circulation with the velocities necessary for good heat transfer.

f. Heat Transfer to Boiler Tubes and Water by Convection. Heat transfer by convection depends on the temperature and velocity of the gases on one side of the boiler tube and the velocity of the water on the other side. Heat can be transferred to quiet water at the rate of approximately 2.8 Btu per hour per square foot per degree Fahrenheit of temperature difference (2.8 Btu/hr/ft^2/° F). Increasing the velocity of the water aids convection and increases heat transfer to about 1,500 Btu/hr/ft^2/° F. 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 1-8. 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. The 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 the 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 but only convective heat.

g. Optimizing Heat Transfer. Boiler furnace heat i absorbed by a combination of radiation and convection. The absorbed heat is conducted through the boiler tubes. Water in the boiler tubes is heated by convection. Tubes and other heating surfaces close to the fire which 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 the gas flow is high receive heat by both radiation and convection. Surfaces distant from the furnace receive all their heat by convection. Heat transfer can be optimized by controlling excess air, keeping boiler tubes clean, and maintaining optimum gas and water velocities.

(1) **Excess Air Control.** The rate at which radiant heat is transmitted varies as the fourth power of the absolute or Rankine temperature. (Rankine temperature is based on a scale whose zero represents a complete absence of heat; 0° R is approximately minus 460° F. To convert from Fahrenheit to Rankine, add 460° to Fahrenheit 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 a fuel bed at a temperature of 1050° F (1510R) can be doubled by increasing the temperature of the refractory wall or bed to 1350° F (1810° R). 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° F to 1925° F (2185° R to 2385° R).

Table 1-10. Water/Steam Mixtures

Mixture %		Specific Volume, (ft^3/lb)			Volume Ratio = volume of mixture / volume of water		
		Pressure(psig)			Pressure(psig)		
Steam	Water	15	100	400	15	100	400
0.0	100.0	.0170	.0179	.0194	1.00	1.00	1.00
0.1	99.9	.0309	.0217	.0205	1.82	1.21	1.06
0.2	99.8	.0448	.0256	.0216	2.64	1.43	1.11
0.5	99.5	.0863	.0370	.0249	5.08	2.08	1.29
1.0	99.0	.1556	.0562	.0305	9.15	3.15	1.57
100.0	0	13.88	3.88	1.12	816	217	57.8

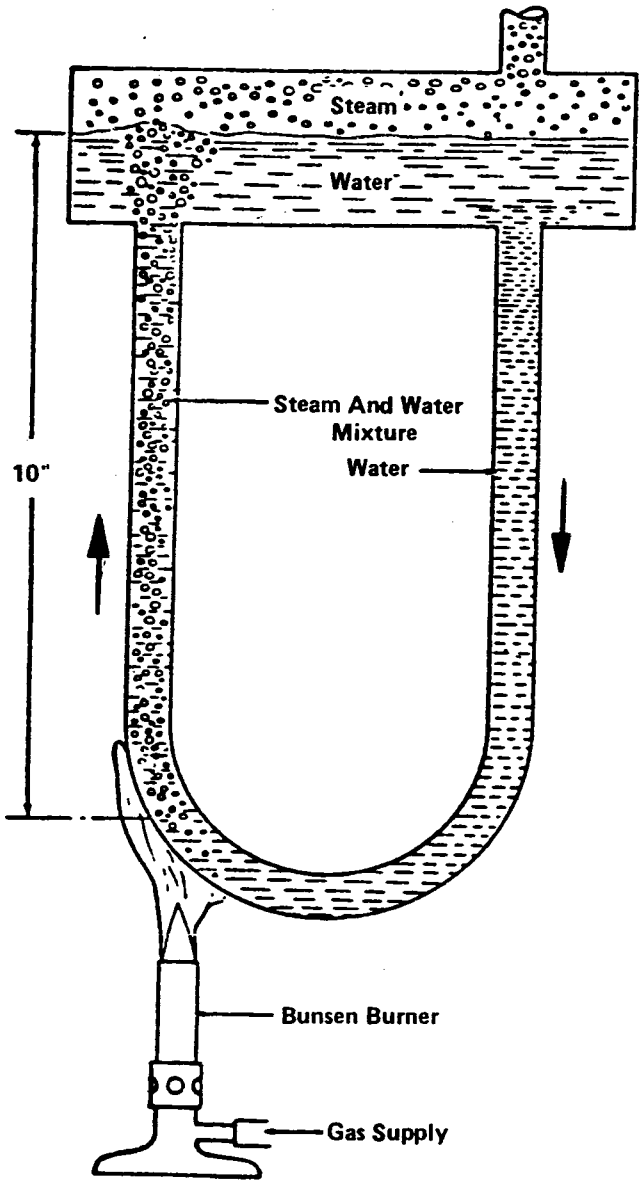


FIGURE 1-8. WATER CIRCULATION

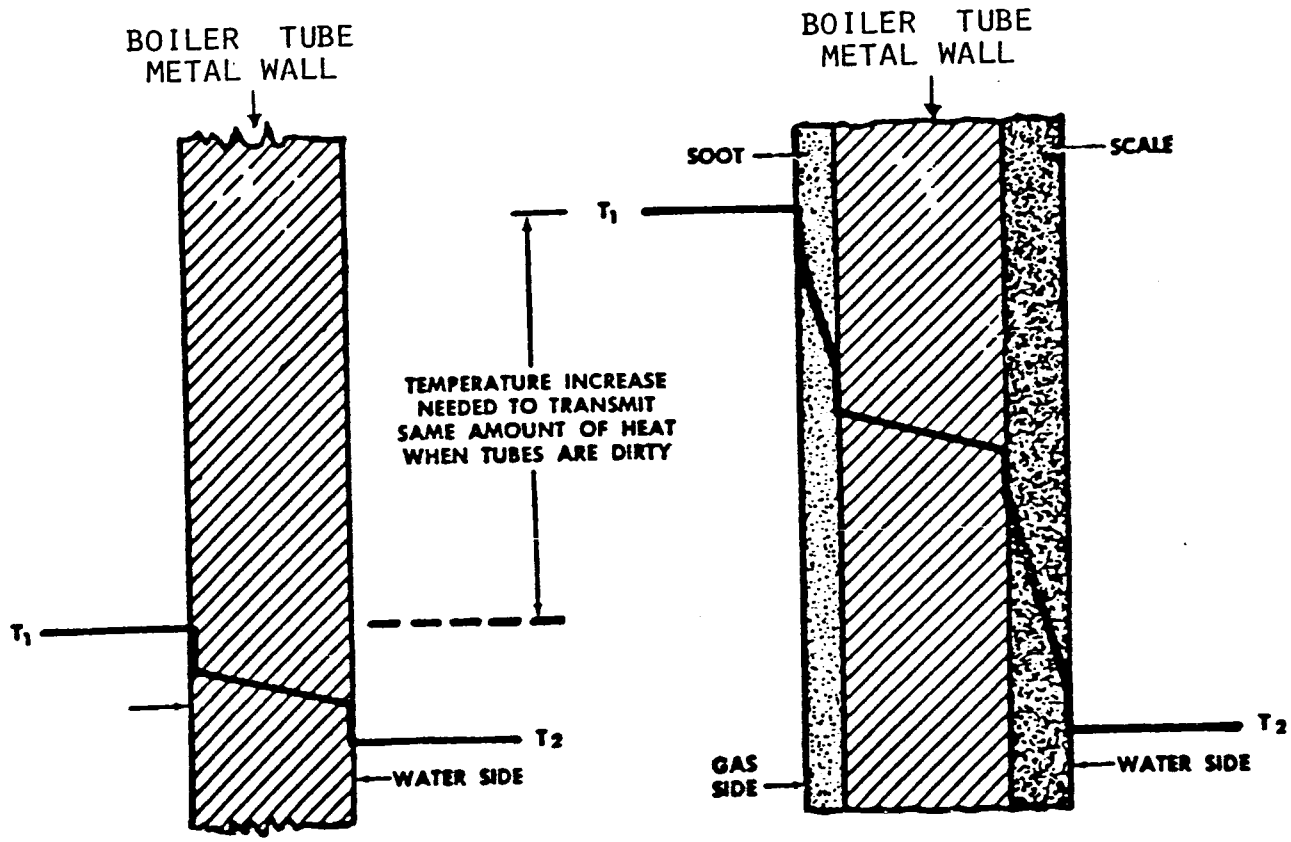


FIGURE 1-9. EFFECT OF SOOT AND SCALE ON HEAT TRANSFER

Reducing the excess air used to combust 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 the boiler surfaces.

(2) **Maintaining Clean Boiler Tubes.** The amount of heat transferred by conduction depends on the type, thickness, and condition of the conductive material as well as the difference in temperature. Heat is readily conducted through metal, while ash, soot, and scale are poor conductors. Figure 1-9 illustrates the effects of soot and sale. If the 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. Reference paragraphs 3-16**d** and 3-34 for further information.

(3) **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 all heat transfer surfaces. Keeping water passages free from accumulations of sludge and scale ensures proper water flow and velocity for cooling of the heat transfer surfaces and generating steam or hot wa.

(4) **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 of furnace brickwork. The maximum temperature which can be safely maintained is determined by, among other considerations, the kind of firebrick used, furnace construction (self-supporting, or supported), the quantity and kind of ash in the fuel, furnace size, and the amount and type of cooling of the 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 as discussed in paragraph 1-15**d**. 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 the design of the boiler. It is the responsibility of the boiler manufacturer to balance the requirements of maximum heat transfer with economi and produce a cost-effective design.

CHAPTER 2
DESCRIPTION OF EQUIPMENT

SECTION I. BOILERS AND HEAT EXCHANGERS

2-1. BOILER CLASSIFICATIONS.

There are a few fundamental types of boilers and many variations of each type. Boilers are generally classified according to the relative position of combusion gases and water as either fire tube or water tube. Boilers are also classified by the form of energy produced; low or high pressure steam; low, medium, or high temperature water. Other methods of classifying boilers are listed below.

— Type of Water Circulation - natural circulation, forced circulation.

— Type of Steam Produced - saturated, superheated.

— Method of Assembly - package, modular, field erected.

— Type of Use - stationary, marine, power, heating.

— Type of Fuel - coal, oil, gas.

— Method of Combusion- spreader stoker, fluidized bed, pulverized coal.

— Boiler Capacity - Up to 20,700 pounds per hour (up to 600 horsepower) for fire tube boilers; up to 10,000,000 pounds per hour for water tube boilers; up to 200 million Btu per hour for hot water boilers.

2-2. BOILER DESIGN REQUIREMENTS.

A boiler must meet the following requirements:

— Operational safety.

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

— Economy of operation and maintenance.

— Conformance to applicable codes.

A set of rules for the construction and operation of boilers, known as the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vellel Code, has been widely adopted by insurance underwriters and government agencies. Section I of the Code contailns 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 low temperature water boilers are classified as heating boilers. Section VI of the Code provides "Recommennded 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. To meet the above listed requirements, a boiler must have the following characteristics:

— Adequate water or steam capacity.

— Properly sized steam/water separators for steam boilers.

— Rapid, positive, and regular water circulation.

— Heating surfaces which are easy to clen on both water and gas sides.

— Parts which are accessible for inspection and repair.

— Corret amount land proper arrangement of heating surface.

— A furnace of proper size and shape for efficient combustion and for directing the flow of gases for efficient heat transfer.

2-3. FABRICATION.

All boilers, superheaters, economizers, and other pressure parts must be built using materials and construction methods specified by the applicable Code sections. 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.

a. Drums, Shells, Headers. Boiler drums, shells, or headers are used to collect steam or hot water generated in the boiler and distribute it as necessary within the boiler tubes. These components must be strong enough to contain the steam or hot water that is generated and to lmechanically hold the boiler tubes as they expand and contract with changes in temperature. The shells of fire tube boilers may be reilnforced 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 rivered boilers are still in operation.

b. 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 headerss. The expander tool consists of a tapered pin which fits into a cage containing several small rollers. A ldifferent size expander is required for ech size tube. Durilng 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, as shown in figure 2-1. 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 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 injuring the tube. Figure 2-2 illustrates flared and beaded tubes.

c. 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 numer 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 which 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. Provision must be made to permit movement between 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 which 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, lmade of specially shaped forms which fit between and around lthe tubes, can be installed after the boiler has been erected and ean 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.

2-4. FIRE TUBE BOILERS.

Many of the first steam boilers produced were designed with the products of lcombustion passing inside the tubes. Fire tube boiler design has developed primarily in the direction of the Scotch-type boiler shown in figure 2-3. The Scotch oboiler is shop-fabricate1 and is capable of supplying saturated steam at pressur:s below 250 psig at capacities below 20,000 lb/hr. At pre:surs above 250psig, 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 :wo, three, and four gas pass designs, as illustrated in fi:ure 2-4. With more gas passes and more heat transfer su:face, boiler exit gas temperatures are lower and efficiencies higher. Wet-back construction in a Scotch boiler mea:is that a water wall 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 fire tubes are not easily cleaned and ash removal is restricte:. 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 apacity 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 2-5. The firebox in this type of boiler permits the burning of coal lusing stokers or fluidized beds.

2-5. 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 hanges, and increased safety due to the reduced water volume. Water tube boilers have water inside the tube and the flue gases on the outside. The early straight-tube design boilers were replaed with today's bent-tube designs to inrease the amount of available heat transfer surface, solve mechanical problems, and general eonomic reasons. Figure 2-6 illustrates a four-drum boiler with a water-cooled back wall. The bottom drum is called a mud drum beecause of the tendency of boiler sludge to collect in this low area. The upper drums are called steam drums. Water enters the top rear drum, passes through the tubes to the bottom drum, and then up through the tubes to the 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 the 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. The baffles are arranged to encourage flue gas flow over all the boiler

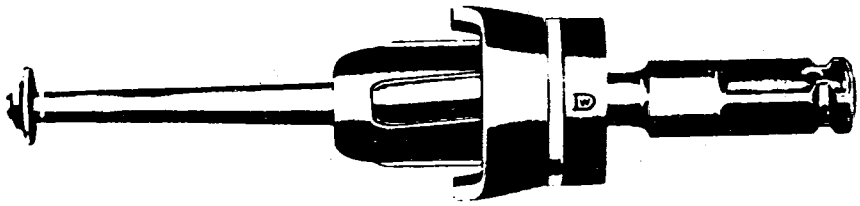
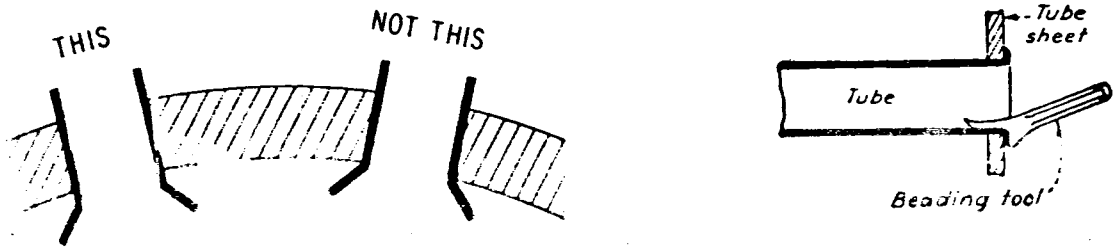


FIGURE 2-1. TUBE EXPANDER



FLARED TUBE

BEADED TUBE

FIGURE 2-2. FLARED AND BEADED TUBES

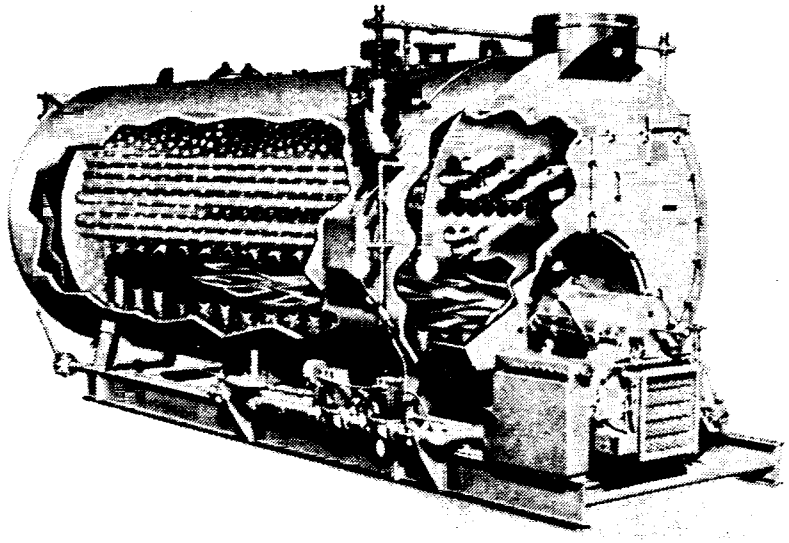


FIGURE 2-3. SCOTCH BOILER

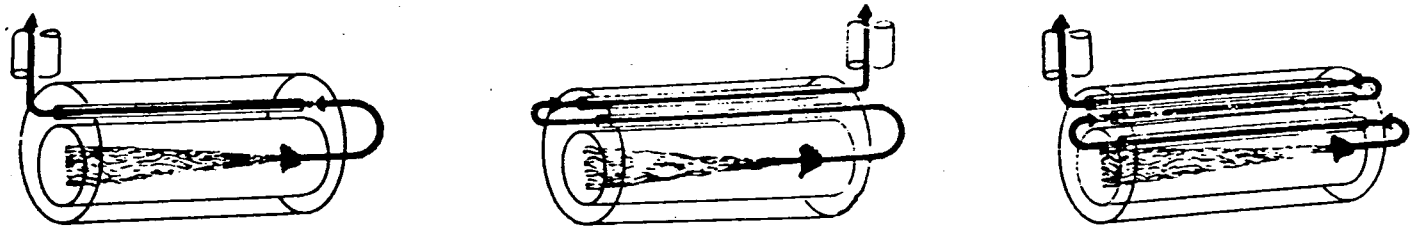


FIGURE 2-4. TWO, THREE, AND FOUR PASS SCOTCH BOILER DESIGNS

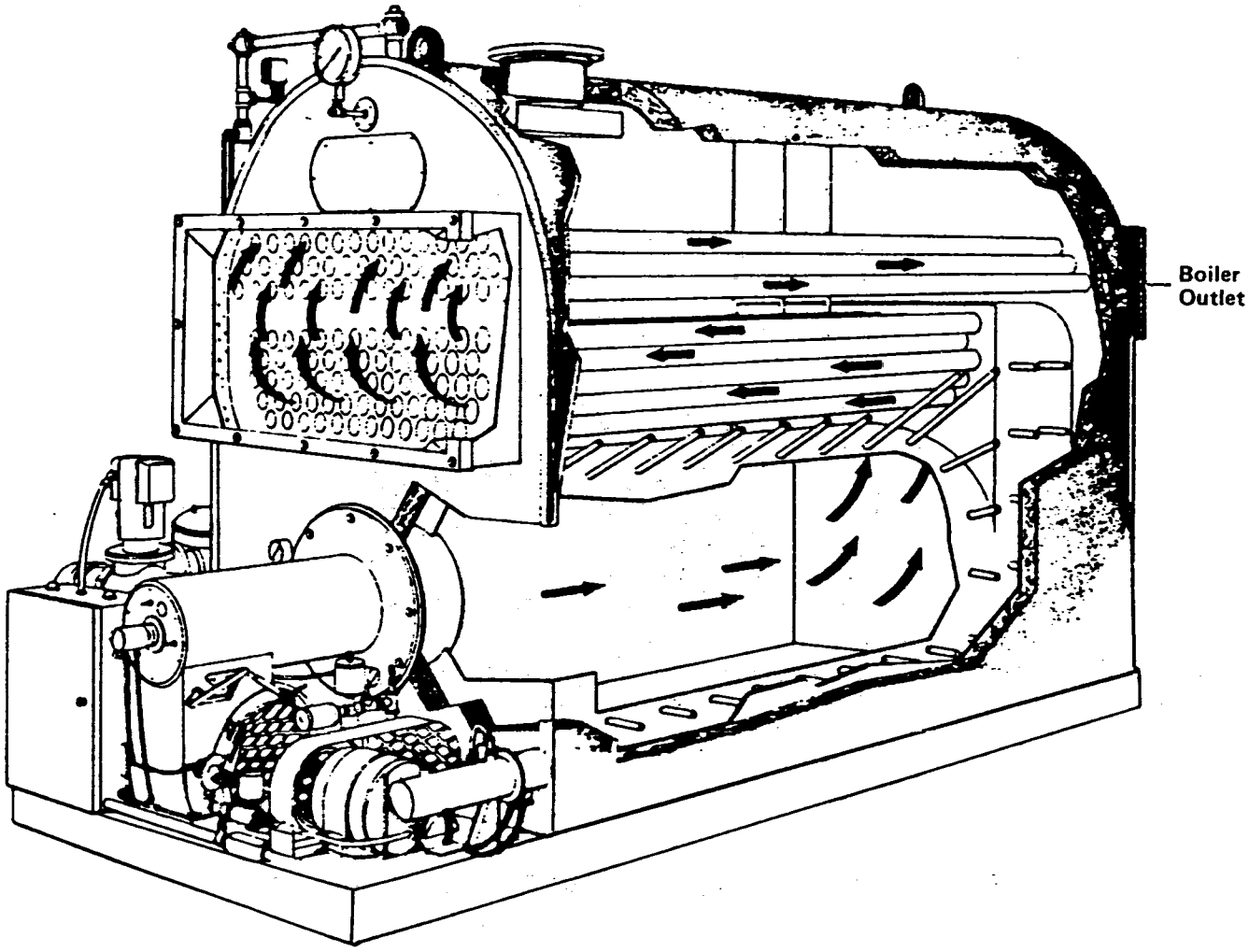


FIGURE 2-5. HORIZONTAL RETURN TUBULAR BOILER

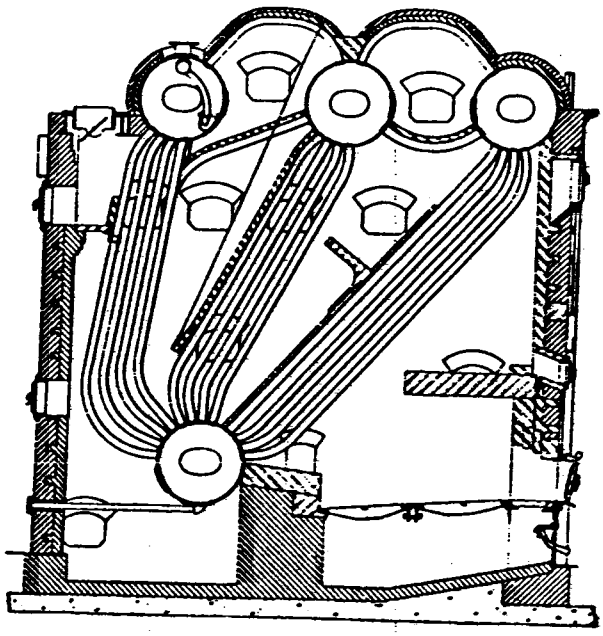


FIGURE 2-6. FOUR DRUM WATER TUBE BOILER

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.

a. 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 limberation 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 constrution it is important to allow for the thermal expansion which occurs as the refractory is heated to operating temperatures. Figure 2-7 illustrates typical expansion joint arrangements. The development of high alumina super-duty firebrick, insulating firebrick, blok insulation, castable refractory, and plastic refractory have greatly improved refractory life and reduced radiation losses from boiler furnaces. The NAVFAC "Central Heating Plant" Manual MO-205 discusses refractories in greater detail.

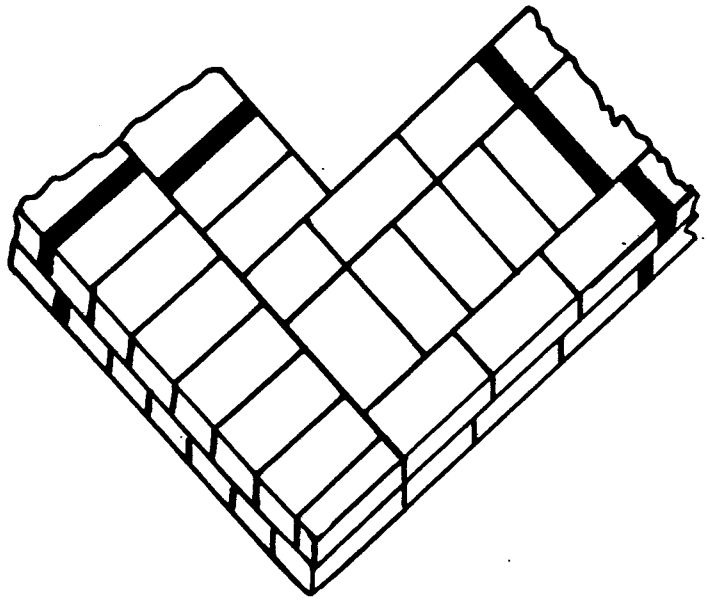
b. Water Wall Construction. Water walls were developed to allow the use of higher firing rates and higher furnace heat release rates, while reducing heat losses and maintenance. Improvements to water wall furnaces and associated casings and lagging also reduce air infiltration into the boiler, reducing excess air levels and improving boiler efficiency. The four types of water wall construction are: tube and tile, tangent tube, studded tube, and membrane wall (reference figure 2-8). The tube and tile construction which was first developed provided only a partial solution to the maintenance and heat loss problems. Minimum practical tube spacing is limited by ability to economically roll the tubes into drums or headers. This, in turn, limits the amount of heat transfer surface added and the amount of protection given to the refractory, and thus limits 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 water wall construction was developed and remains the best, though most expensive, water wall design.

c. 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 mall 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 2-9 illustrates modern steam drum internals. The cyclones are arranged in a row and receive the water/stean mixture tangentially from the boiler water wall and generating tubes. The water is spun to the outside of the yclone and exits through the open bottom of the cyclone. The 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 ondensed steam from a well-designed steam drum should be less than 3 ppm.

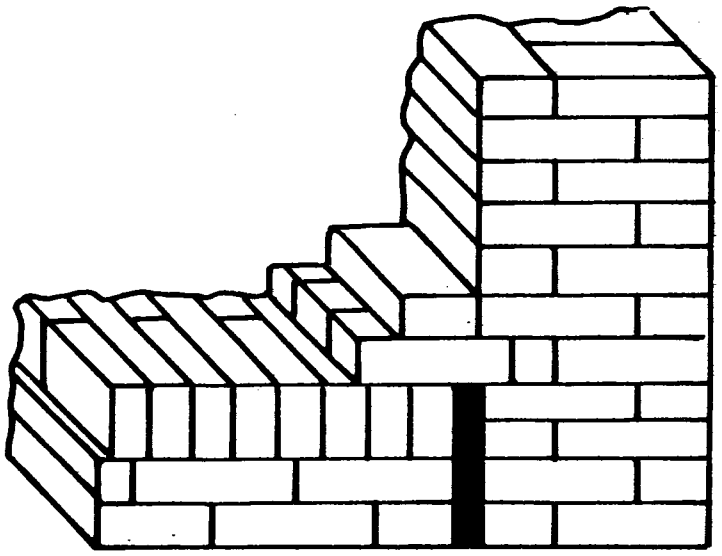
d. Generating Surface. Boiler tubes that connect the upper and lower drums are called generating surfaces and are included with the water wall surface in computing the total heating surface. Many different tube spacings are used, depending on the type of fuel being fired. The tubes may be inline or staggered.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

e. Superheaters. Some processes and turbines require steam that is super-heated above the saturated steam temperatures. Figure 2-10 illustrates a two-drum boiler equipped with a superheater, water walls, spreader stoker, and economizer. The steam from the steam drum is directed to a superheater inlet header and then through the 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 the furnace gases somewhat before reaching the superheater tubes and shield the superheater tubes from radiant heat. Superheaters are not commonly found in Army Central Boiler Plants.

f. Package Boilers. Packaged water tube boilers are factory-assembled, complete with combusion equipment, mechanical draft equipment, automatic controls , and accessories. These factory-assembleld packages can be purchased in capacities exceeding 200,000 lb/hr. Package boilers are available in three basic configurations: "D", "A", and "O" (Figure 2-11). Figure 2-12 illustrates a "D" type package boiler arranged for oil and gas firing. Note

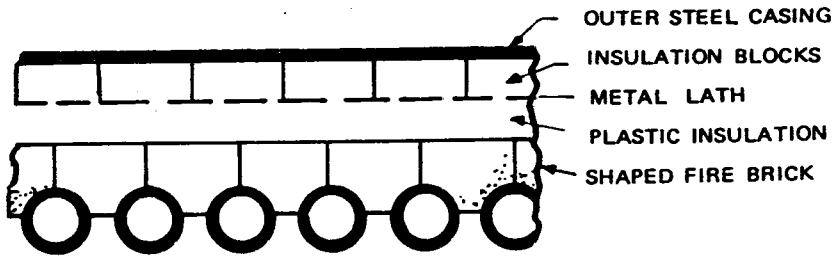


Corner Construction With
Staggered Expansion Joints
(18" Wall)

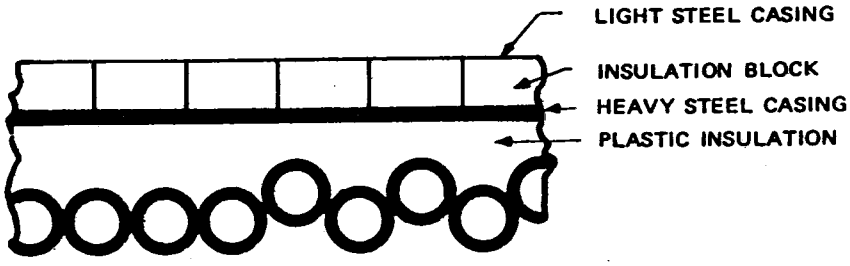


Floor to Wall Expansion Joint

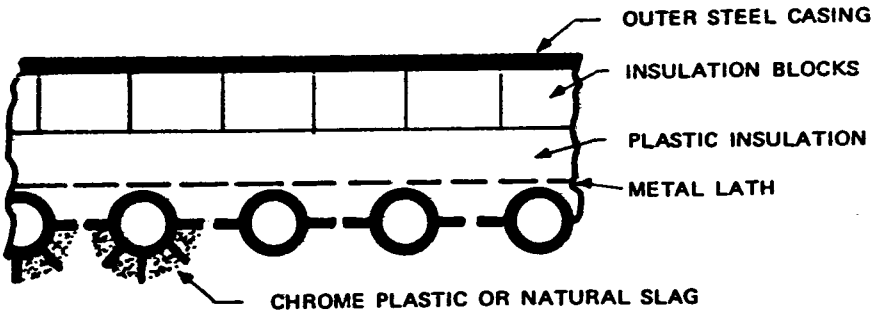
FIGURE 2-7. REFRACTORY EXPANSION JOINTS



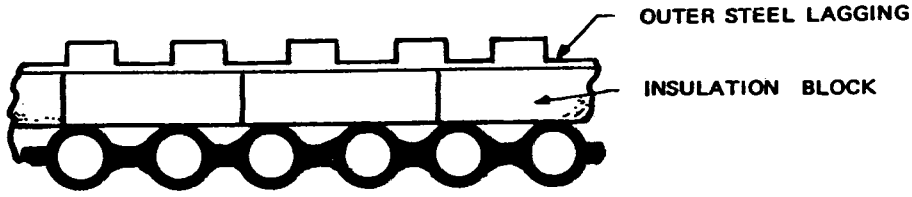
TUBE AND TILE



TANGENT TUBE



STUDDED TUBE



MEMBRANE WALL

FIGURE 2–8. WATER WALL CONSTRUCTION

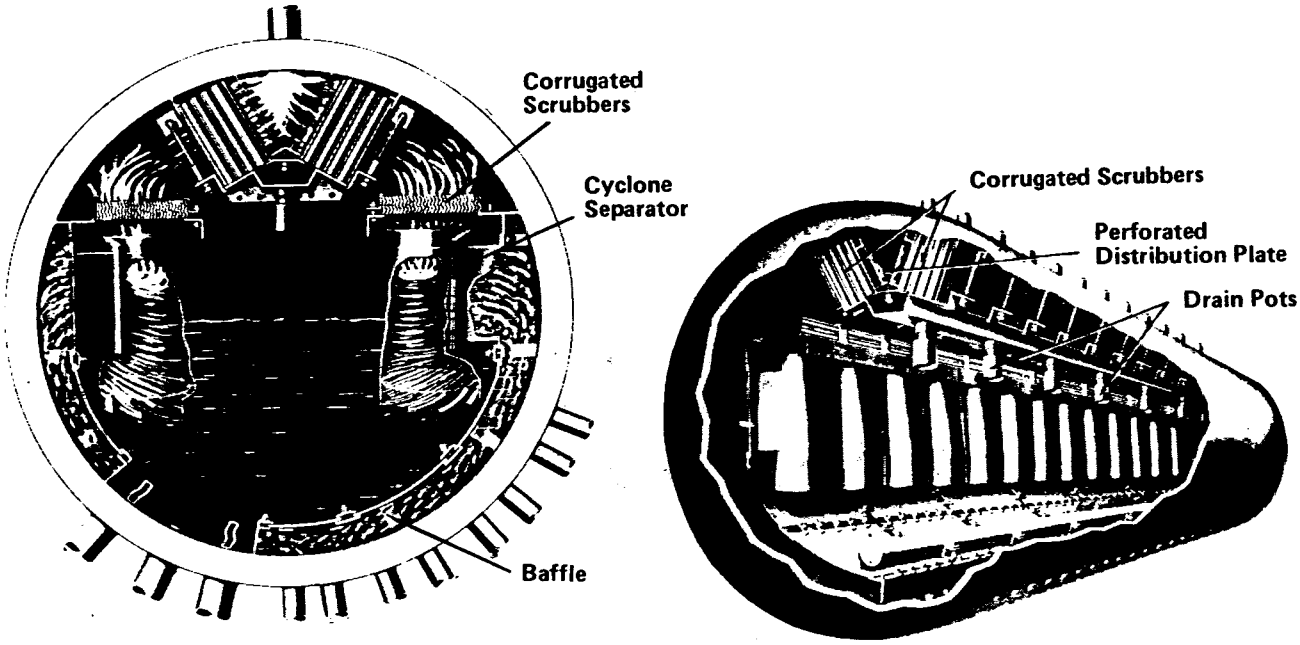


FIGURE 2-9. STEAM DRUM INTERNALS

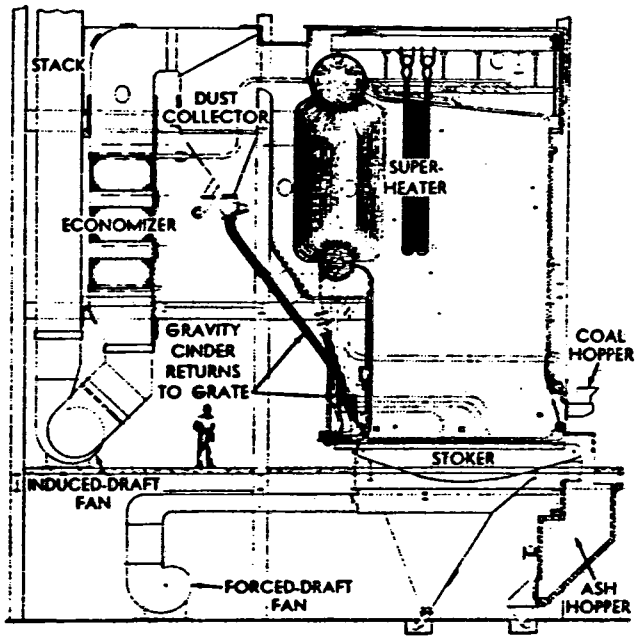


FIGURE 2-10. SUPERHEATER IN TWO DRUM BOILER

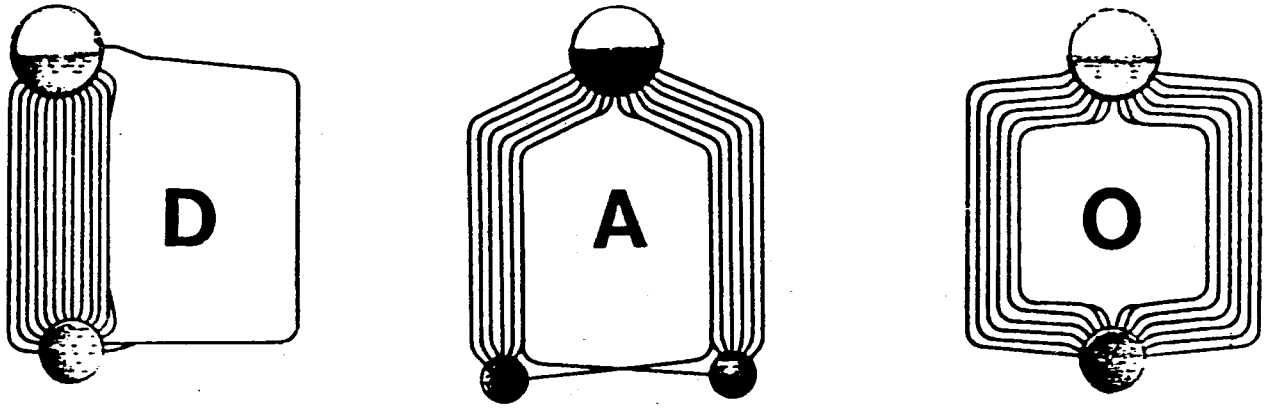


FIGURE 2-11. PACKAGE BOILER CONFIGURATIONS

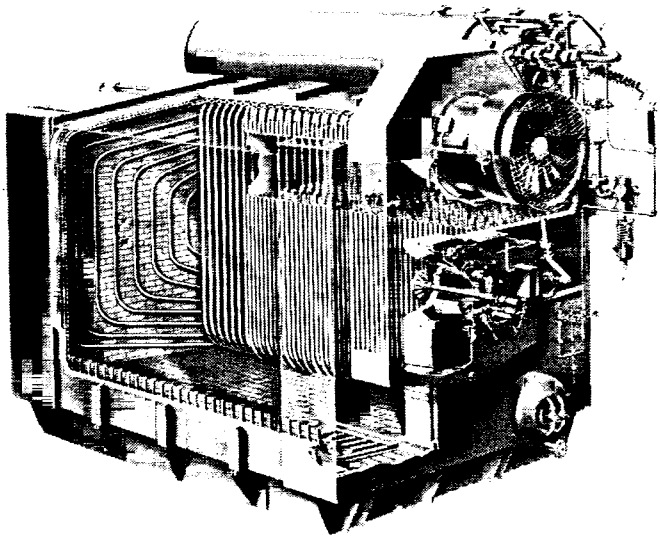


FIGURE 2-12. "D" PACKAGE BOILER

that the flame travels lengthwise down the furnace where combustion is completed. The flue gases then make a 180° 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 the coal which would plug the boiler generating banks. Package boilers have been widely and successfully applied for Central Boiler Plant service.

2.6. HOT WATER GENERATORS.

Hot water generators are often called hot water boilers, even though little or no boiling occurs. Modified Scoth 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 thus been developed that use forced circulation to improve heat transfer rates. Figure 2-13 illustrates this type of hot water generator. Note that the steam and mud drums have been 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, as illustrated in figure 2-14. the water cools and contracts. An expansion drum, pressurized by either steam or inert gas, is provided to adjust for these volume changes. One or more centrifugal pumps are required to cirulate water through the system. Figure 2-15 illustrates a high temperature water system equipped with a steam-pressurized expansion drum, a circulating pump for the generator, and a circulating pump for the distribution system. Many other arangements are possible. A more detailed discussion of hot water generators and distribution systems is provided in Army Manual TM 5-810-2, entitled "High Temperature Water Heating Systems."

2-7. 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 2-16 shows a continuous bare tube economizer. Figure 2-17 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 sootblowers is necessary for economizers on coal- or 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 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 2-18 provides curves which establish minimum metal temperatures allowable for corrosion protection in economizers and air heaters. Since the water temperature in the economizer is normally above 212° F, the fuel sulfur content would have to be less than 2% for stoker-fired coal or 2.6% for oil-fired boilers to minimize corrosion problems during operation. Methods for avoiding corrosion during idle or standby periods are discussed in paragraph 3-27. Economizers are pressure parts and, as such, must be manufactured and stamped in accordance with the ASME Boiler and Pressure Vessel Code. Economizers equipped with three-valve bypasses must be equipped with one or more safety valves.

2-8. AIR HEATERS.

Air heaters, like economizers, are used to recover heat from boiler flue gases and thereby increase the boiler efficiency. The heat absorbed by the air heater is transferred to the combusion air befor 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 air heaters, like the tubular air heater illustrated in figure 2-19, 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 2-20, 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 which must be considered when sizing forced and induced draft fans. Provisions for sootblowers are required if dirty or high-ash fuels are being fired. Cold

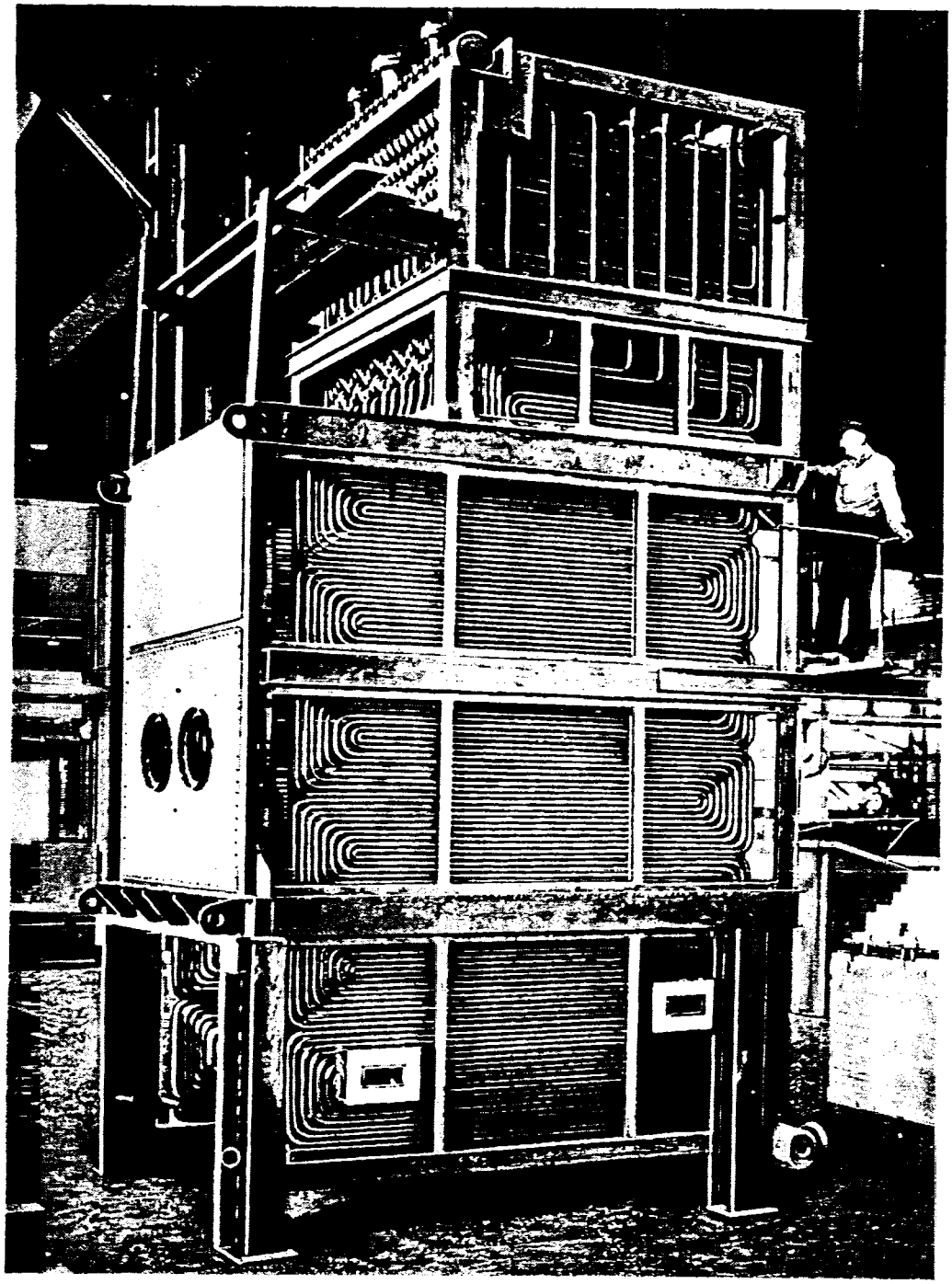


FIGURE 2-13. HOT WATER GENERATOR

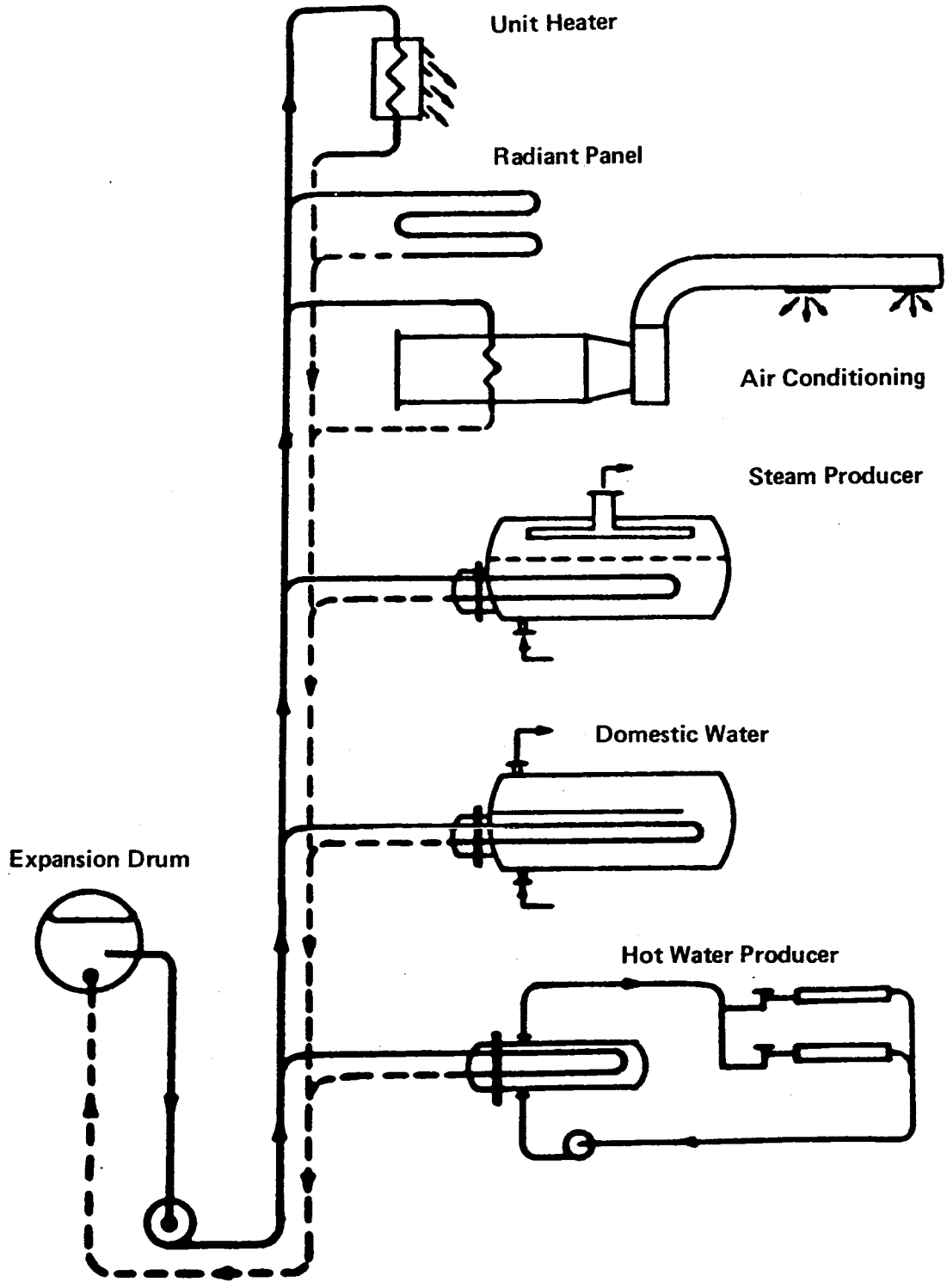


FIGURE 2-14. HOT WATER END USES

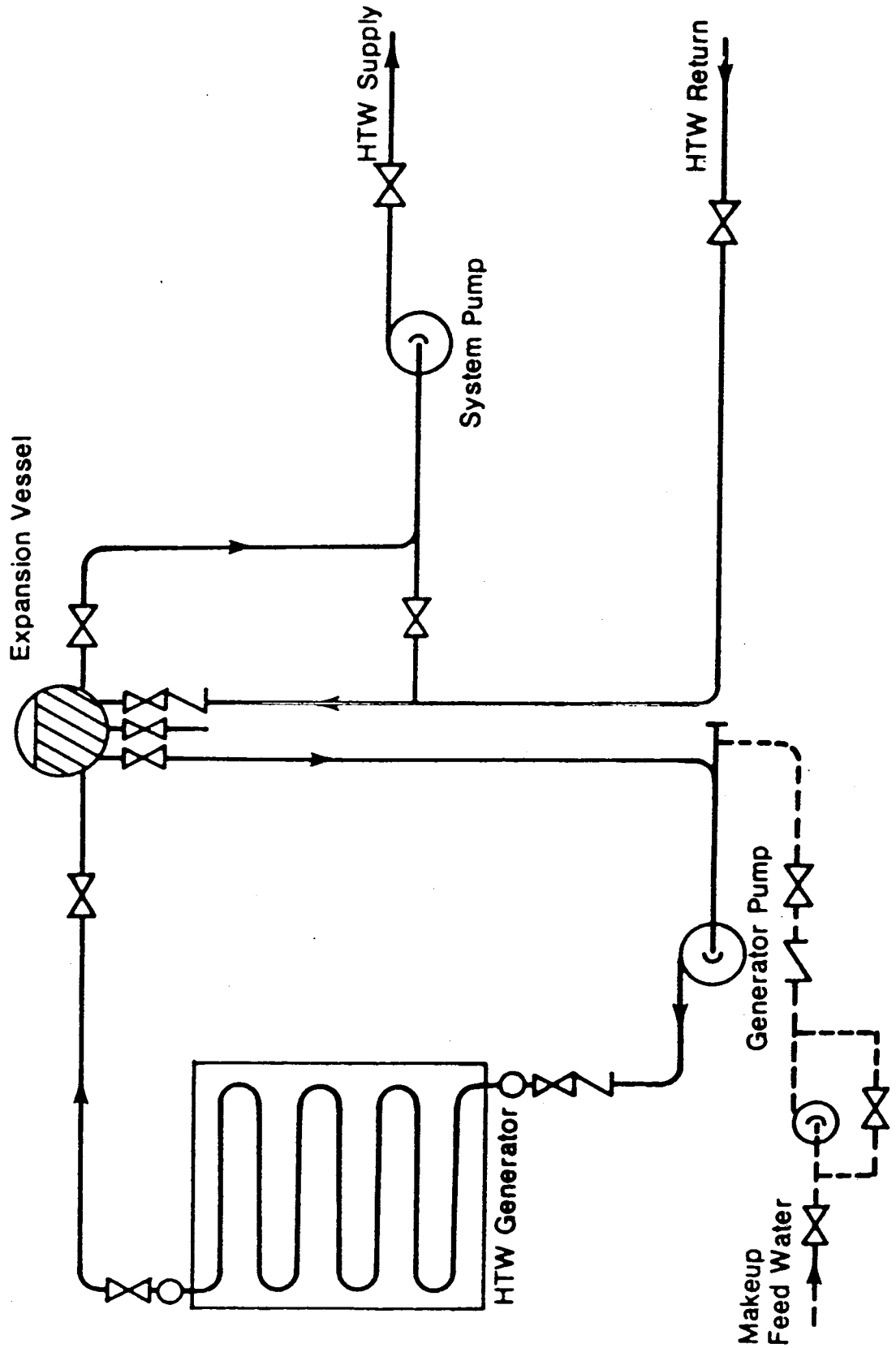


FIGURE 2-15. HOT WATER DISTRIBUTION

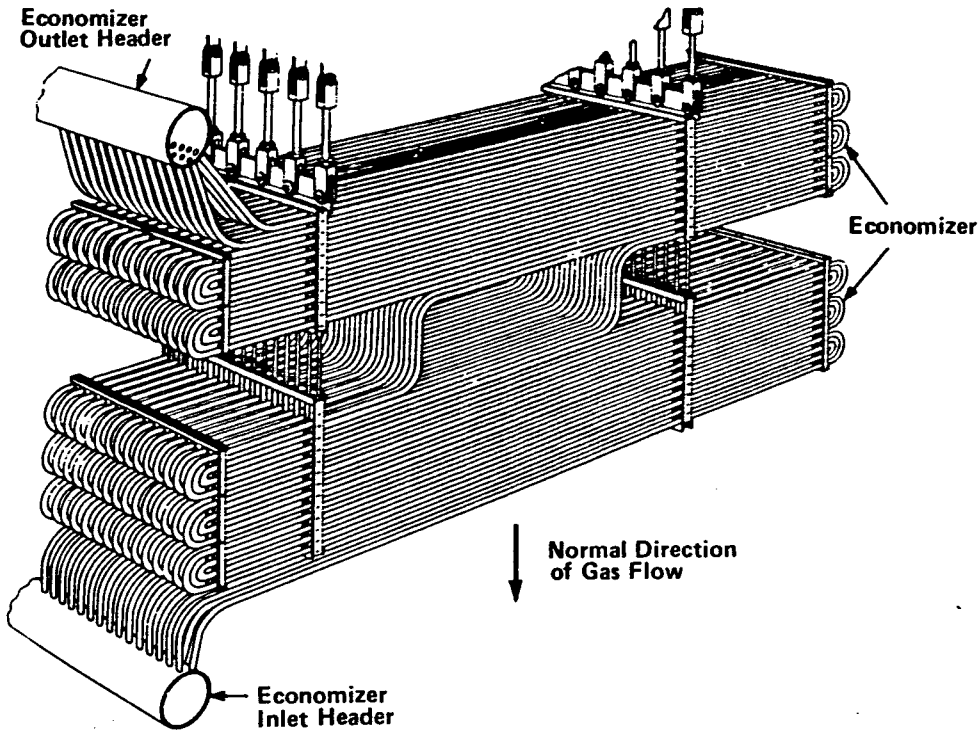


FIGURE 2-16. BARE TUBE ECONOMIZER

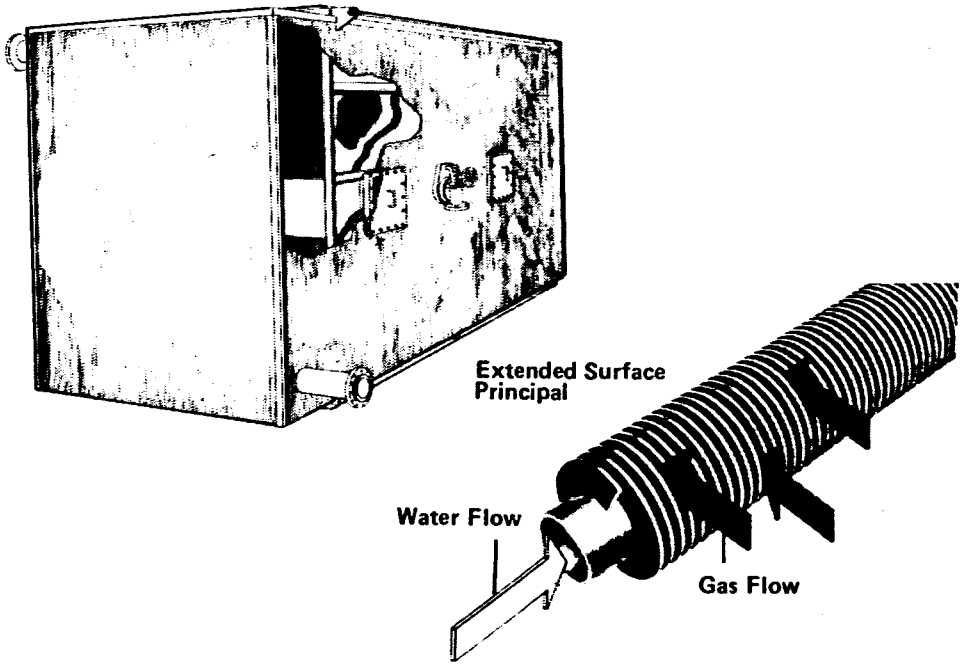


FIGURE 2-17. EXTENDED SURFACE ECONOMIZER

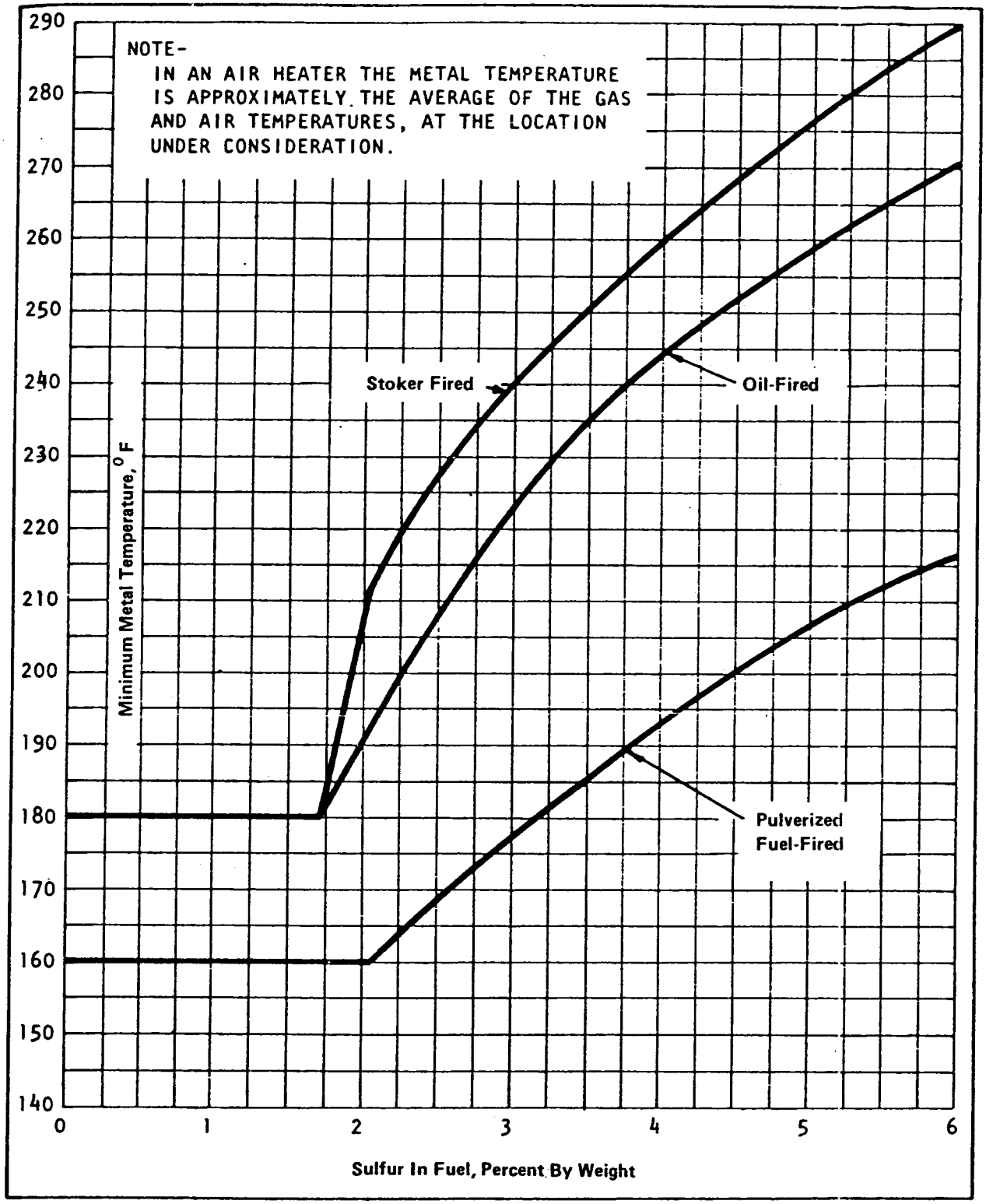


FIGURE 2-18. COLD END CORROSION - MINIMUM METAL TEMPERATURES

end corrosion is more of a problem in an air heater than an economizer because of the low entering combustion air temperatures. Figure 2-18 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.

SECTION II. BOILER ACCESSORIES AND FITTINGS

2-9. 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, high temperature water boilers which 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 ASME Boiler and Pressure Vessel Code, and the 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 so as 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 boilerts. 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.

2-10. 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. Eaqch gage glass must have a valved drainj, and the gage glass and pipe connections must not be less than ½ inch pipe size. 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 age 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 2-21 illustrates a typical water gage. Each gage consists of a strong glass tube connected to the boiler or water column by two special fittings. Thee 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, chain wheel, 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.

2-11. WATER COLUMNS

A water column is a hollow cast-iron, malleable-iron, or steel vessel lhaving 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. The 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-type gate valves are generally used for this service. Lever-lifting-type gaate 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 the 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 all blowdowns should be open and located for ease of inspection. The water column shown in figure 2-22 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.

2-12. PRESSURE GAGE, TEMPERATURE GAGE.

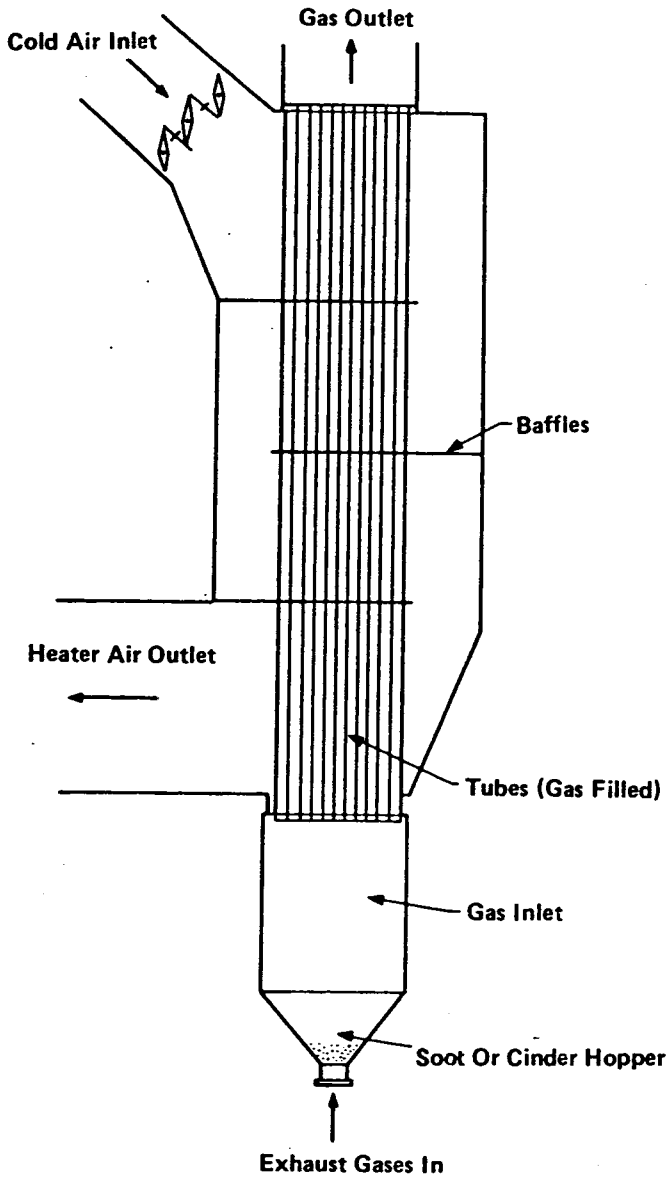


FIGURE 2-19. TUBULAR AIR HEATER

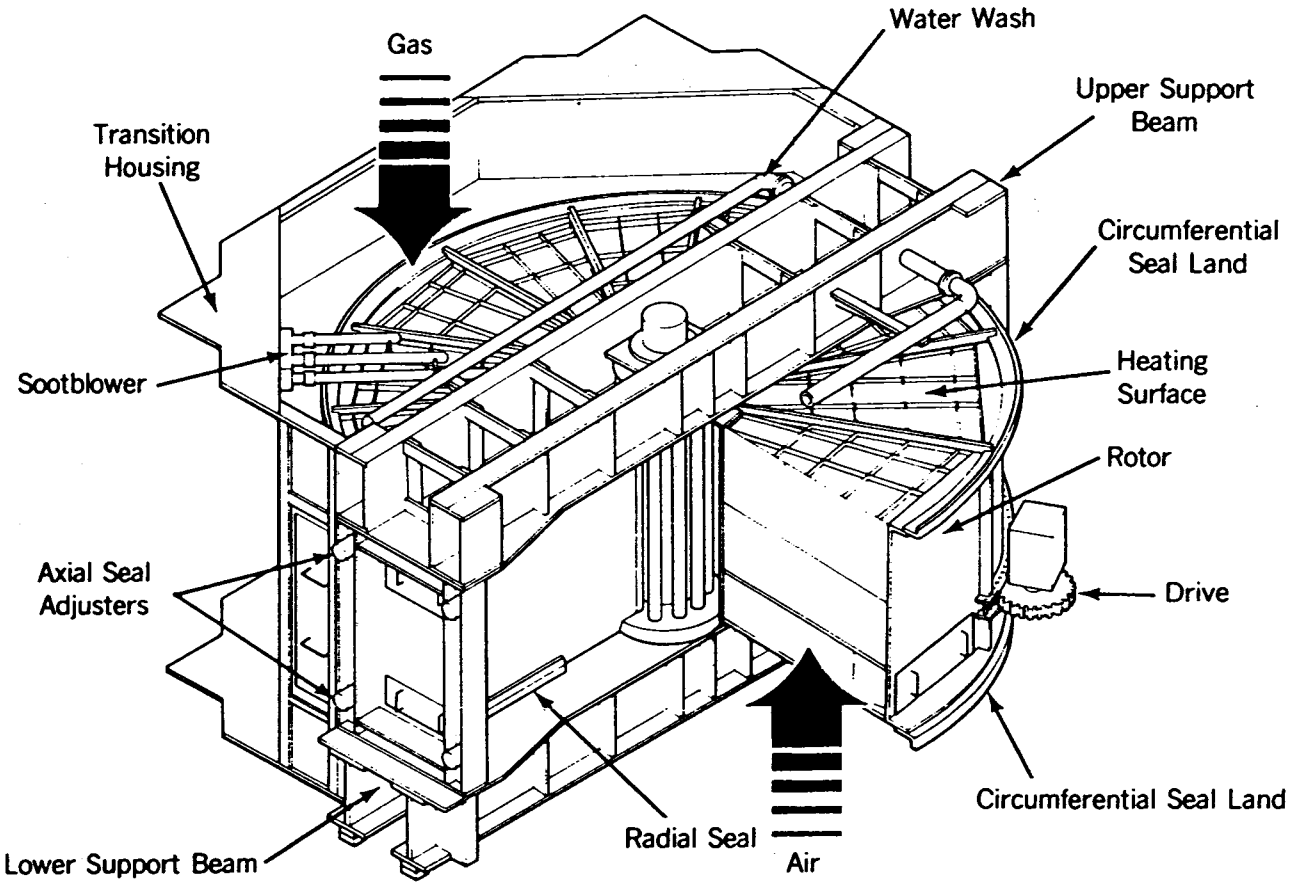


FIGURE 2-20. REGENERATIVE AIR HEATER

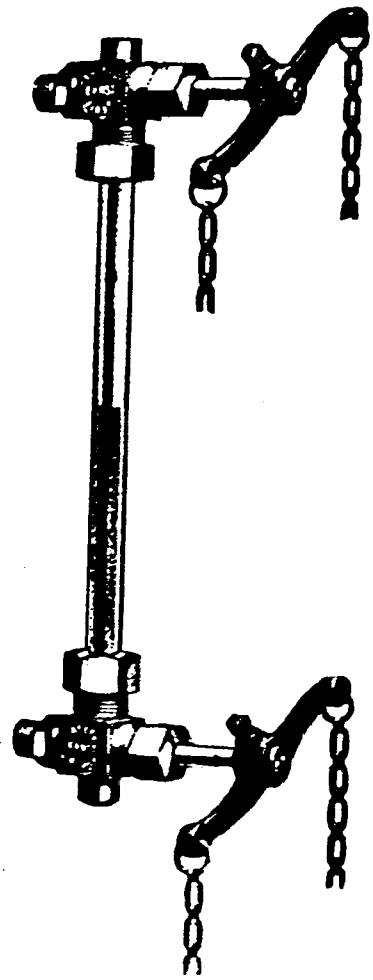


FIGURE 2-21. WATER GAGE GLASS

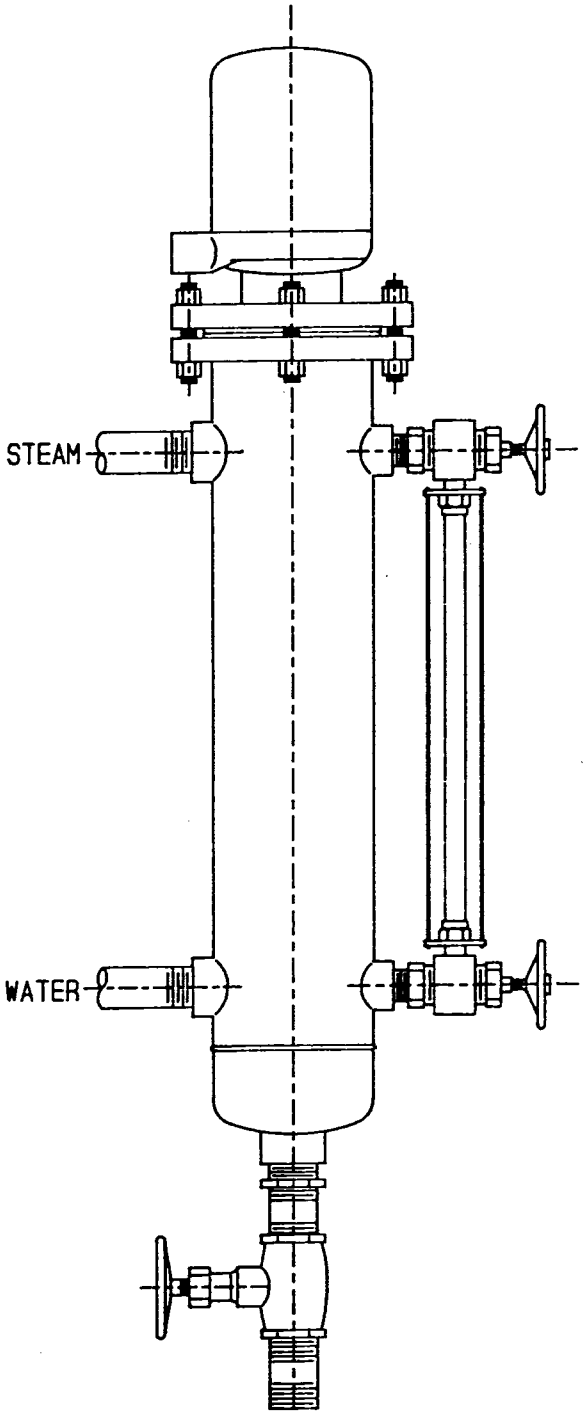


FIGURE 2-22. WATER COLUMN

Every boiler must be equipped with an easily readable prssure gage. The pressure gage must be installed so that it indicates the 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 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. The connections to the boiler must not be less than ¼ inch standard pipe size. Where steel or wrought iton pipe or tubing is used, it must be at least ½ 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 1½ 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.

2-13. SAFETY VALVES.

Safety valves are installed to prevent excessive pressure buildup 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 2-23. 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 sfety valves located near the superheater outlet. A safety valve os 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." All 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. Figure 2-23. Safety Valve Installation

a. Types of Safety Valves. One common type of safety vavle is the huddling chamber safety valve illustrated in figure 2-24. This safety valve opens rapidly because of the additional area on which steam pressure is exerted as soon as the valve startes to life from the seat, and 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 2-24, 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 esape 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. Becaus4e 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 that which 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. Power-actuated pressure relief valves are also allowed by ASME Code but are not used in Army installaltions.

b. Safety Valve Capacity. The safety valve capacity for each boiler must be such that the valve or valves will discharge all the steam that can be generated by the boiler without allowing the pressure to rise more than 6% above the highest pressure at which any valve is set, and in no case to more than 6% above the maximum allowable working pressure. The safety valve valve capacity must be in compliance with 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 1000. Economizer safety valve capacity is calculated from the maximum heat absorption in Btu/hr divided by 1000.

c. Safety Valve Settings. One or more safety valves on

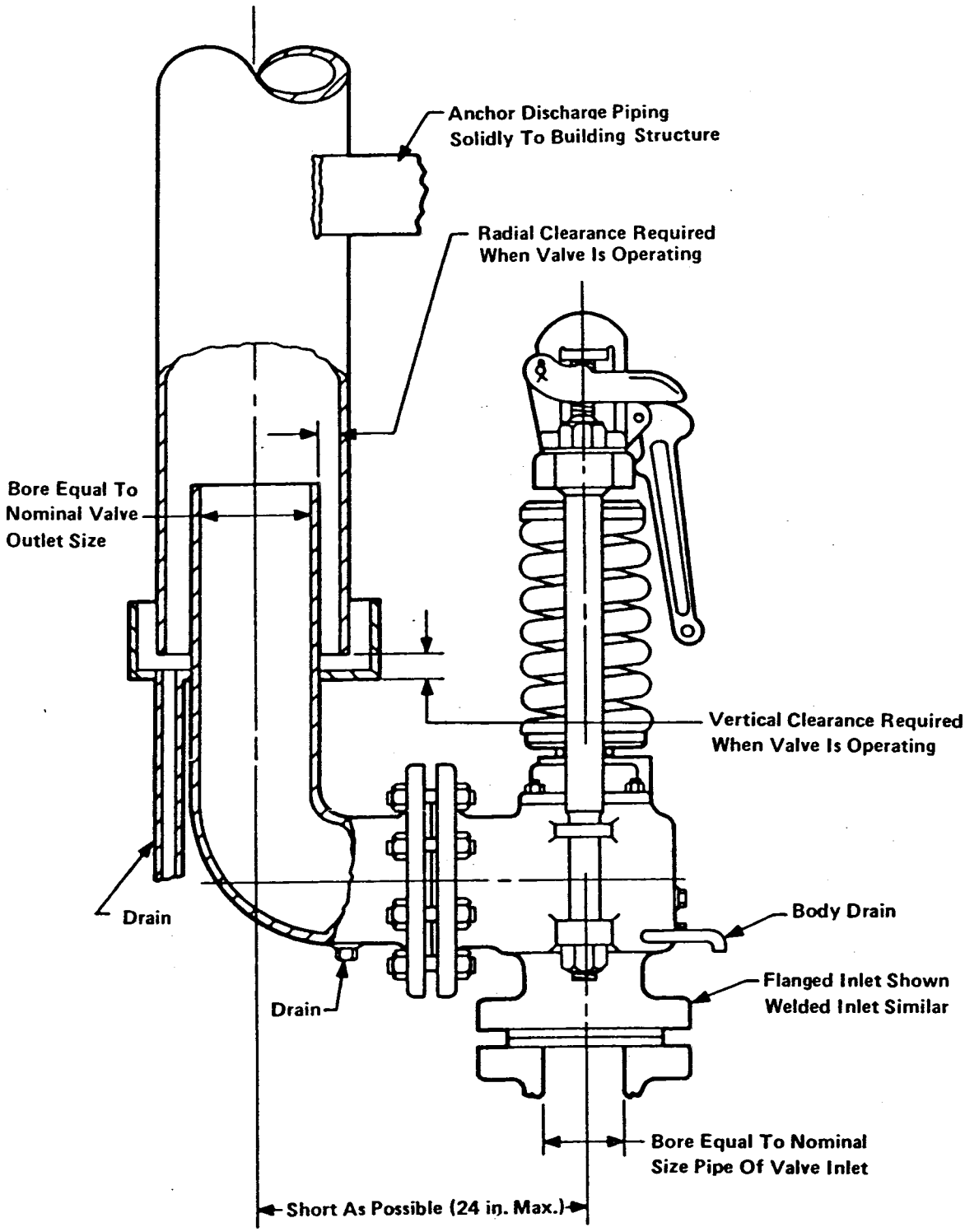


FIGURE 2-23. SAFETY VALVE INSTALLATION

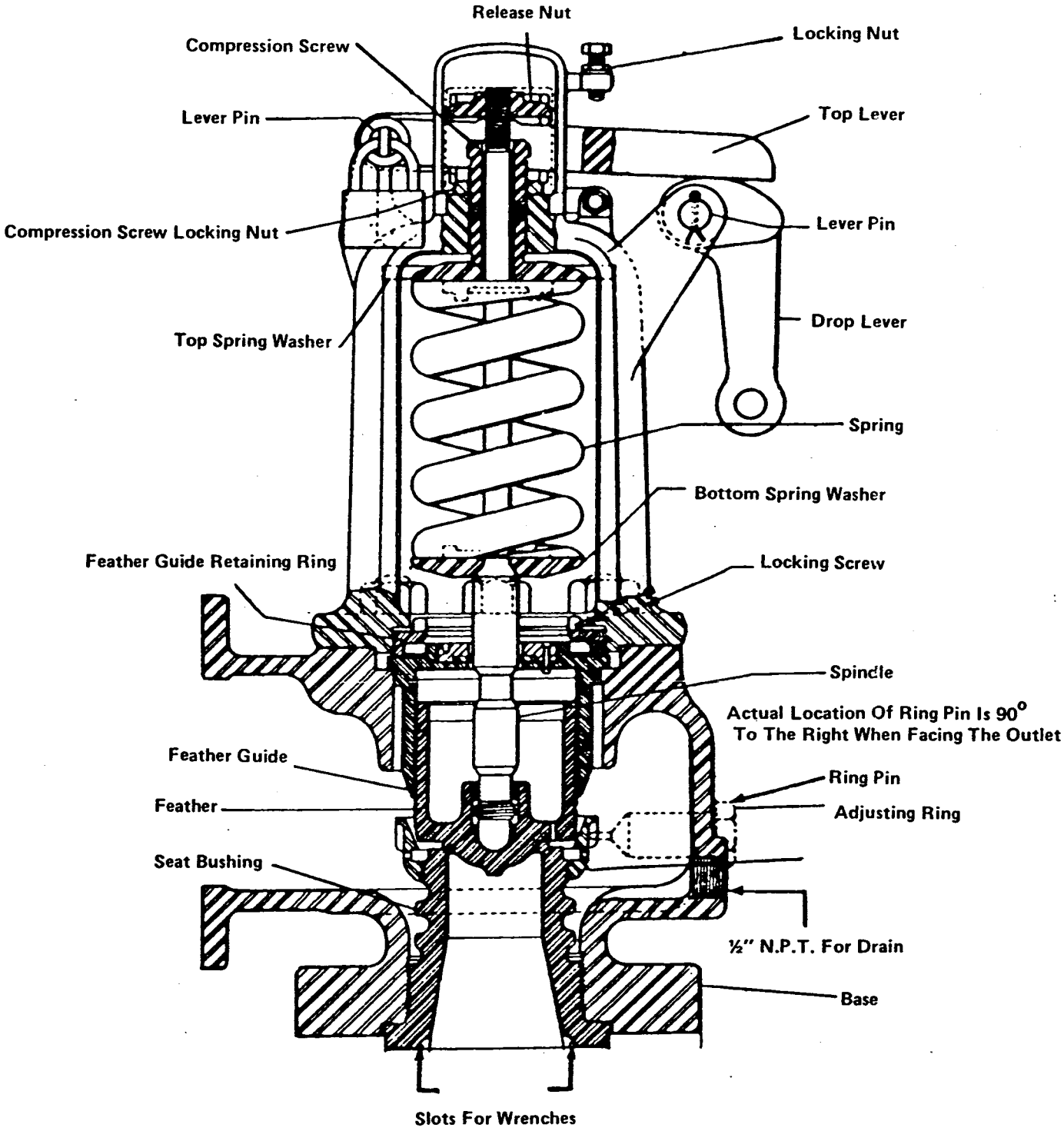


FIGURE 2-24. HUDDLING CHAMBER SAFETY VALVE

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%. The complete range of pressure settings of all the saturated-steam safety valves on a boiler must not exceed 10% of the highest pressure to which any valve is set. Pressure setting of safety relief valves on high-temperature water boilers may exceed this 10% 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 high-temperature water boilers be selected substantially higher than the desired operating presure to minimize the frequency of safety relief valve lift.

2-14. 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 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. Refernce figure 2-25. 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 with an ample, free blow drain between them. The stop valves should consist, prefereably, of one nonreturn valve set next to the boiler 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 (reference figure 2-26). 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 burst tube, loss of fire, or other reasons. The valves require a very small difference in pressure for proper operation. A dashpot is provided to prevent chattering or too rapid movement of the valve. Ladders and catwalks or other means for operating the valves from the operating floors in boiler rooms should be provided.

2-15. BLOWOFF VALVES AND PIPING.

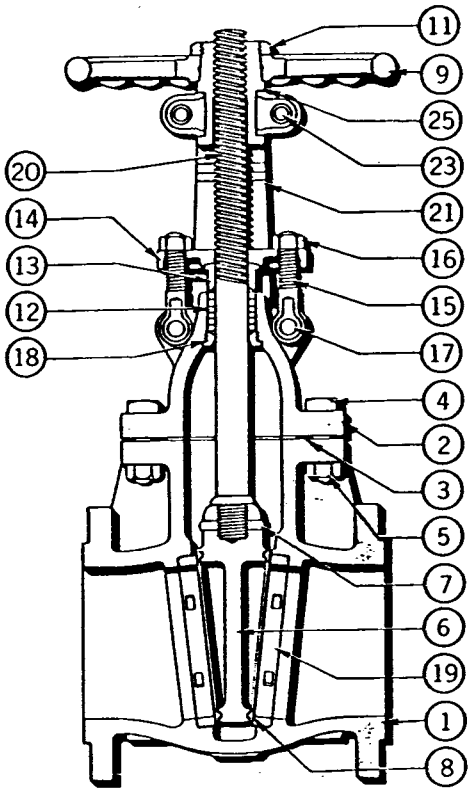
Each boiler must have at least one blowoff connection installed at the lowest water space available to allow removal of sludge. The pipe used must not be less than 1 inch or over 2½ inches. Extra-trong pipe must be used for pressures above 100 psig. The bolowoff line must be protected from direct furnace 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 slow-opening valve set is shown in figure 2-27. A slow-opening valve is one which 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 ilnjury to personnel. Valves which have dams or pockets in which sediment can collect must not be used. Boiler blowdown is provided for the control of dissolved and suspended solids which concentrate in steam boilers. This is a separate subject and is discussed in paragraph 4-8.

2-16. FUSIBLE PLUGS.

Fusible plugs are sometimes used on fire tube boilers to provide added protection against low water. They are constructed of bronze or bradd 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.

a. Fire-Actuated Plug. Fire-actuated plugs are filled with an alloy of tin, copper, and lead with a melting point of 445 to 450° 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 ldrops below the plug, the tin melts and is blown out. The boiler then must 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 boilder manufacturer.

b. 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 the plug and the drum. The metal in the plug melts at a temperature below that of the steam in the boiler. The pipe is small enough to prevent water from circulating inside it and cooling the plug. The 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 wter level drops below the open end of the pipe, the ool water runs out of the pipe and steam ondenses on the plug. The steam



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 2-25. OUTSIDE SCREW AND YOKE GATE VALVE

	PART
1	HANDWHEEL NUT
2	HANDWHEEL
3	STEM
4	YOKE BUSHING NUT
5	YOKE BUSHING
6	YOKE BONNET
7	GLAND STUD NUT
8	GLAND
9	GLAND STUD
10	PACKING
11	BONNET BOLT NUT
12	BONNET GASKET
13	BONNET BOLT
14	DASH POT
15	PISTON RINGS
16	PISTON
17	LOCK NUT
18	DISC
19	DRAIN PLUG
20	SEAT RING
21	BODY
22	LUBRICATION PLUG

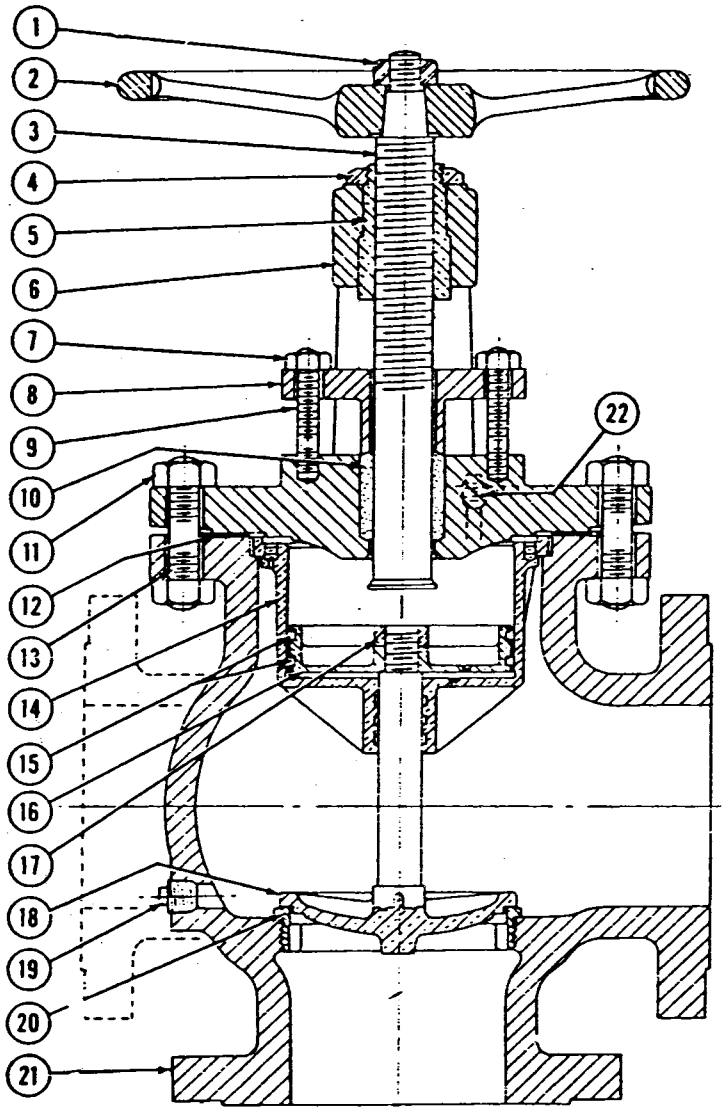


FIGURE 2-26. NON-RETURN VALVE

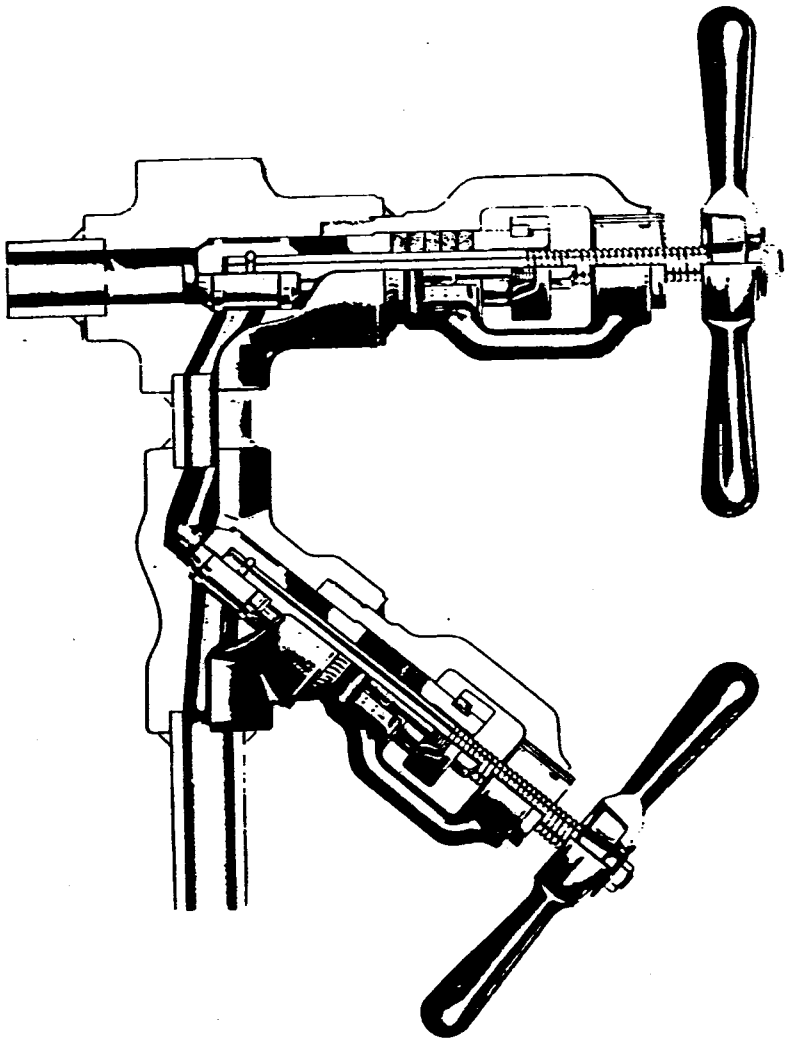


FIGURE 2-27. SLOW OPENING BLOWDOWN VALVE SET

melts the plug and steam blows out, watning the operator. This type of plug can be replaced without taking the boiler out of service, by closing the valve in the plug line.

2-17. SOOTBLOWERS.

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 excessinve amounts are deposited on the tubes, passages become plugged and gas flow is restricted. Brushes, scrapers, hand lances and occasionally sootblowers are used to remove these deposits in fire tube boilers. Hand lances and mechanical sootblowers are used to clean water tube boilers.

a. 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. Figure 2-28 illustrates a fire tube cleaning system. The 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 sootblowers.

b. Mechanical Sootblowers. Permanently mounted mechanical sootblowers 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 which admits steam or air and turns the element, the element itself which distributes the steam or air, and the necessary bearings, piping, and other supports.

(1) **Head.** The head consists of an operating mechanism, usually a chain or handwheel loperating 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 (reference figure 2-29).The poppet valve is adjusted at startup 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.

(2) **Elements.** Elements are tubes containing a number of nozzles. These nozzels are spaced along the element to blow between the boiler tubes for lane blowing, or at a number of tubes for mass blowing. When elements are installed for lane 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. The elements are made of plain, carborized, or alloy steel, depending on the temperature to which they are to be subjected; they are supported at regular intervals by bearings clamped on the boiler tubes. The distance between these bearings is determined by the flue-gas temperature in that specific area.

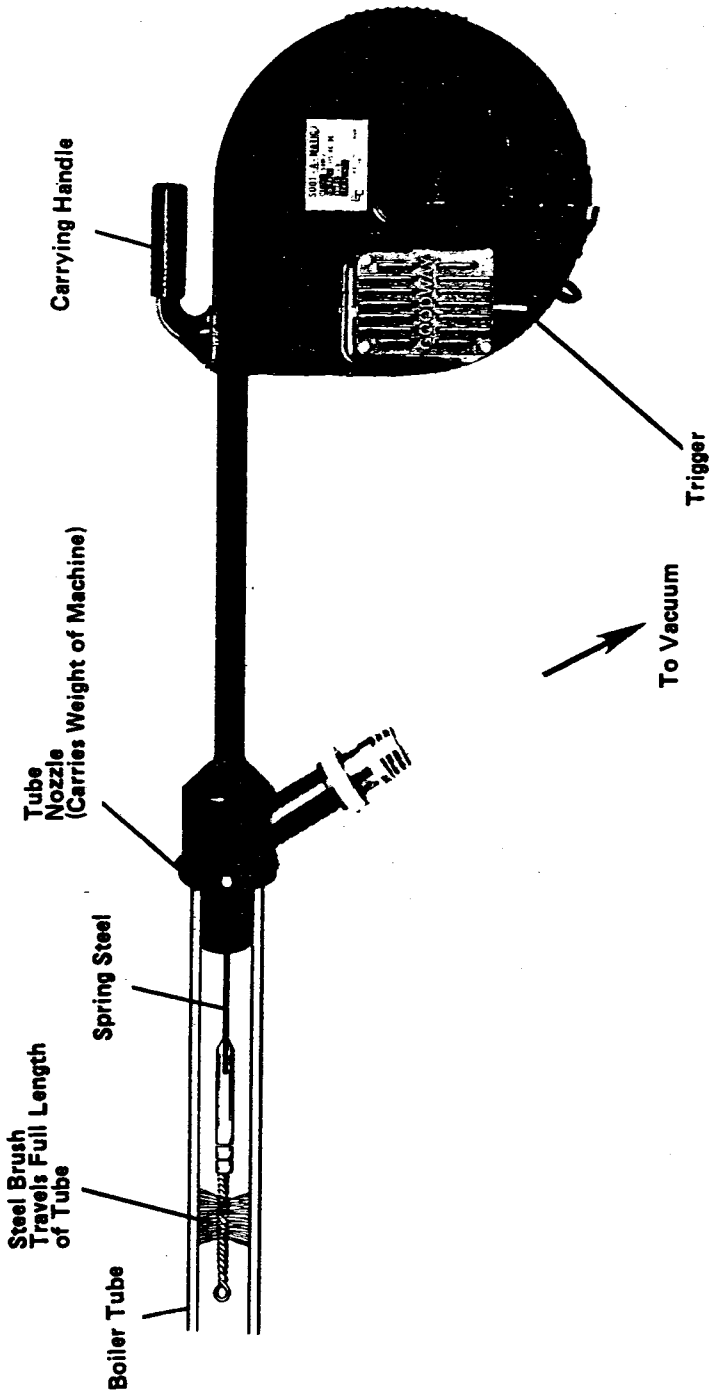


FIGURE 2-28. FIRE TUBE CLEANING SYSTEM

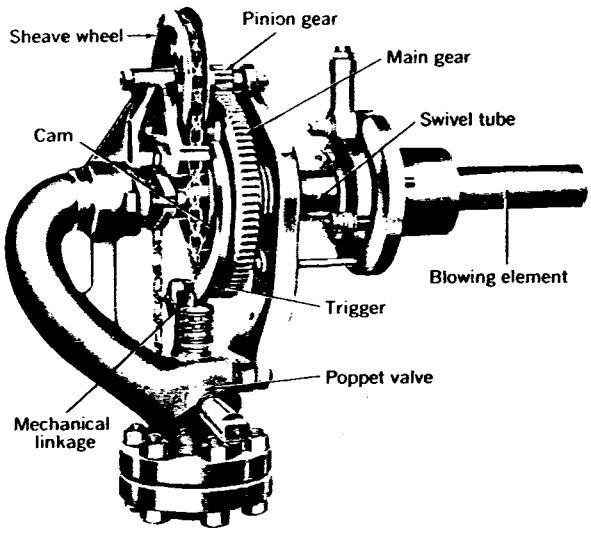


FIGURE 2-29. FIXED POSITION MECHANICAL SOOTBLOWER

SECTION III. FUEL-HANDLING AND COMBUSTION EQUIPMENT

2-18. COAL COMBUSTION EQUIPMENT.

Coal may be fired by one of four methods:

— Manually on stationary grates
— Automatically by stoker
— In suspension as pulverized coal
— 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 TM 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 each method.

a. 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 mizing. The result is that stokers have several advantages over hand firing: they pemit 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 the fuel, and the amount of draft available.

b. 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 volatiles have 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 2-30 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 1½ to 2 inches and not more than 50% slack being typical. The principal elements of an underfeed stoker are hoppers, feeders, retorts, and combustion air fan. Each is discussed in the following paragraphs.

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

(2) **Feeders.** Feed screws or reciprocating rams may be used to deliver coal from the hopper to the stoker retort as shown in figure 2-30. Even distribution of the coal is obtained by the shape of the screw, shape of the retort, and the stroke of the 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.

(3) **Retorts.** The size and shape of the retort depend 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

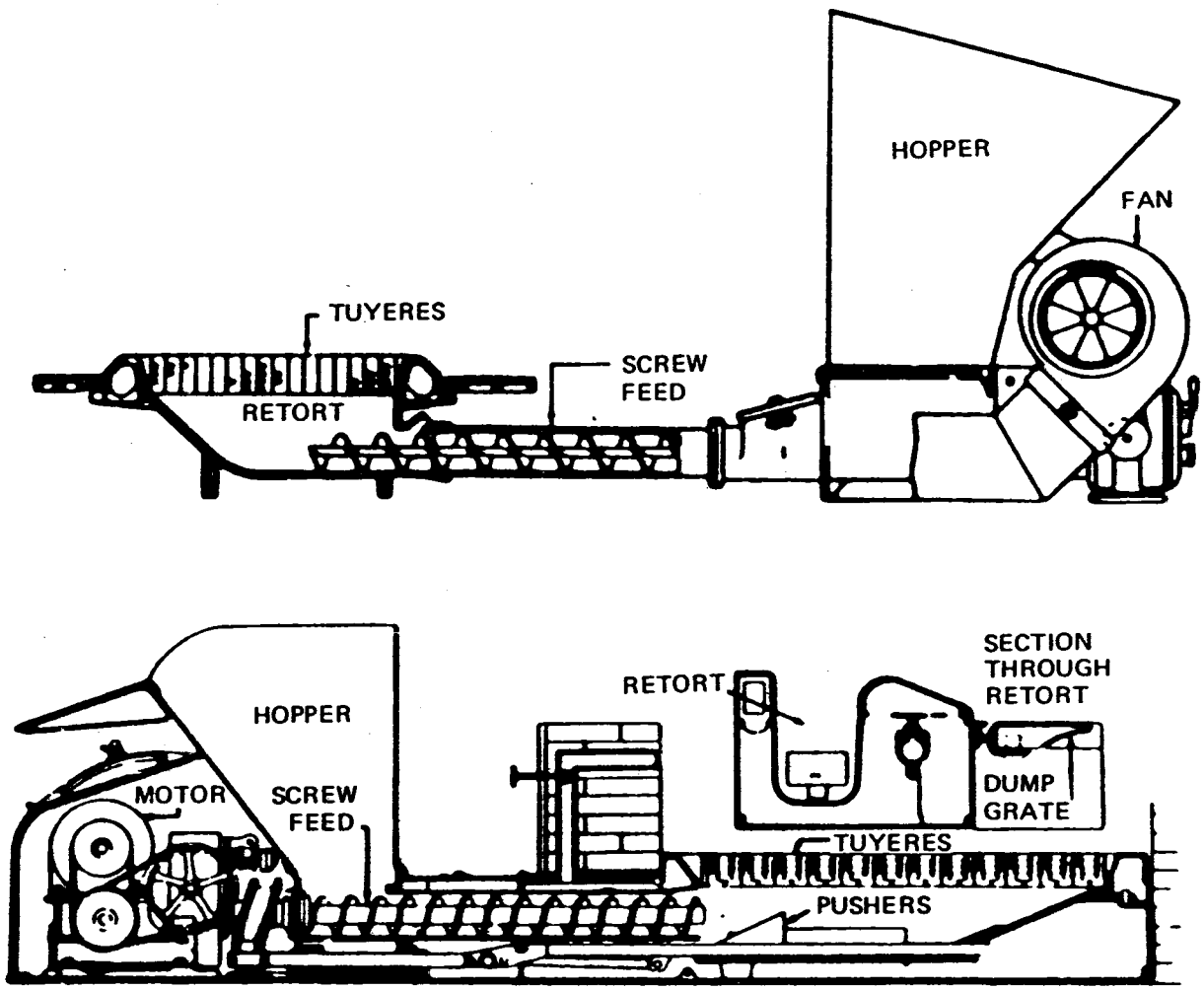


FIGURE 2–30. UNDERFEED STOKER

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.

(4) **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. The windbox may be divided into zones to permit better control of combustion air. The volume of the air supplied is controlled by inlet or outlet control dampers on the fan. Air flow should be controlled automatically to correspond to changes in the firing rate. Methods of control are discussed in paragraph 2-26.

c. Spreader Stokers. 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 reminder 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 the 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 non-caking properties of coal to the same extent as other types of stokers, and they can handle coal ranging in size from dust to about 1¼ 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. All 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 2-31 illustrates a power dumping type spreader stoker. The principal elements of a spreader stoker are described below.

(1) **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 2-32 illustrates an underthrow rotor. The 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 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 the distribution of fuel along the length of the grate. The feeder mechanism, the grates, and the air supply are usually constructed to operate as a unit. The feeders are usually driven from a single line shaft, with each having its own drive gearing. When dumping grates are used, sections pf the fire can be cleaned alternately by shutting off the fuel to one feeder and allowing the fuel to burn out in that section of grate before dumping. The variable speed-driven mechanisms are similar to those found on underfeed stokers. Variable speed motors often replace the mechanical gearing to drive the individual feeder and distribution shaft on newer designs.

(2) **Overfire Air Fan.** A separately driven centrifug: fin 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 the coal.

(3) **Cinder Reinjection System.** Since the spreader stoker burns a significant percentage of the coal in suspension, carryover of unburned coal is common. To improve boiler efficiency by reducing this unburned carbon loss, the fly ash and coal can be collected in a mechanical ecollector 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 the fly ash and coal and pneumatically conveys it back to the furnace via special piping and reinjection ports.

(4) **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 2-10 illustrates a spreader stoker with traveling grate installation.

(5) **Combustion Air Fan.** As with all stokers, combustion air under pressure is neded to ensure complete and efficient combustion and control. Inlet or outlet dampers are provided to control the air flow rate.

d. Traveling Grate and Chain Grate Stokers. These type of stokers consist of an endless belt-type grate which moves slowly and conveys the burning coal from the feed end

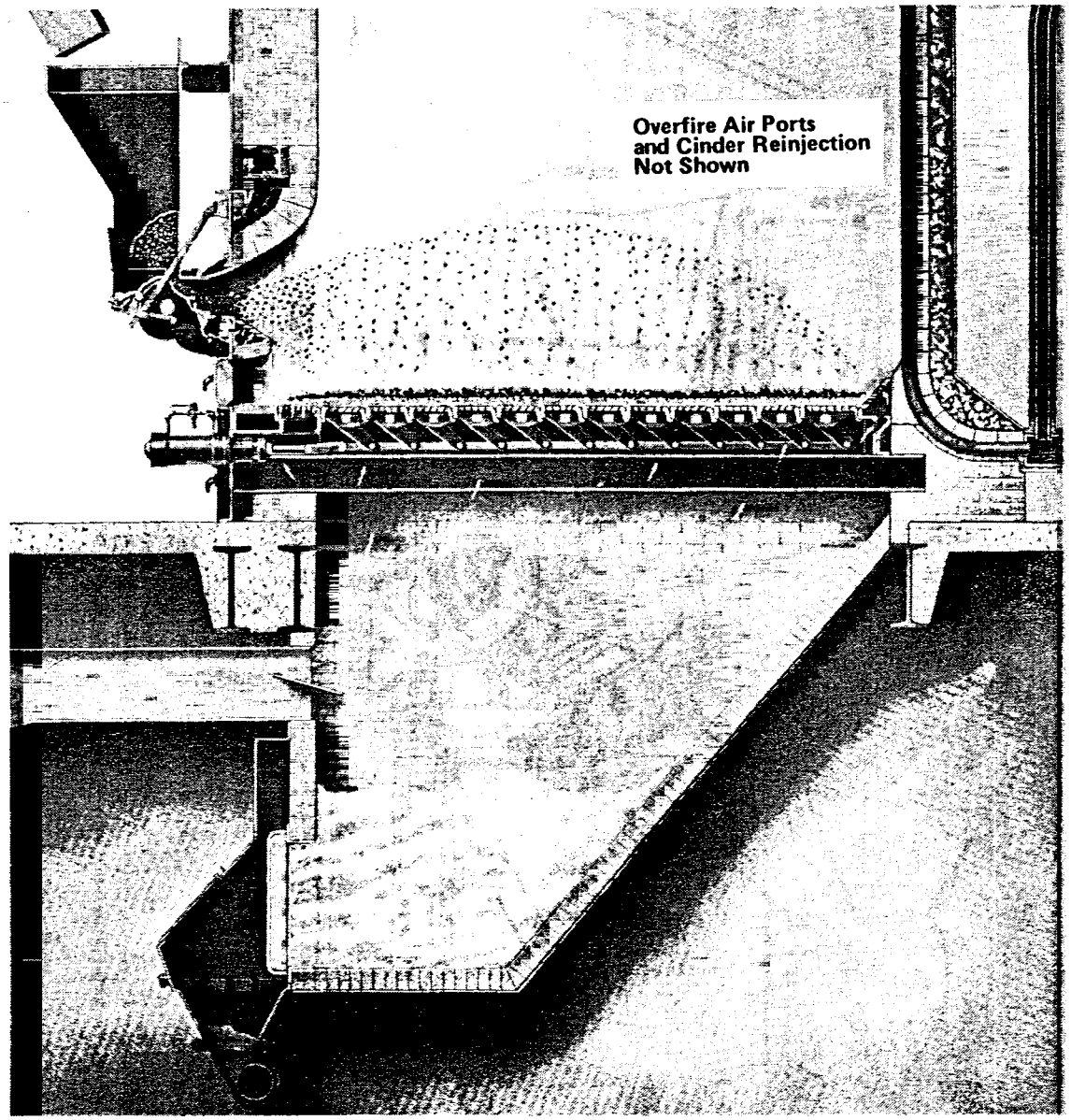


FIGURE 2-31. POWER DUMP GRATE
SPREADER STOKER

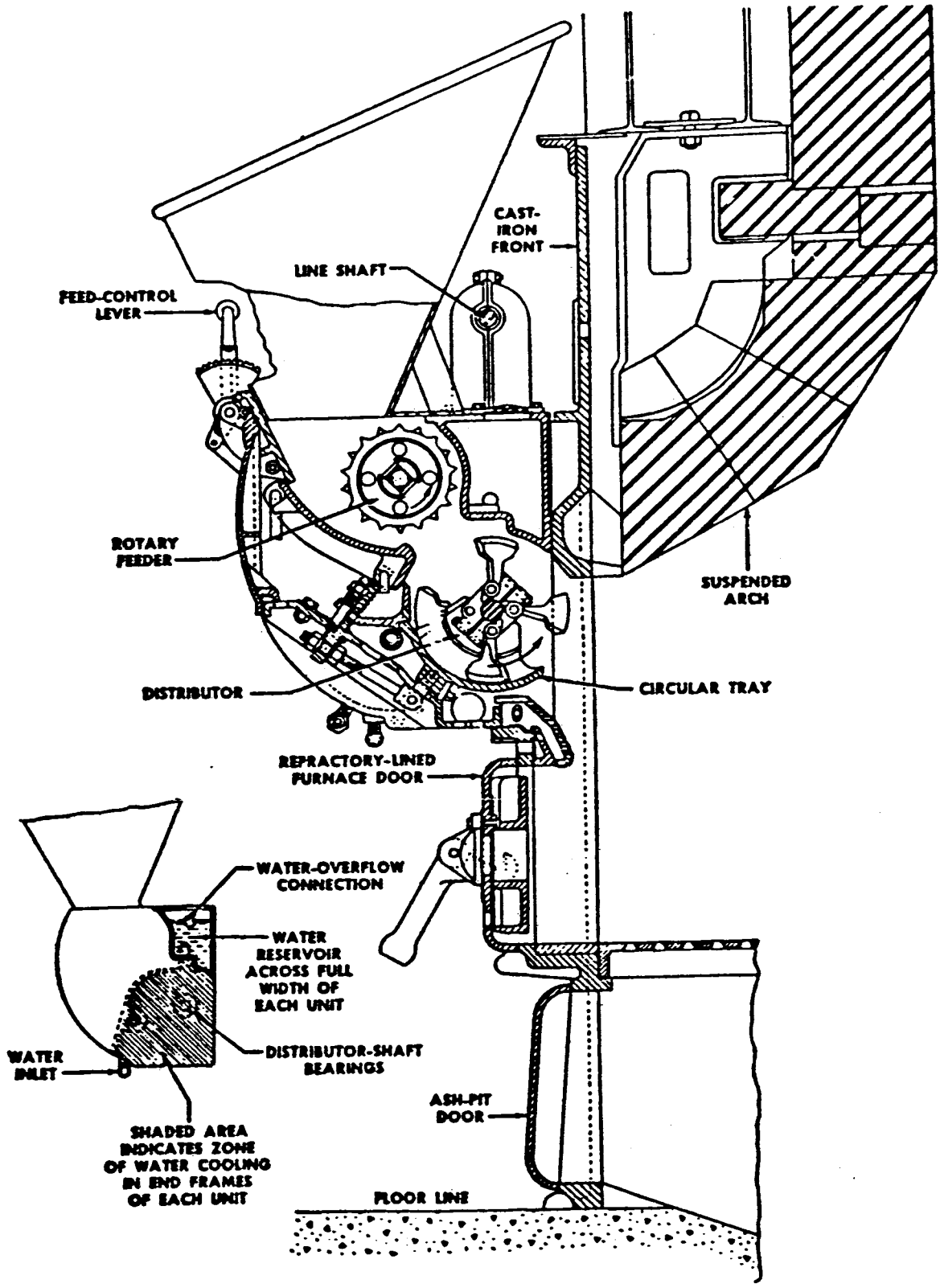


FIGURE 2-32. UNDERFEED SPREADER

to the ash discharge end of the stoker. With chain grate stokers, the links are assembled so that as they pass over the rear idler drum, a scissor-like action occurs between the 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 2-33 illustrates a traveling chain grate stoker. Traveling or chain grates may be used with spreader feeders discussed above, or the coal may be placed directly on the stoker, as described below.

(1) **Feed Mechanism.** A hopper on the front of the stoker has an adjustable gate which regulates the depth of the fuel bed. The rate of feeding coal to the furnace is regulated by changing the speed at which the grrate travels. The amount of ash carryover from the furnace is kept to a minimum with this feeding method, and fly-ash injection, typical of spreader stokers, is not required. Figure 2-33 illustrates the overfeed of coal onto a chain grate.

(2) **Combustion Air.** The space between the grates is divided into zones and the flow of air to each of these zones is contolled by dampers. This is necessary if uniform combustion is to be attained, because the resistance of the fuel bed to the flow of air decreases as the grates nove 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 the combustion of volatiles driven off from the fuel bed.

e. Vibrating Stokers. In this type of stoker the 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 intermittnet grate vibrations. Ash is discharged over the end of the grate (reference figure 2-34). The furnace water tubes are positioned under the stoker grates to cool the 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.

f. Pulverized Coal. Pulverized coal firing requires the operation and maintenance of pulverizers. Historically, it has not been economical to install pulverized coal firing systems on boilers with a steam flow of less than 100,000 pounds per hour, and they are uncommon in Army Central Heating Plants. For further information on pulverized coal systems, refer to Navy Manual MO-205, Volume One, Sections 19 and 20.

g. Fluidized Bed. Fluidized bed combustion is a relatively new method of burning coal while complying with sulfur dioxide emission regulations. In fluidized bed combustion the 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 FD fans. Combustion takes place in the bed. The sulfur in the fuel combines chemically with the 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 the flue gases. The main advantage of the fluidized bed boiler is thus 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 the added electrical operating costs associated with the larger combustion air fans necessary for fluidizing the bed, higher particulate and unburned carbon carryover from the furnace, and high initial cost.Figure 2-35 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.

h. Fuel Characteristics and Specifications. The following paragraphs provide general guidelines on the types of coal which arc applicable to the various firing methods. There is, however, much overlap in these guidelines, and the equipment manufacturer or tother combustion expert should be consulted if a change in fuel type is considered.

(1) **Underfeed Stokers.** 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 1½ inch nut and slack, preferably containing not more than 50% slack. Slack is defined as coal of a size that will pass through a ¼ inch round-hole screen. For multiple retort underfeed stokers the ide al coal should vary in size from 2 inch to slack, with not more than 50% slack. The volatile content should preferably be between 20 and 30%; the ash content should range between 6 and 8%, and the ash softening temperature should be above 2400 F in a reducing atmosphere. Iron content of the ash should be not more than 20% 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 F.

(2) **Spreader Stokers.** Spreader stokers were developed to burn the lower grades of coal, but they are capable of handling all ranks from semianthracite to lignite, plus numerous waste and byproduct fuels. As might be expected, spreader stoker performance is best when quality and sizing

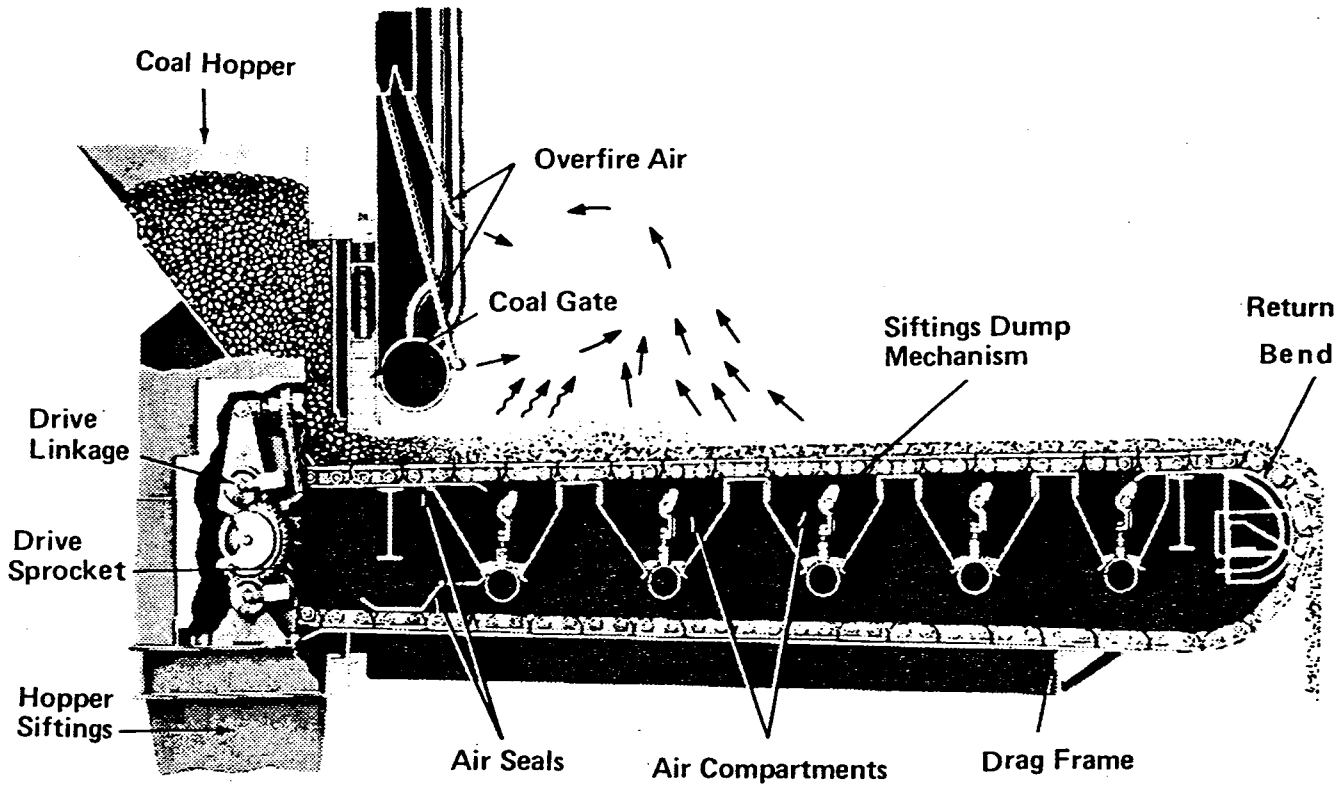


FIGURE 2-33. TRAVELING CHAIN GRATE STOKER

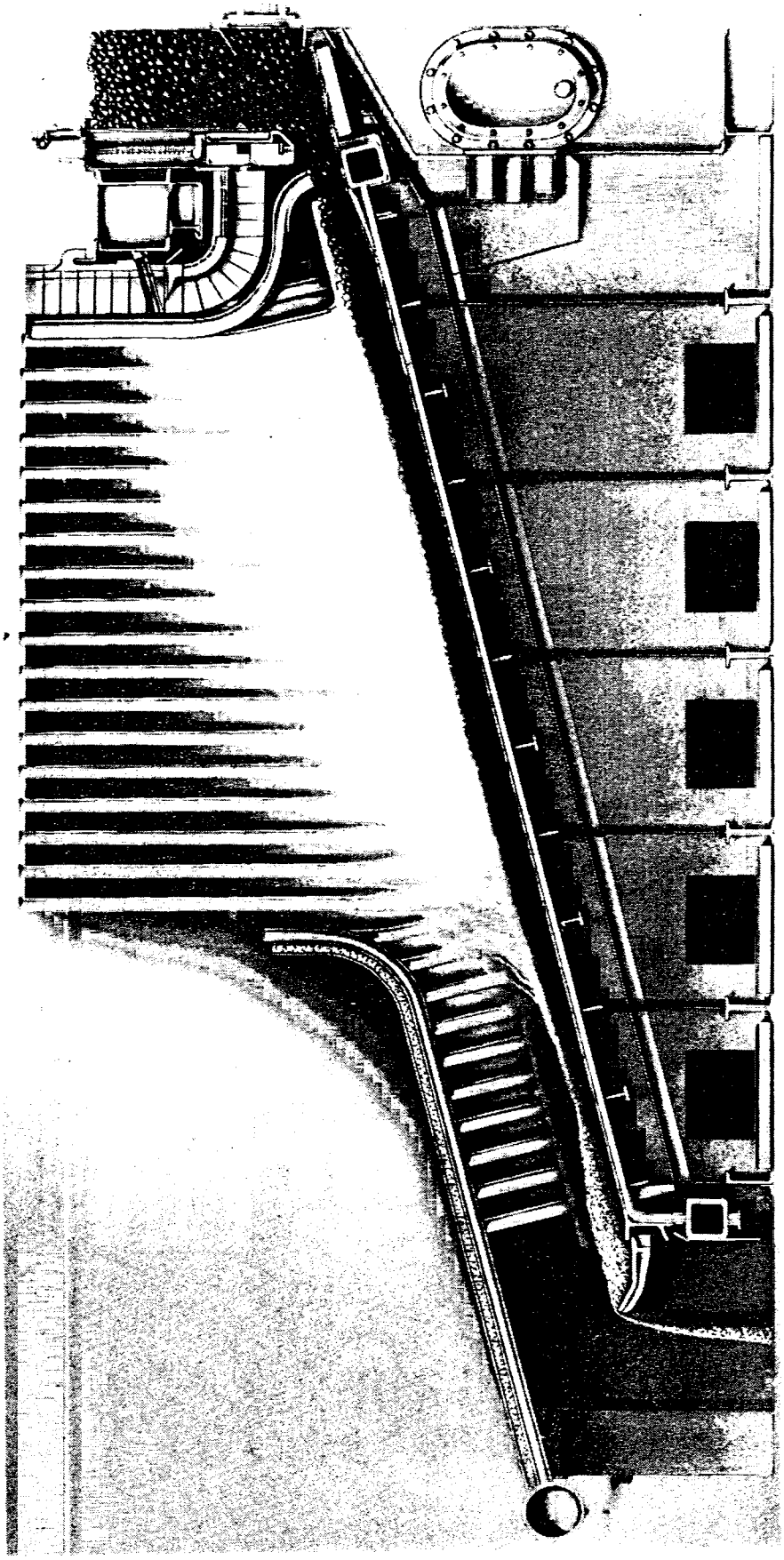


FIGURE 2-34. VIBRATING GRATE STOKER

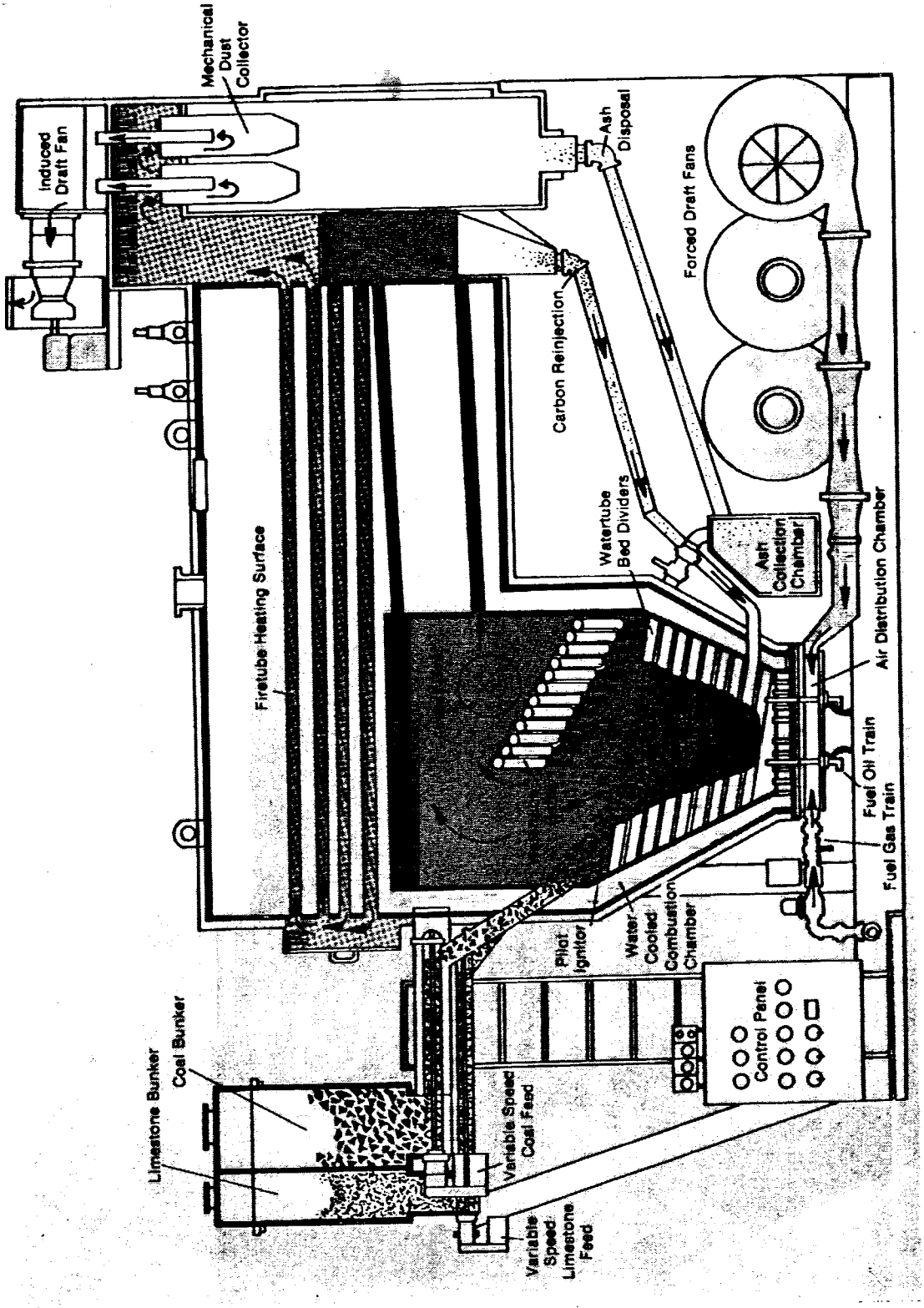


FIGURE 2-35. FLUIDIZED BED FIRE TUBE BOILER

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 ⅛ or ¼ inch screen, to 1¼ or 1½ 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) **Traveling Grate and Chain Grate Stokers.** The fuels most widely used on traveling grate stokers are anthracite, semianthracite, 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 the 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 (D-388) as shown in table 1-1. For anthracite (Rank I-2), the size of No. 3 buckwheat (barley) should be all through 3/16 inch round hole screen and not more than 20 percent through 3/32 inch screen; No. 4 buckwheat should pass through a 3/32 inch round hole screen with not more than 10% through a 3/64 inch creen and not more than 1% through a 100 mesh screen. For coals of ASTM Ranks II-4, 5, III-1, 2,3, and IV-1, 2 the size should be 1 inch nut and slack with not more than 50% slack through a ¼ inch round-hole screen and tempering to 15% moisture. For friable coals of ASTM Ranks II-1, 2, 3, the sizing should be 1 ¼ or 1½ inch nut and slack with not more than 50% slack through a ¼ inch round screen. For nonfriable coals of ASTM Ranks II-1,2,3, the sizing should be ¾ inch nut and slack with not more than 50% slack through a ¼ inch round-hole screen. If coke breeze is burned on traveling grate stokers, it should contain 8 to 10% moisture and not less than 1% volatile matter; the entire quantity should pass through a ⅜ inch round mesh with not more than 50% or less than 25 percent through a ⅛ inch round-hole screen.

(4) **Vibrating Grate Stokers.** 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, the 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-fushion temperature coals. A well-distributed, uniform fuel bed can be maintained without blow holes or thin spots.

(5) **Fluidized Bed.** Fluidized bed boilers may be used o burn almost any fuel, including not only bituminous and anthracite coals but also lignite, refuse, wood, and various solid waste fuels.

2-19. 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.

a. Storage. Coal lmay be stored in covered bins or bunkers, in silos, or in the open. Only relatively small amounts 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. For additional information, see TM 5-675 concerning handling, storing, and sample preparation.

b. Coal Handling in Plant. Figure 2-36 illustrates a system typical of those found in Army Central Heating Plants. It includes the following major components: track or truck hopper, feeder, bucket elevator or conveyor, bunker or silo, and coal weighing device.

(1) **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 which could plug or damage the conveying equipment.

(2) **Feeders.** Manytypes 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-type feeders which are often used. Final selection is dependent on the particular site characteristics.

(3) **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 (reference figure 2-

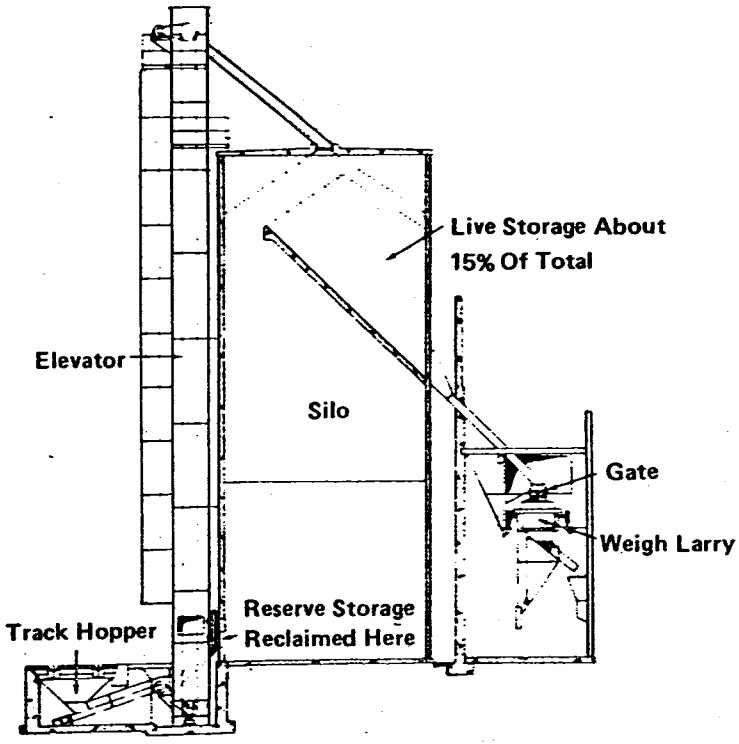


FIGURE 2-36. COAL HANDLING SYSTEM

37). Elevator boots are provided with clean-out 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.

(4) **Bunkers and Silos.** Bunkers and silos provide covered storage of the 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 wilth live storage sections and reserve storage sections.

(5) **Coal Weighing.** A knowledge of the 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 which measures its volume. Weighing equipment ordinarily consists of automatic or semiautomatic weigh larries. As shown in figure 2-38, a weigh larry consists of a framework which supports a hopper mounted on scale beams. The framework can be ıoved over the various bunkers. The coal hopper of the ıarry is filled and the weight determined and recorded. The larry is then moved to the desired stoker hopper and dumped. Coal scales which weigh coal automatically are also available. One type of scale consists of three major assemblies: a belt feeder, a weigh hopper with bottom dump gate, and a weigh lever with controls. A mechanical register is provided to record the amount of coal delivered. A belt feeder transfers the coal into the weigh hopper until the weigh lever is balanced. The weigh hopper is then dumped and the cycle is repeated.

2-20. ASH-HASNDLING 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. All the 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-size 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.

a. Pneumatic Ash Handling. Figure 2-39 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 the ash to the system. One end of the ash-conveying line is open, and the suction created by the exhauster causes a rapid flow of air through the line. Dry ash is admitted to the 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 the ashes into the silo. As the system goes into operation the negative pressure in the receivers closes and seals the drop doors. At the end of each cycle, the doors swing open when the pressure is equalized, and drop the ashes into the silobelow. The air washer condenses the incoming steam from the exhauster, washing out ash and dust particles entrained in the air stream. Clean air is thus exhausted to the atmosphere. The mixture of water and dust passes to a sump, where the dust settles and the water is drawn off to waste. 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 which wet the ashes as they are discharged from the bottom of the silo. Vacuum systems are limited in the distance which 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.

b. Hydraulic Ash Handling. Figure 2-40 illustrates a hydraulic ash-handling system. This is a pressure velocity system in which the otivating force is provided by a ser.es of high-pressure water jets. When the system operates, the ash is taken from the ash jet hopper beneath the boiler. Sprays and water jet nozzles flush the 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 a landfill. The fly ash and dust are aspirated pneumatically from the dust hoppers by water jet exhausters and passed through an air separator where the air is collected and vented to the atmosphere. Finally, the mixture of fly ash, dust, and wateer 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

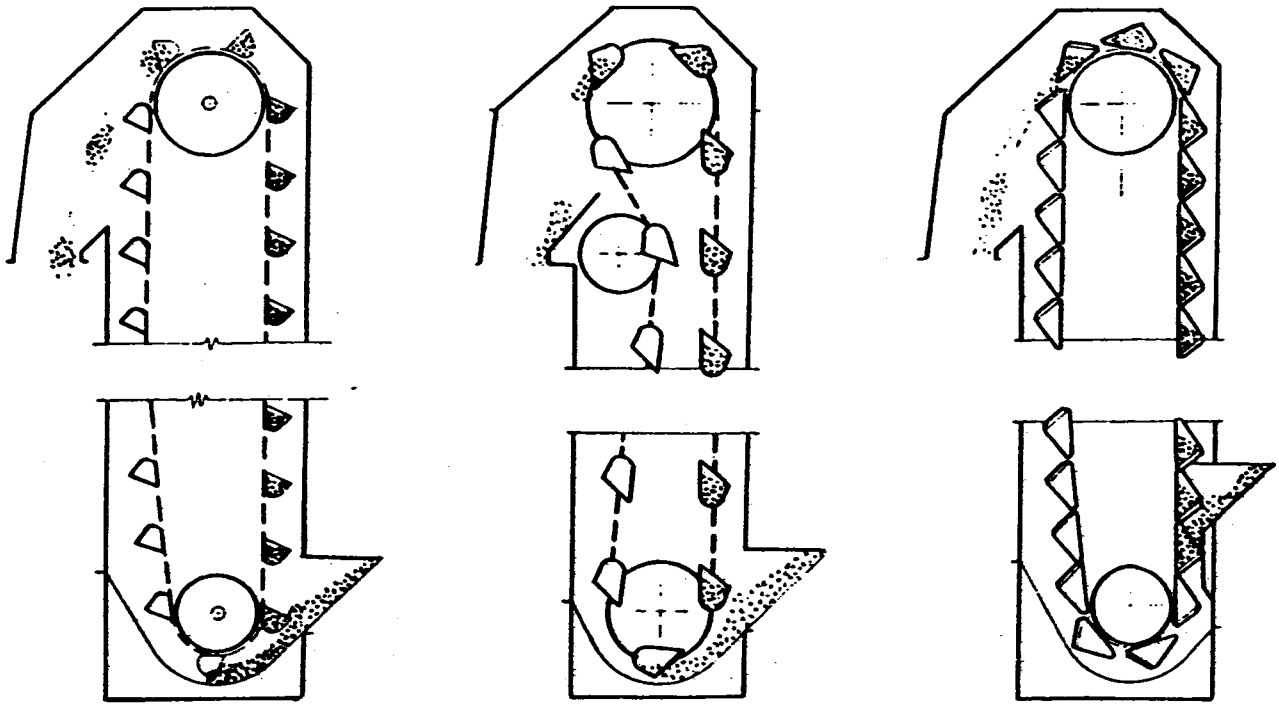


FIGURE 2-37. TYPES OF BUCKET ELEVATORS

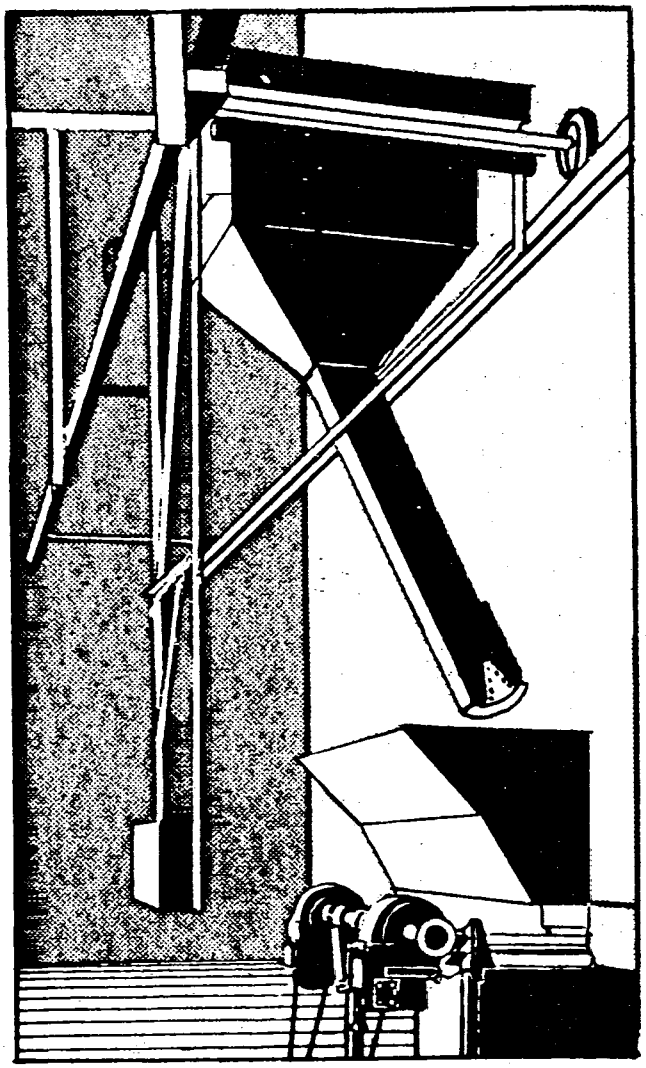


FIGURE 2-38. WEIGH LARRY

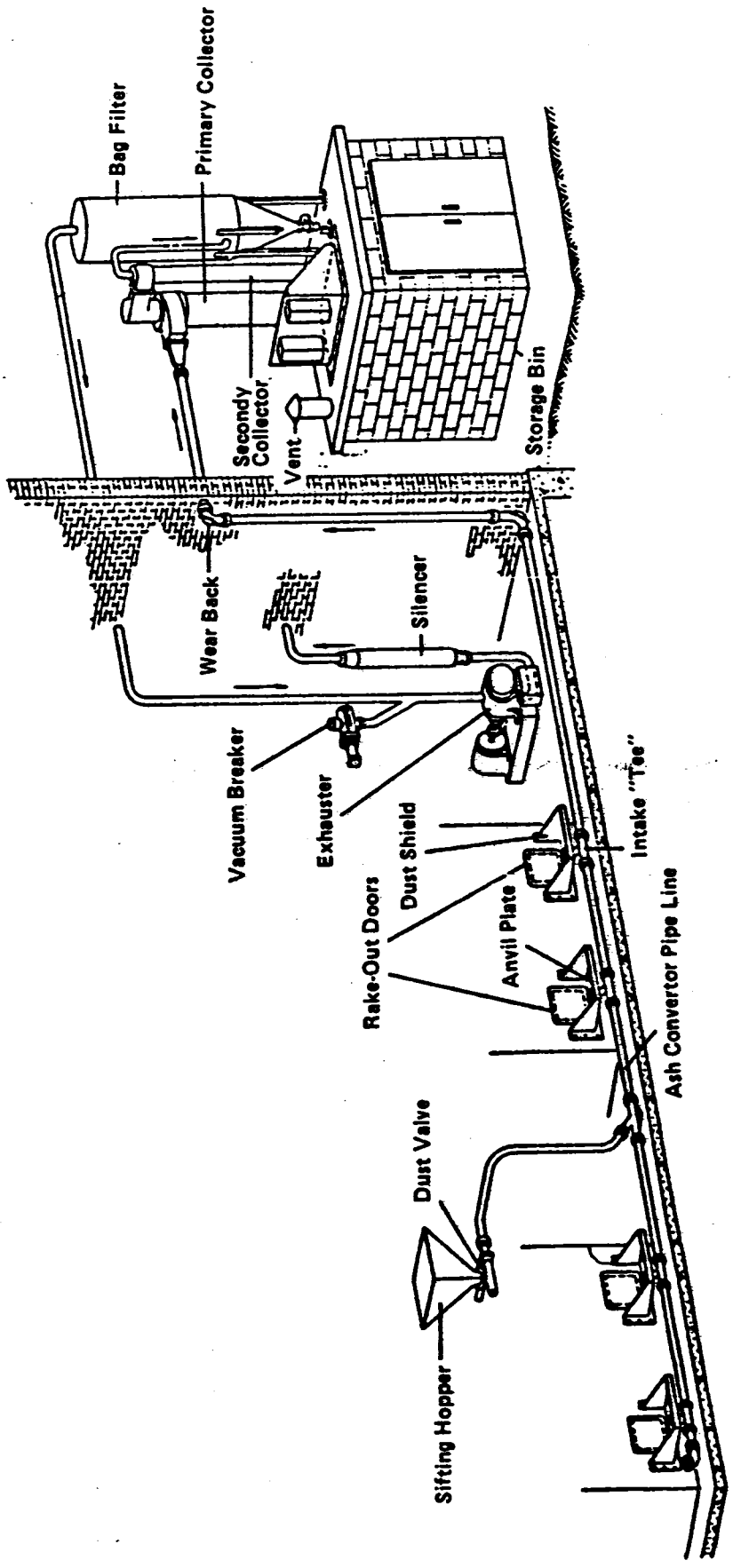


FIGURE 2-39. PNEUMATIC ASH HANDLING SYSTEM

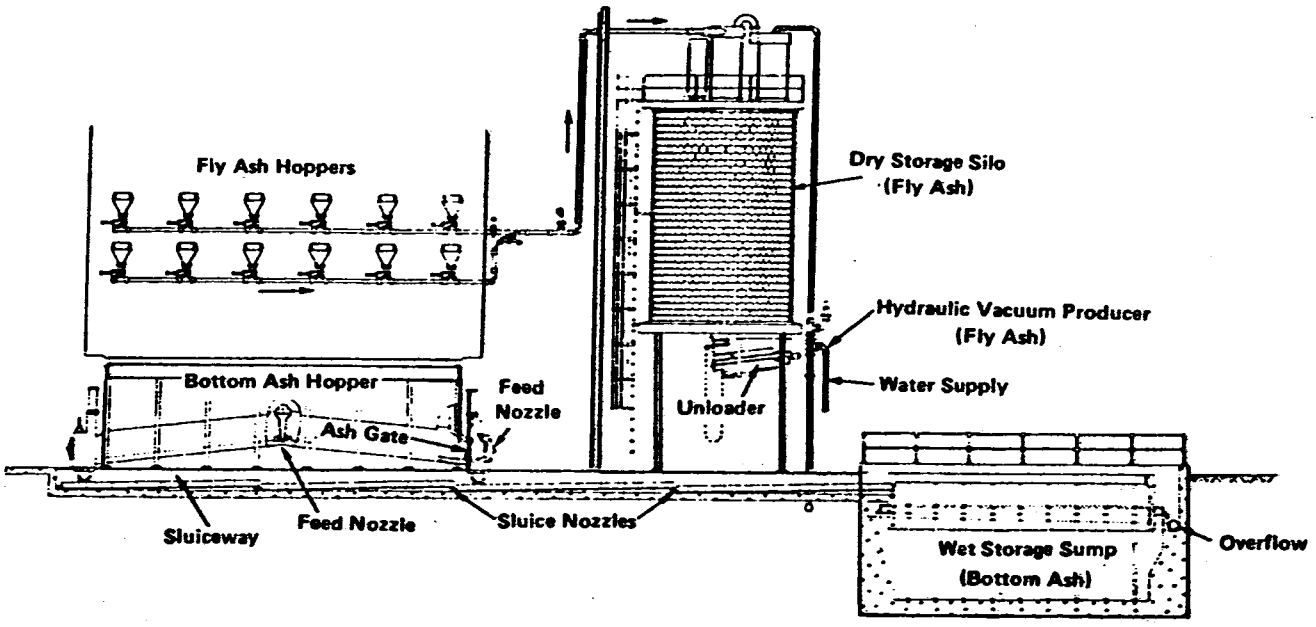


FIGURE 2-40. HYDRAULIC ASH HANDLING SYSTEM

installations due to environmental and water usage regulations.

c. Mechanical Ash Handling. Drag, screw, and bucket conveyors can be used to move ash from the 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.

2-2l. OIL-FIRING EQUIPMENT.

Oil has a number of advantages over coal when used to generate steam or hot water: the cost of fuel handling is lower, less labor is required for operation and maintenance, less storage space is required, the 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 ontrols, and its cost, which is two or three times higher than coal on a heating value basis. Refer to paragraphs 1-4b and 1-8 for a more detailed discussion of fuel oil and the combustion process and to table 1-3 , which presents the physical properties of common grades of fuel oil. The operator should be familiar with the fundamental principles of combustion to make best use of this concentrated and valuable fuel.

a. 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 the fuel into fine particles that readily mix with combustion air. The 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 viccosity 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 the fuel. The burner manufacturer should recommend a proper viscosity range at which to operate. Proper preheating of oil will be discussed in paragraph 3-17.

(1) **Fluid Atomizers.** Fluid atomizers use either steam or air to break the fuel oil into a fine mist. Steam atomizers operate by mixing the oil and steam inside the atomizer tip under pressure. As the steam and oil mixture leaves the tip, the steam rapidly expands, breaking the oil into small droplets to begin the combustion process. Figure 2-4l illustrates a steam atomizer. Steam is supplied to the atomizer at a pressure of between 10 and 20 psi above the oil pressure. Under normal conditions, a steam atomizer uses approximately one-tenth pound of steam to atomize one 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 the 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 startup 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 firing rate is possible over a range of 15 to 100 percent of capacity.

(2) **Pressure Atomizers.** Pressure atomizers use pressures of 600 psig or more to accelerate the oil into the furnace through the atomizer tip. The oil is spun inside the tip and leaves as a cone of oil which thins out and breaks apart into fine droplets for combustion. The advantage of pressure atomizers is the simplicity of the system. The disadvantages are the high pressure required and the fact that turndown 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 the small passages in the atomizer tips tend to clog and wear. Pressure atomizers are not frequently used on modern Central Heating Plants. (3) Rotary Atomizer. The rotary atomizer uses the energy from a spinning cup and primary air from a small fan (refernce figure 2-42). A thin cone of oil is spun off the end of the cup and, aided by the primary air, thins out and braks 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 1930s 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 the 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. Figure 2-42. Rotary Atomizer

b. Types of Burners. Once the oil is effectively atomized, the next step is to effectively mix it with the combustion air. Three general types of burners are available: register, low excess air, and package burners. All of these burners incorporate an igniter for automatic light-off and 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 the fuel with a minimum of excess air throughout the firing range. Excess air levels at 100, 75, 50, and 25% load should be determined when

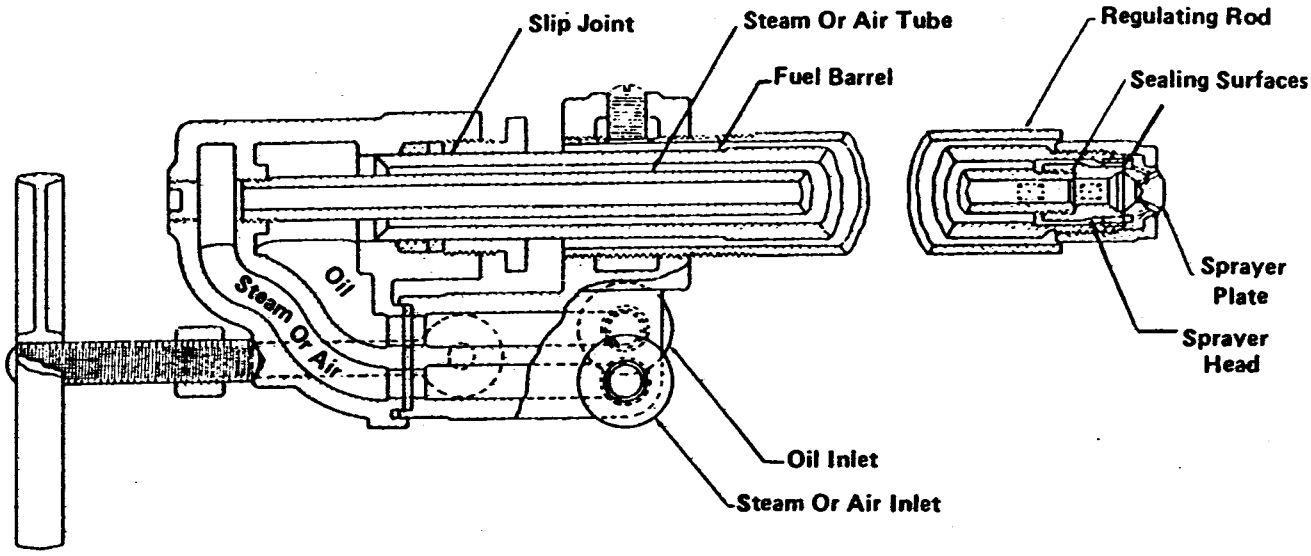


FIGURE 2-41. STEAM ATOMIZER

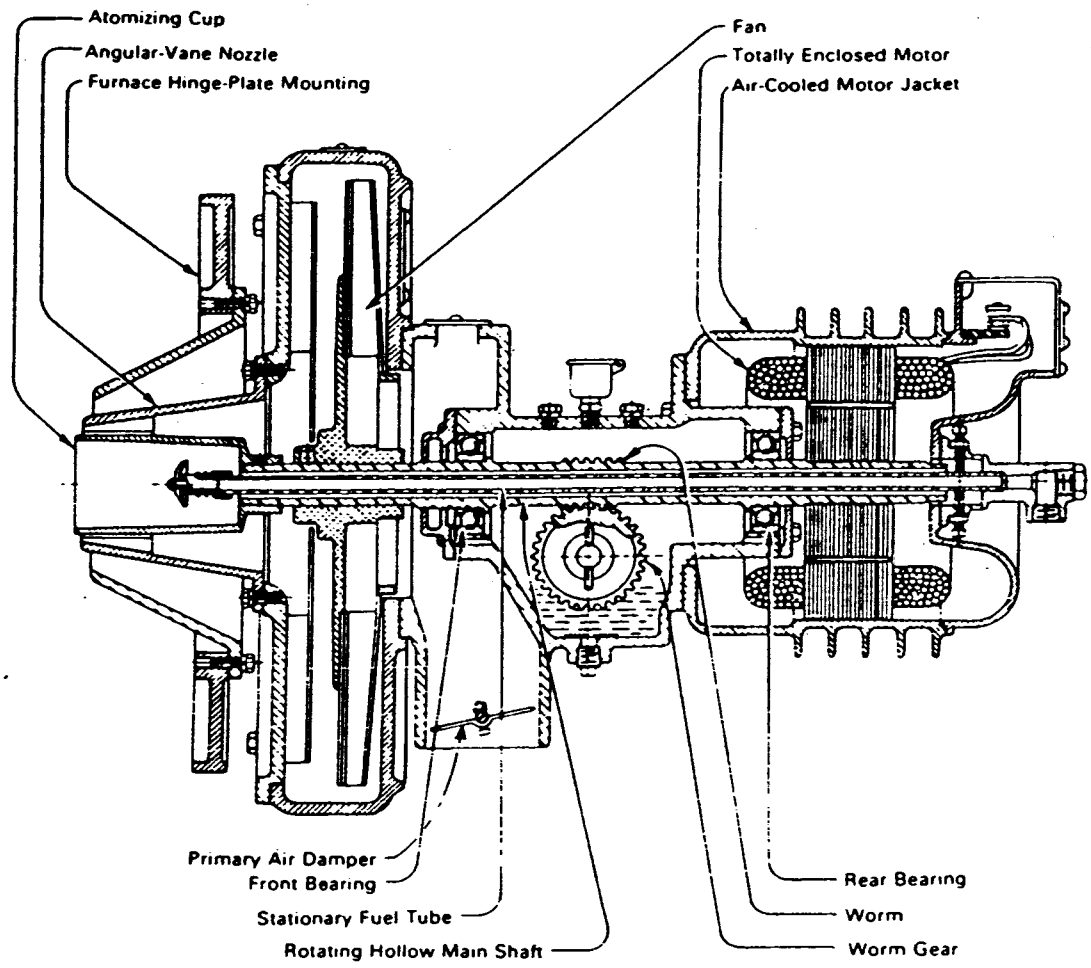


FIGURE 2-42. ROTARY ATOMIZER

evaluating burner effectiveness. Reference paragraph 3-34 and table 3-1 for more information.

(1) **Register Burners.** Register burners are characterized by one or more circular registers which admit combustion air into the burner throat as illustrated in figure 2-43. An impeller is provided to protect the atomizer from the direct blast of the combustion air and to provide a zone to stabilize ignition. The refractory throat helps to control air flow and velocity, and the hot refractory helps to stabilize ignition by radiating heat back into the base of the flame. Adjustment of the air registers either initially or on a continuous basis 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.

(2) **Low Excess Air Burners.** Low excess air (LEA) burners, as shown in figure 2-44, were developed to achieve lower excess air levels throughout the burner load range than is possible with register burners. A venturi section ensures uniform air flow at the burner outlet. An impeller is used to swirl a portion of the air into the atomized oil. The remainder of the air moves axially through the burner at a velocity designed to cause it to mix later with the fuel and impeller- swirled. air. The advantage of the LEA burner is its ability to operate at low excess air 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 burners low excess air capability.

(3) **Package Burners.** Package burners include the forced draft fan and its air control damper, the oil and/or gas control valves, actuators, igniters, flame safety system, and combustion controls as a shop-assembled unit. Figure 2-45 illustrates an air atomizing oil- and gas-fired package burner. The 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 rate. Package burners are available for firing rates of several gallons to several hundred gallons per hour. Either register or low excess air type burners may be supplied as packages, and rotary, pressure, or fluid atomizers may be used.

2-22. OIL STORAGE AND HANDLING.

Above-ground and underground fuel storage tanks are available as illustrated in figures 2-45 and 2-46. 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, fire-fighting connections, gage connection, suction box, suction or tank heater, steam connection, level indicator, temperature indicator, access manholes, ladders, piping, and valves. 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 NFPA 30 "Flammable and Combustible Liquids Code," and NFPA 31, "Standard for the Installation of Oil Burning Equipment.

a. 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. The 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 the oil to the combustion equipment. Figure 2-47 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.

b. 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 85A, "Standard for Prevention of Furnace Explosions in Fuel Oil- and Natural Gas-Fired Single Burner Boilers-Furnaces". Figures 2-48 and 2-49 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 85D. 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.

2-23. 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 availablity, and a greater danger of explosion. Paragraphs 1-4c, 1-9, and 1-9a 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

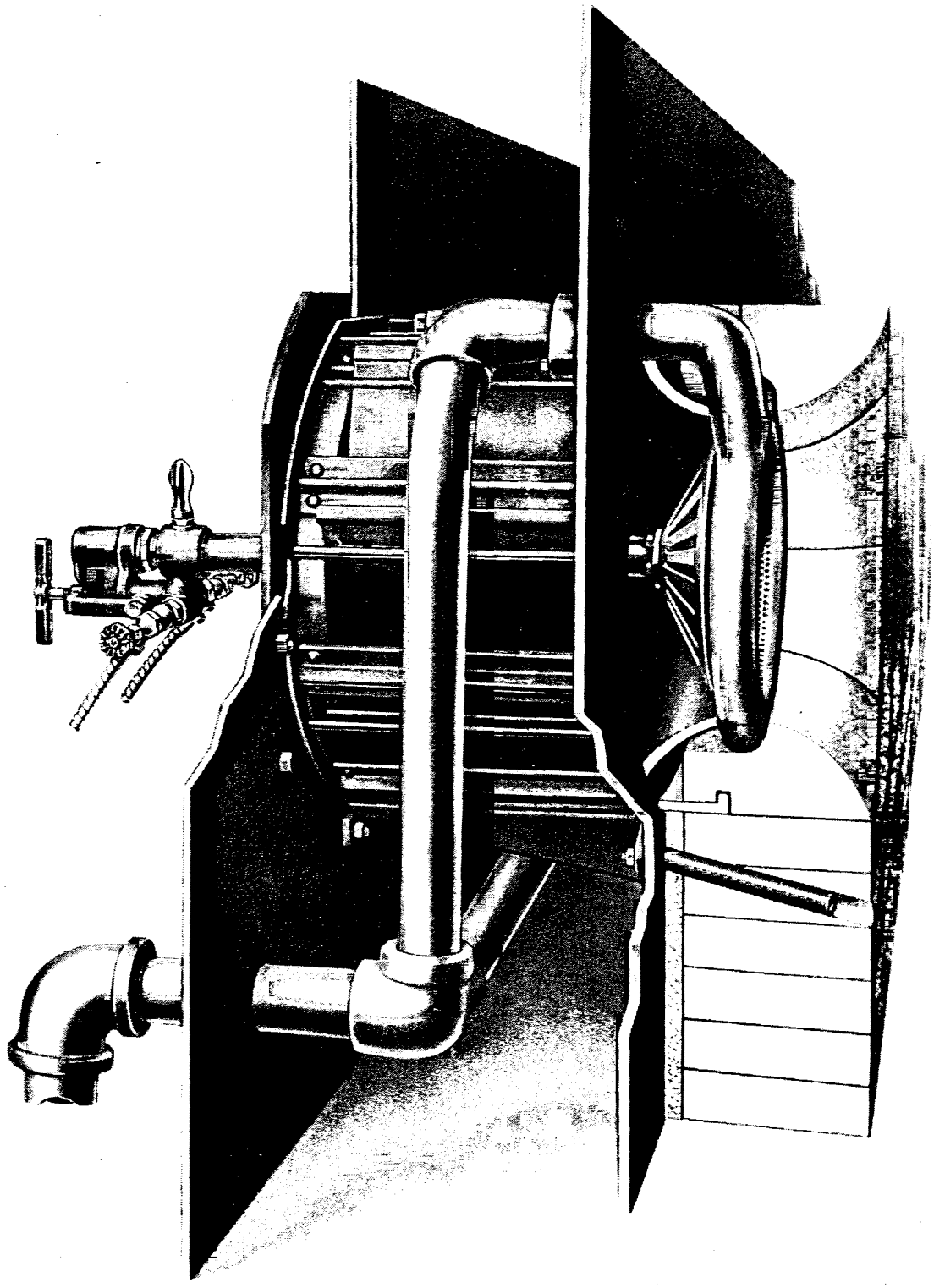
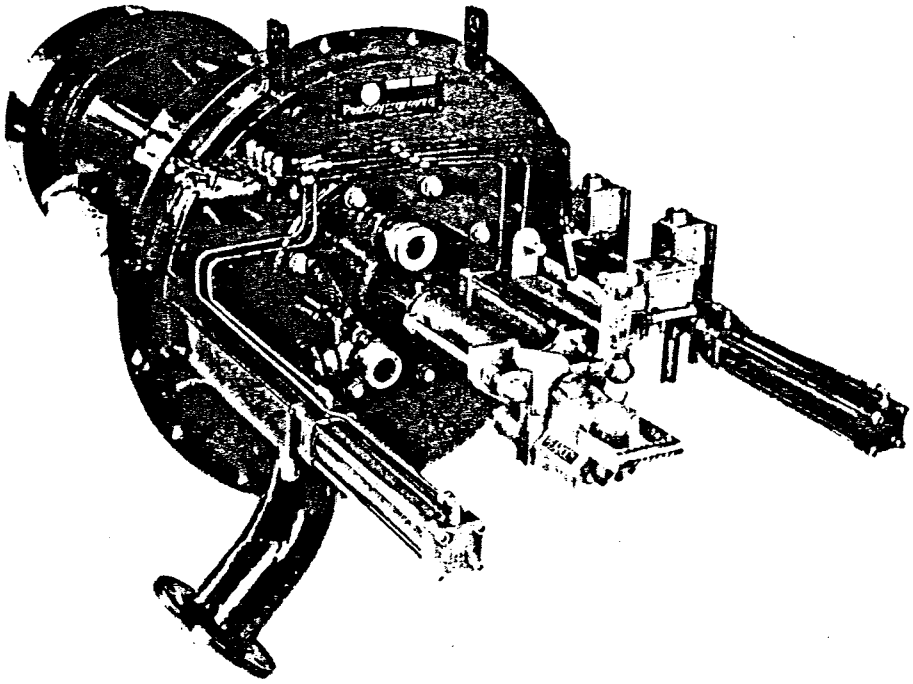


FIGURE 2-43. REGISTER BURNER



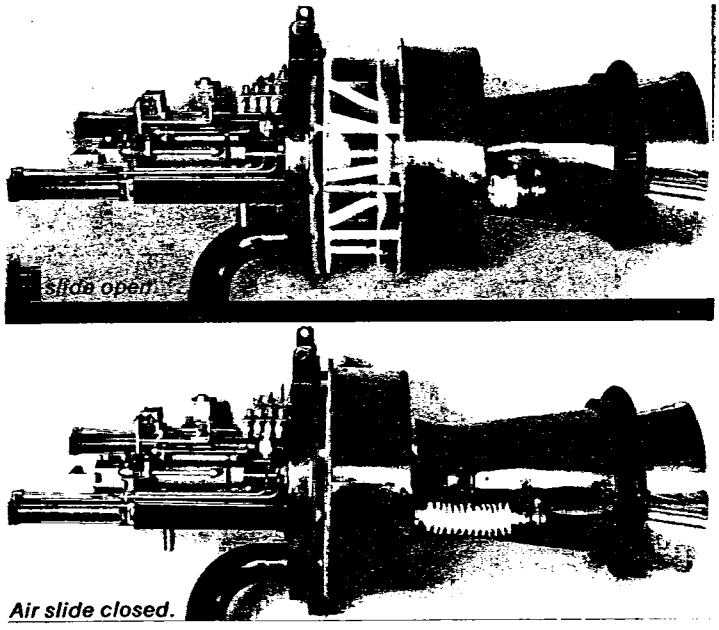


FIGURE 2-44. LOW EXCESS AIR BURNER

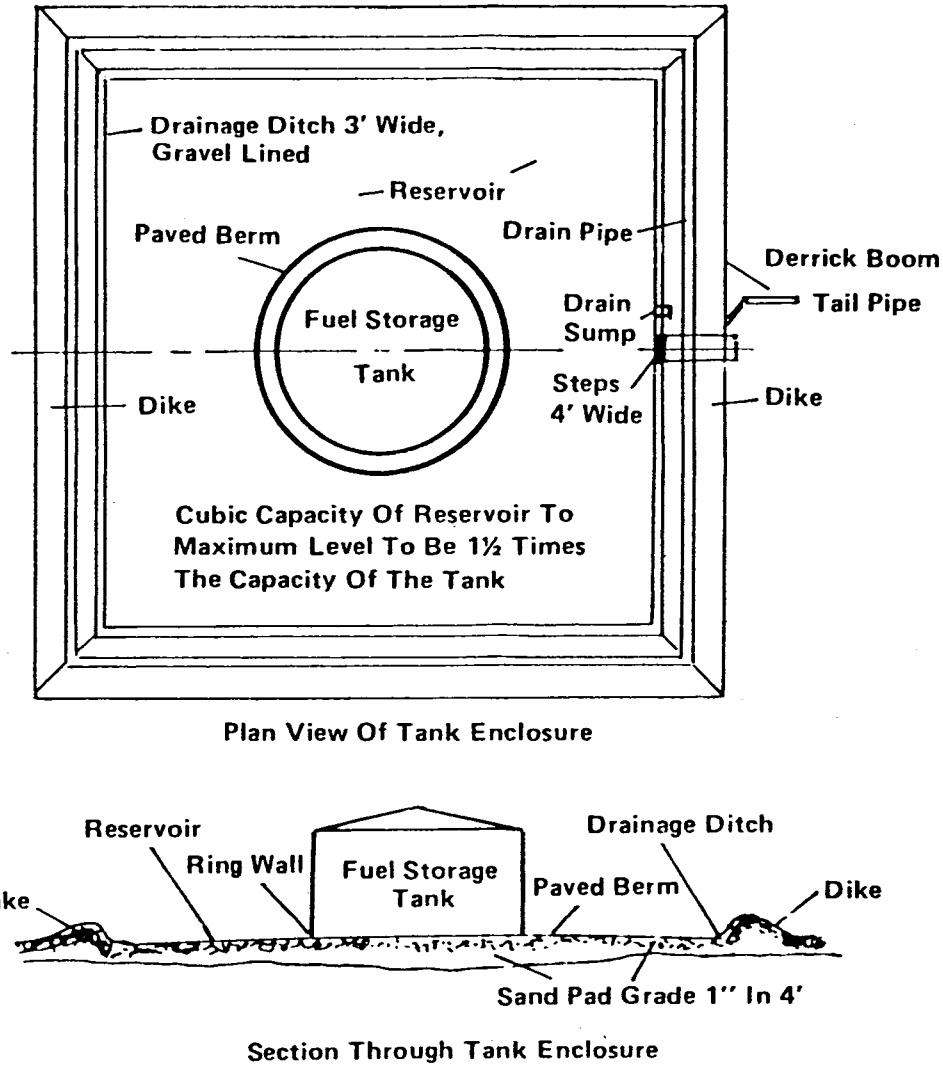


FIGURE 2-45. ARRANGEMENT OF ABOVE-GROUND FUEL OIL TANK

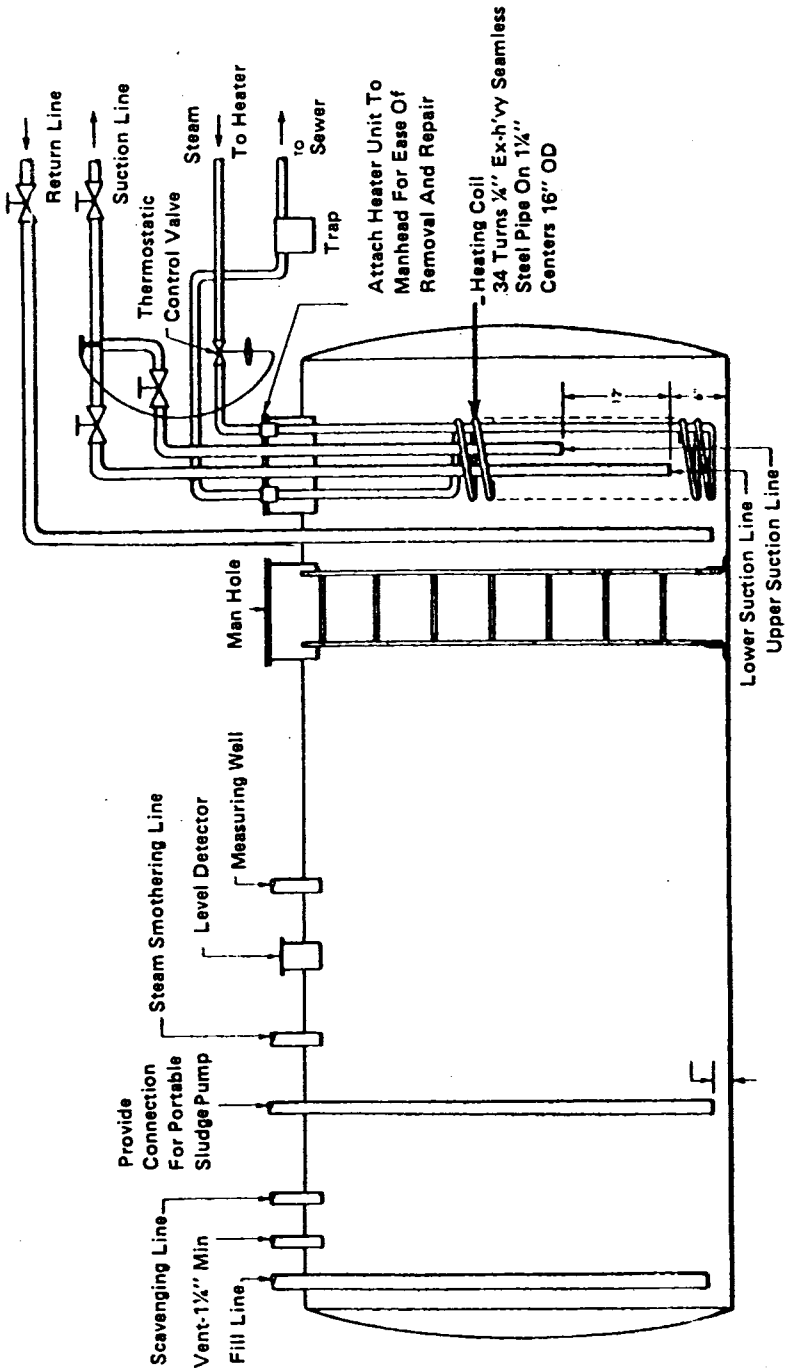


FIGURE 2-46. UNDERGROUND FUEL OIL STORAGE TANK

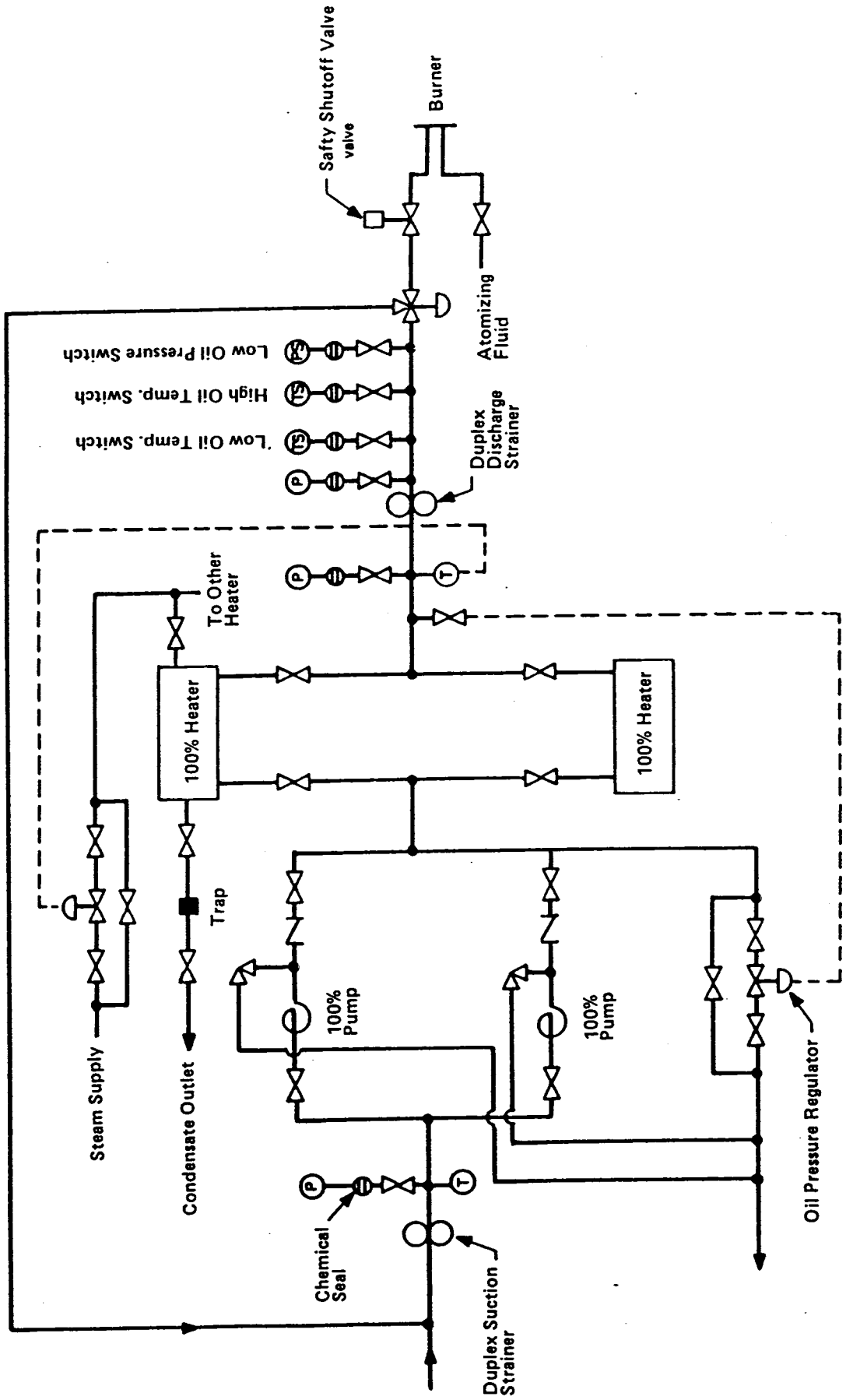
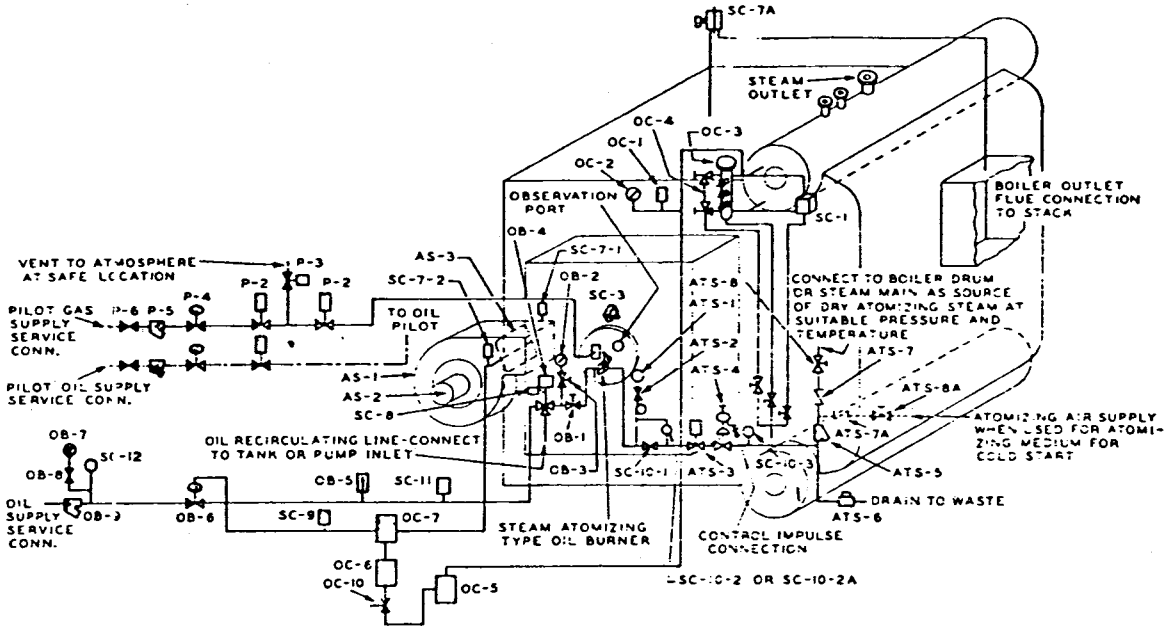


FIGURE 2-47. FUEL OIL PUMPING AND HEATING EQUIPMENT



OIL FIRING ONLY
Typical Schematic Arrangement of Safety Equipment
Fuel Oil-Fired 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 shut-off 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 shut-off valve
ATS-8A	Atomizing air supply shut-off 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 valve
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 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: (All switches in "hot" ungrounded lines. See 4662)

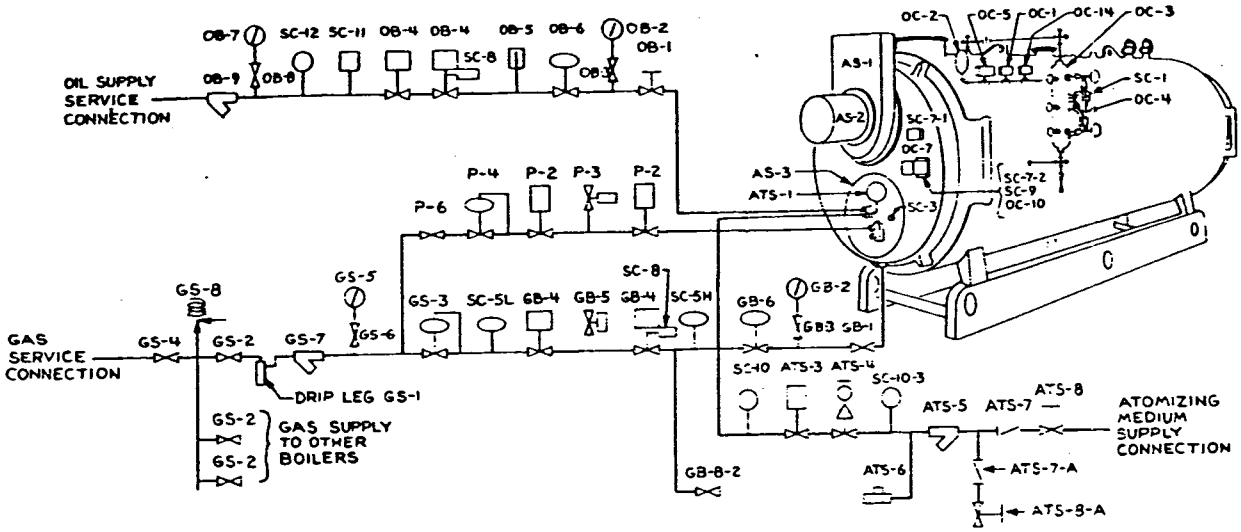
SC-1	Low water cut out integral with column or separate from water column
SC-3	Flame scanner
SC-7-1	Windbox pressure switch (Note 2)
SC-7-2	Fan damper position switch (Note 2)
SC-7A	Purge airflow switch (Note 2)
SC-8	Closed position interlock on OB-4
SC-9	Light-off position interlock
SC-10-1	Atomizing 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-11	Low oil temperature interlock (Note 4)
SC-12	Low oil supply 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 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 2-48. SAFETY EQUIPMENT OIL-FIRED WATER TUBE BOILER



ALTERNATE GAS OR OIL FIRING

Typical Schematic Arrangement of Safety Equipment
Gas- and Oil-Fired (alternately) Firetube Boiler With One (1) Burner
Automatic Recycling Controls

LEGEND

Atomizing Medium System (See Note 5):
- ATS-1 Atomizing pressure gage
- ATS-3 Atomizing medium shut-off valve
- ATS-4 Atomizing medium differential pressure control (if req'd.)
- ATS-5 Atomizing medium 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 shut-off valve
- ATS-8A Atomizing air supply shut-off 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 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

Ignitor (Pilot) System:
- P-2 Safety shut-off valve, auto. opening, spring closing (NC) (See Note 6)
- P-3 Vent valve, auto. closing, spring opening (NO)(See Note 6)
- P-4 Gas pressure regulating valve optional, depending on ignitor 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, auto, draining, spring closing (NC)
- GB-5 Vent valve, auto. closing, spring opening (NO)
- GB-6 Gas fuel control valve
- GB-8-2 Leakage test connection downstream safety S.O. valves

Oil Burner System:
- OB-1 Manual oil shut-off valve
- OB-2 Oil burner pressure gage
- OB-3 Oil burner pressure gage cock
- OB-4 Safety shut (with recirculation-optional)
- OB-5 Oil temperature 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 (All Switches in Hot Ungrounded Lines):
- SC-1 Low water cut-out (integral with 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(See Note 2)
- SC-7-2 Fan damper position switch (See Note 2)
- SC-8 Closed position interlock on GB-4 (overtravel)
- SC-9 Light-off position interlock
- SC-10 Atomizing medium pressure interlock switch
- SC-10-3 Atomizing medium supply pressure interlock switch
- SC-11 Low oil temp. interlock (See Note 4)
- SC-12 Low oil supply pressure interlock

Operation Controls & Instruments:
- OC-1 High steam pressure switch (See Note 3)
- OC-2 Steam drum pressure gage
- OC-3 Water column (may be equipped with low water cut-out and feedwater pump control)
- OC-4 Water gage and valves
- OC-5 Steam pressure controller
- OC-7 Combustion control drive unit
- OC-10 Modulating control — low fire start positioner
- OC-14 Excessive steam pressure switch (See Notes 1 & 3)

NOTES:
1. Actuation of this switch normally requires manual reset.
2. Purge air flow may be proven by providing SC-7-1 and/or SC-7-2.
3. For hot water boilers, switches OC-1, OC-5 and OC-14 would be temperature sensing device.
4. Temperature interlock and thermometer omitted for light oils which do not require heating.
5. Arrangement shown is applicable to straight mechanical pressure atomizing or burners by omitting atomizing medium system.
6. For pilots of less than 400,000 BTU/HR the vent valve (P-3) may be eliminated and only one safety shut-off valve (P-2) may be required.

FIGURE 2-49. SAFETY EQUIPMENT OIL- OR GAS-FIRED FIRE TUBE BOILER

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.

Figure 2-43 illustrates a register burner equipped with gas spuds nd an oil atomizer. Figure 2-44 illustrates a low excess air burner equipped with a gas ring. NFPA 85A, "Standard for Prevention of Furnace Explosions in Fuel Oil- and Natural Gas-Fired Single Burner Boilers-Furnaces," establishes requirements for safe operation of gas-fired boilers. Figures 2-49 and 2-50 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 85B. For boilers rated less than 10,000 pounds of steam per hour, standards are set by Underwriters Laboratories Inc., Underwriters Laboratories of Canada, and other nationally recognized organizations.

2-24. LIQUEFIED PETROLEUM GAS.

Liquefied petroleum gas (LPG) is used for igniter service and occasionally as a standby fuel for natural gas- or oil-fired installations. LPG is a combination of propane and butane maintained in a liquid state through storage under pressure. NFPA Standards 58 and 54, Part 2 establish requirements for the storage and handling of LPG. For further information on LPG, refer to the Air Force Manual, No. 85-12.

SECTION IV. CONTROLS AND INSTRUMENTATION

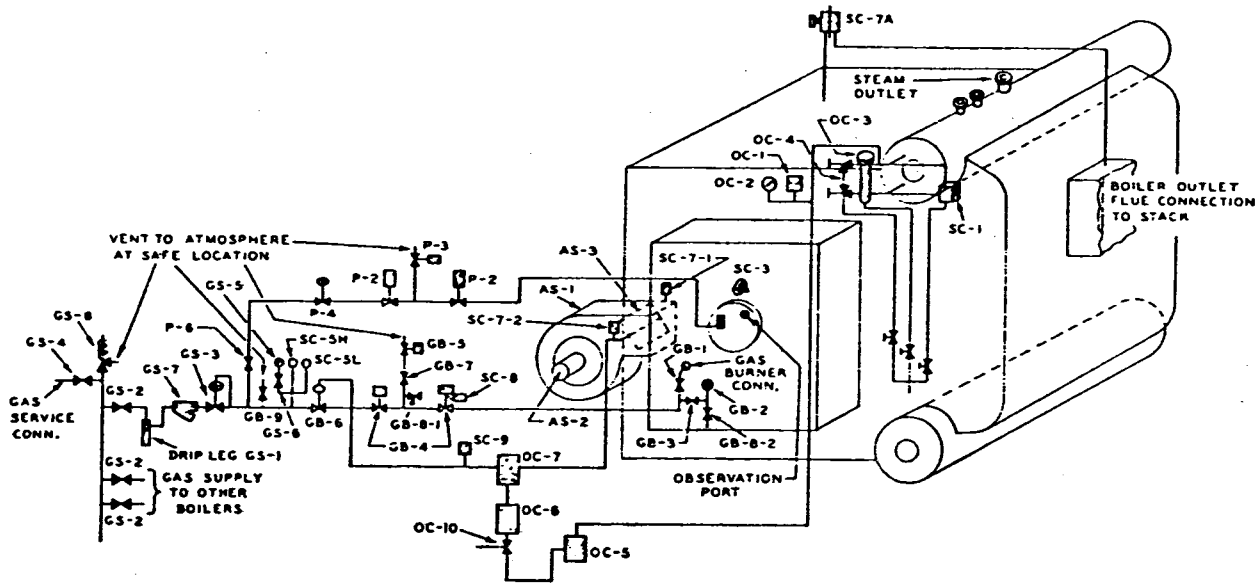
Controls and instrumentation are an integral and essential part of all central boiler plants. They serve to assure safe, economic and reliable operation of the equipment. They range from the simplest of manual devices to completely automated, microprocessor-based systems for control of boilers, turbines, 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 chapter. Only those systems and items which are commonly used in central boiler plants are discussed.

2-25. 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 (paragraph 2-38), low water fuel cutoffs (paragraph 2-27), and feedwater heaters (paragraph 2-37) are all 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 opeating 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/cintroller, and lectronic level transmitter/controller. Each is described oelow.

a. Positive Displacement. The positive-displacement type feedwater regulator (figure 2-51) 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 the 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 counterct the 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 the high and low limits. This type of control will maintain a different water level for each steam flow produced by the boiler.

b. Thermohydraulic. Operation of the thermohydraulic or vapor-generator type of feedwater regulator (figure 2-52) 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 the 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 the water surrounding that portion of the tube and converts part of it to steam. This increases the 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. The water which is



NATURAL GAS FIRING ONLY
Typical Schematic Arrangement of Safety Equipment
Natural Gas-Fired Watertube Boiler with One (1) Burner
Automatic (recycling) or Automatic (nonrecycling) 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, 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

Safety Controls: (All switches in "hot" ungrounded lines. See 4662)

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 GB-4
SC-9	Light-off position 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 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.

FIGURE 2-50. SAFETY EQUIPMENT
GAS-FIRED WATER TUBE BOILER

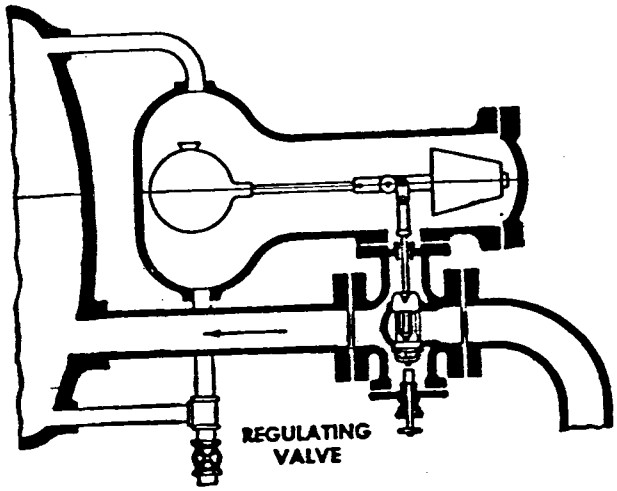


FIGURE 2-51. POSITIVE DISPLACEMENT
FEEDWATER REGULATOR

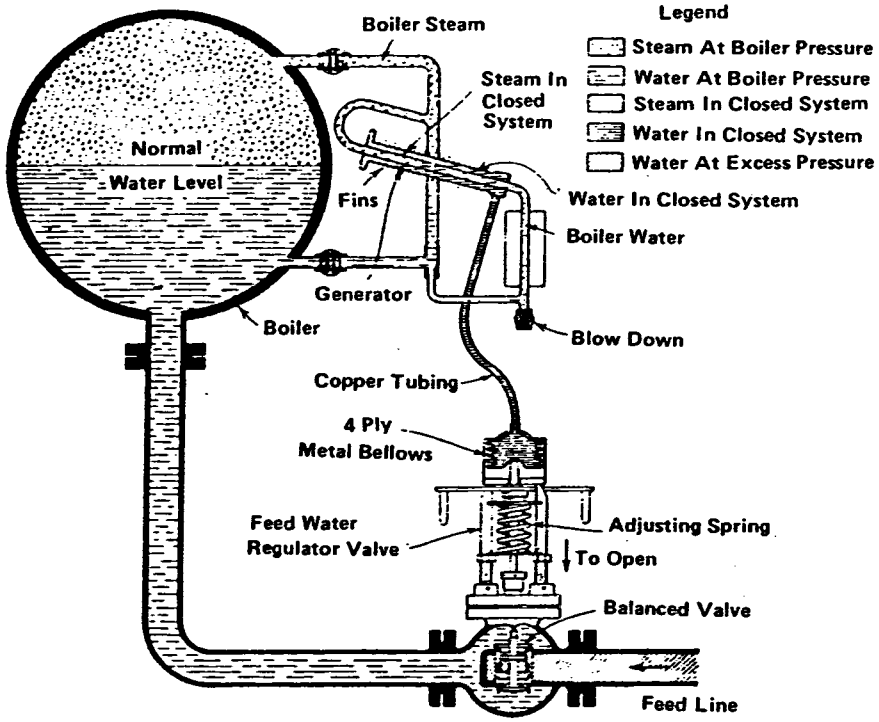


FIGURE 2-52. VAPOR-GENERATOR/THERMOHYDRAULIC FEEDWATER REGULATOR

forced out of the generator moves the diaphragm and opens the valve. When the 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 nd increasing the speed of response of the regulator. This type of regulator establishes a relation between water level in the drum and the valve opening. Therefore, for each stream flow rate, a slightly different water level will be maintained. **c. Thermostatic.** Operation of the metal thermostat or expansion type of regulator (figure 2-53) depends upon the 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 the steam and water spaces of the boiler so that it contains only steam when the water is at its lowest level. The tube is then expanded to its maximum length. As the water level in the boiler rises, the 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 which move the valve as the tube length changes. The feedwater valve is at its maximum opening when the water level is low and the tube is filled with steam, and closes as the water level rises and the tube shortens. Note that all of the above regulators increase the flow of water as the level drops.

d. Pneumatic Transmitter/Controller. As boiler firing rates increased with the development of the modern water-cooled furnaces, the 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 supplyis shut off. Changes in steam pressure result in expansion or swelling of the steam/water mixture and false water-level dindications. The 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 all 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. Siingle-, two- and three-element feedwater controls are available.

(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 (reference figure 2-54). 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 pressur changes during load swings. Two-element control is recommended for systems with frequent and large load changes.

(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 or temperature change or feedwater valve inaccurcies. 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.

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

2-26. COMBUSTION CONTROLS.

Combustion controls adjust fuel and air flows 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, the 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, the combustion controls must also adjust fan inlet dampers or boiler outlet dampers to control furnce draft. A combustion control system, no matter how sophisticated, cannot do a better job of controlling a boiler than an operator. However, a combustion control system will operate continuously to make the necessary adjustments, while an operator has other responsibilities that prevent this kind of attention. Combustion controls systems are comprised of the following general types of components:

- — Sensing elements
- — Transmitters
- — Controllers
- — Indicators
- — Actuators
- — Control drives
- — Control valves
- — Dampers

These components may be combined in an endless variety of arrangements to provide almost any degree of sophistication required.

a. Control Concepts. Open-loop and closed-loop control are both used in the boiler plant. Open-loopo control (also called "feed-forward") takes an input-demand signal and generates a single output in response to the demand. The

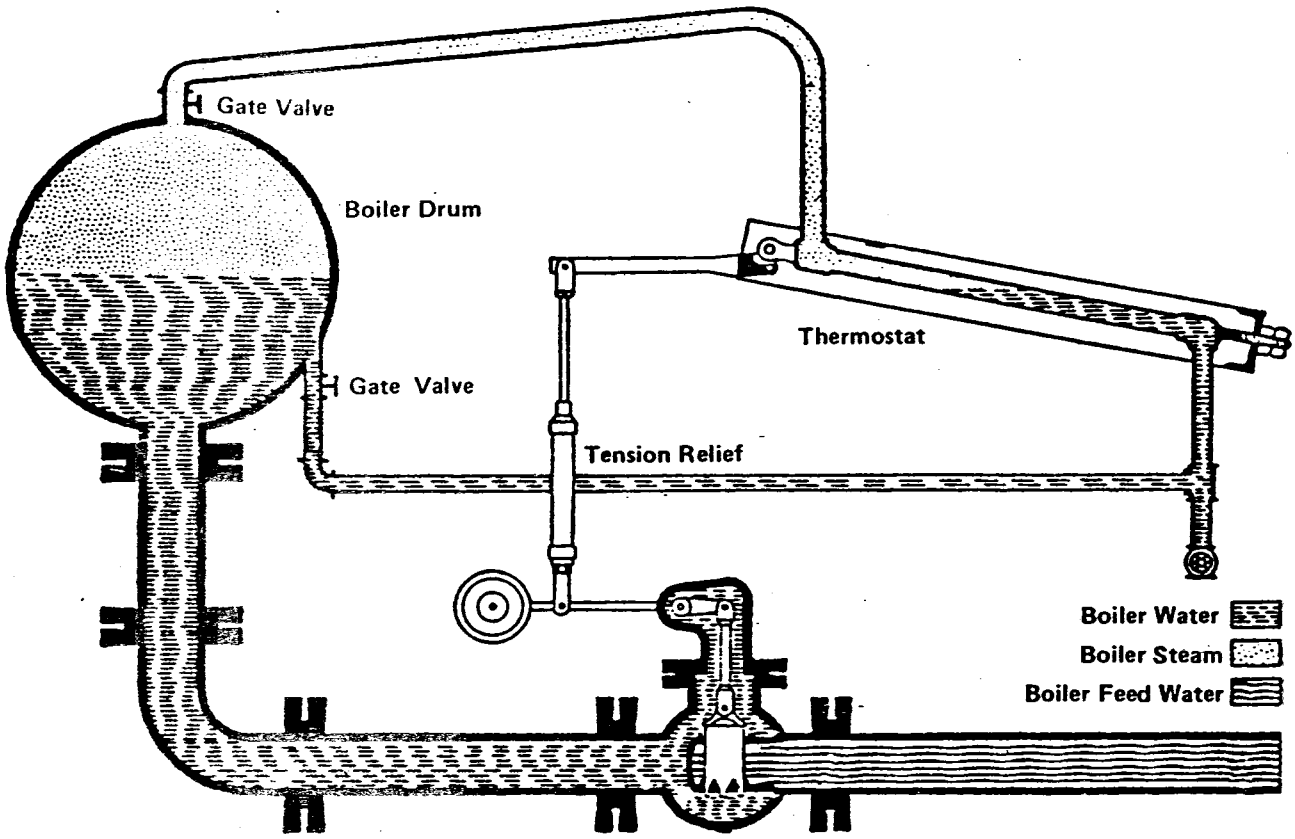


FIGURE 2-53. THERMOSTATIC/METAL EXPANSION FEEDWATER REGULATOR

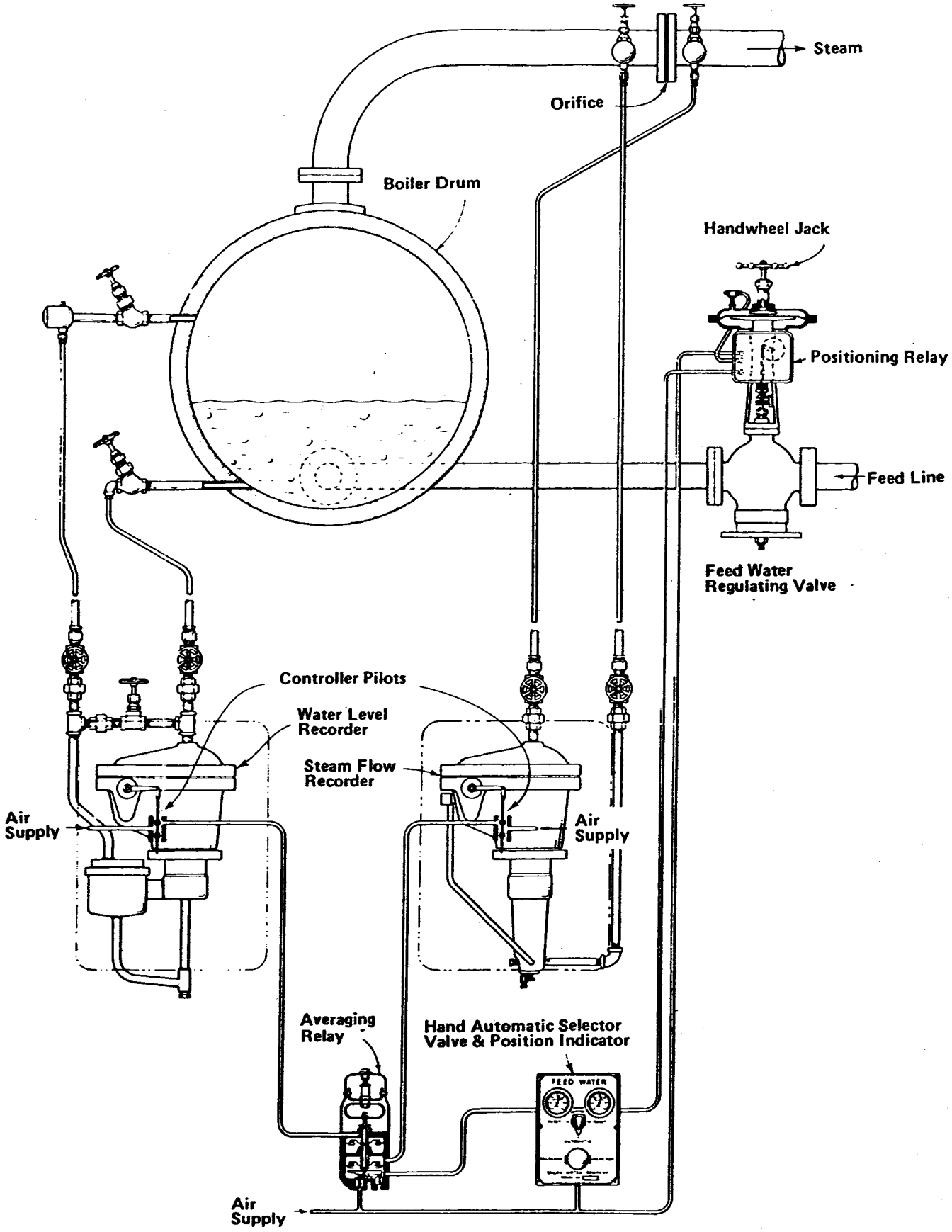


FIGURE 2-54. TWO ELEMENT FEEDWATER CONTROLS

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 (reference figure 2-55). The actuator receives a signal and generates an output, the movement of its shaft. This same poneumatic actuator could be converted to closed-loop control by equipping it with a positioner (reference figure 2-56). 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 lilnkages, 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 wo within plus or minus 5% of a desired setting, whereas a closed-loop control can typically control to approximately plus or minus 1%. Closed-loop control is available as one-, two-, or three-mode control using proportional, integral, or derivative responses. These different responses are discussed below.

(1) **Proportional.** Proportional control (also called gain control) is the simplest form of closed-loop control. In proportional control, the fifference 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 2-57. Steam pressure setpoint and actual steam pressure are compared, and an output is generated in proportion to the difference. Figure 2-58 illustrates proportional control. For a proportional gain setting of 5, the fuel valve is opened 5% for each 1% 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."

$$\text{Gain} = \frac{\text{Change in Control Output,\%}}{\text{Change in System Variable, \%}}$$

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

$$\text{Proportional} = \frac{1}{\text{Gain}} \times 100 = \frac{\text{Change in System Variable,\%}}{\text{Change in Control Output, \%}} \times 100$$

Thus, a gain of 5 is equivalent to a proportional band of 20. Figure 2-59 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:

(a) Proportional control operates and establishes steady-state positions because a difference exists between the setpoint and the system variable. In the example shown in figure 2-58, only at the 50% fuel valve position would steam pressure exactly match the setpoint. At all other fuel valve positions, a difference of up to 10 psi from setpoint would be required to maintain the fuel valve position which would satisfy a steam flow demand.

(b) 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.

(c) 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.

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

(2) **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 orminimum output is reached. Figure 2-60 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.

(3) **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 boiler outlet water temperature starts to fall after having been rising, 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. To much derivative control can dampen other control responses.

b. Pneumatic Control Basics. A basic pneumatic controller is shown in figure 2-61. The controller consists of the five

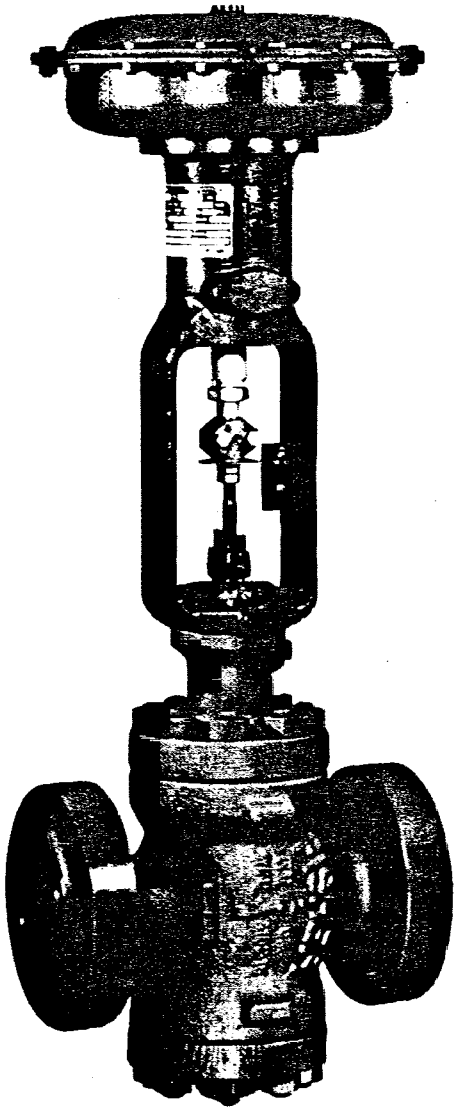


FIGURE 2-55. CONTROL VALVE WITH PNEUMATIC ACTUATOR

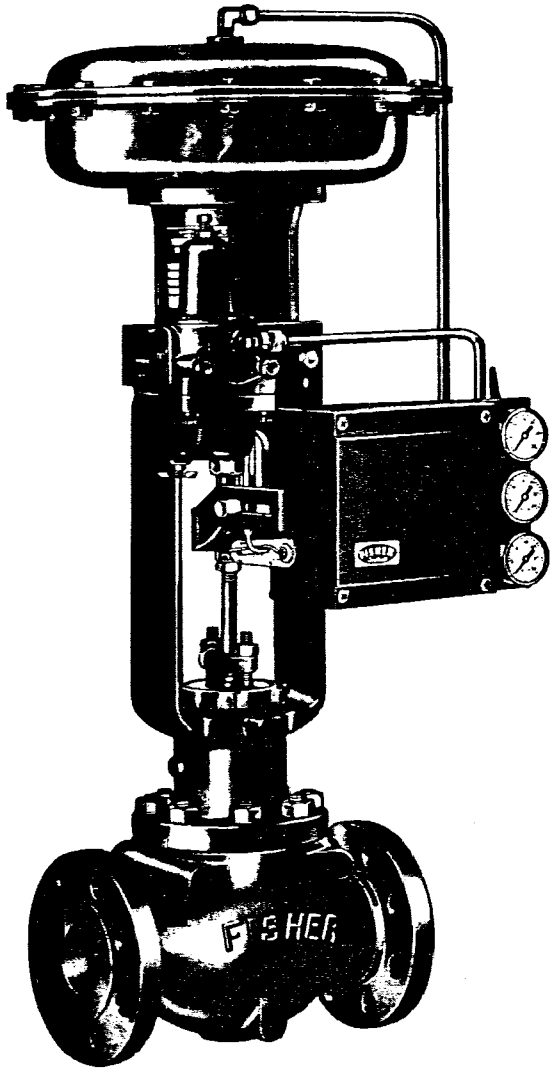


FIGURE 2-56. CONTROL VALVE WITH PNEUMATIC ACTUATOR AND POSITIONER

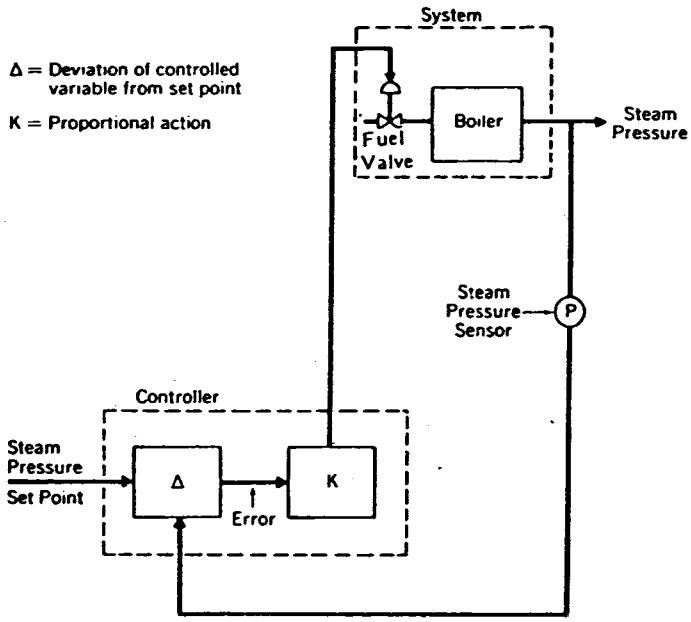


FIGURE 2-57. STEAM PRESSURE CONTROL SYSTEM

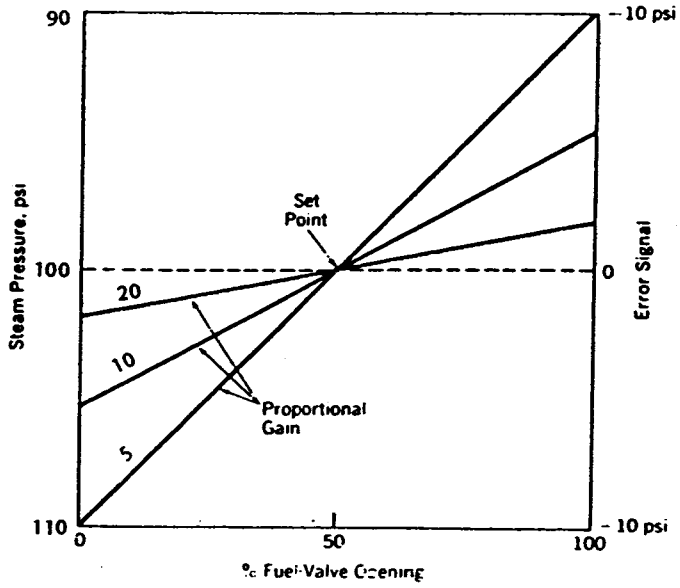


FIGURE 2-58. PROPORTIONAL CONTROL

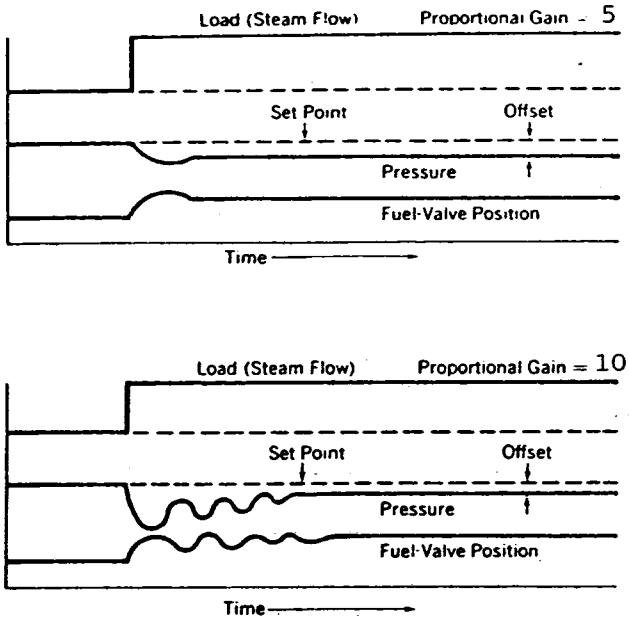


FIGURE 2-59. PROPORTIONAL RESPONSE

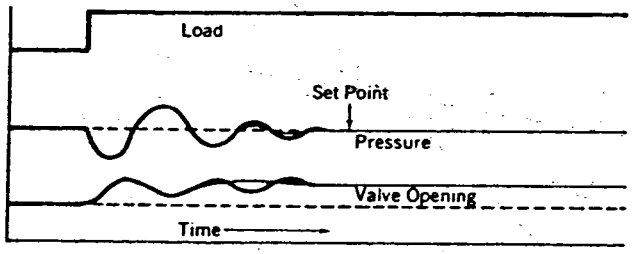


FIGURE 2-60. PROPORTIONAL PLUS INTEGRAL RESPONSE

basic components listed below.

— Measuring element.
— Flapper
— Nozzle or venting orifice
— Restrictive or input orifice
— Chamber between the orifices

The flapper is situated so that it can shut off or throttle the flow of air out of the nozzle orifice, and is moved by the sensing element in response to a change in the controlled variable. The flapper and venting orifice are often considered as one unit, called a vent valve. Instrument quality air is supplied to the controller through the input orifice and is vented to the atmosphere through the venting orifice, as long as the flapper is positioned away from this orifice. The venting orifice is larger than the input orifice; therefore, if the flapper restricts the flow of air, air pressure in the chamber and control air pressure to the final control drive positioner both increase. The mount of clearance between the flapper nd the nozzle controls the air pressure fed to the control drive. The measuring element controls the flapper-nozzle clearance as dictated by the pressure, temperature, flow level, etc., being controlled. This fundamental controller has rather limited capability and, if used, must be situated close to the device it controls. It ıust actuate a control requiring only a small volume of .ir, and it must control a process that requires only a limited control range. It is a one-mode controller, with the proportional band determined by the position of the pivot point, venting orifice, and measuring element. Two-mode and three-mode controllers are developed by using additional measuring elements, flappers, orifices, chambers, adjusting mechanisms, and springs. The basic controller is flexible if equipped with a power or volume booster relay. A typical two-dddiaphragm booster relay is shown in figure 2-62. The ratio of the two-diaphragm areas may be varied to suit the desired input-output ratio. A relay with a three-to-one diaphragm ratio will give a 3-psi change in the control air output signal for each 1-psi change in chamber "A". Depending upon the ratio of the diaphragm areas, this type of relay may be used to increase either the volume of air or the control air pressure at the drive. Control air from the controller chamber, acting on the diaphragm in chamber A causes diaphragms "A" and "B" to move downward, thus opening valve 2 which admits air from chamber "D" to chamber "C." When the force exerted by the control air in chamber "C" equals the force in chamber "A", the downward movement of the diaphragm assembly ceases and the control air output pressure to the control device will remain constant. When the pressure in chamber "A decreases, the diaphragm assembly will move upward; valve 2 will lose and valve 1 will open, thus venting air out of chamber "C" to the atmosphere through chamber "B". This causes a decrease of control air pressure to the control device.

c. 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 the coal in suspension, react differntly 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 air flow rates. Two types of control, paralled positioning control and series/parallel control, are commonly used with stokers.

(1) **Parallel Positioning Control.** Figure 2-63 illustrates a parallel positioning control system. A deviation of steam pressur 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 ID fan inlet damper to maintain a slightly negative pressure in the furnace. Manual/automatic stations are provided to allow manual control.

(2) **Series/Parallel Control.** Figure 2-64 illustrates the series/parallel system. In this system, steam pressure is used to control the fuel feed rate and steam flow to control the air flow rate. A combination air-flow and steam-flow meter is discussed in paragraph 2-28. Operators use this type of meter as a guide to control the relationship between air **required** to burn the 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 lmeter has been in use for lmany years and is commonly called a "boiler meter". The series/parallel control combines poositioning control for the fuel with metering control for the air flow. Initial calibration and repeatability of the air flow 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 2-64, it would be provided for many applications.

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

(1) **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 2-65 illustrates a typical jackshaft system.

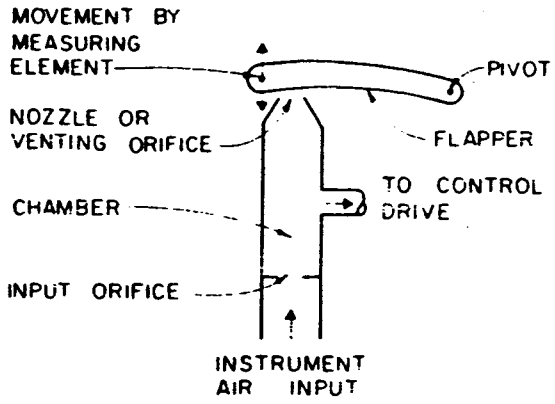


FIGURE 2-61. BASIC PNEUMATIC CONTROLLER

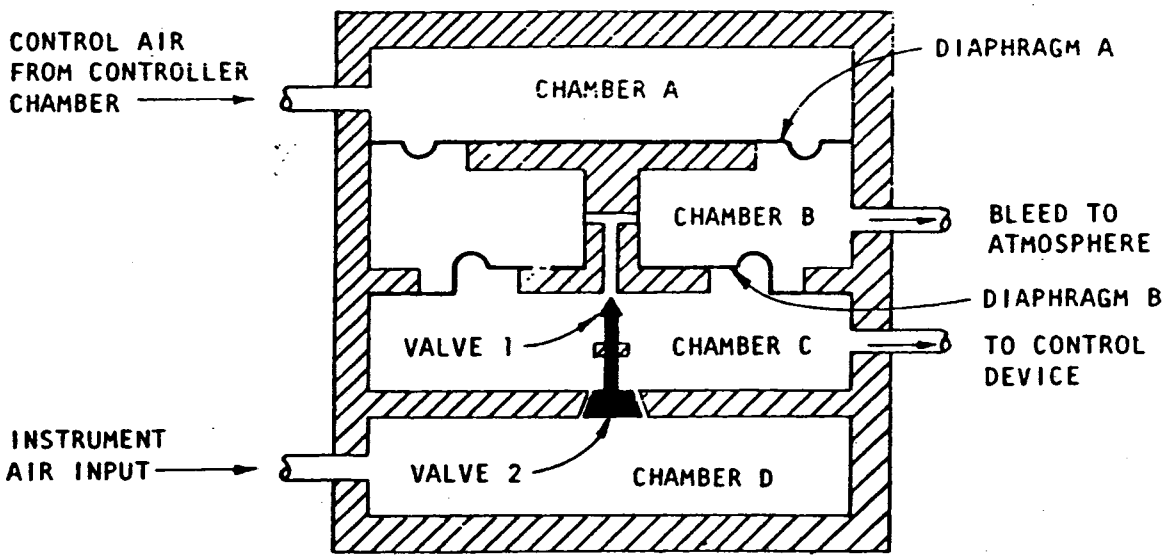
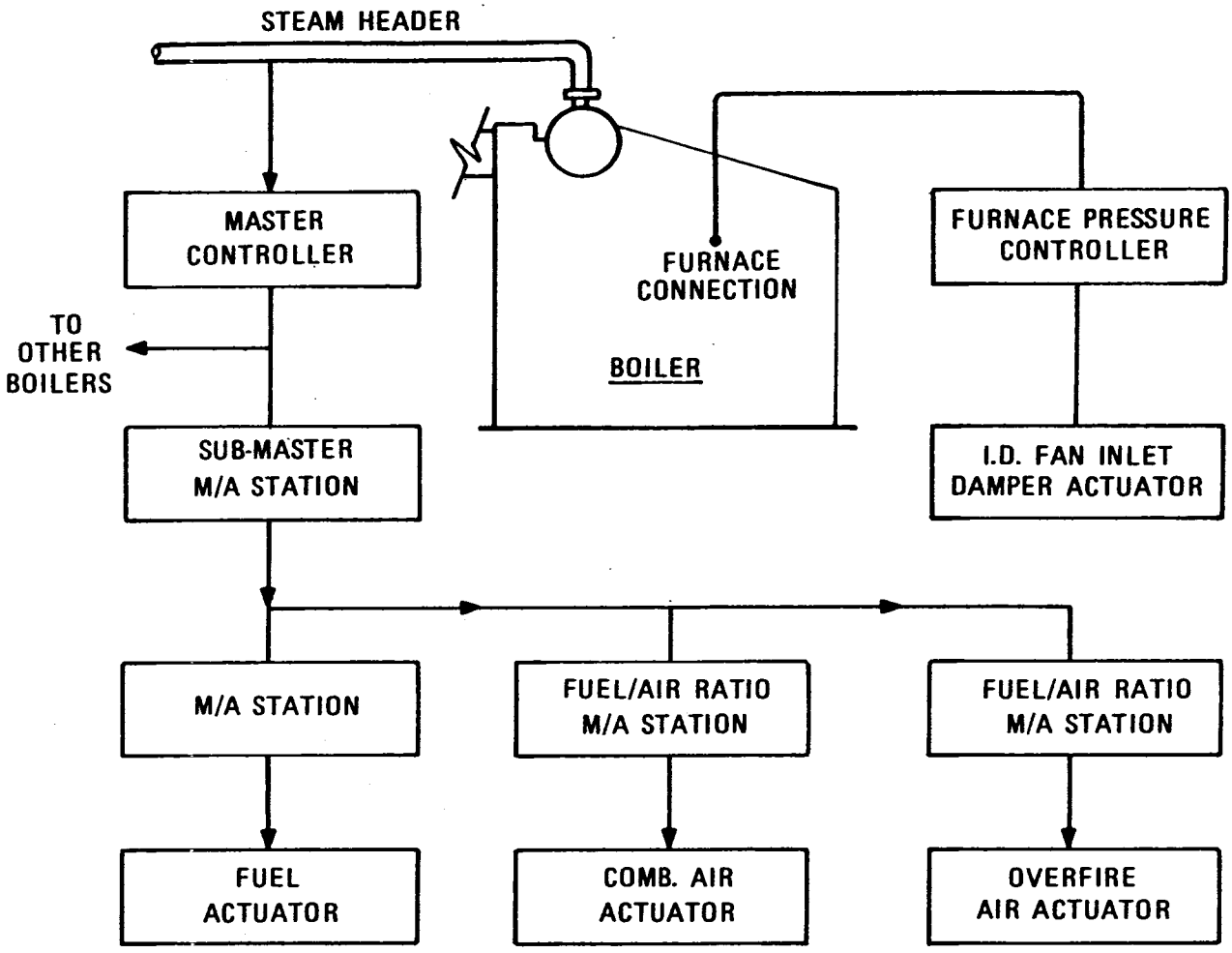


FIGURE 2-62. PNEUMATIC BOOSTER RELAY



M/A = MANUAL/AUTOMATIC

FIGURE 2-63. PARALLEL POSITIONING CONTROL SYSTEM

The master regulator is a proportional control which senses steam pressure and generates a rotary output, which moves the jackshaft. Adjustable valves are used to control and characterize the fuel oil and gas flow. These valves, together with the mechanical linkage that connects them to the 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 lpositioning 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 2-63, can be more accurate and more easily adjusted or trimmed. Positioning control type systems assume that the fuel and air flows always change the same amount for each change in valve or damper position. They are open-loop type control systems.

(2) **Parallel Metering Controls.** If the fuel and air flow to the burner are metered, a controller can be used which 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 2-66. TM 5-810-2, High Temperature Water Heating System, requires metering controls for hot water boilers with capacities greater than 20 million Btu per hour. This type of system is also commonly used on larger sizes of steam boilers.

(3) **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 the flue gas verifies proper fuel/air ratio. Control systms have been developed to allow automatic adjustment of the fuel/air ratio, based upon the reading of the oxygen analyzer. These systems are called oxygen trim control systems. Figure 2-67 illustrates a typical loxygen trim control, although many other arrangements are also available. These controls are not applicable to all systems because trim adjustments are small. If the accuracy of an actuator is plus or milnus 5% and the trim required is 2%, oxygen trim will not be effective. The following conditions must exist before oxygen trim can be effectively added to a boiler.

(a) Air infiltration into the boiler must be minimal, since the trim controller cannot distinguish between air which entered through the burner and infiltration air. The flame could be starved for air at the burner and producing smoke, while still registering excess air at the analyzer. Trim control can also become unstable if the leakage rate changes.

(b) The combustion equipment must be capable of operation at the new fuel/air 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.

(c) The existing combustion control components must be able to operate accurately. Ocygen trim can be expected to compound any deficiency in an existing system.

2-27. BOILER SAFETY CONTROL.

Boilers are equipped with safety devices to minimize the risk of low water- and explosion-related damage. Figures 2-48 through 2-50 illustrate typical safety systems. A typical oil- or gas-fired boiler safety control system includes the following components:

— Low water-fuel cutoff switch.
— High steam pressure or high watetr temperature switch.
— Flame scanner(s).
— Gas supply high-pressure switch.
— Gas supply low-kpressure switch.
— Combustion air flow switch.
— Purge air flow switches.
— Fuel safety shutoff valves with closed-position switches.
— Fuel control valves with low-fire position switch.
— Manual valves, cocks, strainers, and traps.
— Atomizing steam or air switch(es).
— Atomizing steam or air shutoff and control valves.
— Low oil pressure switch.
High furnace pressure switch (for boilers with induce. draft fans).
— Fan motor switch(es).
— Control logic.

National Fire Protection Association Standards 85A (for single burner systems),85B (for multiple burner gas-fired systems), and 85D (for multiple burner oil-fired systems) establish rules for operation of the equipment listed above. Notes on some of the more important items are given below.

a. Control Logic. Control logic provides for the following actions:

— Pre-purging the boiler below lightoff.
— Proper operation of limits and interlocks.
— Low-fire start and release to modulation sequence.
— Trial for igniter flame sequence. The igniter is shut off at the end of the trial for main flame.
— Trial for main flame ignition sequence.
— Main flame or normal operation
— Safe shutdown of the system.
— Boiler post-purge.

Electronic controls are available which receive the flame scanner signals and provide the control sequences listed above when connected to the proper switches, valves, and motor starters. The electronic controls are equipped with self-checking circuits which prove the controls to be operational. Figure 2-68 shows an electronic programming ontr incorporated into a simple control cabinet typical of a fire tube boiler application. Note that motor starters, draft

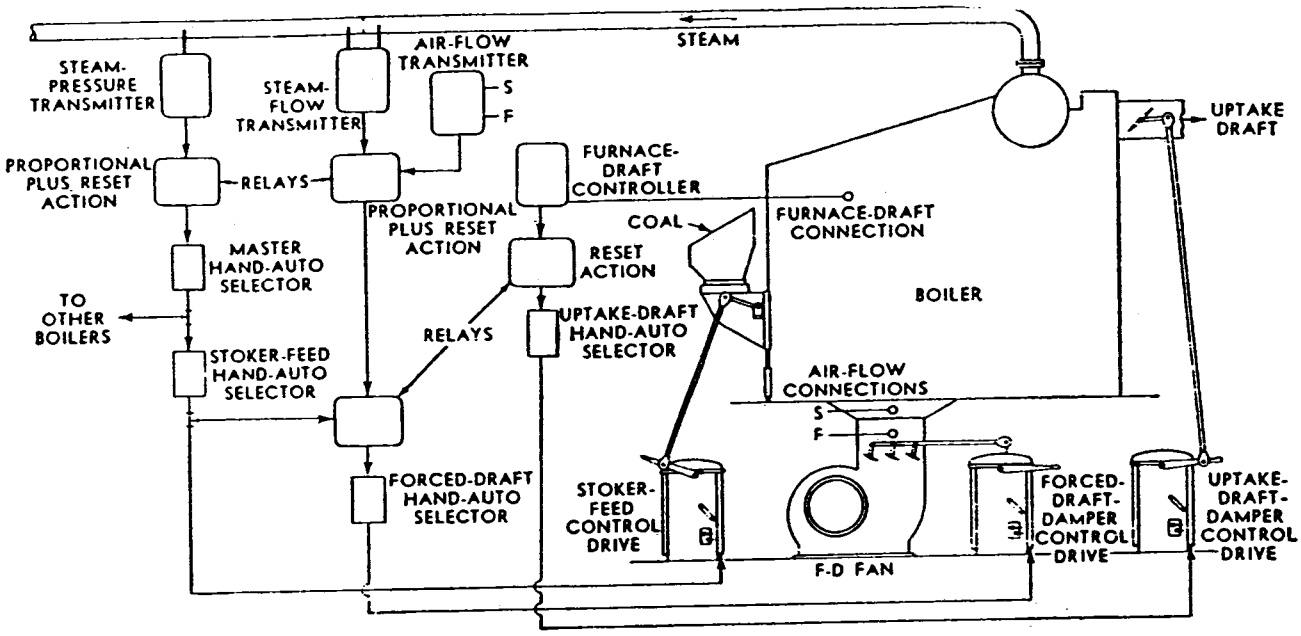


FIGURE 2-64. SERIES/PARALLEL CONTROL

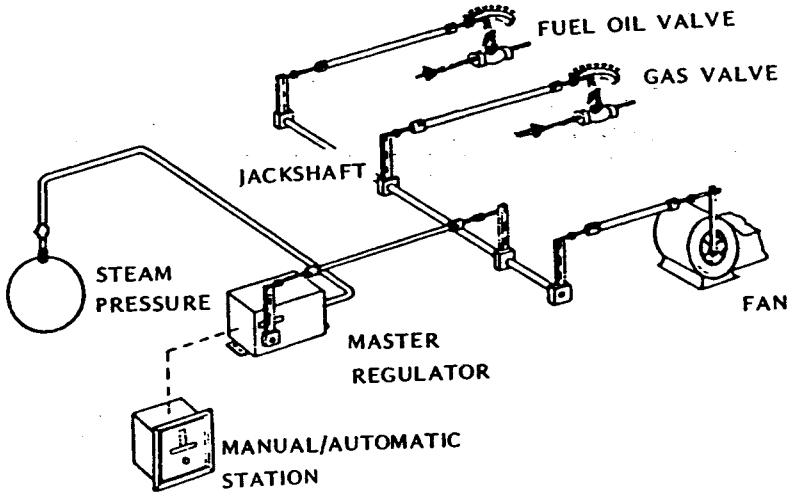
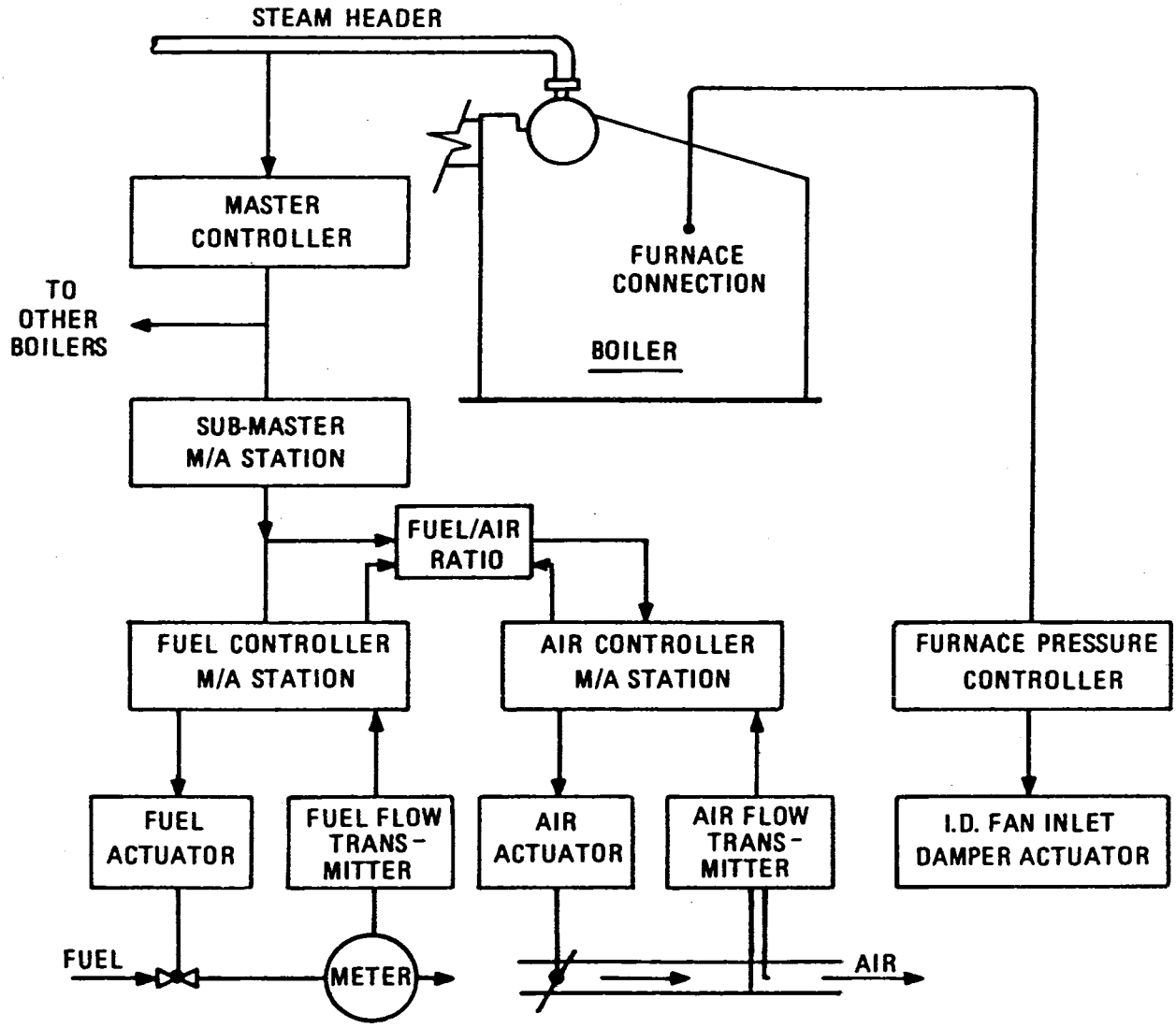


FIGURE 2-65. JACKSHAFT CONTROL SYSTEM



M/A = MANUAL/AUTOMATIC

FIGURE 2-66. PARALLEL METERING SYSTEM

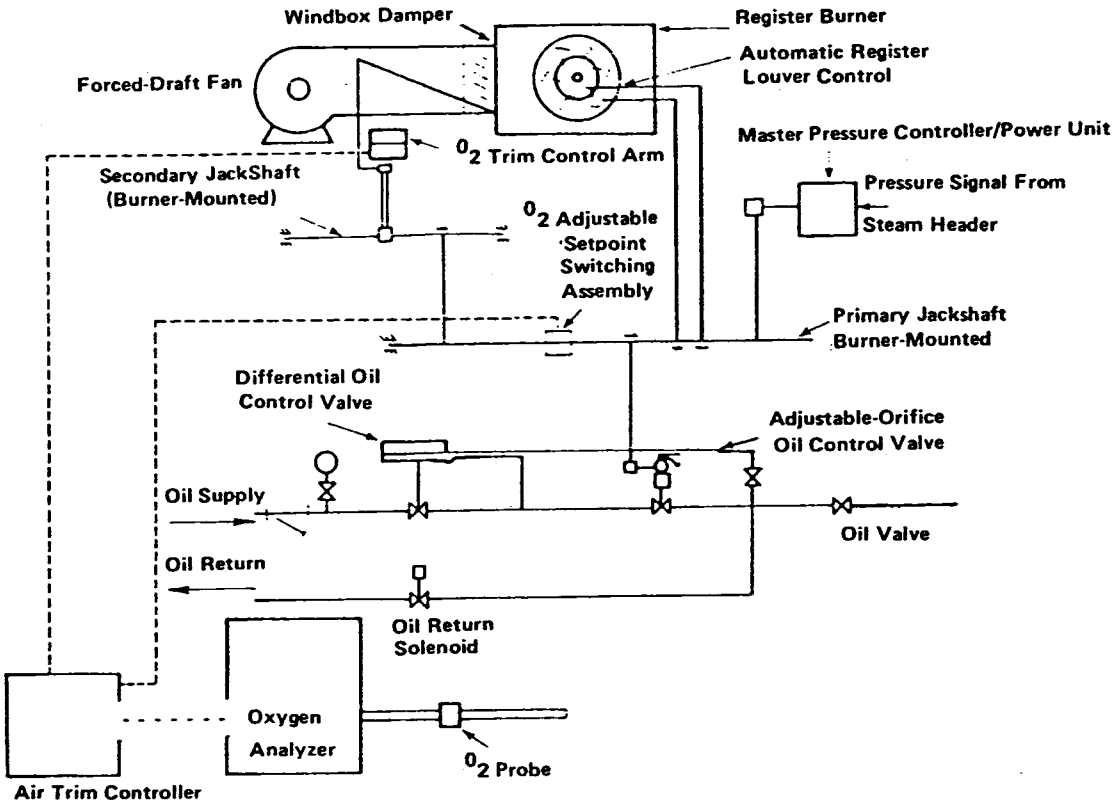


FIGURE 2-67. OXYGEN TRIM CONTROL SYSTEM

control, and a draft indicator are included. Relay logic has been commonly used in the past on multiple burner applications, but it is likely that in the near future, many new systems will be operated and monitored by programmable controllers.

b. Low-Water Fuel Cutoff. FLoat/magnet type and electrode-type low-water fuel cutoff devices are commonly used. Reference figures 2-69 and 2-70. Their purpose is to eliminate the major cause of boiler failure, 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.

c. 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. Pressurs range from a few inches of water in the furnace to hundreds of pounds per square inch in the steam drum. Figure 2-71 illustrates a Bourdon-tube type pressure element with mercury-filled switch typicallyused for applications in the range of 5 to a few hundred psig. Diaphragm-type mechanisms with snap- action switches, as shown in figure 2-72, are used are air pressur 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 (reference figure 2-73).

d. Flame Scanners. Flame scanners which view the ultraviolet range of light are commonly called UV scanners. Lead sulfide type scanners which view the infrared and visible range of light are also common. Self-checking scanners, like the UV scanner shown in figure 2-74, are equipped with shutters thta allow the scanners electronic controls to prove that all of 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 the various burners.

e. Annunciators. Figure 2-75 illustrates a typical annunciator system. Annunciators are frequently used in boiler plants to perform the following functions:

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

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

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

— Advise operator when the condition returns to normal.

2-28. ADDITIONAL CONTROLS AND INSTRUMENTATION.

There are many types of controls and instruments which are applied to Army 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.

a. 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 the fuel and the air actually supplied. A typical air-flow steam flow meter is shown in figure 2-76, and its application is discussed in paragraph 2-26. Essential parts of the meter are: two air-flow bells supported from knife edges on a beam which is supported by other knife edges, and a mercury displacer assembly, also supported by a knife edge on the beam. The bottoms of the bells are sealed with oil, and spaces under the bells are connected to two points of the boiler setting. The point of higher draft is connected to the left-hand bell and point of lower draft to the right-hand bell. This arrangement is similar to that of a flow meter, because it consists of a device for measuring a pressure or draft differential. Flow of gases through the boiler setting follows the same law as steam or water flowing through an orifice: the pressure differrential, or "head," causing the flow is proportional to the square of the velocity. The flow meter is constructed so that movement of the pen on the chart is directly proportional to velocity. Therefore , if the airflow pen is to follow the movement of the steam-flow pen, the airflow mechanism must be compensated so that its movement is directly proportional to the flow of steam when the proper air-to-fuel ratio is being supplied. This compensation is accomplished by the airflow displacer, which is a parabolic float. l Enough weight is placed on the system to cause the displacer to be submerged in mercury when there is no pressure differential on the bells. As the gas flow through the boiler increases, the right end of the beam moves up and the effective weight of the displacer increases. This reduces the amount of beam movement and, in turn,

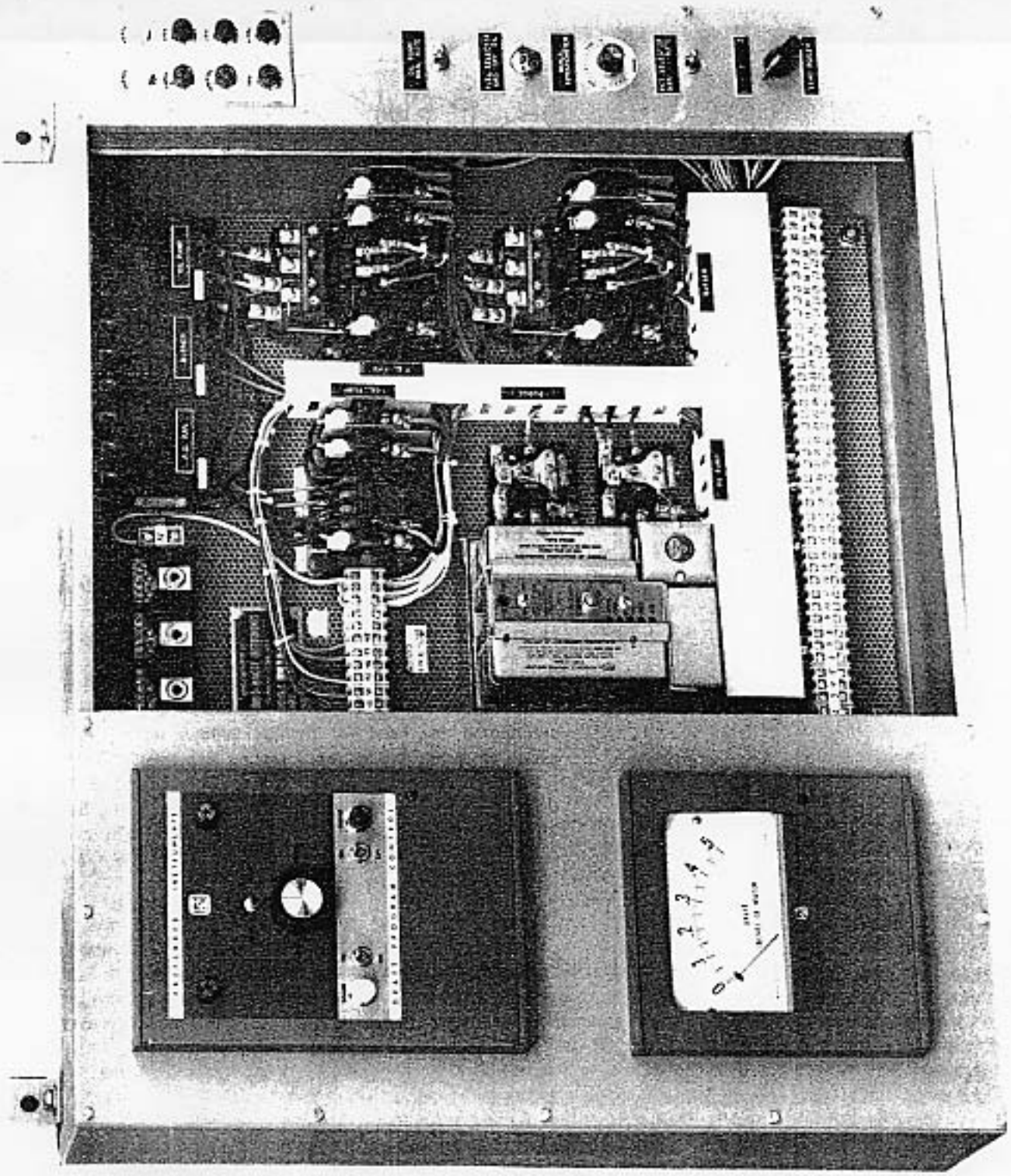
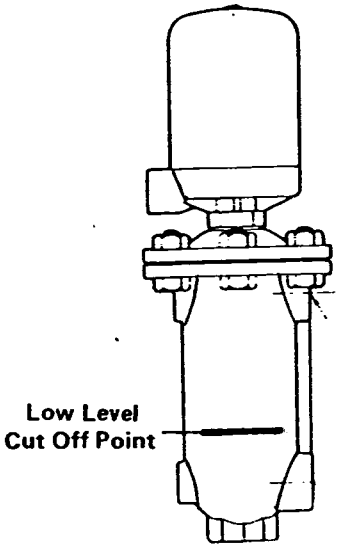
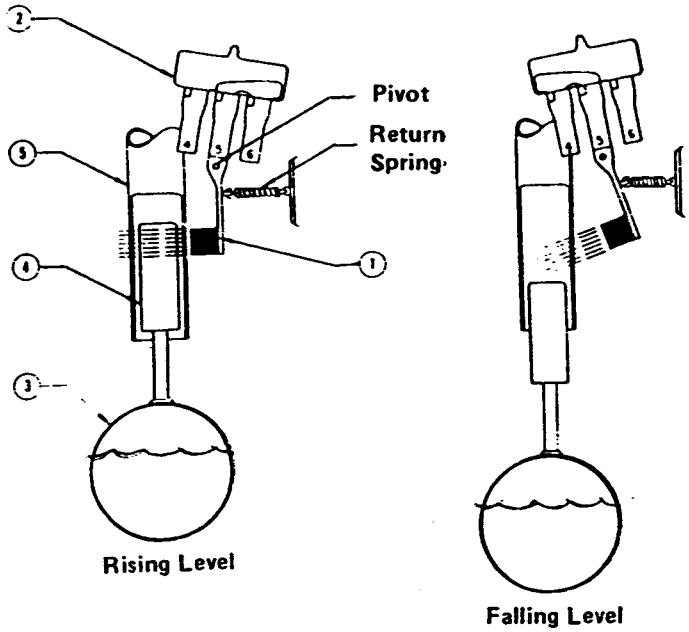


FIGURE 2-68. ELECTRONIC PROGRAMMING CONTROL IN A BOILER PANEL





OPERATING PRINCIPLE

A permanent magnet ① is attached to a pivoted mercury switch ②. As the float ③ rises with the water level, it raises the magnet attractor ④ into the field of the magnet. The magnet snaps against the non-magnetic barrier tube ⑤, tilting the mercury switch. The barrier tube provides a static seal between the switch mechanism and the float, eliminating the need for flexible bellows seals, packing glands or other failure prone sealing elements. When the water level falls, such as with a low water condition, the float draws the magnet attractor below the magnetic field. The magnet swings out and tilts the mercury switch to the reverse position, actuating the low water alarm and operating the burner cutoff circuit.

FIGURE 2-69. FLOAT/MAGNET LOW-WATER FUEL CUTOFF

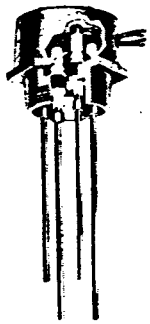


FIGURE 2-70. ELECTRODE TYPE LOW-WATER FUEL CUTOFF

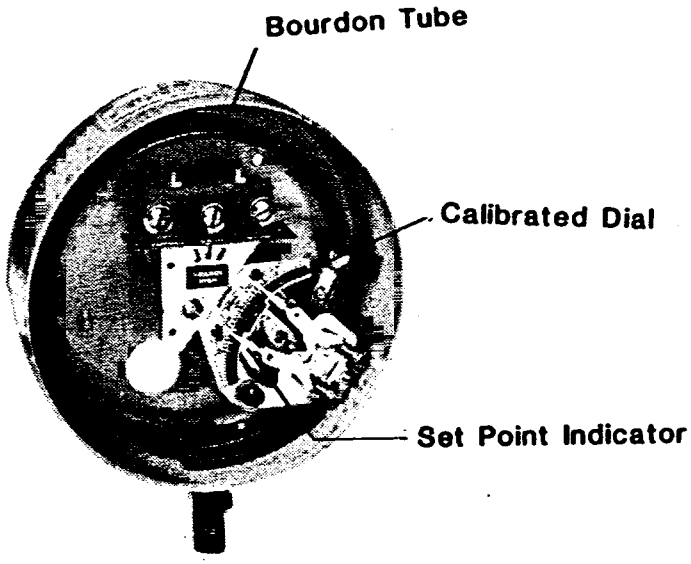


FIGURE 2-71. BOURDON-TUBE PRESSURE SWITCH

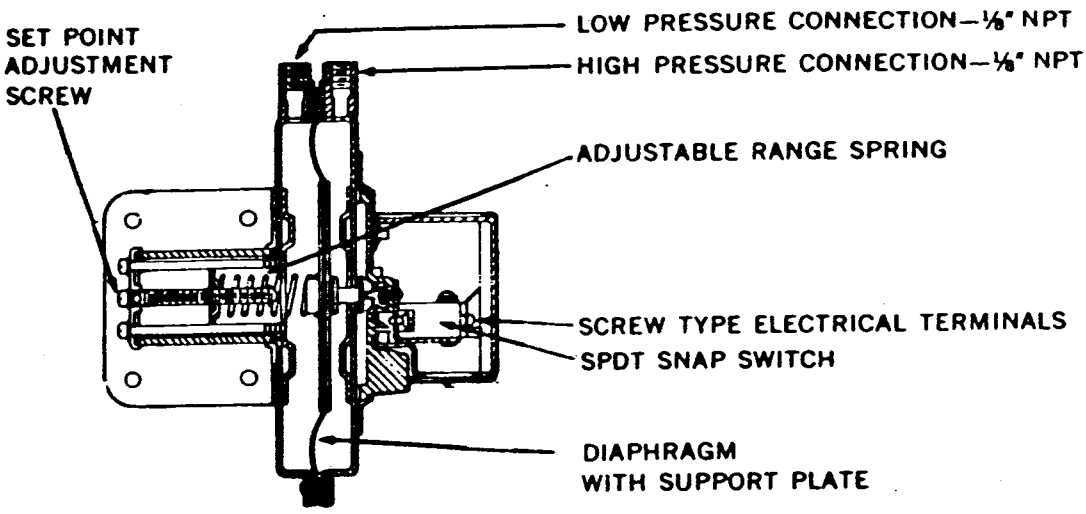


FIGURE 2-72. DIAPHRAGM PRESSURE SWITCH

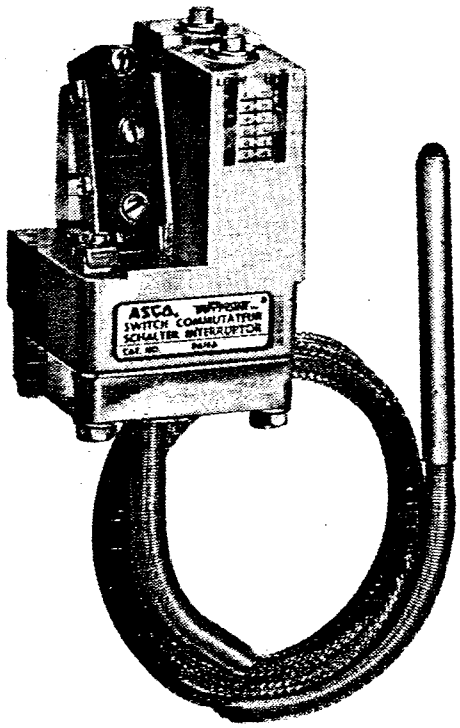


FIGURE 2-73. TEMPERATURE SWITCH

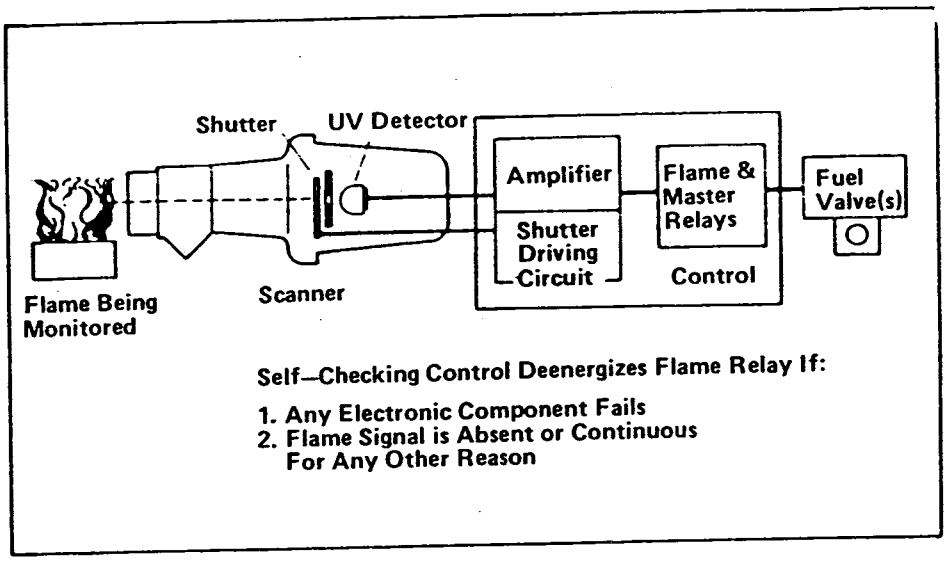


FIGURE 2-74. U-V FLAME SCANNER

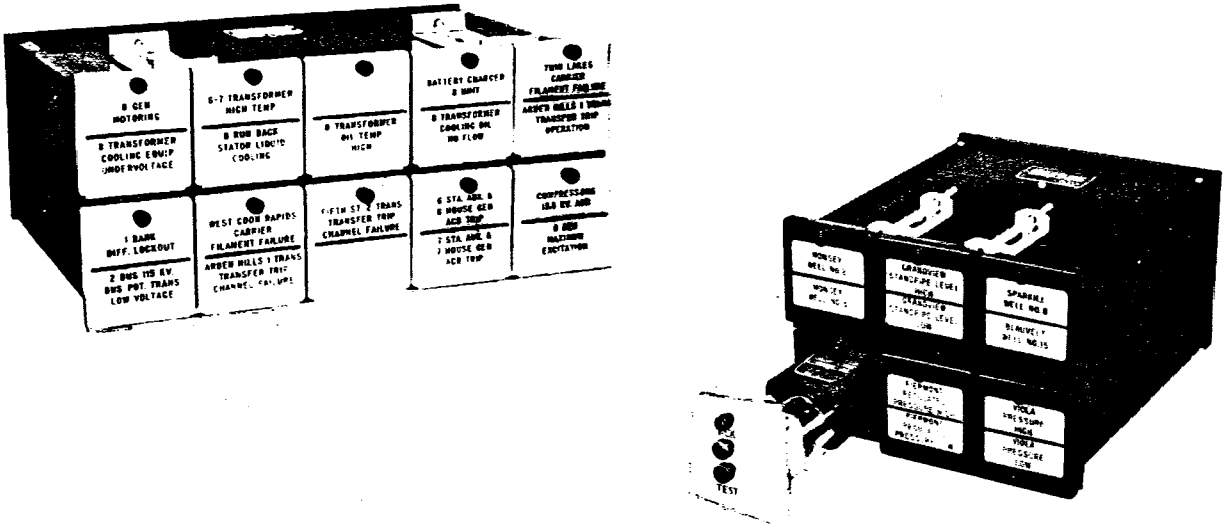


FIGURE 2-75. ANNUNCIATOR

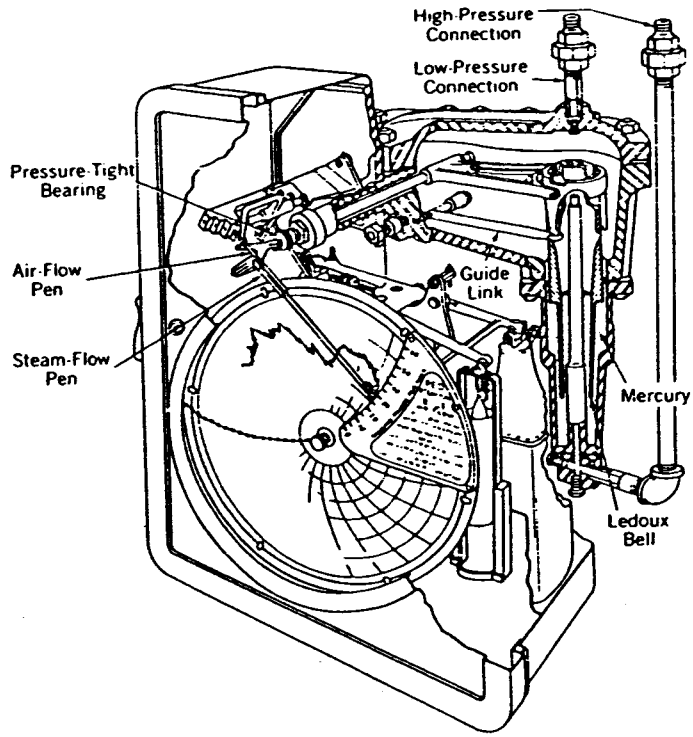


FIGURE 2-76. AIR-FLOW STEAM-FLOW METER

the amount of pen-arm movement. During initial startup, this mechanism is adjusted so that steam-flow and airflow pen recordings are together when the correct air-to-fuel ratio is being maintained. If, during operation, the airflow pen records higher on the chart than the steam-flow pen, the operator has an indication that too much air is being supplied, and vice versa.

b. Temperature Controls. Direct-acting, pilot-operated, and pneumatic or electronic temperatue controls are available. Direct-acting temperature control regulators, ashown in figure 2-77, 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. Dirrct-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.

(1) **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. The variable loading pressur produced by the pilot valve controls teh movement of the control valve. Figure 2-78 shows a pilot-operated temperature control valve. Both direct-acting and pilot-operated temperature regulators are proportional devices.

(2) **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 (RTD's) 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.

c. Pressure Controls. Pressure controllers may be divided into two general types. One type maintains a set pressure in one part of the system while the 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 feed water system to maintain a fixed differential between the prssure 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 opeates the regulating valve dirctrly, 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 the 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-pressur valve, but to only one side in a pressure-reducing valve. A spring or weight is used to balance the valve in either case.

(1) **Pilot-Operated Pressure-Reducing Valve.** The valve shown in figure 2-79 is a self-contained prssure-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 necewssary to move the piston up. When the valve is in equilibrium (that is, when flow through it is sufficient to maintain the 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 the discharge pressure rises. Discharge pressure setpoint is regulated by adjusting the spring.

(2) **Diaphragm Pressure-Reducing Valve.** The valve in figure 2-80 is equipped with a diaphragm actuator and is used for many purposes. It is commonly conneted 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 teh 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 2-8l 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

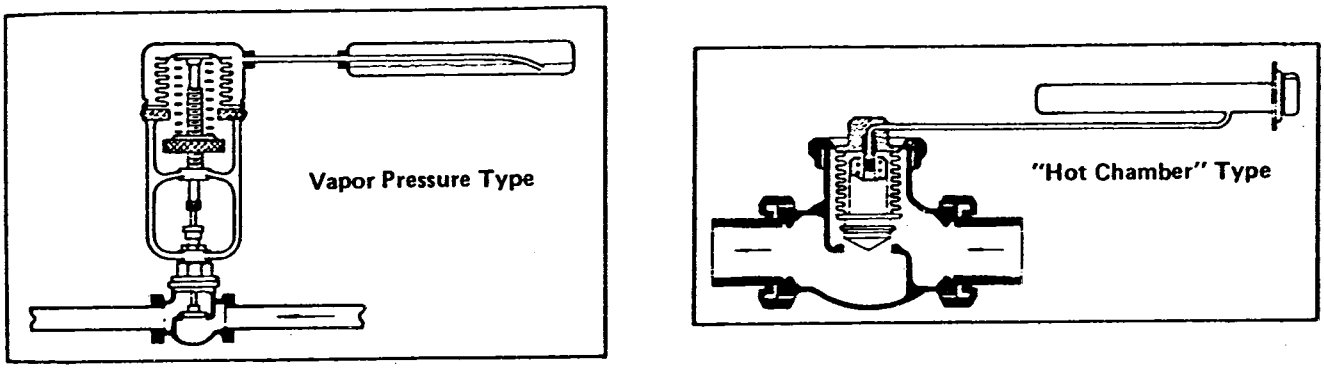


FIGURE 2-77. DIRECT-ACTING TEMPERATURE REGULATOR

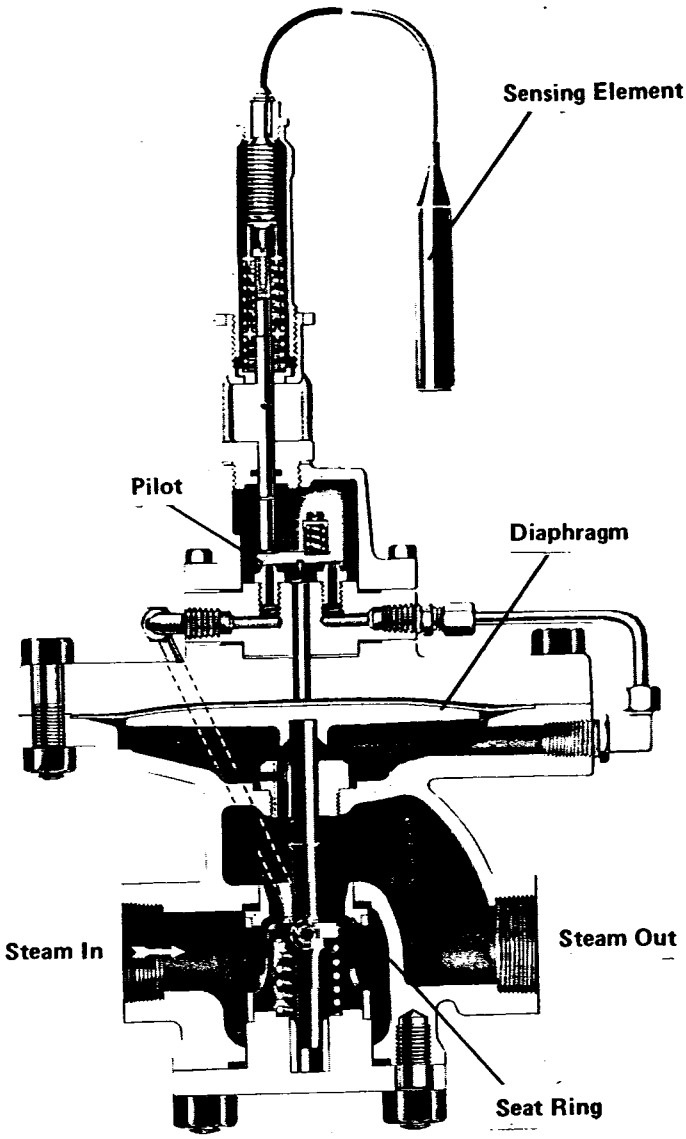


FIGURE 2-78. PILOT-OPERATED TEMPERATURE CONTROL VALVE

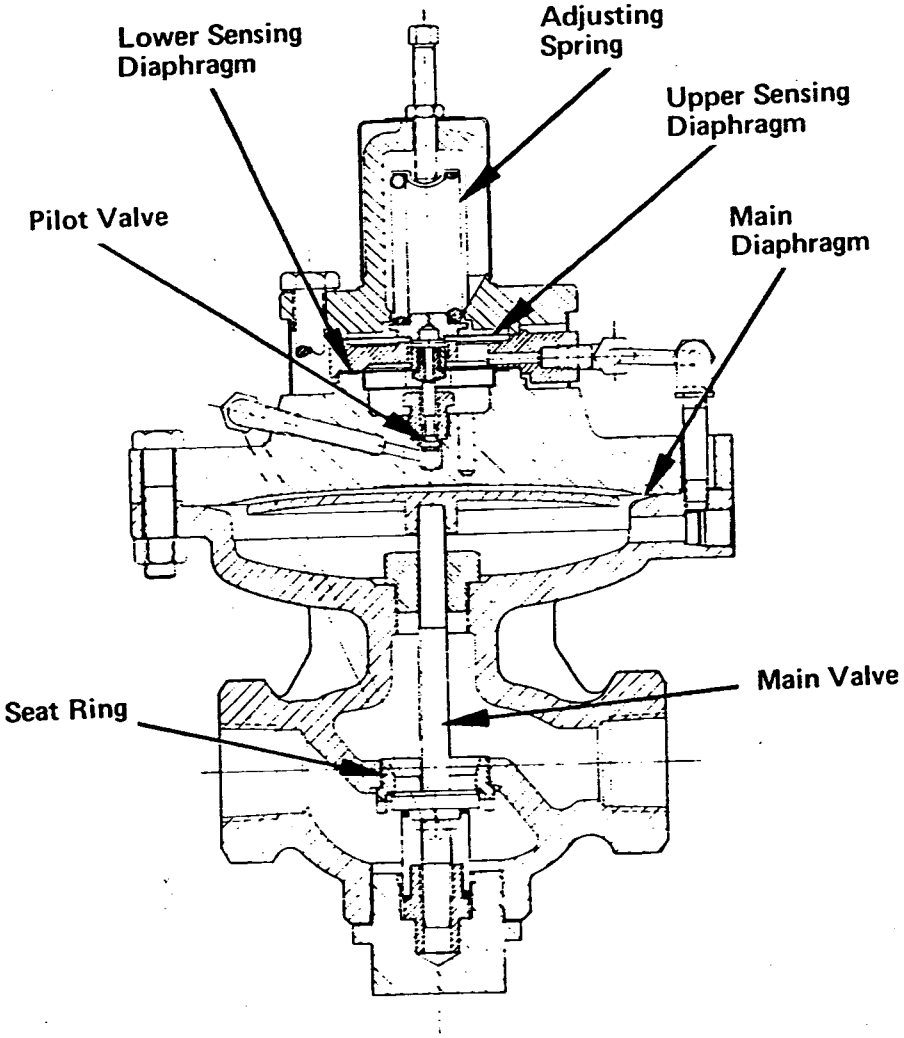


FIGURE 2-79. PILOT-OPERATED PRESSURE-REDUCING VALVE

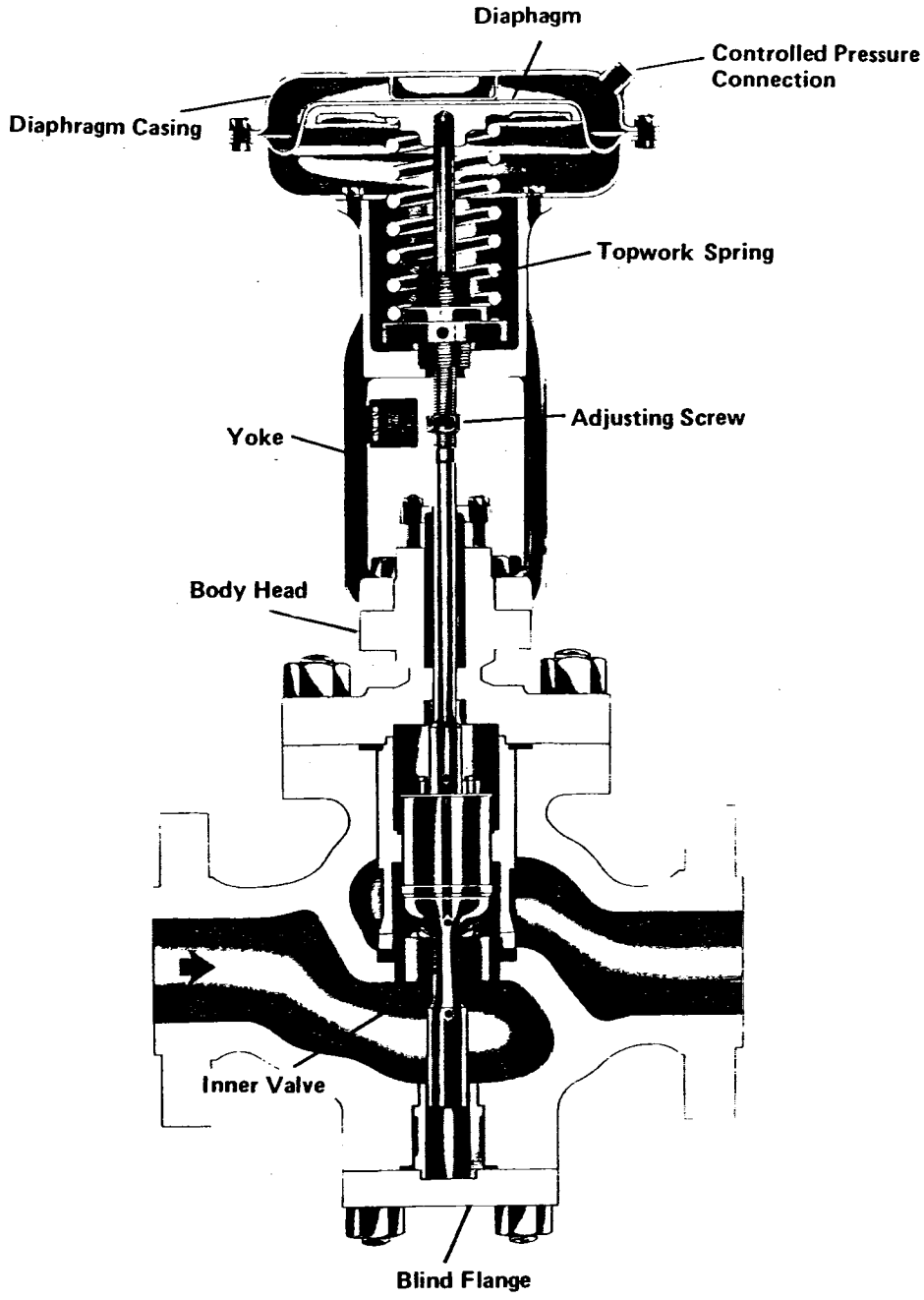


FIGURE 2-80. DIAPHRAGM ACTUATOR PRESSURE-REDUCING VALVE

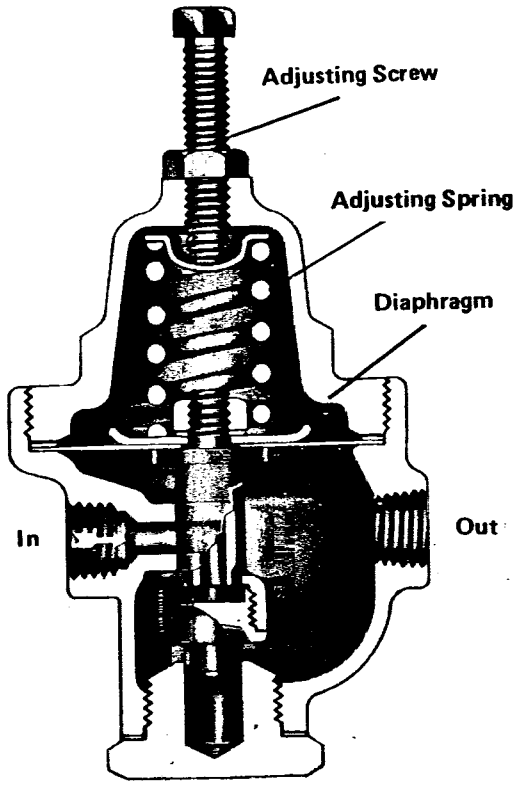


FIGURE 2-81. SELF-CONTAINED DIAPHRAGM PRESSURE-REDUCING VALVE

of the previous valve is eliminated by the simplicity of this valve.

(3) **Differential Pressure-Reducing Valve.** In the valve shown in figure 2-82, 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 conrolled. 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 simulateously, maintaining a constant differential.

(4) **Steam Differential Pressure-Reducing Valves.** Figure 2-83 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. The force applied by the spring establishes the differential pressure between the oil and steam.

d. Flow Meters. Five types of flow-measuring elements are typically found in central heating plants:

— Differential pressure
— Variable area
— Volumetric/positive displacement
— Propeller and turbin
— Weirs and flumes

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

(1) Differential Pressure Meters. Differential pressure flow meters measure the prssure loss created by fluid flow through a pipeline restriction such as an orifice, flow nozzle, or venturi (reference figure 2-84). Water, steam, or gas flowing through a restriction increases in velocity and decreases in prssure. The pressure drop increases by the square of flow or velocity. Thus, if an orifice has a pressure drop of 100 ilnches of water at 100 percent flow, the pressure drop is only 1 inch of water at 10% flow. This explains why it is difficult for differential flow meters to provide accurate information at low flow rates. Figure 2-85 illustrates a steam sflow recorder equipped with a Ledoux bell. The Ledoux bell is shaped to take the square root of a signal from the line restriction. The 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 2-86 are available to replace the function of the Ledoux bell. Very accurate electronic transmitters are also available.

(2) **Variable Area Meters.** A variable area or rotameter is shown in figure 2-87. In this type of meter, the fluid passes upward through a tapered meter tube which contains a float. The float position indicates the rate of fluid flow.

(3) **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 2-88 illustrates a positive displacement-type meter for oil service. These meters can also be equipped to generate flow rate signals.

(4) **Turbine Meters.** In these turbine type meters, the rotational velocity of the propeller or turbine is proportional to the fluid velocity or flow. FLow rates are measured by electonic equipment which senses this rotational velocity and converts it to a volumetric reading. Figure 2-89 illustrates a turbine meter.

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

e. Pressure Gages. A number of devices may be used to measure pressure, with the Bourdon tube being the one most commonly applied in boiler plants.

(1) **Bourdon Tube Pressure Gage.** The measuring element of the Bourdon tube gage (figure 2-90) 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 the pressure within the tube increases, the cross-section tends to become circular and causes the tube to straighten. The movement of the free end of the Bourdon tube is transmitted through a ger sector and pinion to a pointer which indicates the change in pressure. The exact 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 the hot steam does not come into direct contact with the tube.

(2) **Other Types of Pressure Gages.** Diaphragm-type 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 2-91) 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 1000 psi at pressures up to 6000 psig, far above the ranges used in Army Central Boiler Plants. More sophisticated devices for the 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

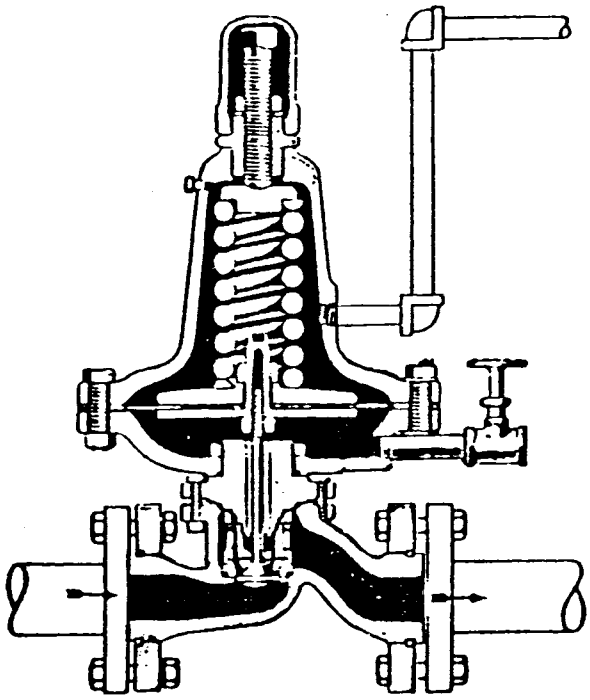


FIGURE 2-82. DIFFERENTIAL PRESSURE-REDUCING VALVE

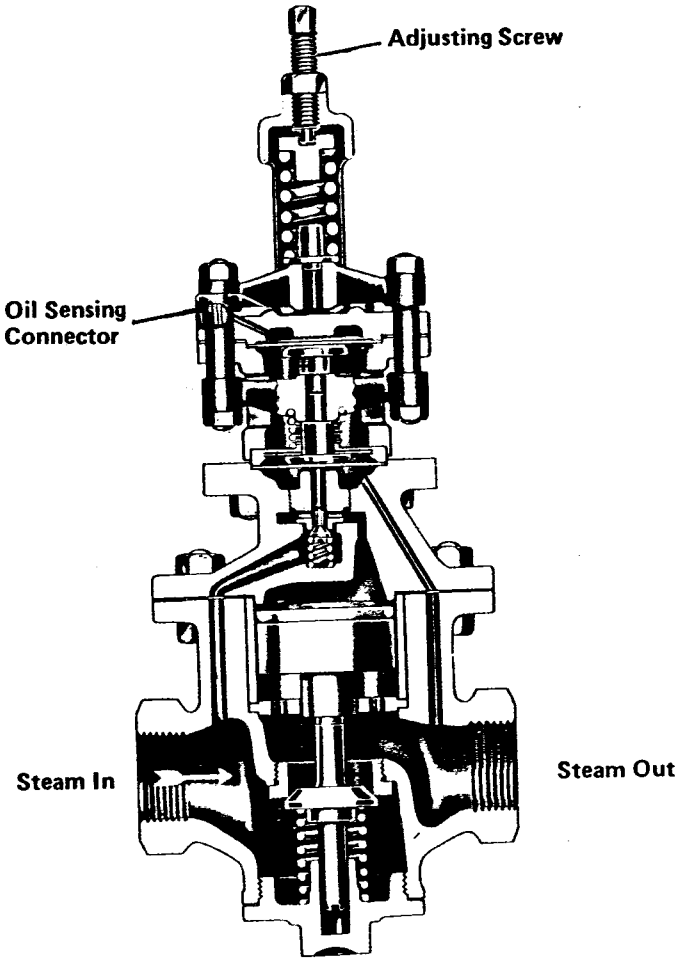


FIGURE 2-83. STEAM DIFFERENTIAL PRESSURE-REDUCING VALVE

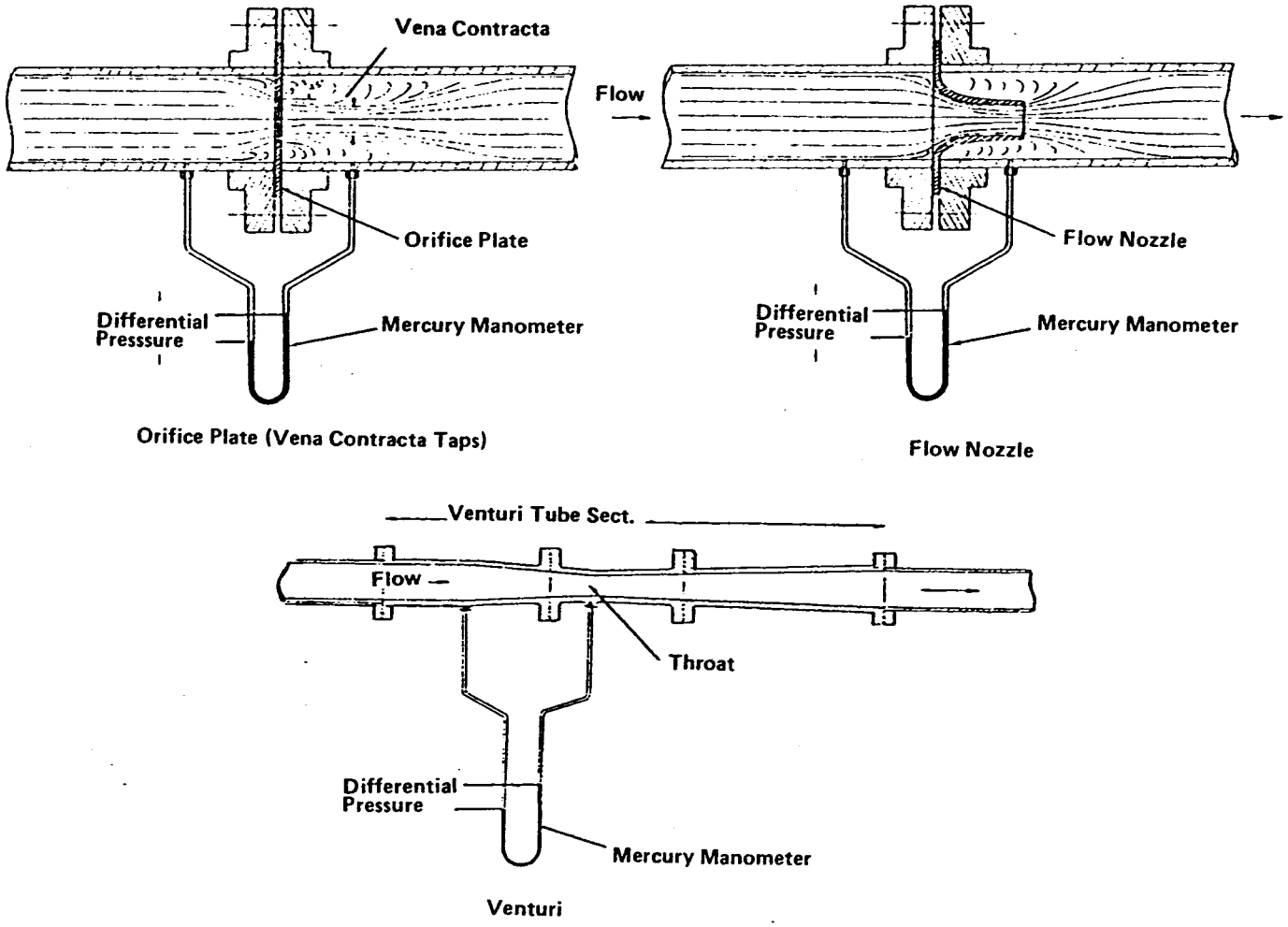


FIGURE 2-84. ORIFICE, FLOW NOZZLE, AND VENTURI

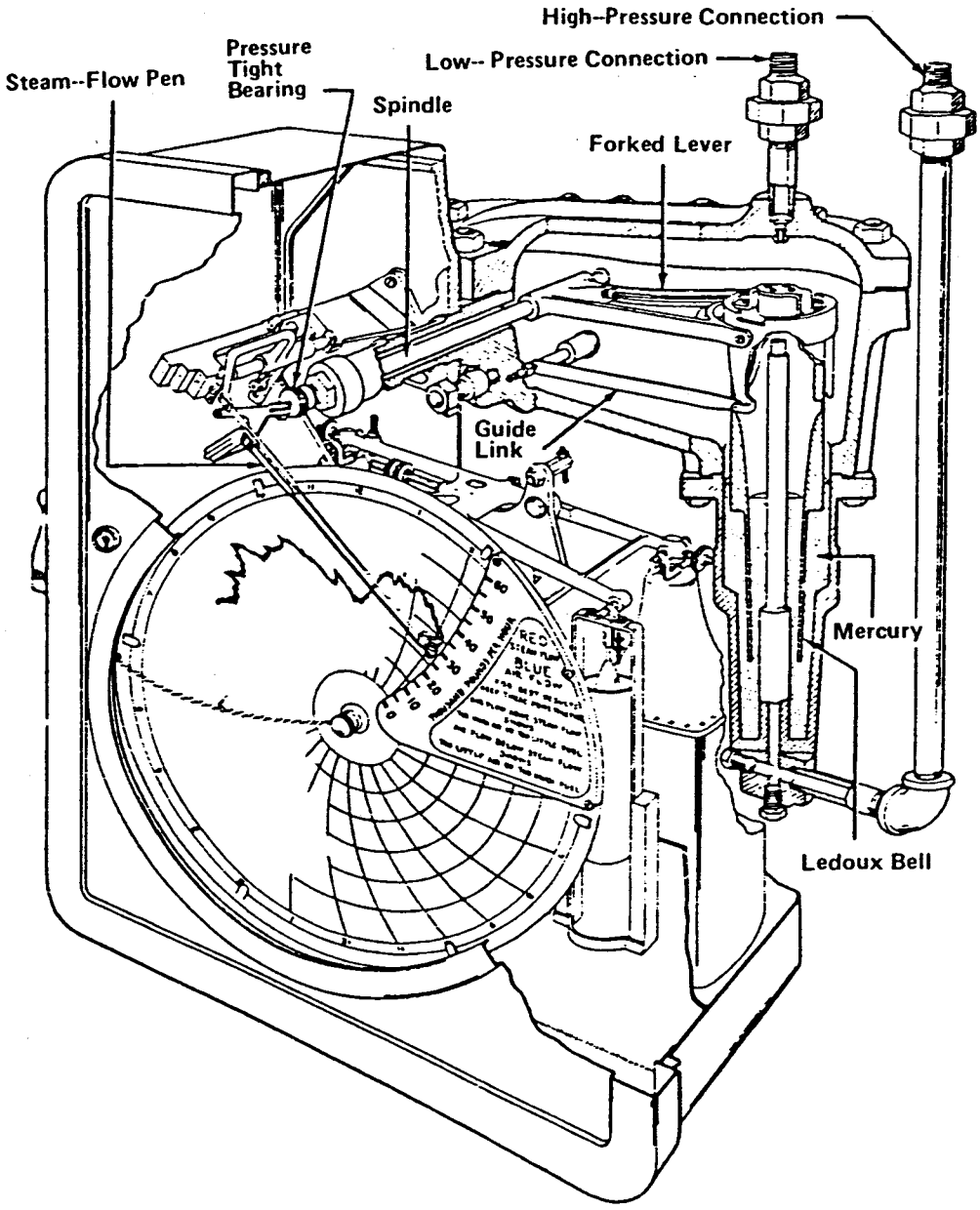
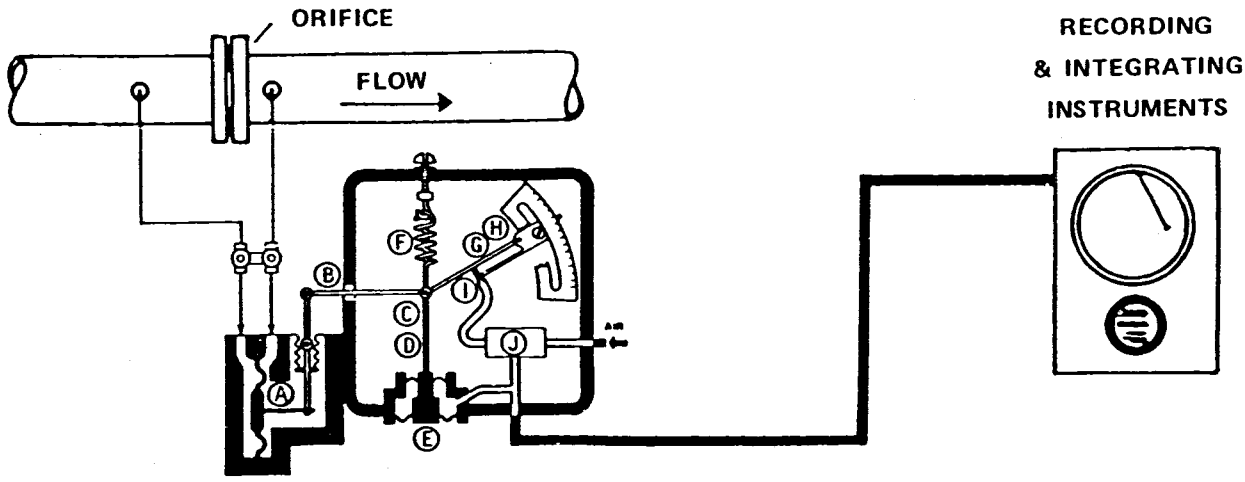


FIGURE 2--85 STEAM FLOW RECORDER



A.	DIFFERENTIAL DIAPHRAGM	F.	ZERO SPRING
B.	LINK	G.	BAFFLE
C.	FLOATING PIVOT	H.	PIVOT
D.	LINK	I.	NOZZLE
E.	FEED BACK DIAPHRAGM	J.	REVERSING RELAY

FIGURE 2-86. PNEUMATIC DIFFERENTIAL PRESSURE TRANSMITTER

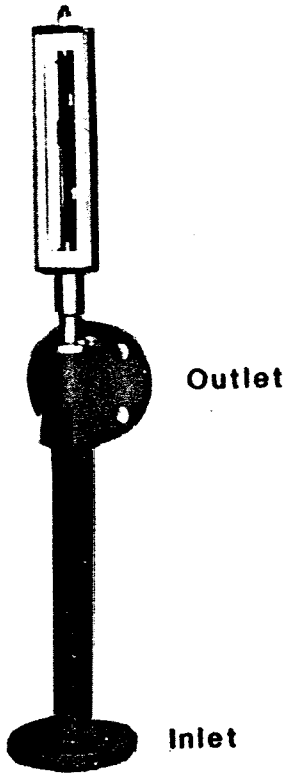


FIGURE 2-87. ROTAMETER

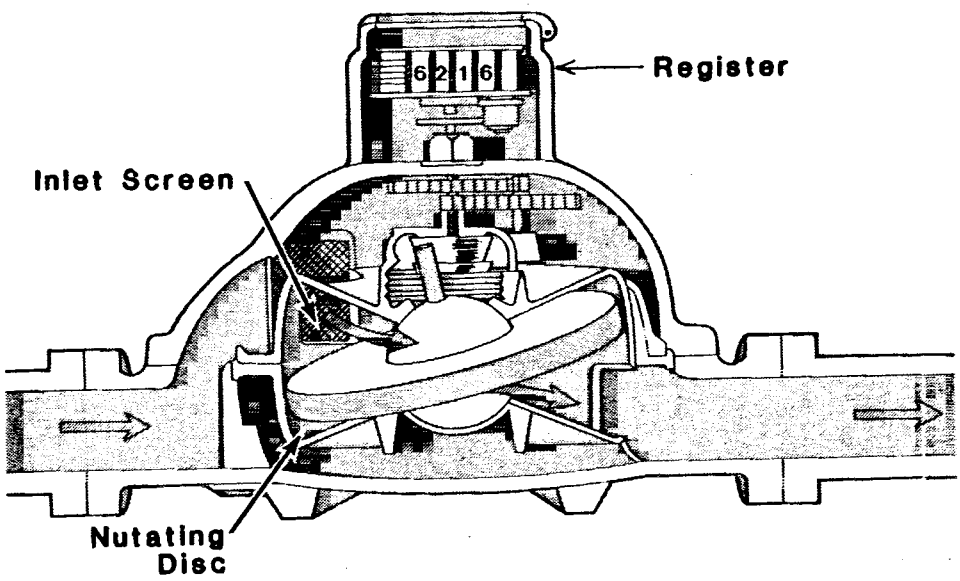


FIGURE 2-88. POSITIVE DISPLACEMENT METER

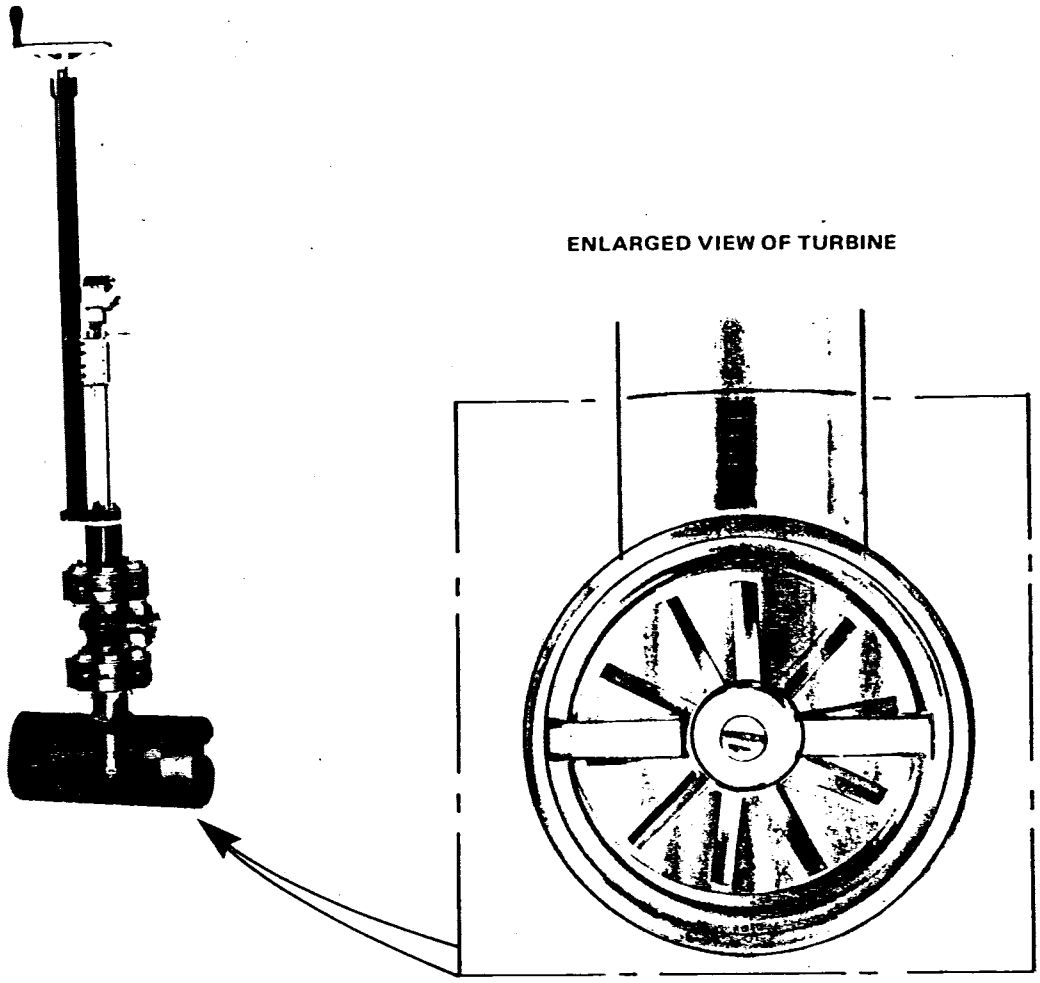


FIGURE 2-89. TURBINE METER

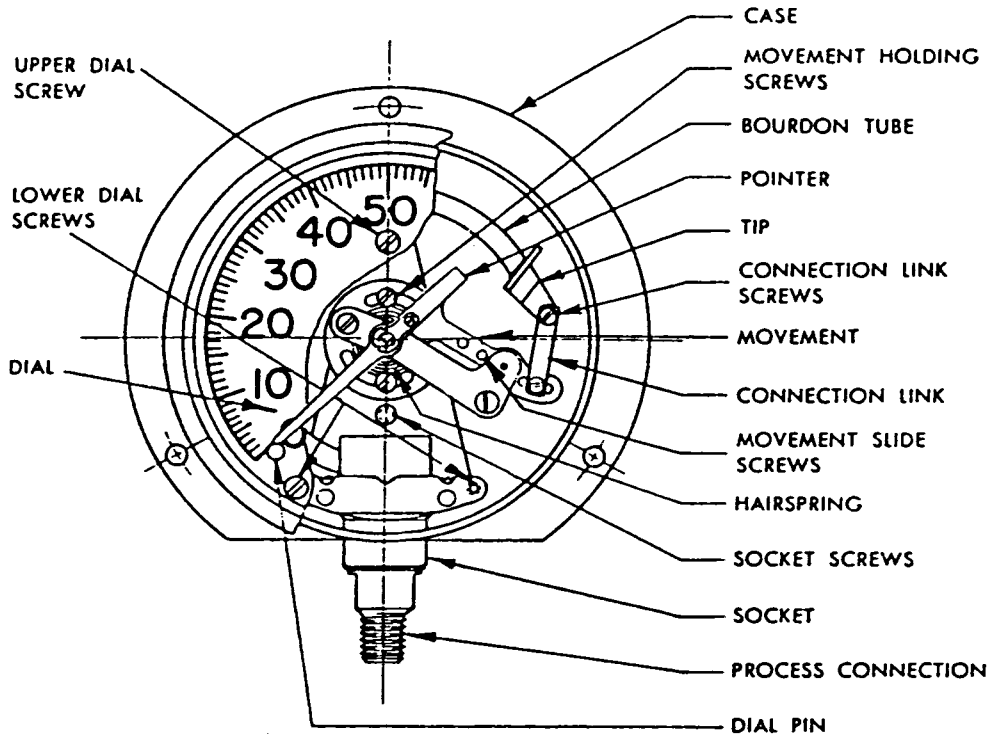


FIGURE 2-90. BOURDON TUBE PRESSURE GAGE

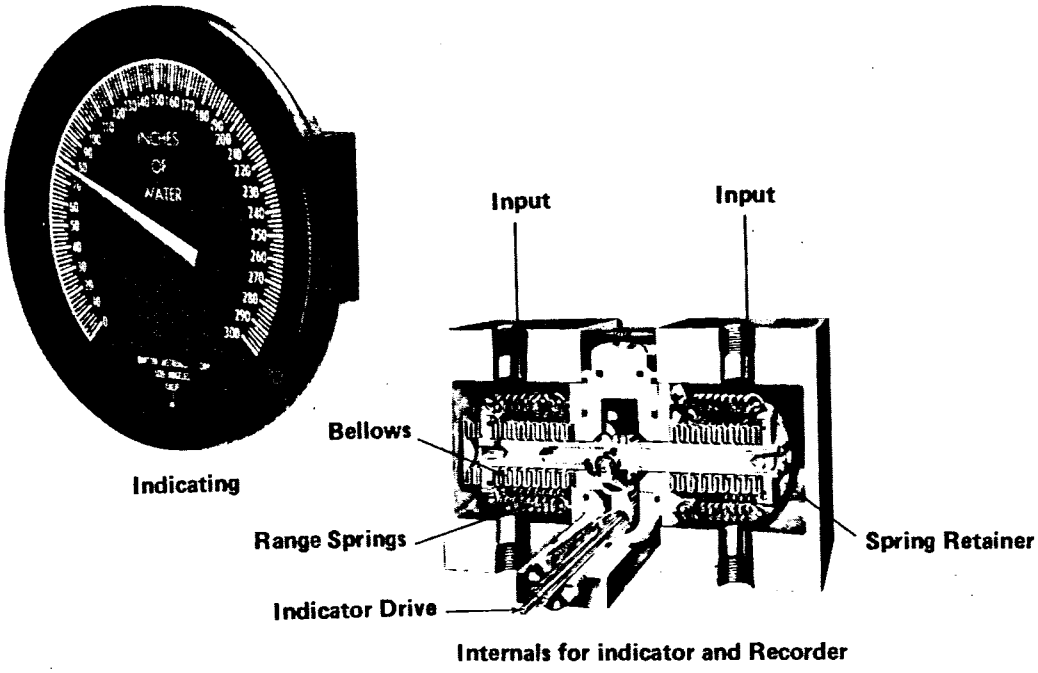


FIGURE 2-91. OPPOSED BELLOWS DIFFERENTIAL PRESSURE GAGE

elaborate and frequent calibration, they have not historically been used as basic instruments in Army Central Boiler Plants. However, with their rapidly increasing reliability and ease of application, pressure transducers are finding wider application and will become more frequently seen.

f. Draft Gages. A draft gage is a form of pressure gage which 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-type draft gages are common.

(1) Manometers. Figure 2-92 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 1 inch of water draft measured. It is important to use the gage oil for which the manometer ws 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.

(2) **Diaphragm Draft Gages.** The draft gage shown in figure 2-93 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. The downward movement is resisted by the cantilever spring. The 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 aarc. The area of the diaphragm is large, thus greatly magnifying the force available for moving the pointer.

g. Glue 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.

(1) **Oxygen Analyzer.** The percentage of oxygen in the boiler flue gas is an effective combustion guide. Continuous monitoring of oxygen levels scan be accomplished by using a zirconium oxide oxygen analyzer shown in figure 2-94. The analyzer consists of a sampling system which pulls flue gas into the zirconium oxide cell located in an electric furnace. At approximately 1700 F, the cell responds to the percentage of oxygen in the 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.

(2) **Carbon Monoxide Analyzer.** Carbon monoxide (CO) in the flue gas indicates incomplete combustion due to either a lack of sufficient combustion air or inefficient mixing of the fuel and air. Modern boiler plants may be equipped with CO analyzers to provide the operator with an indication of how much CO exists. The CO in the 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 in 2-26d(3).

(3) **Smoke Density Indicator.** Coal- and oil-fired plantrs are often provided with smoke-density indicators and recorders where smoke is particularly objectionable. 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.

(4) SO_2 and NO_x Analyzers. Continuous monitoring of pollutants is sometimes required by environmenta' regulations. Sulfur dioxide (SO_2) and oxides of nitroge. (NOx) 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 NOx, chemiluminescence analyzers for NOx, flame photometric and fluorescence analyzers for SO_2. Each of these types 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.

h. 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 (reference paragraph 2-28b(2)). Figure 2-95 illustrates a typical recording thermometer.

i. Recorders. A variety of recorders is available to provide a permanent record of almost any variable which can be measured. Some recorders may be connected directly tc the instrumentation which provides the recorded signal, such as the air-flow steam-flow meter shown in figure 2-

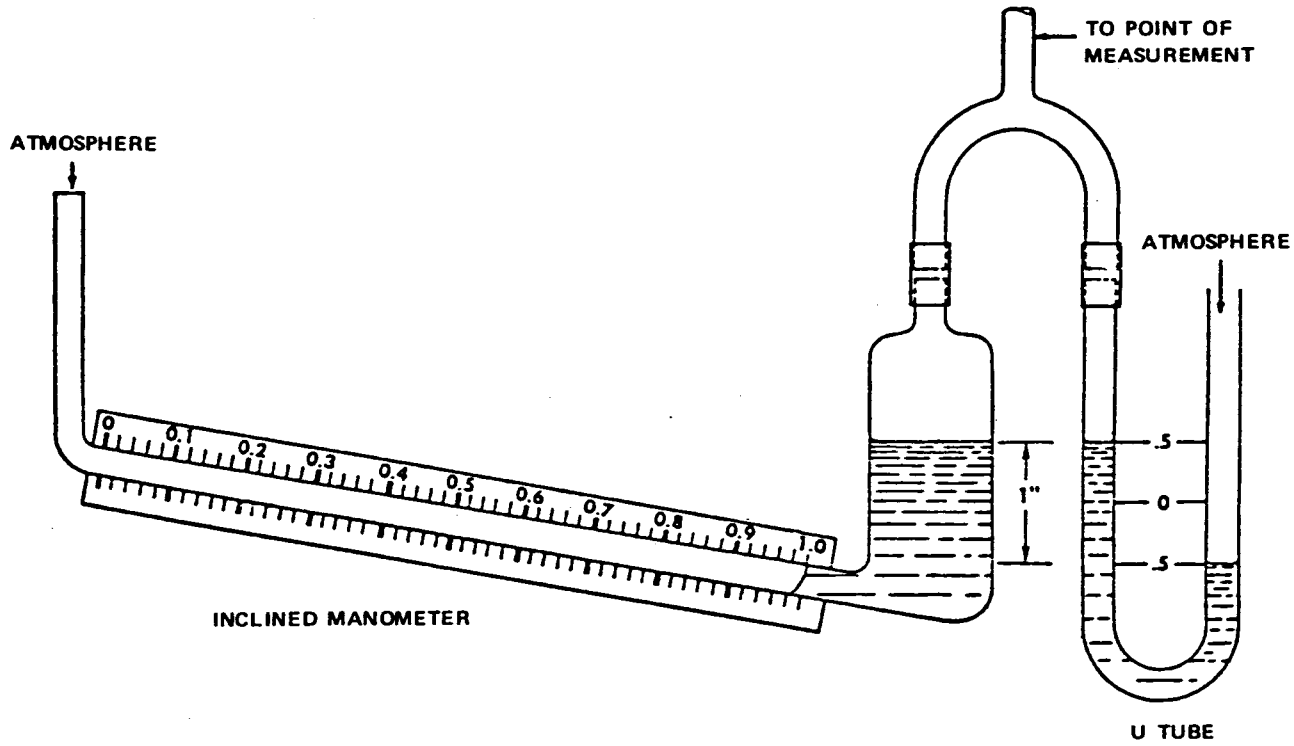


FIGURE 2-92. INCLINED/U-TUBE MANOMETER

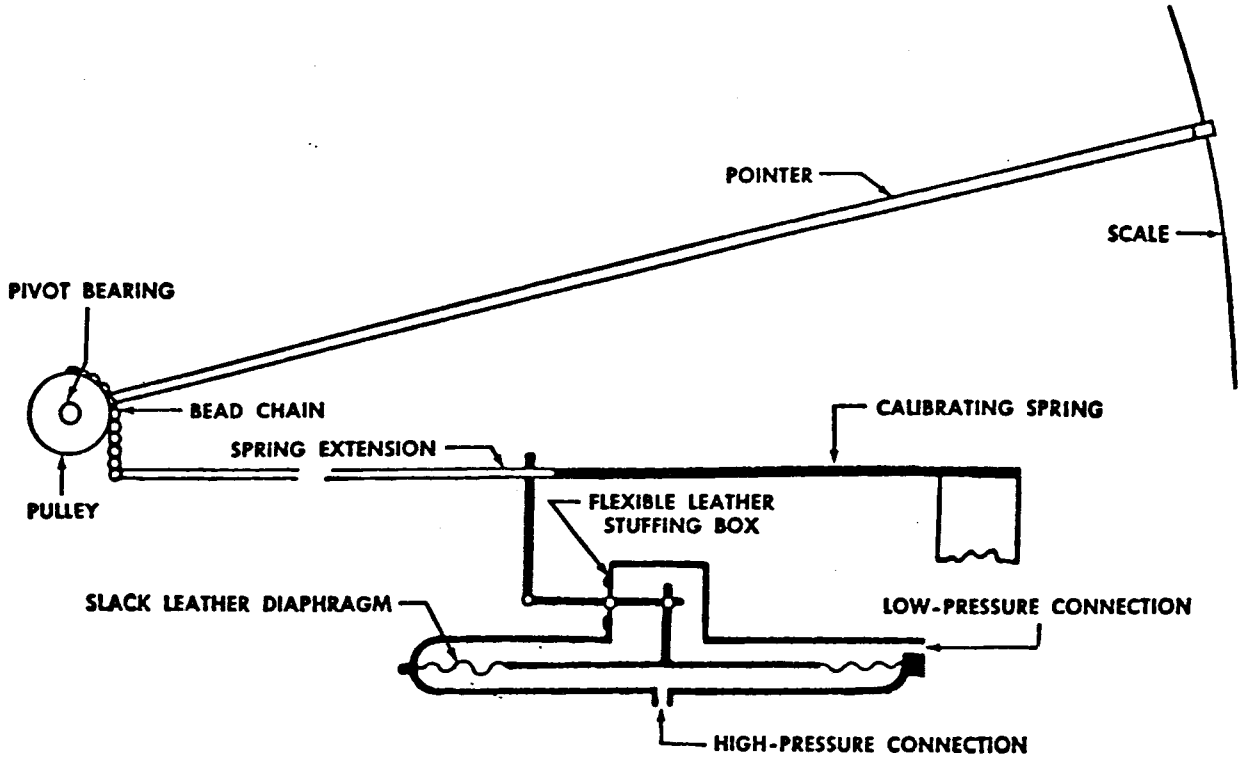
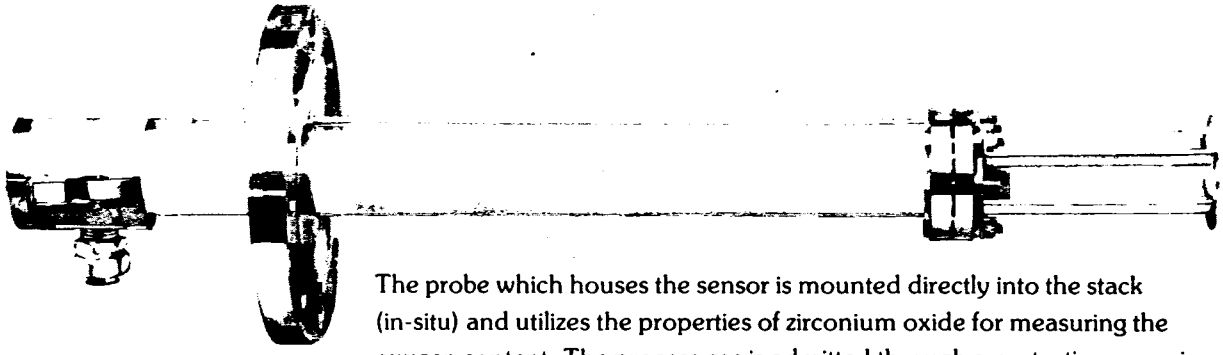


FIGURE 2-93. DIAPHRAGM DRAFT GAGE



The probe which houses the sensor is mounted directly into the stack (in-situ) and utilizes the properties of zirconium oxide for measuring the oxygen content. The process gas is admitted through a protective ceramic filter to the sample side of the sensor and produces an inverse logarithmic DC voltage signal which is sent to the temperature controller.

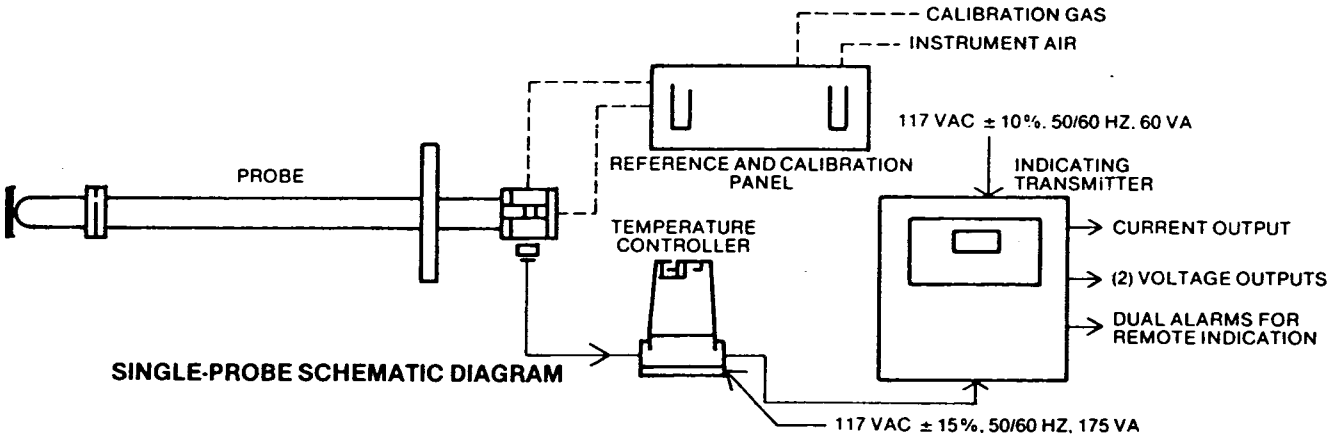


FIGURE 2-94. ZIRCONIUM OXIDE OXYGEN ANALYZER

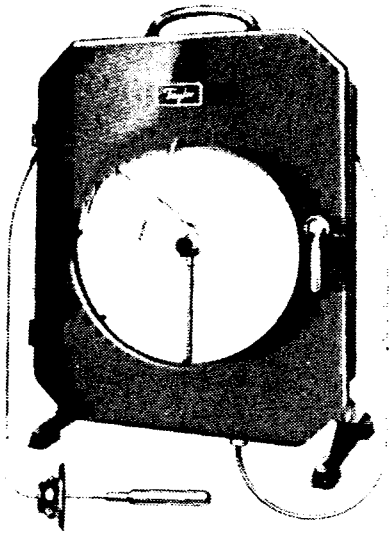


FIGURE 2-95. RECORDING THERMOMETER

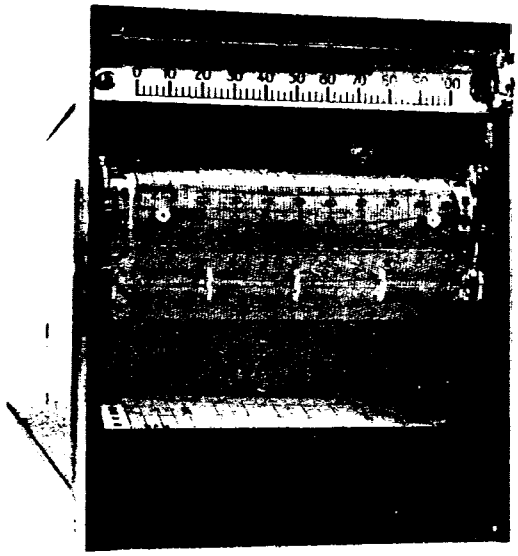


FIGURE 2-96. STRIP CHART RECORDER

76. Others are remotely mounted and receive an electronic or pneumatic signal from the instrumentation element. A typical strip chart type recorder is illustrated in figure 2-96. This particular model 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 are in typical use in Army Boiler Plants and generally record two to four variables.

2-29. WATER TREATMENT CONTROL.

Instrumentation controls for water treatment systems are discussed in chapter 4.

SECTION V. POLLUTION CONTROL EQUIPMENT

2-30. POLLUTION REGULATIONS.

Control of pollutants from the 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 arir quality standards.

a. Point Source Regulations. Point source regulations place limits upon the quantity of a 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 applicabled, must always be met. Typical point source emission levels for the commonly regulated hhpollutants are listed in table 2-1. In most cases, some or all of these regulations will be inapplicable to Army boilers. Federal regulations do not, at the present, apply to boilers of less than 250 million Btu/hr heat input (approximately 180,000-200,000 pounds of steam/fr). Most state and local agencies also have minimum size limitations.

TABLE 2-1.
TYPICAL POINT SOURCE EMISSION LEVELS FOR VARIOUS POLLUTANTS

Poilutant	Fuel	Maximum Allowable Emission	
		LB-Pollutant/ Million Btu	PPM at 3% O_2
Particulate	All	0.1	N/A
NO_x	N.G.	012	160
		Oil	0.3 230
		Coal	0.7 510
SO_x	Oil	0.8	440
		Coal	1.2 630

b. Ambient Air Quality Standards. Ambient air quality standards may be applicable to any size boiler. These standards require that the 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. The emission levels determined under ambient air quality standards may be the same as, more stringent than, or less stringent than the applicable point source regulations for a given boiler plant. The actual determination of the applicable limits usually warrants a separate study by a consultant.

2-31. TYPES OF POLLUTANTS AND CONTROL METHODS.

The pollutants listed in table 2-1 are those that are commonly regulated from Army boilers. Their generation and control are discussed briefly in this section. More detailed information can be found in TM 5-815.

a. 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 the 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 the burners aimed at lowering the peak flame temperatures in the furnace and by minimizing the amount of free oxygen available in the highest temperature combustion zones. New boilers which have been 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. Some of the modifications and adjustments which can be implemented are listed in table 2-2, as well as advantages and disadvantages of each and the anticipated reduction in NO_x emissions. Additional information on these NO_x reduction techniques is available in Army Manual TM 5-815. However, since relatively few Army boilers are required to meet NO_x regulations, these topics are not discussed further in this manual.

b. Oxides of Sulfur. The primary oxide of sulfur (SOx) formed by the combustion of fossil fuel is sulfur dioxide or SO_2. SO_2 is formed when sulfur from the fuel combines with oxygen from the air in the high temperature zones of the furnace. In a conventional boiler, essentially all the sulfur that enters with the fuel converts to SO_2. No practica form of combustion modification has been developed to reduce SO_2 generation in the furnace. In order to control

Table 2-2. 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.

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_2d after it leaves the boiler. The most common types of scrubbers used on boilers in the size range employed at Army bases 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 203. 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 Army plants, compliance with regulations generally being by means of low sulfur fuel instead. Details on the installation and operation of scrubbing equipment is discussed in detail in Army Manual TM 5-815, chapter 10. Atmospheric fluidized bed boilers are also becoming more commonly applied when control of SO2 emissions is required. These are generally more cost-effective than scrubbers but have not been commonly applied because of their limited operating experience (reference paragraph 2-18g).

c. Particulate. Particulate matter, also called fly ash, is the pollutant that is of most concern to Army boiler operators. It is comprised primarily of unburned carbon and the portion of teh ash which 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 the 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 the 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, the 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 the burners which 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 nd the stack. Several suitable types of devices exist, as itemized in table 2-4 and discussed in sections 2-32 through 2-35. 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 the particulates to be mor widely dispersed in the atmosphere, and thus can be a means of meeting ambient air quality regulations. This technique is rarely applicable to Army boiler installations, however. For more details on the use of tall stacks as a particulate control device, refer to Army Manual TM 5-815.

d. Pollutants from Natural Gas. Of the fuels commonly burned in Army installations, 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.

e. Pollutants from Oil. When oil is burned in a boiler, a variety of pollutants can be formed including NOx, SOx, and particulates. The grades of oil most commonly burned in Army facilities are No. 2 and No. 6. No. 2 oil is a highly refined, clean-burning oil having little ash or sulf and emissions can generally be controlled by burne. 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 the use of particulate-control devices. While SO_2 emissions can also become high enough to violate regulations, the use of scrubbing equipment with small boulers is not generally cost effective, and regulations are usually met by conversion to an oil having a lower sulfur content.

f. 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 the use of SO_2 scrubbing equipment be cost-effective on small boilers.

2-32. MECHANICAL COLLECTORS.

The term "mechanical collector" refers to a widely used type of particulate-collection device in which dust-laden

Table 2-3. Performance Characteristics of Flue-Gas Desulfurization Systems

System Type	SO_x Removal Efficiency (%)	Pressure Drop (inches of water)	Recovery and Regeneration	Operational Reliability	Retrofit to Existing Installations	Advantages	Disadvantages
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 MgO and sulfuric acid	Low	Yes	High efficiency; no solids disposal.	Low reliability; corrosion and erosion of scrubber and piping; need pre-cleaning 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.

Table 2-4. 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°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; weather-proofing may be required.

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 the dust particles from the carrier gas stream by virtue of their inertia. The particles migratge to the cyclone walls by means of gas flow and gravity and fall into a hopper. Because of the pattern of the gas flow through the collector, mechanical collectors are often referred to as "cyclones." Cyhclones 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 employed on Army boilers are the conventional, medium-efficiency, single cyclone, and the multicyclone.

a. 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 2-97. Single cyclones are 4 to 12 feet in diameter and are limited to about 20,000 actual ft^3/min gas flow. More than one unit can be combined in parallel to accept greater gas flows.

b. 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 2-98. 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 paralled into the gas stream.

c. Other Cyclones. Other types of cyclones which are less commonly used are the high-efficiency single cyclone and the wetted cyclone. The principal characteristics of the four types are summarized in table 2-5.

d. 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, the size and quantity of the dust particles, and the pressure drop through the cyclone. Typical collection efficiences for the various types of cyclones, operating in various applications, are given in tables 2-5 and 2-6. 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 2-99. These curves are determined by actual testing of similar prototypes in the manufacturers 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 all the collected weights as a percentage of the toal weight of dust entering the collector.

e. Pressure Drop and Energy Requirements. Through any given cyclone, there will be a loss in static pressure of the 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 1000 actual ft^3/min of gas per 1 in-H_2O pressure drop. Thus, a mechanical collector applied to a 40,000 lb/hr boiler (approximately 16,000 actual ft^3/min flue gas flow) and designed to operate at 3.0 in-H_2O pressure drop would require about 12 horsepower in fan power.

f. 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 onditions such as gas flow, dust load, and particle size. In general, changes which increase pressure drop or particle size will improve the collection efficiency, which changes that decrease pressure drop or particle size will decrease efficiency.

g. 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 as 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 the chapter must be applied.

h. Application as Precleaners. Another common application of cyclones to Army Central Boiler Plants 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 them 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

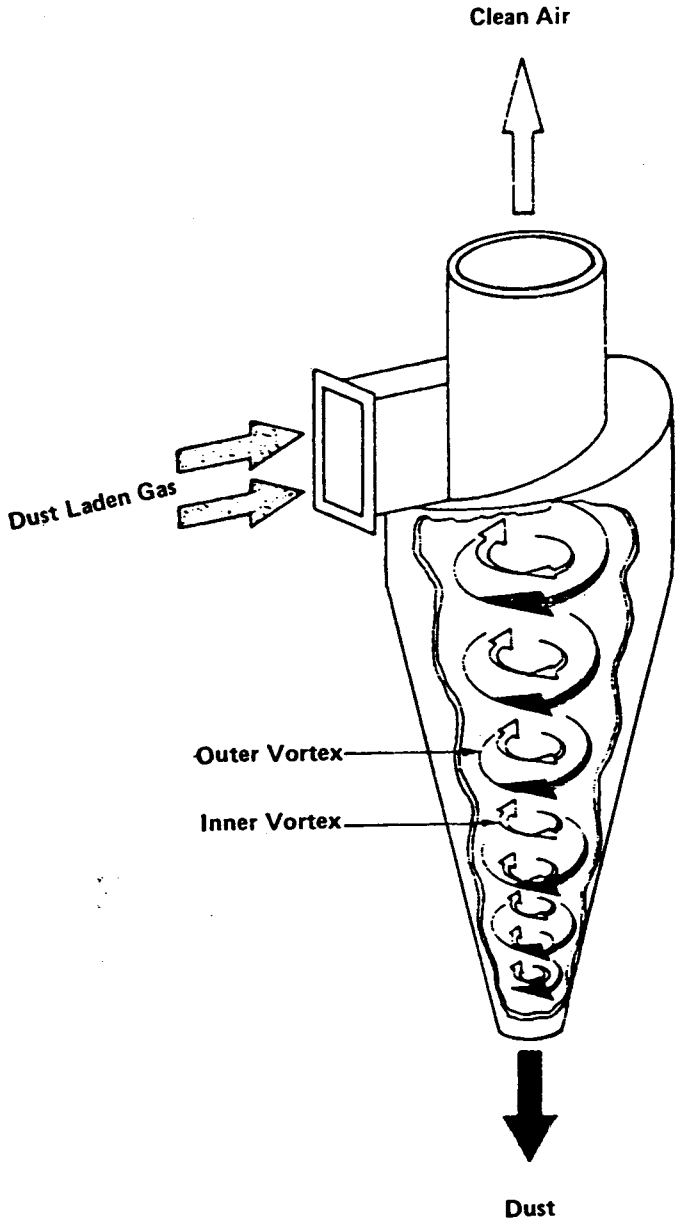
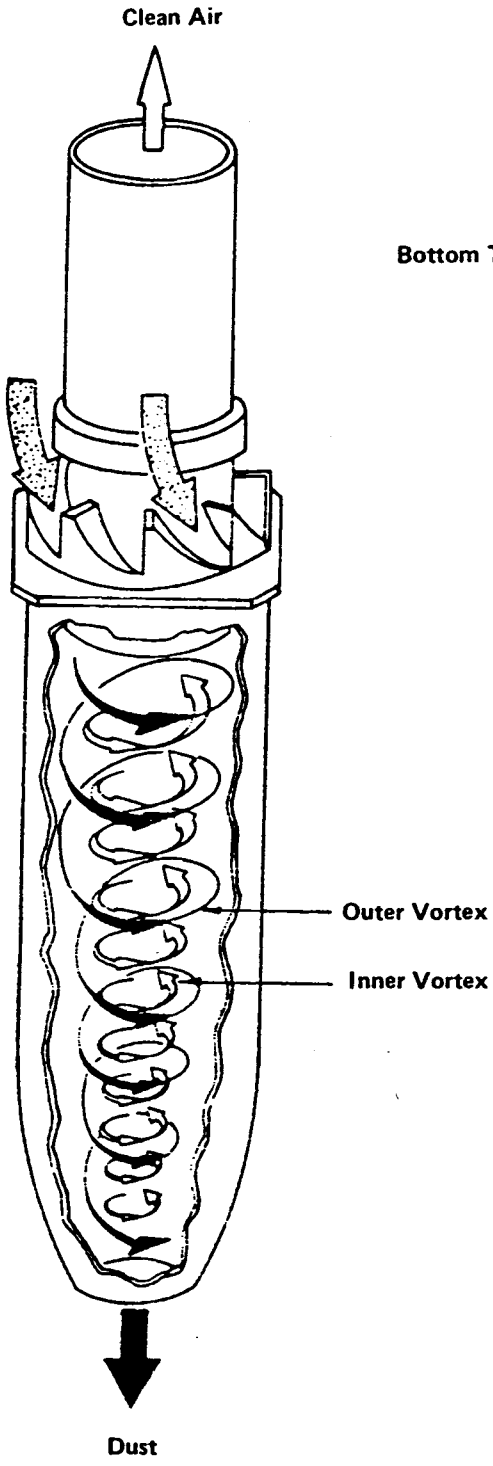
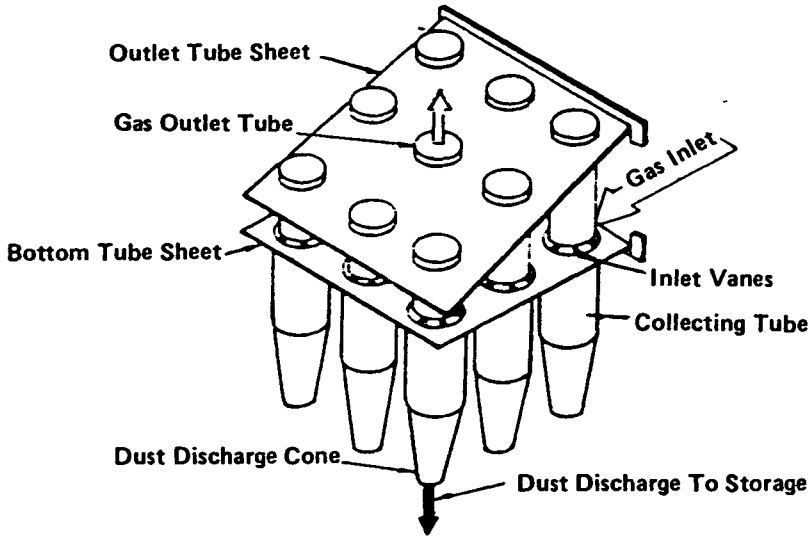


FIGURE 2-97. MEDIUM EFFICIENCY CYCLONE CONFIGURATION



a. Configuration Of Individual Cyclone Tube From Multicyclone



b. Typical Multicyclone Configuration

FIGURE 2-98. MULTI-CYCLONE CONFIGURATION

Table 2-5. Characteristics of Mechanical Dust Collectors

Type	Body Diameter (feet)	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	.5-2	20-70	50-80	Material Handling Exhaust gas pre-cleaner	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.
Multicyclones	.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.

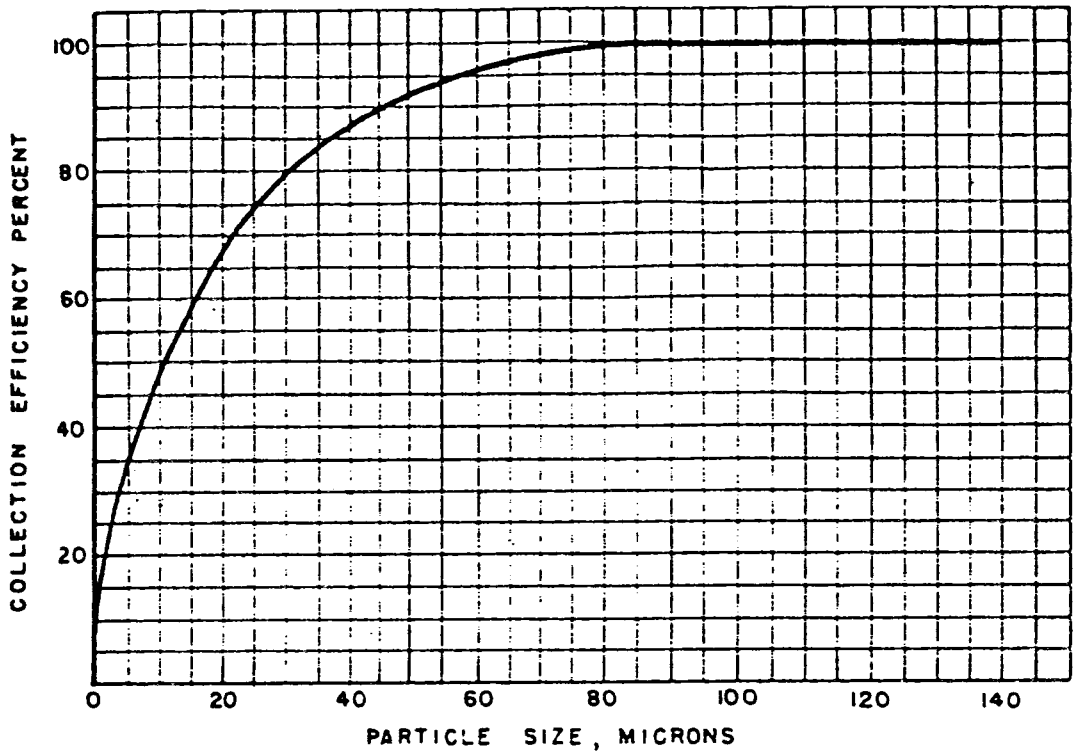


FIGURE 2-99. CYCLONE FRACTIONAL EFFICIENCY CURVE

complement each other to provide good efficiency over a wide range of gas flow and dust loading conditions.

i. 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.

j. Effect of Firing Modes. The method by which the 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 2-6 illustrates the optimum expected performance of mechanical collectors for particulate removal in various combustion process applications.

TABLE 2-6
REMOVAL EFFICIENCIES OF UNTROLLED 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

2-33. FABRIC FILTERS.

Fabric filters, commonly called "baghouses", are used to remove particulate from the flue gas stream. The 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 the cloth filters, and the dust is removed from the gas stream as it passes through the filter cloth. The filters are cleaned periodically.

a. Housing Design. For practical resons, most baghouses used for boiler flue gas are designed to operate under negative pressure and are located between the last heat trap and the induced-draft fan. Pressurized-type 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. The hoppers and housing are insulated, and the fan is located on the clean side of the collector.

b. 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 buildup occurs.

c. Filter Cleaning Methods. The dust may be remov from the filters by several methods. The most comm methods applied are shaking, reverse gas flow, and reverse pulse.

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

(2) **Reverse Gas Flow.** See figure 2-100. 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 the 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.

(3) **Pulse Jet.** See figure 2-101. The pulse jet cleaning method utilizes a short blast of high-pressure air (90-100 psig) to blow backwards through the bag and dislodge the 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 small physical size. This leads to lower initial cost, fewer bags, and lower space requirements. Other advantages are the

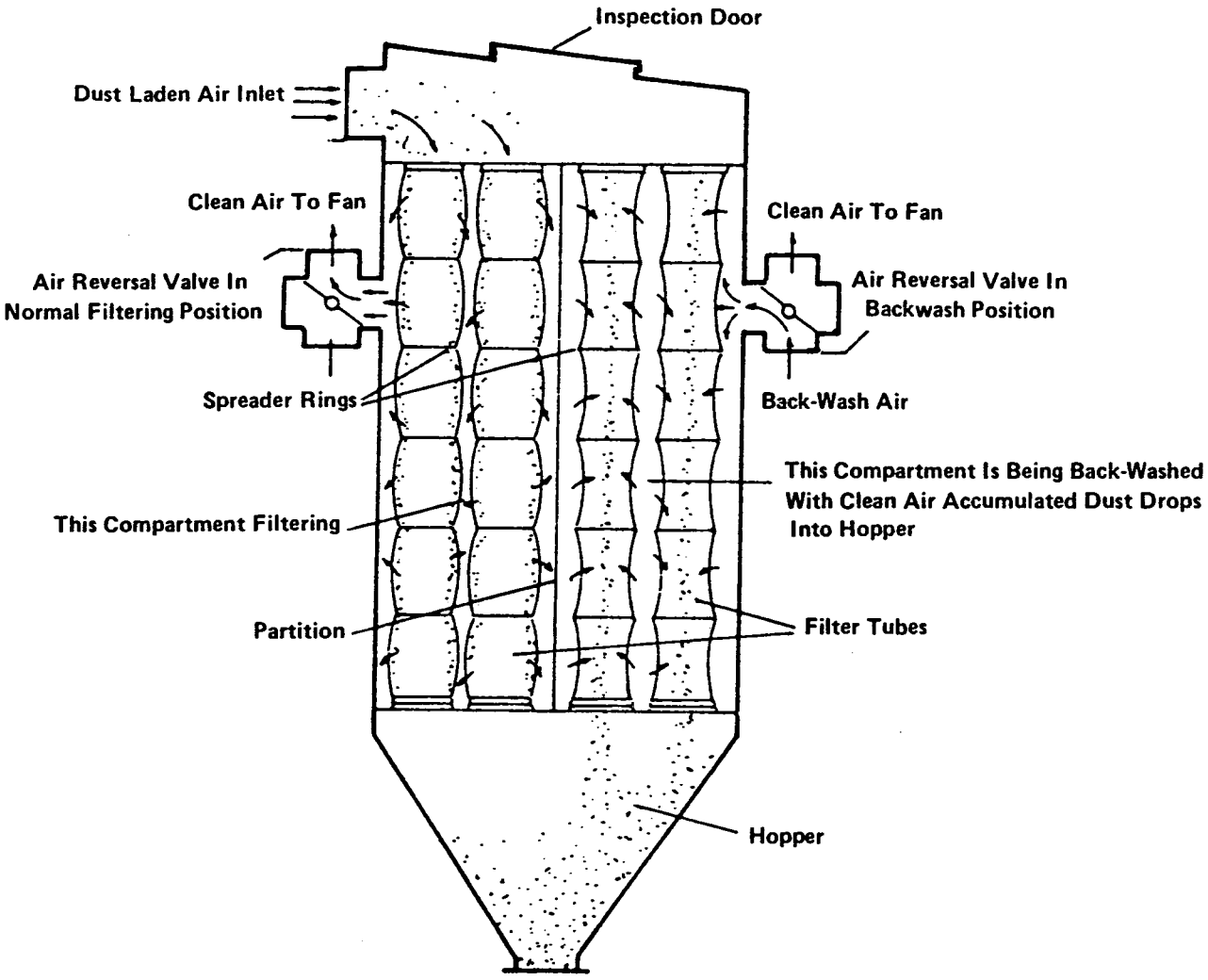


FIGURE 2-100. REVERSE FLOW BAGHOUSE

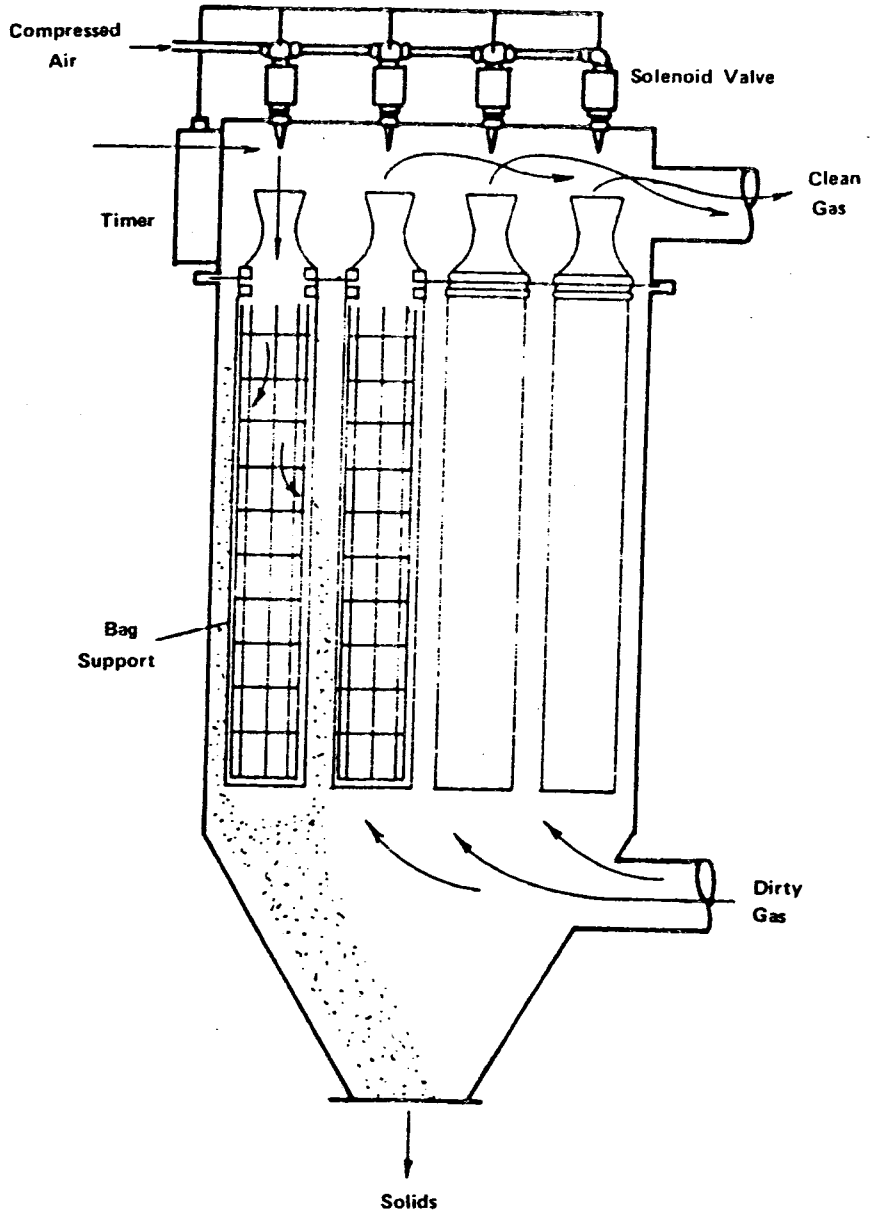


FIGURE 2-101. PULSE JET BAGHOUSE

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, in order to withstand the severe cleaning cycles.

d. Energy Requirements. The primary energy requirement of a baghouse is the fan horsepower necessary to move the 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. e. Application of Fabric Filters. Properly designed fabric filters may be applied to most coal-fired Army 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 under OPERATION (Chapter 3). 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 which must burn both coal and oil.

2-34. ELECTROSTATIC PRECIPITATORS.

An electrostatic precipitator (ESP) is a device which removes particles from a gas stream by means of an electric field. 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 the dust particles from the collection plates to dust hoppers located below the precipitator. The entire prcipitator is enclosed in a metal housing which has a flue gas inlet and outlet and is connected into the boiler flues between the boiler and the 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. The most common applications for Army boilers are discussed below.

a. Electrode Design. Most electrostatic precipitators applied to Army boilers are of the parallel plate design with horizontal gas flow. The plats 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 desilgned in two basic configurations.

(1) **Weighted Wire.** Reference figure 2-102. In the weighted wire design, both the plates and the wires are suspended from the top and allowed to hang vertically by gravity. Weights are attached to the wire to maintain the 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 proved and relatively inexpensive. It is a common type of installation for Army boilers, particularly older units.

(2) **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.

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

(1) **Hot Precipitators.** Hot precipitators are generally applied to units designed for low sulfur coal because the characteristics of the 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 the 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 the higher temperatures. Finally, radiation losses from the precipitator housing increase at the higher temperatures, necessitating either more insulation or a reduction in boiler operating efficiency.

(2) **Cold Precipitators.** Cold precipitators are designed to operate at temperatures between 300° F to 350° 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 may be subject to corrosion due to condensation of sulfuric jacid at lower temperatures.

c. Cleaning and Dust Removal. Dust is removed from the electrodes by means of 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 the collected dust to slide down the electrode, eventually reaching the dust collection hopper at the bottom of the unit. Once collected in the hoppers, the dust is removed by the fly ash removal system.

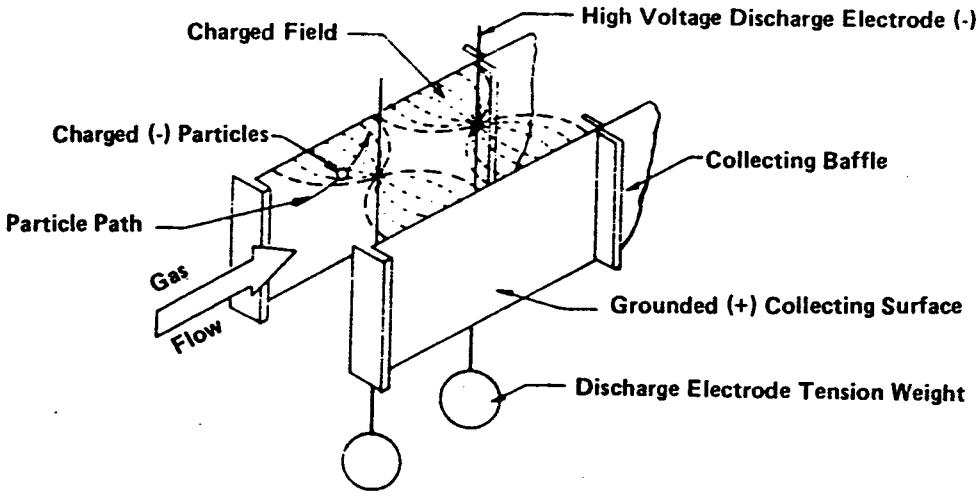


FIGURE 2-102. WEIGHTED WIRE TYPE ELECTROSTATIC PRECIPITATOR

d. Energy Requirements. The main uses of energy in an electrostatic precipitator are the fan horsepower to move the 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.

e. 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 which 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.

2-35. WET SCRUBBERS.

A wet scrubber is a device designed to use a liquid to separate particulate contaminants from a flue gas stream. Although they are rarely used on Army boilers, they have some potential application and advantages over other types of particulate control devices and are thus discussed briefly in this manual. More details can be found in Army Manual TM 5-815. Most wet scrubber applications to Army boilers would be of the wet approach venturi type (figure 2-103). 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 the centrifugal and inertial forces. The incoming gas steam accelerates and atomizes the liquid droplets. These atomized droplets then wash the dust out of the gas steam in the same manner that a severe rainstorm can wash dust out of the atmosphere. Pressure drop through a wet scrubber increses with decreasing particle size and increasing collection efficiency. For a venturi scruber applied to a coal-fired boiler, pressure dropo typically ranges from 20 to 25 in-H_2O. This creates a significant penalty in fan horsepower requirements and is one of the primary reasons that wet scrubbers are seldom applied to Army boilers. Other types of scrubbers can lower this horsepower requirement, but their collection efficiencies are also lowr. The other major disadvantage of the wet scrubber is its water usage. The cost of pretreating the water and the cost and complexity of treating the wste 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.

SECTION VI. AUXILIARY EQUIPMENT

2-36. 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. Deaerators, deaerating heaters, surge tanks, and condensate return tanks are discussed in chapter 4. Figure 2-104 illustrates a closed tube and shell heat exhanged used for feedwater heating.

2-37. 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.

a. Installation. The 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 the distance of the pump above sea level as noted in table 2-7. The following rules should be observed when installing a suction line to a pump. Disregarding any of the following rules may ead to unsatisfactory operation or complete failure:

(1) The line must be tight. A leak in the discharge line may be annoying, but a leak in the suction line may

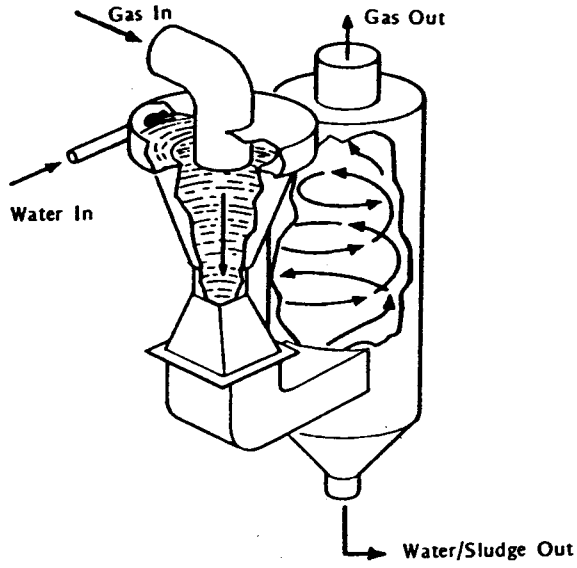


FIGURE 2-103. WET APPROACH VENTURI SCRUBBER

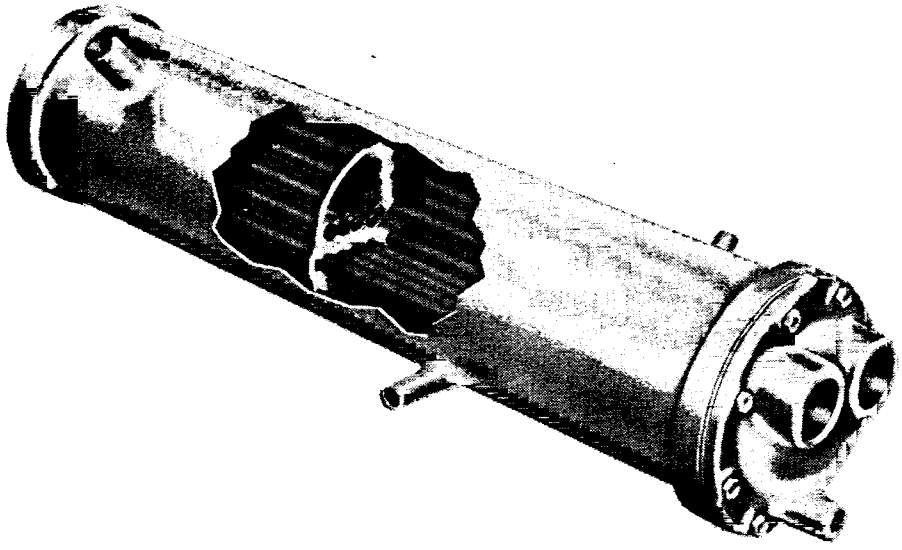


FIGURE 2-104. TUBE AND SHELL HEAT EXCHANGER

lead to inoperation of the pump.

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

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

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

(5) 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. (Reference figure 2-105A). (6) Do not use fittings which permit the formation of air pockets. (reference figure 2-105B). 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.

(7) 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.

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

TABLE 2-7.
PERMISSIBLE MAXIMUM SUCTION LIFTS AND MINIMUM SUCTION HEADS IN FEET FOR VARIOUS TEMPERATURS AND ALTITUDES

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

b. Centrifugal Pumps. Centrifugal pumps use a rotating impeller to give velocity and pressure to the fluid. This type of pupmp is widely used in boiler feed and condensate pumping applications. Figure 2-106 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 all have basically the same components and operate similarly. They are compact, of simple construction, discharge at a uniform rate of flow and prssure, 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.

(1) **Construction.** The pump shown in figure 2-106 consists of the rotating element called an impeller, the casing, the shaft, and the parts used for sealing the pump against leakage.

(a) The impeller consists of two disks separated by a number of vanes which form passages for the 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.

(b) 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 alighment. THe casing guides the water from the inlet connection to th 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.

(c) The shaft supports and drives the impeller and is, in turn, supported by the bearings. Babbit-type bearings are used in the pump shown in figure 2-106, though many pumps use ball bearings.

(d) The impeller is held firmly by shaft sleexes which also help to seal against leakage of air 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 sealilng 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 show, or from an outside source. The casing has renewable rings to reduce leakage from the discharge to the inlet side of the impeller. Renewable wear rings are occasionally installed on the impeller.

(2) **Operation**

(a) When the pump is operating, the impeller rotates at high speed, drwing water into its center, near the shaft. The resultant centrifugal force imparts energy to the water,

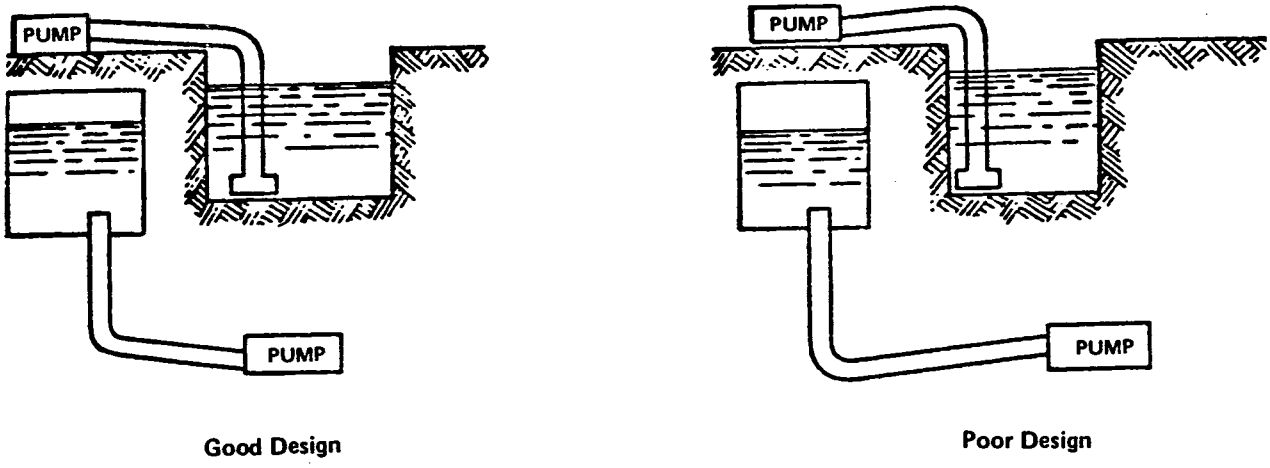


FIGURE 2-105A. MAINTAIN PROPER SLOPE TO SUCTION LINE

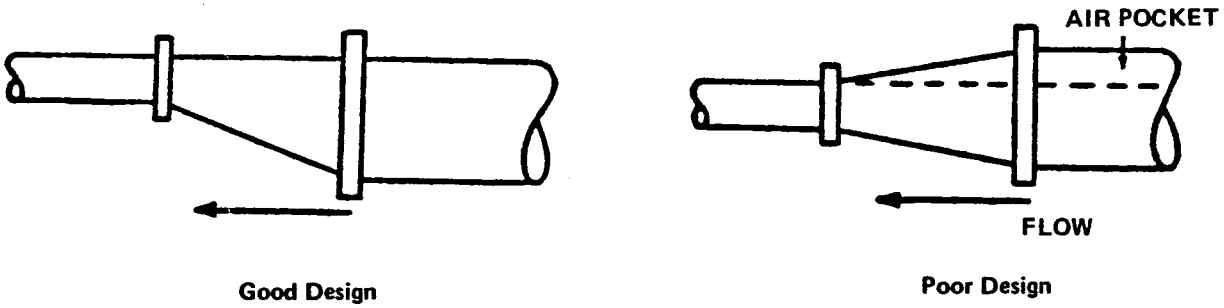


FIGURE 2-105B. SUCTION LINE INSTALLATION

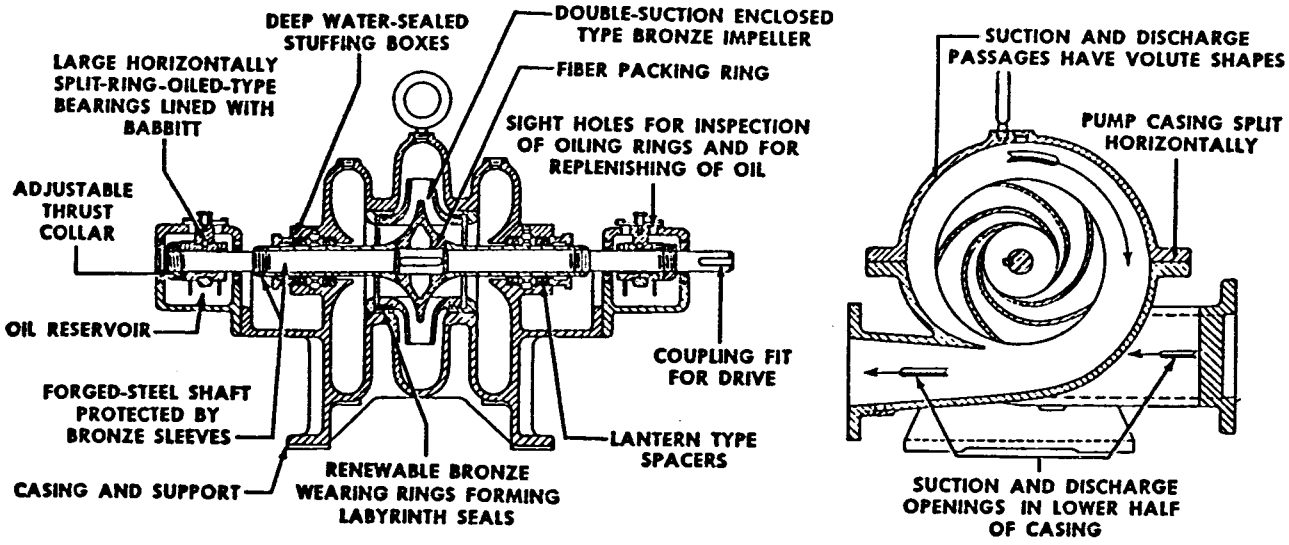


FIGURE 2-106. CENTRIFUGAL PUMP

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 the water passes through only one impeller. Multistage pumps are used when it is necessary to operate against higher heads. In a multistage pump the water travels through successive impellers or stages until it has reached the desired head.

(b) 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 the water through the pump. Throttling the discharge increases the prssure at the pump outlet, causing some of the fluid to slop 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 ıe pump is inoperative. Centrifugal pumps are designed ιo 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.

c. 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.

(1) A horizontal duplex piston pump is shown in figure 2-107. 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. The 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. The steam which is trapped in the cylinder when the exhaust stroke nears completion provides a cushion to prevent the piston from striking the sylinder 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 cyclinder. Maximum cushioning is desired with the pump operating at high speeds, and is obtained by closing the hand valve.

(2) The valves of a duplex pump do not overlap the edges of the ports with the valve in its midposition. The valves are held to their seats by the pressure differential acting on the two sides of the valve. Figure 2-108 shows the relative position of the working parts when pump and valve are in midposition. The illustrations indicate that the 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.

d. Rotary Positive Displacement Pumps. Rotary positive displacement pumps use gears, screws, or sliding vanes to more a volume of fluid through the pump. Rotary positive displacement pumps are most commonly used in Army 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%, 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 overpressurization. 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.

e. 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 F. 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.

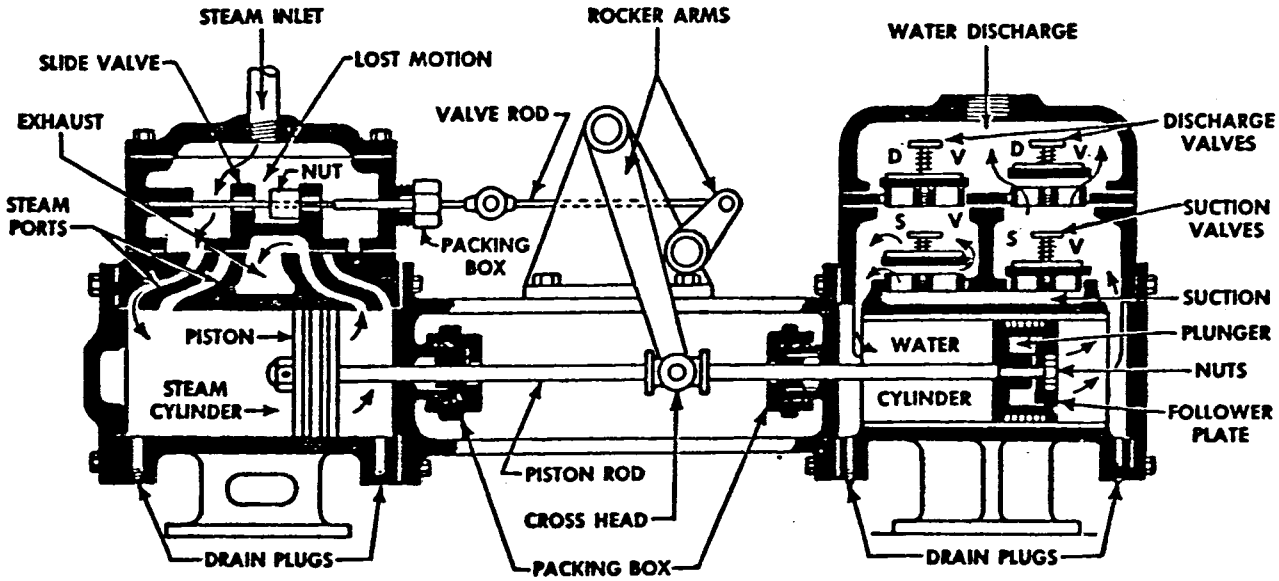


FIGURE 2-107. RECIPROCATING PISTON PUMP

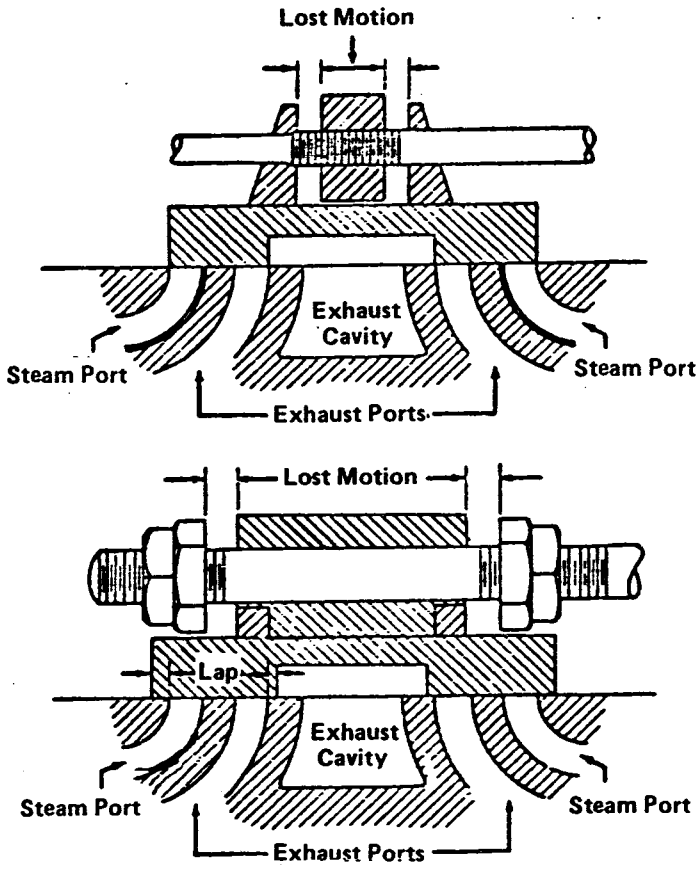


FIGURE 2-108. TWO METHODS OF PROVIDING LOST MOTION

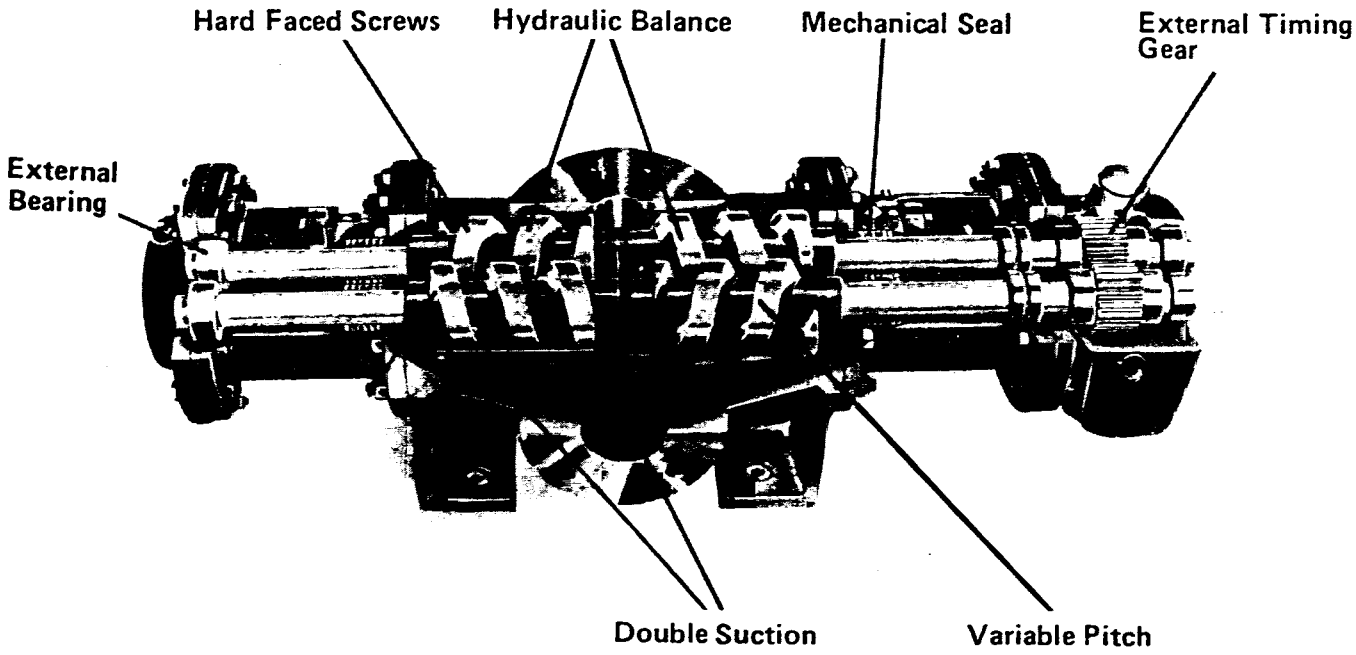


FIGURE 2-109A. ROTARY SCREW PUMP

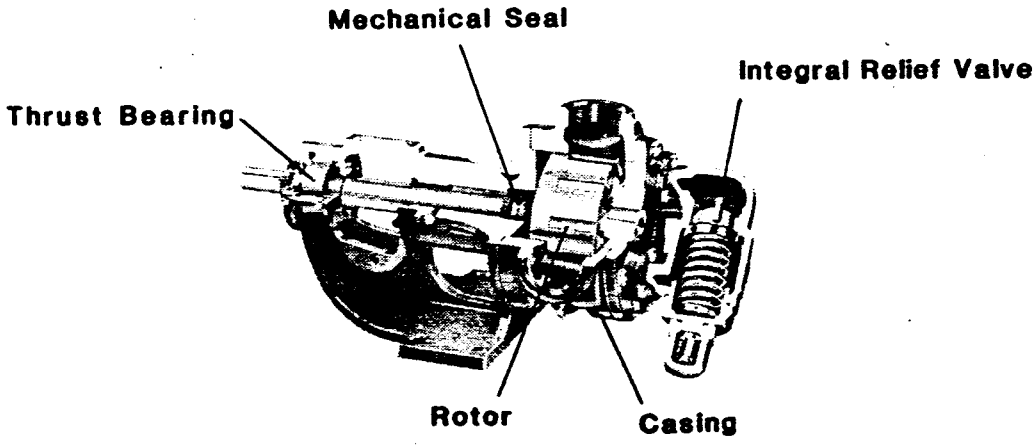


FIGURE 2-109B. ROTARY GEAR PUMP

The essential parts of an injector are the steam tube, combining and delivery tubes, and the necessary casing to guide the water to and from these tubes. Reference figure 2-110. 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 the steam at the entrance of the combining tube. The steam is condensed and imparts considerable velocity to the 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 doule-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 the low temperature 'imitations, injectors are rarely used on modern installations. ſnjector failures are rarely used on modern installations. Injector failures are most often caused by excessive suction lift, hot water, clogged strainer or suctin line, and fluctuating pressurs.

f. Boiler Feed Pumps. The boiler feed pump is probably the single most important auxiliary in the boiler plant. It must be operated continuously while the boiler is in operation, and at a rate of discharge equal to the rating of the boiler. The 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.

(1) **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 approximarely one-half the mzximum 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% of the steam produced by the boiler, but since the exhause is utilized to heat the feedwater, the net heat consumed by the pump can be less than 1%.

(2) **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.

g. Condensate Pumps. 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 tip of the tank and the pump is at the bottom. In another arrangement, the pump and motor are mounted outside and below the re turn tank.

h. Vacuum Pumps. Reciprocating, jet, and positive-displacement rotary-type 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 poump 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 impelller handles the water and the other the air. The condensate flows into the receiver and enters the pump. An automatic control actuated by the water level and the pressure in the receiver (which is below atmospheric) starts and stops the pump as required. This arrangement can maintain a vacuum of l0 to l8 ilnches of mercury in a system which is reasonably free from leaks.

2-38. FORCED DRAFT FANS.

Forced draft (FD) fans are applied to push the combustion air through the burner into the furnace. If an induced draft fan is not supplied, the forced draft fans must also

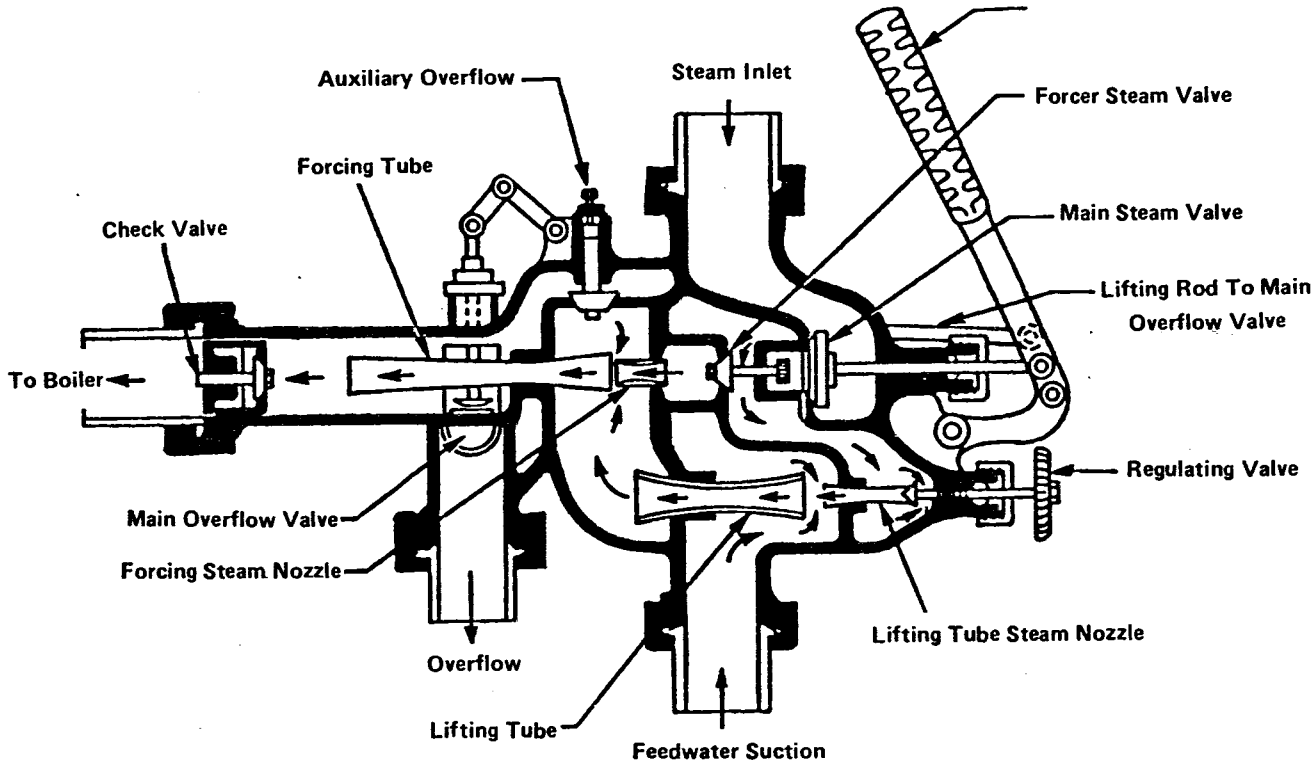


FIGURE 2-110. STEAM INJECTOR

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 forced draft fan service because of their high efficiency, stable operation, and non-overloading horsepower characteristics. Forced draft fans are required to operate over a load range of approximately 25 to 100 percent of capacity. This is accomplished primarily by the use of dampers. Three types of dampers are used: inlet dampers, parallel blade outlet dampers, and opposed blade outlet dampers. Figures 2-111 illustrates a forced draft fan equipped with inlet vane dampers. Figure 2-112 illustrates a typical parallel blade outlet damper. Inlet gvane dampers control air flow 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 2-113. This results in improved control range and horsepower savings over outlet damper applications which control by creating a static pressure on the fan. The increased statis pressure reduces flow and causes the operating point to move back up the fan curce (reference figure 2-114). 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.

2-39. INDUCED DRAFT FANS.

Induced draft (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 the flue gases at the velocities needed for good heat transfer. Induced draft fans are subjected to more severe service conditions than forced draft fans, because they must handle larger volumes of gas at high temperatures and containing ash particles. The physical characteristics of ID fans must therefore be different from those of forced draft fans. Airfoil blades are not recommended for ID fan service. Backward inclined fans are acceptable for non-abrasive 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 induced draft fan capacity.

2-40. 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 the 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.

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

(1) **Steel.** The advantages of steel stacks over masonry or reinforced concrete are reduced construction time, lowr 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 the flue gases and to improve the performance of the stack by minimizing cooling of flue gases. The self-supporting stack is usually mounted on its own foundation oor on the building structure framework. Stub and venturi stacks are typically of steel construction and usually extend no more than about 20 feet above the boiler. When these stacks are used they contribute little to the draft requirements, which must be then supplied entirely by forced-and/or induced-draft fans.

(2) **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.

b. 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 combustin air plenums. Flues and ducts are usually made of steel. Expansion joints are provided to

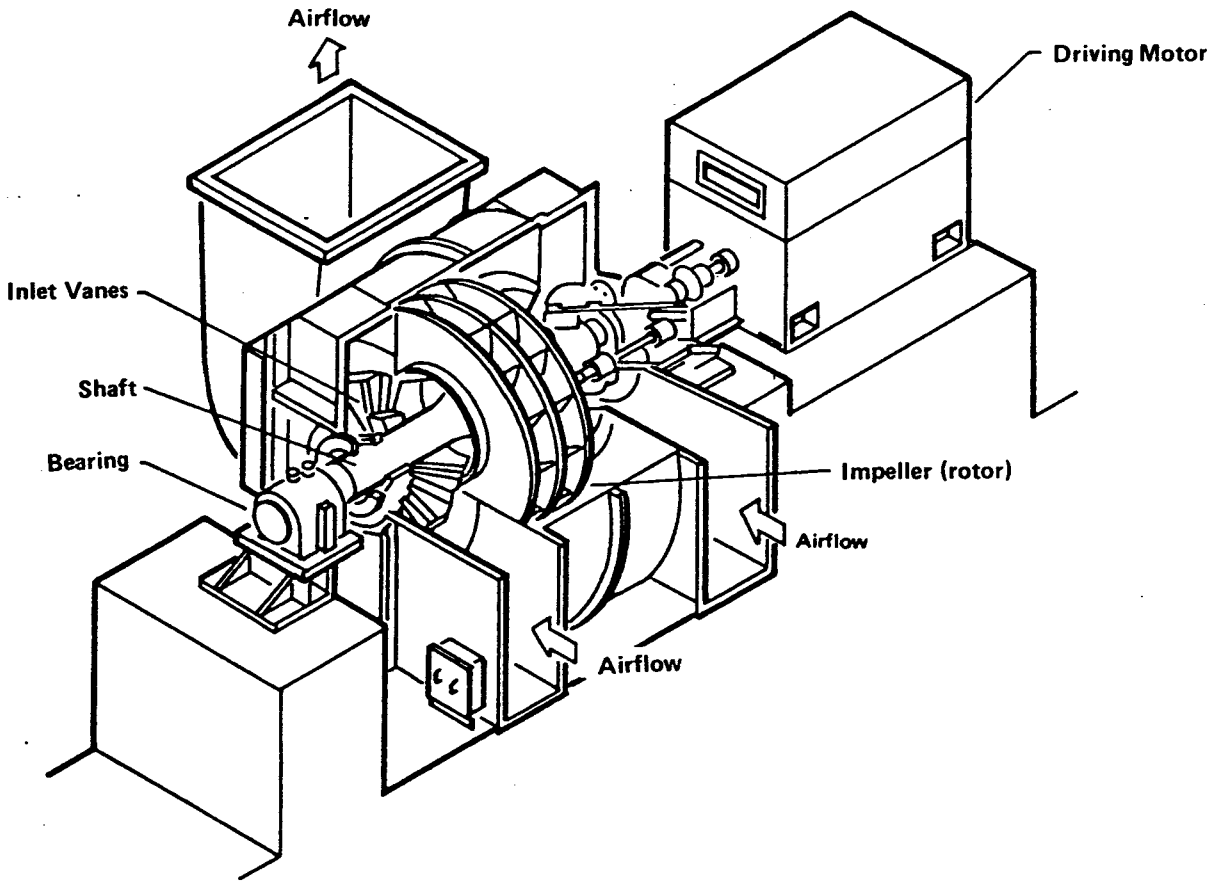


FIGURE 2-111. FORCED DRAFT FAN WITH INLET DAMPER

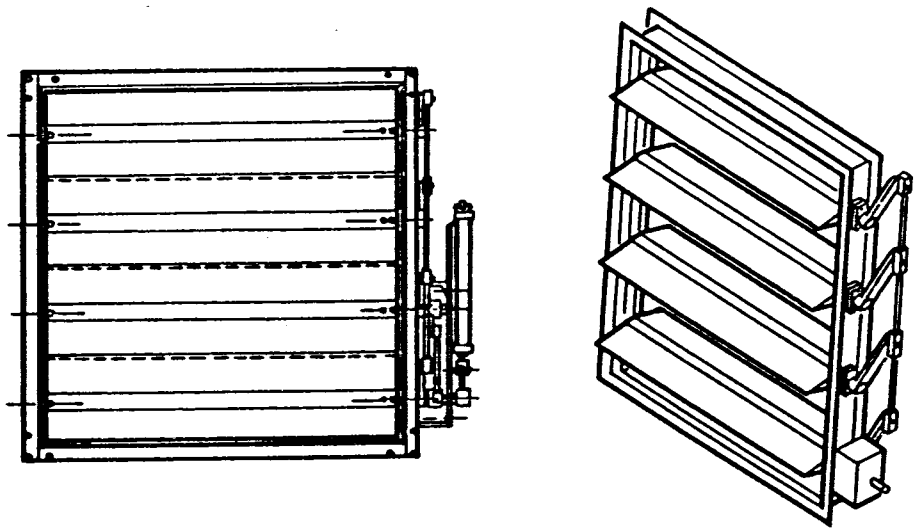


FIGURE 2-112. TYPICAL OUTLET FAN DAMPERS

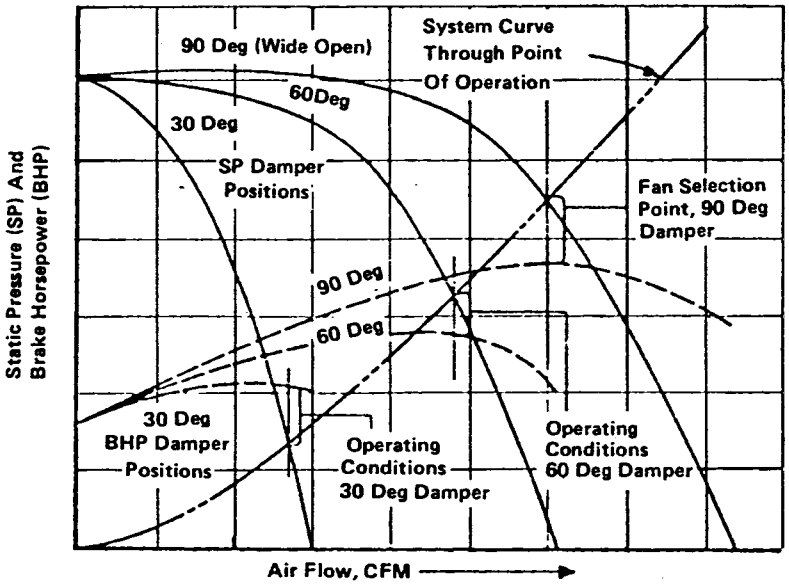


FIGURE 2-113. FAN CURVES FOR DIFFERENT INLET VANE POSITIONS

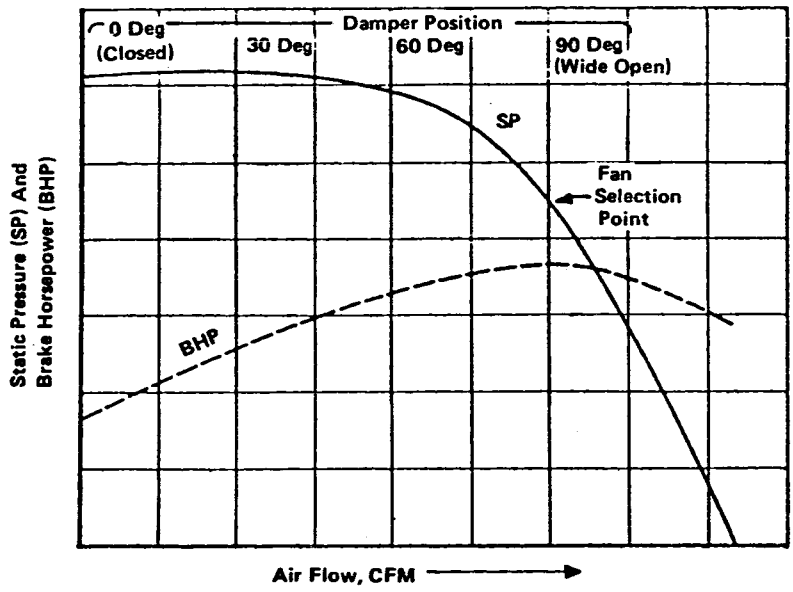


FIGURE 2-114. FAN CURVE FOR FAN WITH OUTLET DAMPER

allow for expansion and contraction. All 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.

2-41. STEAM TURBINES.

The reciprocating steam engine with its need for oil lubrication and the resulting contaminated steam has been replaced by steam turbines and electric motors. Steam turbine driven boiler plant auxiliaries are generally economical only if the exhaust steam can be used for feedwater or other heating applications. The steam turbine uses a rotating wheel, with buckets or blades uniformly spaed 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 non-condensing turbine opoerates at an efficiency of only 20 percent. Only special circumstances, such as the necessity for oil-free exhaust steam, can justify the use of a small turbine for any purposes other than standby or emergency. Figure 2-115 shows a single-stage impulse non-condensing steam turbine.

2-42. ELECTRIC MOTORS.

Electric motors can be grouped into three general classes based on power source. These classes are direct current, single-phase alternative 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% of all electric motor energy is consumed by three-phase squirrel 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.

2-43. ELECTRICAL EQUIPMENT.

Electrical equipment used in central plans includes motors, motor starters, controls, circuit breakers, switchgear, transformers, fire protection, lighting, conduit, and wiring. Opoeration of these devices involves the use of voltages which are dangerous to life. Operating personnel must observe safety regulations found in Army Manual TM 5-682. Additional information on electrical equipment can be found in Army Manuals TM 5-680G, TM 5-683, TM 5-684, and TM 5-687.

2-44. 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. The development of solid state components has allowed the design of variable frequency controls which can opoerate 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.

2-45. 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 Army installations are comparatively small units, with final discharge pressures of approximate' 100 psi. They are typically of rotary screw or single- o. two-stage reciprocating design. These two types are discussed below. TM 5-810-4 may be referenced for additional information on compressed air systems.

a. Compressor Types

(1) **Reciprocating.** The reciprocating compressor is a poston-type, 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 bafflilng structures for noise attenuation requires investigation when reciprocating compressors are to be used.

(2) **Rotary Screw.** 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 anothert. Air volumes can range as high as 3,000 CFM but are more typically in the 100 to 150 CFM. Packaged units are readily available in sizes up to 500 CFM which incorporate all the 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-fre air. This type of compressor is recommended in food processing or health care facilities but is not often used

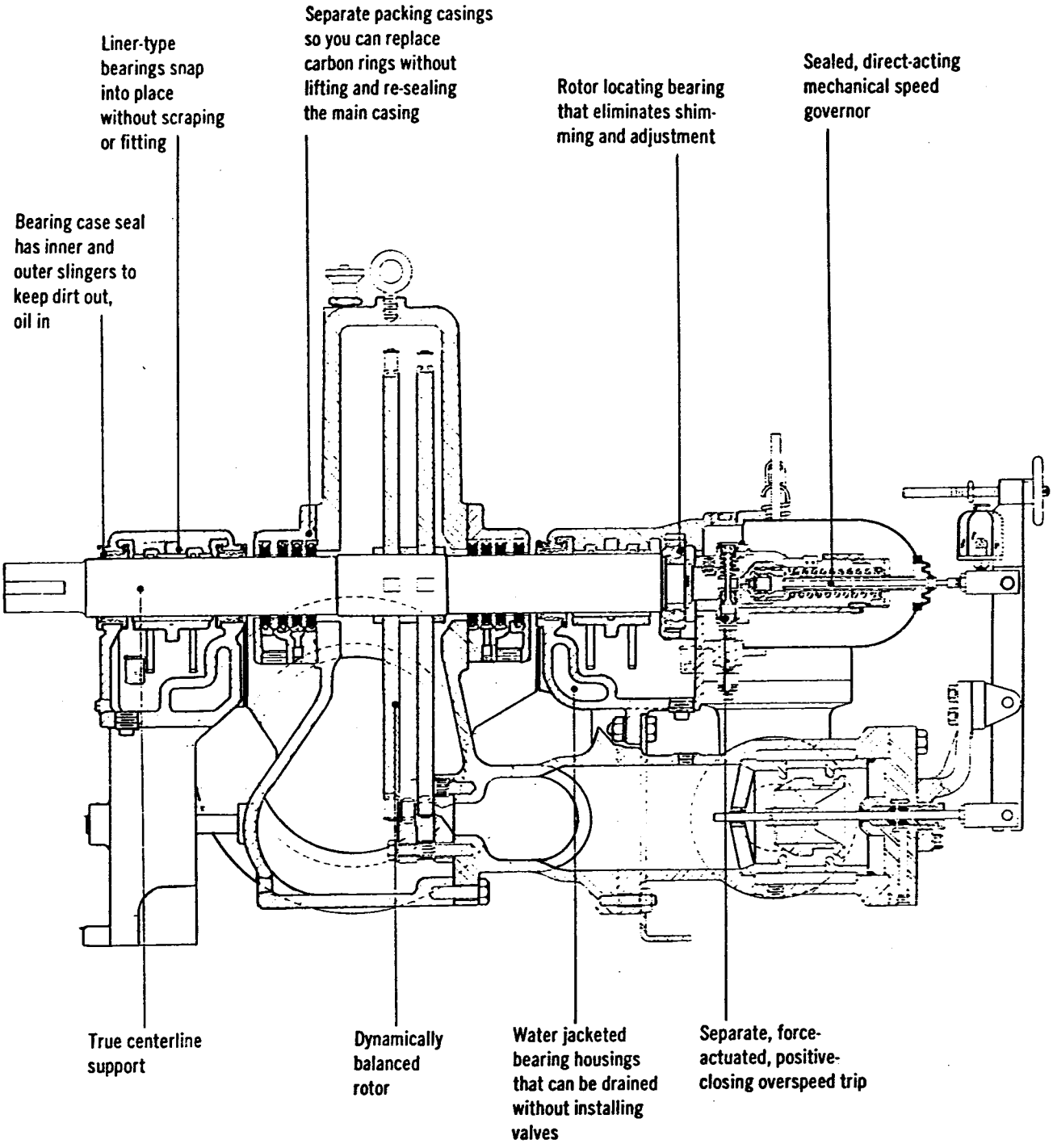


FIGURE 2-115. SINGLE-STAGE IMPULSE NON-CONDENSING TURBINE

in boiler plants. It is more common to provide oil-free air to boiler plants by means of filters nd separators in combination with one of the compressor types discussed above.

b. 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 TM 5-810-4.

c. Aftercoolers. In the process of compressing air, approximately 80 percent of the energy delivered by the electric motor becomes heat energy stored in the compressed air at elevated temperature. 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 the condensed vapors. The aftercooler is normally cooled with water, but it may also use air as its heat exchanger medium. d. 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, opoeration 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 TM 5-810-4. Regenerative dryers are further broken down into three types: heatless desiccant, heat regenerative, and low temperature regenerative.

(1) **Heatless Desiccant Dryers.** Heatless desiccant regeneration passes a quantity of dried (purge) ari 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 minus 150 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.

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

(3) **Low-Temperature Regenerative.** 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 minus 100 F are realized with this type.

e. 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. Recommendations for receiver size and mounting are contained in TM 5-810-4. Drainage valves and piping, safety valves, and prssure gages must be installed in accordance with the Code.

2-46. STEAM TRAPS.

Steam traps are used to discharge condensate and air but not steam from a pipeline or heat exchanger. No single type of trap is ideal for every situation. The four major types of steam traps are thermostatic, float and thermostatic, disc/theremodynamic, and interted bucket. These are discussed below. Orifice or impulse traps are also produced but operate by discharging steam continuously and are therefore nor 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 paragraph 5-40.

a. 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 opoerate a valve head. They usually discharge condensate below steam temperature and therefore require a collecting leg before the trap to allow for some condensate collilng. A balanced pressure thermostatic trap is illustrated in figure 2-116. Thermostatic traps are typically used in low and medium pressure applications such as steam radiators, submerged heating coils, and steam tracing lines.

b. Float and Thermostatic Steam Traps. Float and thermostatic traps (figure 2-117) are recommended for use

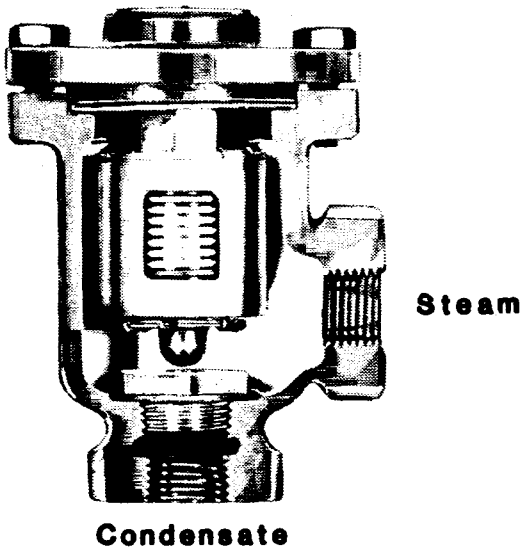


FIGURE 2-116. THERMOSTATIC STEAM TRAP

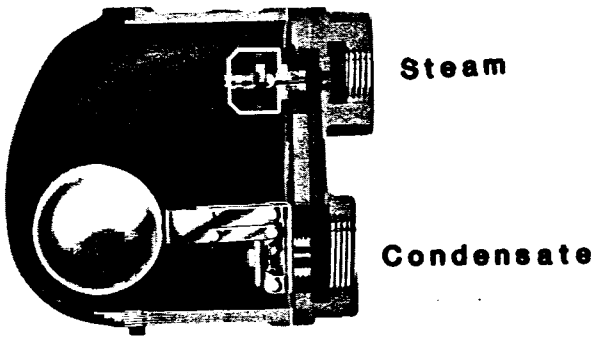


FIGURE 2-117. FLOAT AND THERMOSTATIC STEAM TRAP

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 startup, 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.

c. Disc/Thermodynamic Steam Traps. Disc/thermodynamic traps (figure 2-118) 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 vary widely. Many are prone to air-binding on startup, operate below steam temperature (causing waterlogging), 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.

d. Inverted Bucket Steam Traps. Inverted bucket traps figure 2-119) 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 appliocations include high pressure indoor steam main drips and submerged heating coils.

2-47. 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 which are involved in piping and tubing systems. The word piping in this manual 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 subparagraph c.

a. 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 paragraph 2-9 as it appplies 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 Power Piping Code, ANSI B31.1. Some additional design codes and their applicability are given in table 2-8. These design codes generally specify the materials that may be used within their scope, how the piping sizes and thicknesses must be determined, how the pipe must be supported, what types of fittings, joints, and accessories may be used, and other provisions. Although these codes are w ritten primarily for the pipine designer or engineer, a general knowledge of their provisions is useful to the operator as well.

b. Materials. Piping materials are generally specified by the design code under which the system is built. The most common piping material lin 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 the various materials are included in table 2-9.

c. 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 and wall thickness.

(1) **Pipe Size.** Nominal pipe size or NPS refers to the diameter of the pipe. Nominal pipe sizes range from ⅛ inch up to at least 30 inches, in standard increments. The outside diameter for a given NPS is always the same, while the inside dismeter 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). The dimensions and tolerances corresponding to the 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 inch, and an inside diameter of 0.957 inch.

(2) **Tubing Size.** Tubing size is specified by Outside Diameter (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 ⅛ inch 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 allow steel.

(3) **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

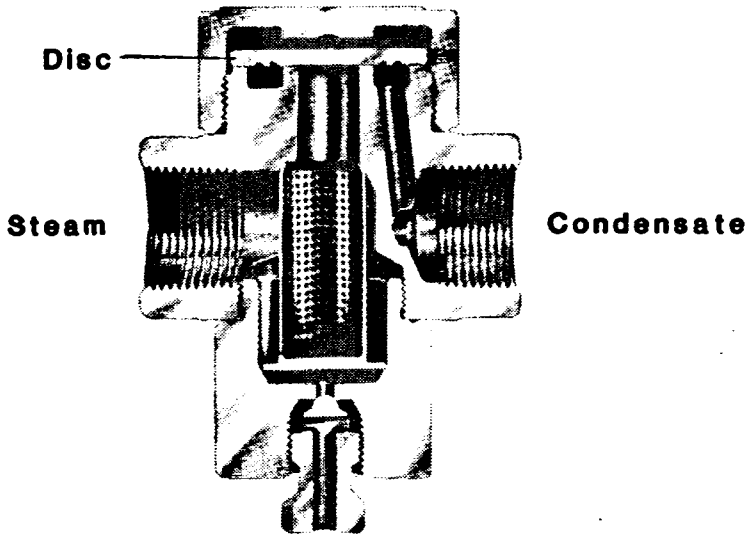


FIGURE 2-118. DISC/THERMODYNAMIC STEAM TRAP

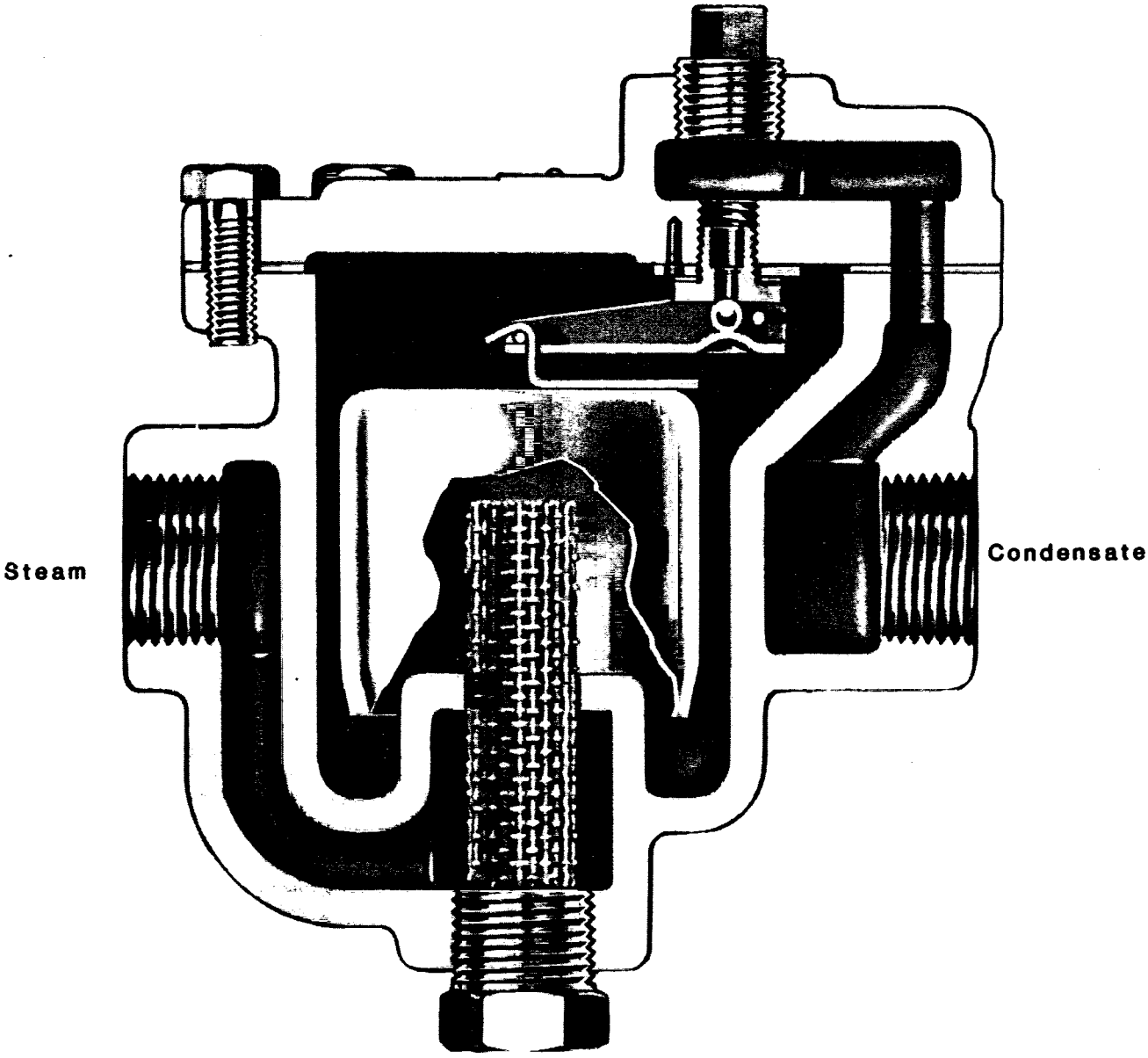


FIGURE 2-119. INVERTED BUCKET STEAM TRAP

Table 2-8. Piping Codes and Standards For Boiler Plants

Sponsoring Agency	Identification	Title	Coverage
ASME	Boiler and Pressure Vessel Code - Section I	Power Boilers	All piping connected to boiler up to first (in some cases second) shut-off valves
	Boiler and Pressure Vessel Code - Section IX	Welding Qualifications	Qualifications for welders on power piping systems
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	13, 15, et al.	Sprinkler Systems and Automatic Spray Systems	Piping for fire protection systems
AWS	D10.9	Qualifications of Welding Procedures and Welders for Piping and Tubing	Qualifications for welding of fire protection systems

Table 2-9. Typical Piping Material Applications

Material	Typical Applications	Typical Joints[1]
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 750F	Screwed, socket- or butt-welded, flanged
Low Alloy Steel	Superheated steam, up to 1000F	Welded
Stainless Steel	Chemical and corrosive applications[2], steam above 1000F, 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 (PVS, ABS)	Sanitary drains, non-potable water; miscellaneous low pressure applications	Solvent welded

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

temperature conditions, allowable velocities, and pressure loss. These calculations can become quite sophisticated and are outside the scopoe of this manual. The pertinent design codes should be consulted for guidance.

d. Fittings and Joints. Pipe ;and tubing may be joined in a variety of ways, including threading, welding, flanges, a variety of mechanical coupling-type joints, soldering (for copper and brass), and solvent welding (for plastics). All of 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 the 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 the pressure and temperature requirements of the piping system.

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

(1) **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.

(2) **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.

(3) **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 2-120. Custom-designed supports using structural steel shapes and standard hardware are also common.

f. 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, paragraph 2-10; Safety Valves, paragraph 2-13; Boiler Outlet Valves, paragraph 2-14; Blowoff Valves, paragraph 2-15; Control Valves, paragraph 2-25). 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.

(1) **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.

(2) **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 dropo 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 2-121.

(3) **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 dropo 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 2-122.

(4) **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 oompression 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 bubbletight sealing, thus making it ideal for gaseous service. In addition, because of its large unobstructed flow passage, the plug valve is ideally suited for sluffy service. A typical plug valve is illustrated in figure 2-123.

(5) **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

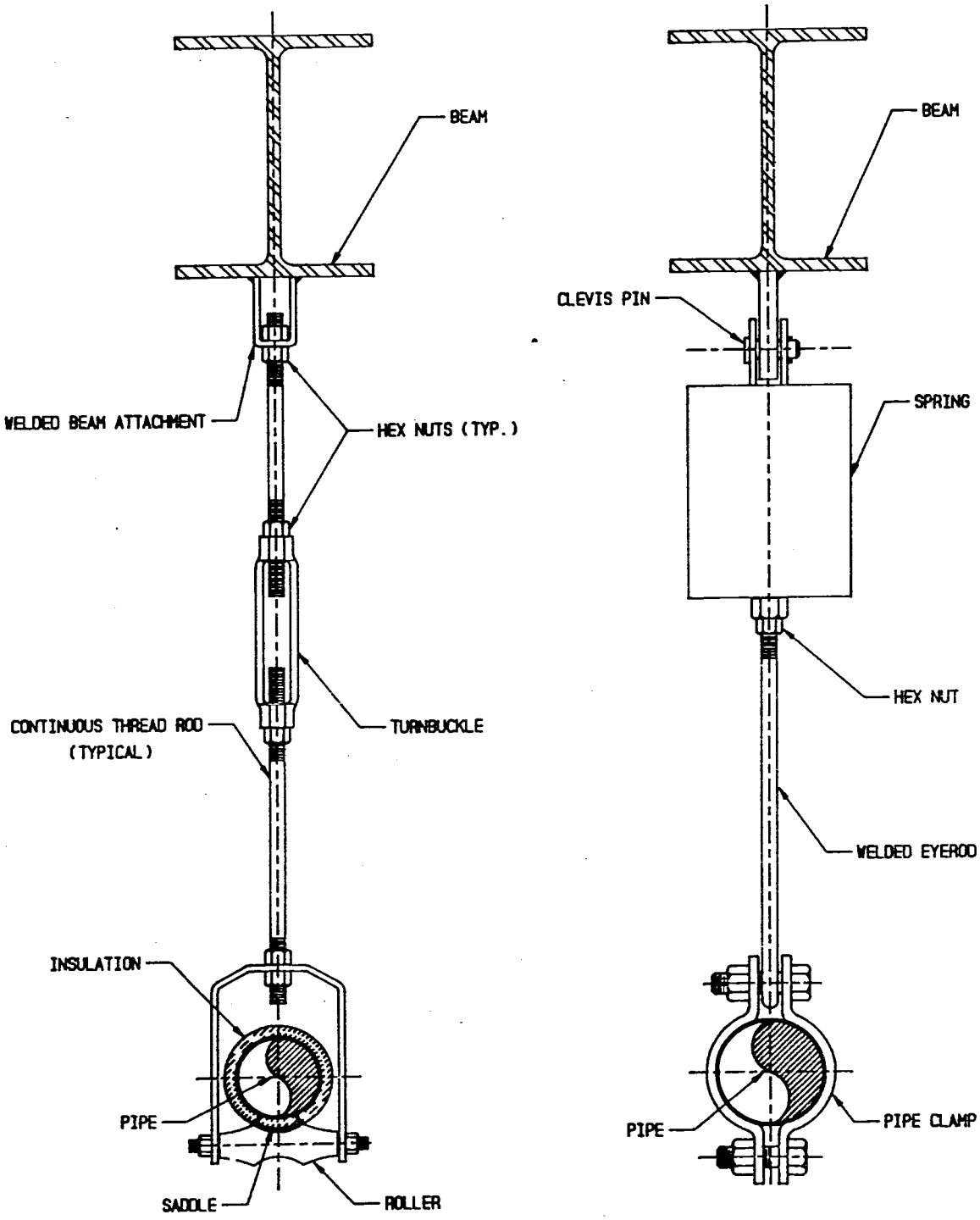


FIGURE 2-120. STANDARD HANGER TYPES FOR PIPING SYSTEMS

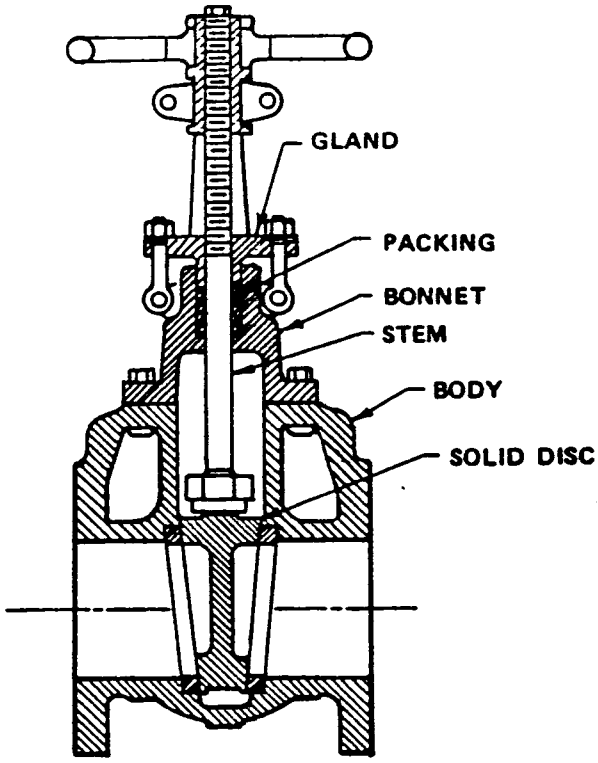


FIGURE 2-121. SOLID WEDGE DISC GATE VALVE

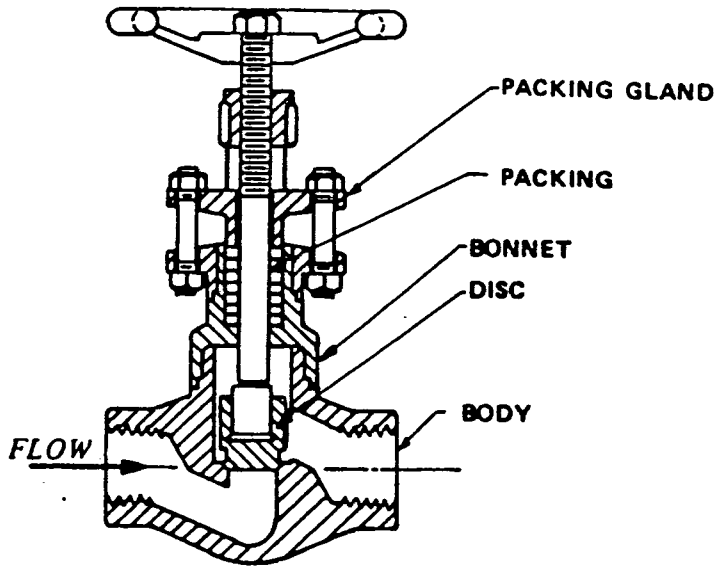


FIGURE 2-122. SINGLE PORT GLOBE VALVE

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 2-124 illustrates a typical butterfly valve.

(6) **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 backflow. The disc weight, seat configuration, and internal spring assistance (if provided) all contribute to the ease with which the disc opens or closes and to a leaktight 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 2-125. g. Insulation. Insulation is used to reduce dheat 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 the insulation to protect the insulation material. Common jacket materials include aluminum, fiberglass cloth, and various other fabrics.

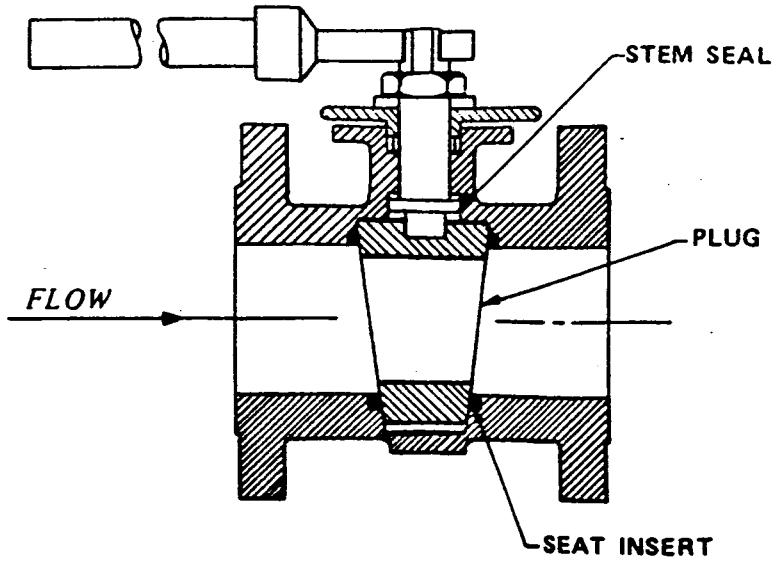


FIGURE 2-123. NON-LUBRICATED PLUG VALVE

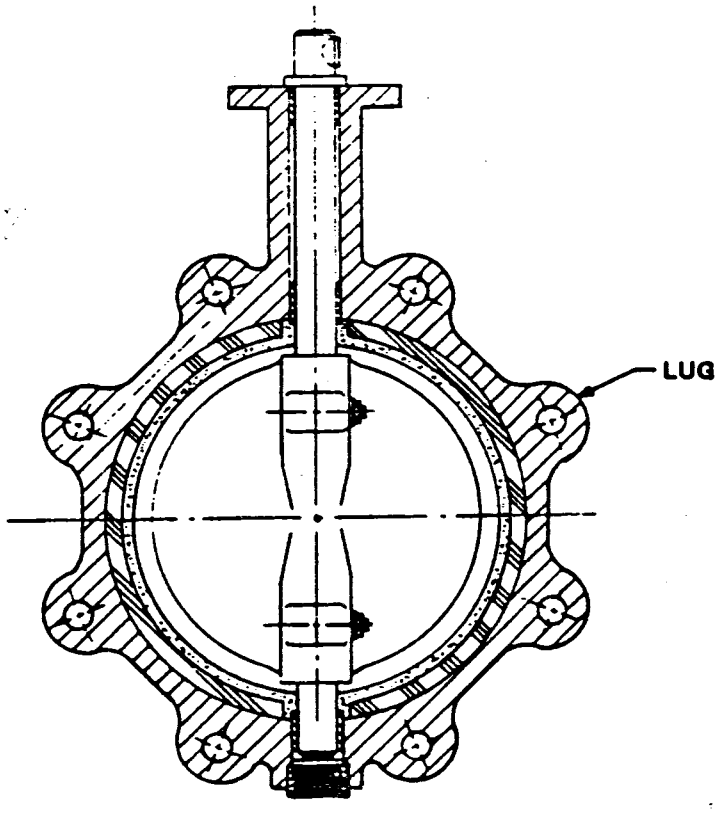


FIGURE 2-124. BUTTERFLY VALVE

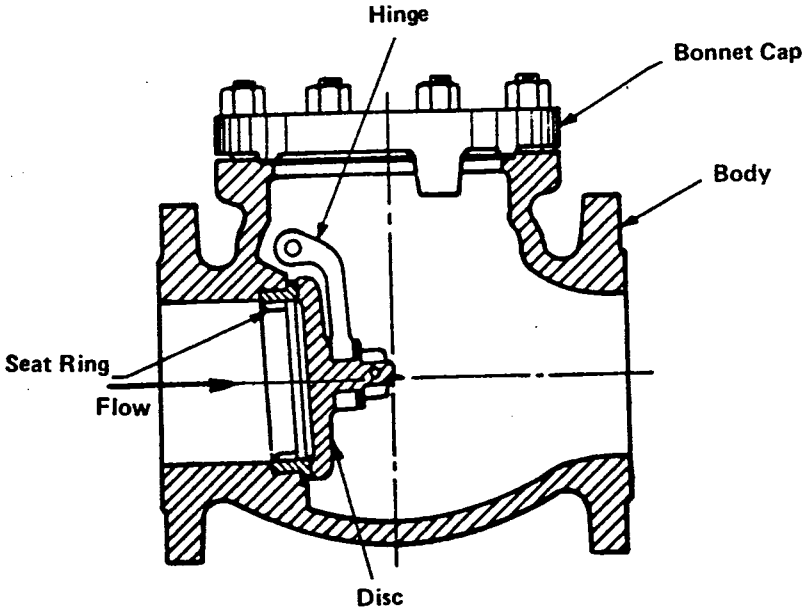


FIGURE 2-125A. SWING CHECK VALVE

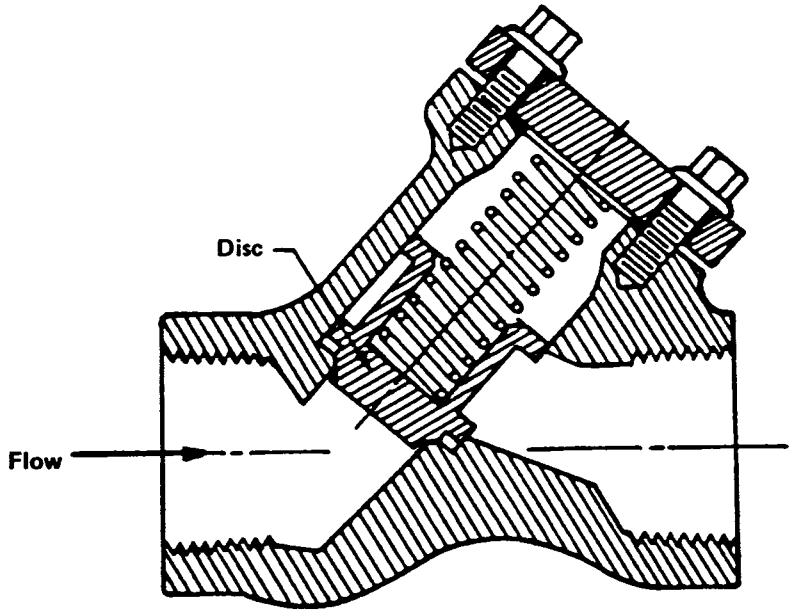


FIGURE 2-125B. Y TYPE SPRING LIFT CHECK VALVE

CHAPTER 3
OPERATION

SECTION I. PRELIMINARY OPRATING PROCEDURES

3-1. PLANT OPERATION CONSIDERATIONS

Plant operation is considered to be satisfactory if the needed energy is produced safely with minimum operating expenses. Operating expenses include manpower, fuel, utilities, supplies, and maintenance of the plant and equipment. Proper daily operation requires inspection and preventive maintenance, discussed in chapter 5. Maximizing efficiency of operation requires an understanding of the basic principles of combustion, steam or hot water generation, and equipment operation. Good operation makes the best use of facilities provided, while avoiding practices which waste fuel, steam, utilities, supplies, or manpower.

3-2. STANDING OPERATING PROCEDURES

Standing operating procedures (SOP) 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 or 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.

3-3. DAILY AND MONTHLY BOILER PLANT OPERATING LOGS

The Daily Boiler Plant Operating Log, DA Form 3995 (figure 3-1), provides a means of recording continuous data on boiler plant performance. The data on this form can be used to analyze plant operation. It is arranged for use over a 24-hour period consisting of three 8-hour shifts. Entries are made in columns, with the explanation of each column provided on the back of the form. A monthly operating log must also be kept at each boiler plant in addition to the daily log. DA Form 3967, shown in figure 3-2, is the standard form for reporting monthly boiler plant operations. Data contained on the Daily Log is compiled at the end of each month and reported on the Monthly Log.

3-4. 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. All boilers must be inspected as required by AR 420-49. Details are included in chapter 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.

3-5. APPLICABLE CODES

The following codes provide rules and practical guidance for the safe and effective opration of boilers and boiler accessories:

- ASME Boiler and Pressure Vessel Code Section VI, "Recommended Rules for Care and Operation of Heating Boilers."
- ASME Boiler and Pressure Vessel Code Section VII, "Recommended Rules for Care of Power Boilers."
- NFPA National Fire Codes, NFPA 85A, "Standard for Prevention of Furnace Explosions in Fuel Oil- and Natural Gas-Fired Single Burner Boiler-Furnaces."
- NFPA National Fire Codes, NFPA 85B, "Standard for Prevention of Furnace Explosions in Natural Gas-Fired Multiple Burner Boiler-Furnaces."
- NFPA National Fire Codes, NFPA 85D, "Standard for Prevention of Furnace Explosions in Oil-Fired Multiple Burner Boiler-Furnances."
- NFPA National Fire Codes, NFPA 85E, "Standard for Prevention of Furnace Explosions in Pulverized Coal-Fired Multiple Burner Boiler-Furnaces."
- INFPA National Fire Codes, NFPA 85F, "Standard for Installation and Operation of Pulverized Fuel Systems."

3-6. BASIS FOR COMMENTS

Chapter 3 discusses the operation of equipment that has been described in chapter 2. Operational recommendations are made for steam andhot 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

DAILY BOILER PLANT OPERATING LOG

For use of this form, see AR 420-49; the proponent agency is Office of the Chief of Engineers.

BOILER PLANT NUMBER 1520

STATION FT GOOD

DATE APRIL 1, 1988

TIME (Hour)	STEAM PRESSURE	STEAM FLOW PER HOUR CHART	FEEDWATER HEATER PRES.	FEEDWATER HEATER TEMP.	FEED PUMP PRES.	DRAFT I FORCE	DRAFT I FURNACE	DRAFT I GAS PASS	DRAFT II FORCE	DRAFT II FURNACE	DRAFT II GAS PASS	DRAFT III FORCE	DRAFT III FURNACE	DRAFT III GAS PASS	% CO2 FLUE GAS No. 1	% CO2 FLUE GAS No. 2	% CO2 FLUE GAS No. 3	FLUE GAS TEMPERATURES No. 1	FLUE GAS TEMPERATURES No. 2	FLUE GAS TEMPERATURES No. 3	FUEL (Coal lbs. Gas MCF Oil Gals.)	OUTSIDE TEMPERATURE	MAKEUP WATER (Gals.)	WATER PRESSURE	HOT WATER STORAGE TEMPERATURE	WATER SOFTENERS No. 1 METER Evening	No. 1 METER Start	No. 1 METER Total	No. 2 METER Evening	No. 2 METER Start	No. 2 METER Total	TOTAL GALS. THRU ALL METERS	POUNDS OF SALT USED	REMARKS
1st SHIFT	100	22000	4	224	150	3.9	1.2	0.2										480				55		60											
0100	100	23000	4	224	150	3.9	1.2	0.2										480				54		60											
0200	100	23000	4	224	150	4.0	1.2	0.2										480				52		60											
0300	100	22000	4	224	150	3.9	1.2	0.2										470				52		60											
0400	100	22000	4	224	150	3.9	1.2	0.2										470				47		60											
0500	100	25000	4	224	150	4.1	1.3	0.2										460				48		60											
0600	100	28000	4	224	150	4.4	1.4	0.3										500				49		60											
0700	100	29000	4	224	150	4.5	1.4	0.3										520				53		60											
0800	100	30000	4	224	150	4.6	1.4	0.3										520				53		60											
TOTAL			4	224														490				52	1930												
AVERAGE																																			
1st SHIFT	100	30000	4	224	150	4.6	1.4	0.3										520				53		60											
0900	100	30000	4	224	150	4.6	1.4	0.3										520				56		60											
1000	100	26000	4	224	150	4.1	1.2	0.2										510				60		60											
1100	100	25000	4	224	150	4.0	1.2	0.2								4.3		510				63		60											
1200	100	26000	4	224	150	4.0	1.2	0.2										510				66		60											
1300	100	25000	4	224	150	4.0	1.2	0.2										500				67		60											
1400	100	27000	4	224	150	4.1	1.3	0.2										470				68		60											
1500	100	26000	4	224	150	4.0	1.3	0.4										470				70		60											
1600	100	26000	4	224	150	4.0	1.3	0.2										480				70		60											
TOTAL																4.3		500					2230												
AVERAGE			4	224																		64													
1st SHIFT	100	24000	4	224	150	4.0	1.2	0.2										480				70		60											
1700	100	20000	4	224	150	3.4	1.0	0.1										470				68		60											
1800	100	19000	4	224	150	3.3	0.9	0.1										470				66		60											
1900	100	18000	4	224	150	3.2	0.9	0.1										470				64		60											
2000	100	20000	4	224	150	3.4	1.0	0.1										480				64		60											
2100	100	21000	4	224	150	3.5	1.0	0.1										470				63		60											
2200	100	20000	4	224	150	3.4	1.0	0.1										470				61		60											
2300	100	19000	4	224	150	3.4	1.0	0.1										470				59		60											
2400	100	20000	4	224	150	3.4	1.0	0.1										480				55		60											
TOTAL																							2200												
AVERAGE			4	224														475				63													
TOTAL																							2760												
AVERAGE			4	224																		60													

STEAM FLOW STOP (Telegraph)	X 1000	SHIFT NUMBER ONE: 170840	SHIFT NUMBER TWO: 170840
STEAM FLOW START	X 1000		171075
TOTAL STEAM FLOW	X 1000	190443	235
POUNDS OF STEAM PER UNIT OF FUEL		177	
STOKER FEED PUMP OR VALVE		0430	1330
SOOT BLOWER - TIME			
BLOW DOWN -			
PHOSPHATE ADDED	SEE WATER LOG		
SODA ASH ADDED			
TANNIN ADDED			
OPERATOR		S Tanner	C Jones
FIREMAN			

SHIFT NUMBER THREE: 191267 / 191095 / 172 / 2130 / T Crowe

TOTAL: 624

REMARKS:

PH Check — OK CJ

Continuous Blowdown Set at Position 4

DA FORM 1 DEC 77 3995

REPLACES DA FORM 6-88, 1 JUL 47 WHICH IS OBSOLETE.

SIGNATURE Chief Operating Engineer

FIGURE 3-1. DAILY BOILER PLANT OPERATING LOG

FACILITIES ENGINEERING OPERATING LOG *(Boiler Plant)*

For use of this form, see AR 420-49; the proponent agency is the Corps of Engineers.

INSTALLATION: FT GOOD | PLANT: CENTRAL | BLDG. NO.: 1520 | MONTH: APRIL, 1988

DATE	STEAM PRODUCED: STEAM PRESSURE	BOILER 1	BOILER 2	BOILER 3	TOTAL	FEED-WATER TO BOILER	FUEL USED ~~LB OR CU. FT.~~ GAL.	EVAP. LB. PER UNIT (9)	OUTSIDE TEMP. AV.	FEEDWATER HEATER: PRESS.	TEMP.	MAKEUP GAL.	% ~~CO2~~ O2: BOILER 1	BOILER 2	BOILER 3	FLUE GAS TEMPERATURE: BOILER 1	BOILER 2	BOILER 3	TEMP. H.W. SUPPLY	TUBES CLEANED NUMBER OF TIMES	PREVENT MAINT. CHECK		
	LB	1,000 LB.	1,000 LB.	1,000 LB.	1,000 LB.	1,000 LB.	#6		°F.	LB.	°F.					°F.	°F.	°F.	°F.				
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)
1	100	624			624		5010	125	60	4	224	6760	4			490				3	CJ		
2	100	540			540		4340	124	64	4	224	5700	5			455				3	ST		
3	100	532			532		4270	125	61	4	224	5760	5			455				3	ST		
4	100	600			600		4820	124	65	4	224	6500	4			480				3	CJ		
5	100	621			621		4990	124	58	4	224	6590	4			485				3	CJ		
6	100	628			628		5005	126	57	4	224	6600	4			490				3	CJ		
7	100	635			635		5050	126	58	4	224	6710	4			500				3	CJ		
8	100	607			607		4800	126	60	4	224	6640	4			480				3	RG		
9	100	511			511		4100	125	63	4	224	5540	4			460				3	ST		
10	100	491			491		4050	121	67	4	224	5440	5			450				3	ST		
11	100	588			588		4720	125	68	4	224	6600	5			475				3	LC		
12	100	597			597		4750	126	65	4	224	6510	4			480				3	LC		
13	100	567			567		4630	122	70	4	224	6400	5			470				3	LC		
14	100	575			575		4700	122	67	4	224	6450	5			470				3	LC		
15	50	560			560		4500	124	70	4	224	6370	5			430				3	RG		
16	50	482			482		3780	128	66	4	224	5200	5			410				1	ST		
17	50	470			470		3720	126	72	4	224	5010	5			410				1	ST		
18	50	545			545		4120	127	71	4	224	5300	5			415				1	CJ		
19	50	500			500		3920	128	71	4	224	5150	5			405				1	CJ		
20	50	425			425		3330	128	68	4	224	4310	7			380				1	CJ		
21	50	410			410		3250	126	72	4	224	4200	7			375				1	CJ		
22	50	400			400		3200	125	70	4	224	4150	7			375				1	RG		
23	50	390			390		3060	127	74	4	224	4010	7			370				1	LC		
24	50	382			382		3040	126	70	4	224	4050	7			364				1	LC		
25	50	405			405		3180	127	72	4	224	4100	7			370				1	ST		
26	50	401			401		3180	126	71	4	224	4070	7			370				1	ST		
27	50	403			403		3170	127	67	4	224	4050	7			370				1	ST		
28	50	410			410		3250	126	70	4	224	4070	7			370				1	ST		
29	50	380			380		2980	128	75	4	224	3830	7			360				1	RG		
30	50	363			363		2850	127	72	4	224	3710	8			360				1	LC		
31	—																						
TOTAL		15042			15042		119760					154010											
MAXIMUM	100	635			635		5050	128	75	4	224	6760	8			500							
MINIMUM	50	363			363		2850	121	57	4	224	3710	4			360							
AVERAGE	73	501			501		3992	125.6	66	4	224	5334	5.5			426							

EVAPORATION LB. STEAM PER ~~LB FUEL~~ GALLON: 125.6

FUEL USED DURING MONTH (STANDARD TONS): 119760 Gal. (719 STD TNS)

REMARKS: START SUMMER OPERATION 4/16 CLOSE SOUTH HDR 4/19

SEE REVERSE SIDE FOR INSTRUCTIONS

PREPARED BY: Charles A Jones | DATE: 5/2/88

APPROVED BY: Robert L Greene | DATE: 5/3/88

POST ENGINEER: James R. Wolf | DATE: 5/6/88

DA FORM 1 NOV 72 3967 REPLACES DA FORM 8-98, 1 JUN 69, WHICH WILL BE USED.

FIGURE 3-2. MONTHLY BOILER PLANT OPERATING LOG

based upon steam boilers producing saturated steam, although in some cases, specific differences are noted for hot water boilers. ASME Code Sections VI or VII, NFPA 85 series standards, 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.

3-7. PREPARATION FOR STARTUP

Specific plant SOPs should be prepared and followed in preparing for boiler startup. In general, before lighting a fire in a boiler the following steps should be taken.

a. Instrumentation. Check all 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.

b. Internal Inspection. Check that all 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, reducing heat transfer and boiler efficiency. Slag, soot, and ash should be removed as discussed in paragraphs 3-16 and 5-1. Check that all doors and openings are closed.

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

d. Fuel Supply. Check the fuel storage system to ensure that there is enough fuel to meet the 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 the 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.

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

g. 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 drum vent and drain valve between header and nonreturn valves. Open feedwater valves and admit water to boiler slowly until water level is just below center line of gage glass. Blow down water column and operate try 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.

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

i. 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 air flow rates of 25% to 75% and purge time of 3 to 5 minutes, or 8 air changes are considered adequate. A boiler must also be purged after an accidental loss of ignition.

3-8. STARTING FIRE

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

a. Hand Firing Coal. Ensure that ashes and clinkers are removed from grates. If lump coal is available, spread a layer three to six inches thick on grates to prevent fines from sifting through. When ash content of coal is low (under about 7%), 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 air flow 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 air flow through the fuel bed.

b. Stoker Firing Coal. To start a fire on a mechanical stoker, supply coal to furnace by operating the feed mechanism or shoveling coal into the furnace. Place enough coal into the furnace to cover all the tuyeres of an underfeed stoker to a depth of about six inches, or the grates of a spreader stoker to about two 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 the products of combustion. Light shavings and regulate the draft as required to keep fire burning. In some plants, fires may also be started with live coals from another furnace. As soon as the coal burns freely, operate forced-draft fan and regulate air flow 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 furnance 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.

c. Pulverized Coal Firing. When firing pulverized coal follow the procedures outlined in NFPA Standards 85E and 85F, and reference the plant's specific SOPs. For additional information, reference the Navy Manual MO-205 and the ASME Code Section VII.

d. 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. Most army installations use No. 4, 5, or 6 fuel oils with either manual, semi-automatic 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.

(1) **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° F, with oil preheaters supplying the 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. 100 to 300 saybolt seconds universal (SSU) viscosity is usually desirable for No. 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.

(2) **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 air flow suitable for light-off. To manually light an oil burner insert a lighted torch adjacent to the oil atomizer and admit oil and atomizing steam at their low fire rates. The trial for ignition of the main flame should not be longer than 15 seconds. If the trial for ignition fails, remove the torch and repurge the furnance before trying again. A torch for safe lighting of oil burners can be made from an iron rod of ¼-inch pipe of suitable length. Wrap 10 inches of the rod end closely with cloth and secure the cloth with wire. Store the torch in an oil container made from a 2- or 3-foot length of 3-inch pipe so that it is saturated with oil and ready for instant use. To light the torch, remove it from the container and ignite the oil-saturated rag. After the burner has been lit, extinguish the torch by immersing it in the oil container. Leave the torch in this position for future use.

(a) Gas igniters or pilots are usually used to light off modern 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 shut-off valve 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 shut-off 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 figure 2-48 and figure 2-49 will result in the safety shutdown of a burner.

(b) High energy spark igniters are now being applied to some oil-fired burners. These igniters eliminate the use of gas igniters by directly igniting the oil with a low voltage, high amperage spark. Operational sequence is similar to the above, except that the igniter trial for ignition period is eliminated.

(c) Maintain a small, stable flame by adjusting the combustion air flow, oil flow, and furnace draft. Insufficient air is likely to cause smoke, while too much air can cause the flame to blow away from the burner. By experimentation, the proper fuel/air ratio for light-off of a cold furnance should be determined for each individual boiler.

(d) The burner and control manufacturer's recommended lighting off procedure for semi-automatic

operation should be rigidly followed. Step by step instructions should be posted in a convenient place near the burners.

e. 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 semi-automatic 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 2-49 or figure 2-50 will result in the shutdown of a burner. The boiler-furnace must be repurged before a new trial for ignition may be attempted.

3-9. 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 ½ to 2½ 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 the 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.

3-10. PLACING A HIGH PRESSURE STEAM BOILER IN SERVICE

When water in the drum begins to boil, steam is discharged from the drum vent. When the boiler pressure reaches about 25 psig, all 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 the burners to promote uniform heating. If the firing rate is too high on a stoker fired boiler, shut off the forced draft fan for a period and operate on natural or induced draft only.

a. Control of Water Level. Observe water level frequently during the warmup 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.

b. Checking Safety Valves. The safety valves should be tested periodically by hand lifting them. Do this when the 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, the 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 saftey valve leaks or fails to operate properly remove the boiler from service immediatley and repair or replace the valve. Checking of safety valves by raising pressure on the boiler must b under direct supervision of a designated, qualifie employee.

c. Operation of Header Valves. When placing a boiler inter 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 the pressure in the boiler land 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 steam line/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.

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

3-11. PLACING A HOT WATER BOILER IN SERVICE

The following general procedures should be followed for placing a single LTW or HTW boiler into service. Procedures are also included for placing additional boilers into service on multiple boiler installations.

a. Procedure for a Single Boiler. When starting a boiler after layup, proceed as follows.

(1) Review manufacturer's recommendations for startup of burner and boiler.
(2) Fill boiler and system; vent air at high point in system.
(3) Check altitude gage and expansion tank to assure system is properly filled.
(4) Set control switch in "OFF" position.
(5) Make sure fresh air to boiler room is unobstructed and manual dampers are open.
(6) Check availability of fuel.
(7) Vent combustion chamber to remove unburned gases.
(8) Clean glass on flame scanner, if provided.
(9) Observe proper functioning of water pressure regulator and turn circulator pumps on electrically.
(10) Check temperature control(s) for proper setting.
(11) Check manual reset button on low-water fuel cutoff and high-limit temperature control.
(12) Set manual fuel oil supply or manual gas valve in"OPEN" position.
(13) Place circuit breaker or fuse disconnect in "ON" position.
(14) Place all boiler emergency switches on "ON" position.
(15) Place boiler control starting switch in "ON" or "START" position. (Do not stand in front of boiler doors or breeching.)
(16) Do not leave boiler unattended until it reaches the established cutout point to ensure that controls shut off the burner.
(17) During the temperature and pressure buildup period, walk around the boiler frequently to observe that all associated equipment and piping is functioning properly. Visually check burner for proper combustion.
(18) Immediately after burner shuts off, inspect water pressure and open the highest vent to determine that system is completely full of water.
(19) Enter in log book:
  (a) date and time of startup
  (b) any irregularities observed and corrective action taken
  (c) time when controls shut off burner at established temperature, tests performed etc.
  (d) ignature of operator
(20) Check safety relief valve for evidence of leaking. Perform try lever test. (Reference Exhibit C in ASME Code Section VI, "Recommended Rules for Care and Operation of Heating Boilers.")

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

c. 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.

SECTION II. OPERATING ADJUSTMENTS AND PROCEDURES

3-12. 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 the quantity of steam discharged, and the 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.

3-13. MAINTAINING PRESSURE OR TEMPERATURE

Pressure gages indicate the difference between pressure inside 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 proper firing rate. If the boiler outlet temperature falls below the setpoint, the firing rate needs to be increased. If the outlet temperature rises above the setpoint, 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 paragraph 2-26, sense pressure or temperature changes and automatically adjust fuel and air supplies. Automatic systems relieve the operator of the tedious and continuous adjustment necesssary with each change in demand.

3-14. 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. The 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. Reference chapter 4, which discusses feedwater treatment, boiler water treatment principles, equipment, chemicals, operating procedures, tests, and records.

3-15. 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 one 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 paragraph 2-25. Most feedwater controls on Army 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.

3-16. BOILER ACCESSORIES

Operating procedures for water columns, gage glasses, safety valves, blowoff lines, and sootblowers are outlined below.

a. 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.

(1) **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 correcte indication, the water column and gage glass must be blown down regularly. Once per shift is the recommended interval. The lines from the boiler drum to the indicating and recording devices should be blown

down daily.

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

(3) **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 void 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 all gage glasses and decide in advance what to do in case of breakage.

(4) **Replacement of Gage Glass.** To replace a broken gage glass, remove all 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 with first putting pressure on gage glass.

(5) **Valves in Water-Column Line.** If valves are supplied in lines from drum to water column they must be sealed or locked open.

b. 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, large capacity is required when a coal fired boiler is converted to oil or gas firing.

(1) **Adjustment.** 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 ten 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 ten percent. Blowdown is varied by means of an adjusting ring. The Boiler and Pressure Vessel Code requires that safety valves be adjusted to close after blowing down not more than four percent of the set pressure but not less than two psi. It also requires that the blowdown be not less than two 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 all foreign matter is blown from around the seat. This will help to prevent leakage after the valve is closed. Adjustment and sealing of safety valves should be performed only by properly trained and authorized personnel, such as qualified boiler inspectors and factory representatives. In case of emergency, the Director of Engineering and Housing may authorize installation personnel who are thoroughly familiar with safety valves to make adjustments.

(2) **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.

(3) **Capacity.** The capacity of the safety valve(s) must be sufficient to discharge all the steam generated by the boiler without allowing the pressure to rise more than six percent above the maximum allowable working pressure. This capacity may be checked by closing the steam outlets and forcing the fire to the maximum. If the pressure builds up more than six percent, additional valve capacity is needed. The safety valve capacity for each boiler must not be less than the minimum ASME Boiler and Pressure Vessel Code requirements shown in table 2-1. When changing from coal to oil gas firing, do not overlook the increased safety valve requirements. Capacity checks must be authorized by the facilities' engineer and made under the direct supervision of a designated qualified employee, an authorized insurance inspector, or a factory representative.

c. Blowoff Lines. All 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.

(1) **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 the 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.

(2) **Continuous Blowdown.** Surface type blowoff connection 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 is determined by the degree to which sludge accumulates in mud drums and headers. A more complete discussion of bottom blowdown and continuous blowdown is given in paragraphs 4-4c and 4-8.

d. Sootblowers. Flue gases carry ash and soot which 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 combusion, and rating at which 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.

(1) **Swinging-Pipe Sootblower.** 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 sootblower with steam jets directed into the boiler tubes. The sootblower is rotated to direct the jets into each tube. After completing the blowing operation, the sootblower is moved to a position where it is protected from heat or gases. Fire-tube boiler tubes should be cleaned daily.

(2) **Long-Handled Brush.** Swinging-pipe sootblowers 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.

(3) **Mechanical Sootblowers.** Many water tube boilers are supplied with mechanical sootblowers. These should be operated once very eight hours, or an internal dictated by operating experience. To operate a sootblowing 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 sootblower elements, as a small quantity of water introduced into a hot sootblower 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 sootblowing periods to prevent smoke and to carry away material removed from tubes. Sootblower 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 admit 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 sootblowing sequence near the furnace and progress toward the boiler outlet.

(4) **Hand Lancing.** If mechanical sootblowers are not available or cannot be used, hand lancing must be employed. A practical hand lance can be made from a section of ½-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 furnance walls and baffles.

3-17. COAL FIRING PROCEDURES

Procedures for firing coal by hand firing, underfeed stoker, spreader stoker, and traveling grate stoker follow. Procedures for pulverized coal firing may be found in manufacturer's instructions and Navy Manual MO-205 Volume One, Chapter 3, Sections 19 and 20. Fluidized bed firing procedures may be found in manufacturer's instructions.

a. Hand Firing. Methods of firing by hand are as follows:

(1) **Coking.** Coking allows time for escape of volat gases before coal is placed directly on the fuel bed. Fi 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.

(2) **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 one inch for one to three 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.

(3) **Spreader Method.** Spreader firing consists of distributing coal over the entire fire bed. Thin spots ar observed by their bright appearance and additional fi applied to keep the fuel bed uniformly thick. Whe 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 fuel bed.

(4) **Cleaning Hand-Fired Furnaces.** Coarse pieces of ash and clinkers which do not fall through the grates must be removed at sufficiently short intervals, or the air passages can become restricted and the rate of combusion reduced. One method of cleaning grates consists of poushing 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 furnace and exposing ash and clinkers, which are then readily removed. All burning coal is then moved to the side which has been cleaned and the 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.

(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 (six to eight inches) so that air flow 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.

b. 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.

(1) **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 grate bars adjacent to the dump grates with coal. The depth of 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 which 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.

(2) **Ash Removal.** 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.

(3) 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 which 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 which adhere to grates or side walls at once with the least possible agitation of the fuel bed.

(4) **Air Supply.** Underfeed stokers are operated with relatively thick fuel beds and require a forced draft fan to supply air. The windbox pressure varies from one to seven 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 combusion air and regulate the induced-draft fan or stack damper to produce the necessary draft to overcome resistance of the boiler. This draft regulation is often accomplished automatically.

(5) **Operation.** Lubricate all moving parts according to manufacturer's instructions. Keep sufficient coal in the retort to prevent fire from reaching this section of 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 coal supply as required during long banking periods. Make frequent inspection of stoker and brickwork and report unusual conditions so that repairs can be made before equipment is seriously damaged.

c. 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 three to five minutes, the thickness of the fuel bed is correct.

(1) **Adjusting Spreading Mechanism.** Adjust 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.

(2) **Effect of Coal Size on Operation.** Spreader type stokers are not suitable for burning coal particles larger than 1½ inches, as they hinder operation of the feeding mechanism. The most efficient size of coal is ¾ inches by zero with not more than 40 percent passing through a ¼-inch screen. Satisfactory results can be obtained with sizes up to 1½ inches. The fine coal burns in suspension with the 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.

(3) **Ash Removal.** Clean the fires at regular intervals, usually twice each operating shift or when ashes are from three to six inches deep on grates. If the grates are divided, clean one zone at a time. Shut off the coal feed and wait three to five minutes with the forced draft 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 ash pit to prevent fires.

(4) **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 in order to build up the fuel bed in that area. Maintain a slight draft in the furnace during the time the furnace is banked.

(5) **Overfire Draft.** The best operating results are usually obtained with an overfire draft from .03 to .07 inches of water. This reduces air leakage to a minimum without causing overheating of the 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 the flue gas temperature at the minimum level consistent with good operation. Some packaged type boilers are operated with positive pressure in the furnace. These boilers should be operated in accordance with the manufacturer's operating instructions.

(6) **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.

d. Traveling-Grate Stoker Firing. 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 2½ to 3½ 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 the grate, too much air will be admitted through the uncovered grate and an excessive quantity of heat carried away of 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 fuel bed can result in clinker formation.

(1) **Air Control.** Traveling-grate stokers are used with either natural or forced draft boilers, with modern units being almost all forced draft type. Forced draft 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 forced draft. 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 one to four inches with forced draft.

(2) **Draft Control.** An overfire draft of .03 to .07 inches of water should be maintained. This minimizes air leakage, overheating of furnace walls, doors and other parts exposed to heat.

(3) **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.

(4) **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.

(5) **Ledge-Plate Clearance.** Many stokers are supplied with ledge plates on the sides to prevent excessive air leakage.Ensure that ledge plates have approximately ⅛-inch clearance. If proper clearance is not maintained, excess air levels increase and boiler efficiency is reduced.

(6) **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 one 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 the furnace walls are heated before resuming normal operation.

3-18. OIL FIRING PROCEDURES

Efficient operation of oil fired burners requires careful oil storage, oil preparation, and burner adjustment.

a. 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:

(1) Return to the tank of overheated oil.

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

(3) Leakage of ground water into the tank.

(4) Storing oil in tanks for excessively long periods. **b. 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. The 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.

c. 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. All strainer baskets should be checked and cleaned on at least a weekly basis, while daily cleaning may be required for heavy oils.

d. Oil Heating. When heating oil in a storage tank or suction line before transfer or supply pumps, do not heat the oil to a temperature at which vapors are given off, as 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.

e. 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 type atomizers, 35 to 250 SSU for steam or air atomizers, and 35 to 300 SSU for rotary atomizers. An atomizer for a low excess air burner may require an 80 to 120 SSU RANGE FOR No. 4, No. 5, or No. 6 oil. Reference paragraph 1-4b, table 1-2, and table 1-3 for further information. Figure 3-3 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 3-3. 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.

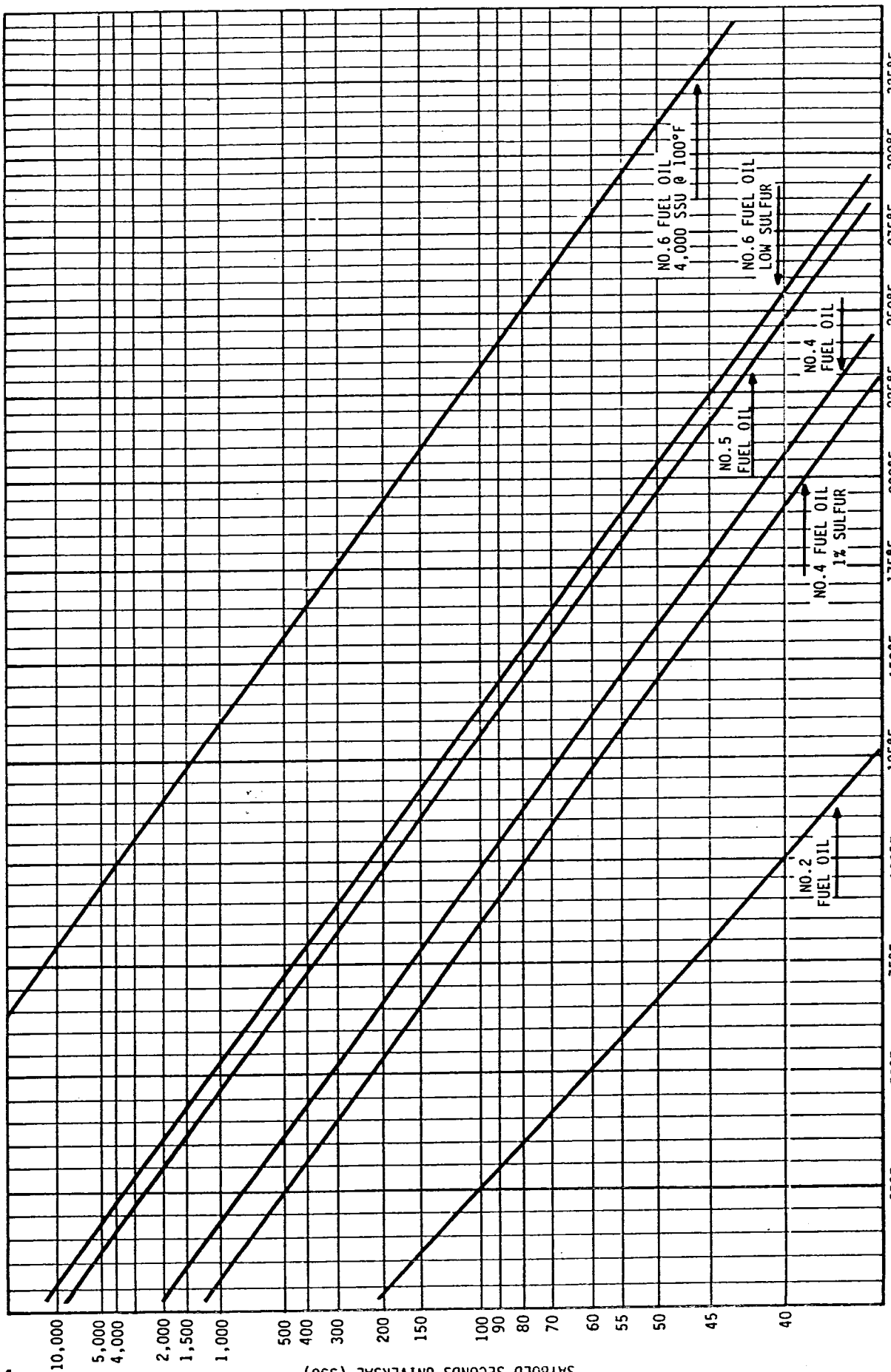


FIGURE 3-3. OIL VISCOSITY VERSUS TEMPERATURE

f. 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 the 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 all used to mix the fuel and air for efficient combustion.

g. Burner Adjustments. Burner adjustments are necessary to ensure that the atomized fuel and combustion air mix completely and efficiently. Position of the atomizer, diffuser, and register baffles are adjusted to optimize burner performance. Some control systems change the register positions automaticlly throughout the firing range to maintain low excess air 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 the burners and controls adjust accordingly.

h. Daily Operation. Oil burners should be inspected daily. The atomizer should be removed and cleaned per 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 paragraph 3-20.

3-19. GAS FIRING PROCEDURES

Efficient operation of gas fired burners requires proper gas handling and burner adjustment.

a. 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.

b. 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 adjustsed to optimize burner performance in that specific furnace. Some control systems automatically change the register positions throughout the burner firing range to maintain low excess air 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 the burners and controls adjusted accordingly.

c. 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 low excess air and/or NOx 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 the excess air levels, ga pressure, burner adjustments, and furnace pressure. Take corrective action or request assistance, as required. Fuel/air ratio control is discussed in paragraph 3-20.

3-20. 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 all control drives and linkages daily for smooth operation and tight connections.

a. Fuel/Air Ratio Adjustment. When the amount of excess air observed in the 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, and atomizing steam or air pressure (of oil), overfire air pressure (if coal), Bacharach or Ringleman smoke desnity, combustion air pressure, combustion air flow if available, fan damper position(s), furnace pressure, percent oxygen or carbon

dioxide in the flue gas, and flue gas temperature. At each load, a curve of smoke density versus percent oxygen or carbon dioxide should be developed. Figure 3-4 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.

b. Standing 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 air flow by a fixed amount. Biasing of air flow does not change the basic fuel/air ratio. Figure 3-5 illustrates fuel/air ratio biasing. When simple biasing of the fuel/air ratio is possible, a Standing 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. Any other adjustment to the combustion control settings must be authorized by the Director of Engineering and Housing or chief operator.

3-21. BOILER SAFETY CONTROLS

The water column discussed in paragraph 3-16**a** is often 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 prove 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 2-48, 2-49, or 2-50, must also be tested periodically. Tests can best be performed during the normal start-up shutdown procedures.

3-22. 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 investigte and correct the cause of the increased pressure.

a. 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 head pump. Exercise care in selecting the required number of pumps to meet load conditions.

b. 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.

c. 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 have roller bearings packed with grease require infrequent attention. Do not overgrease the bearings as this may result in overheating. In 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.

3-23. 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 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 consta

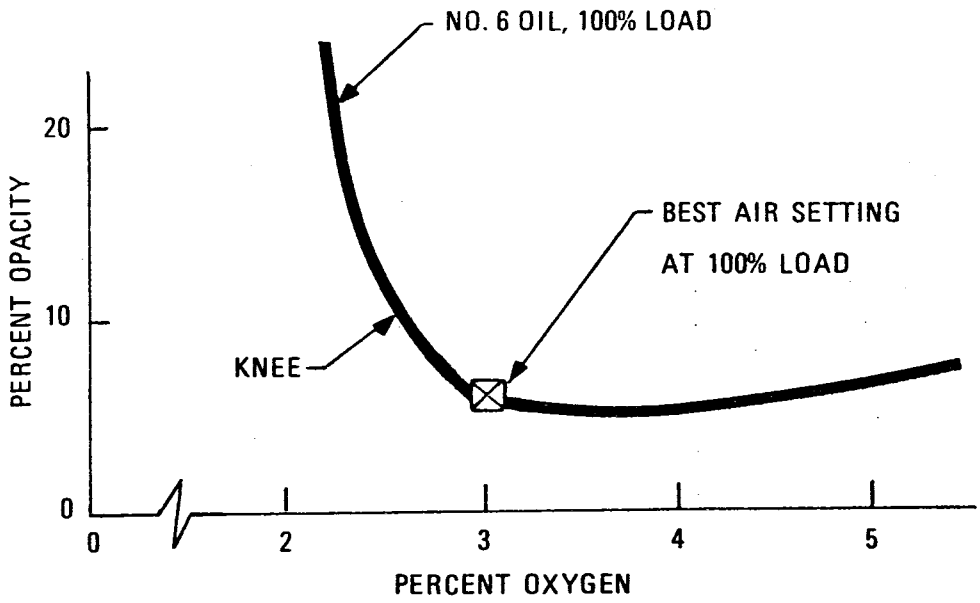


FIGURE 3-4. SMOKE DENSITY VERSUS PERCENT OXYGEN

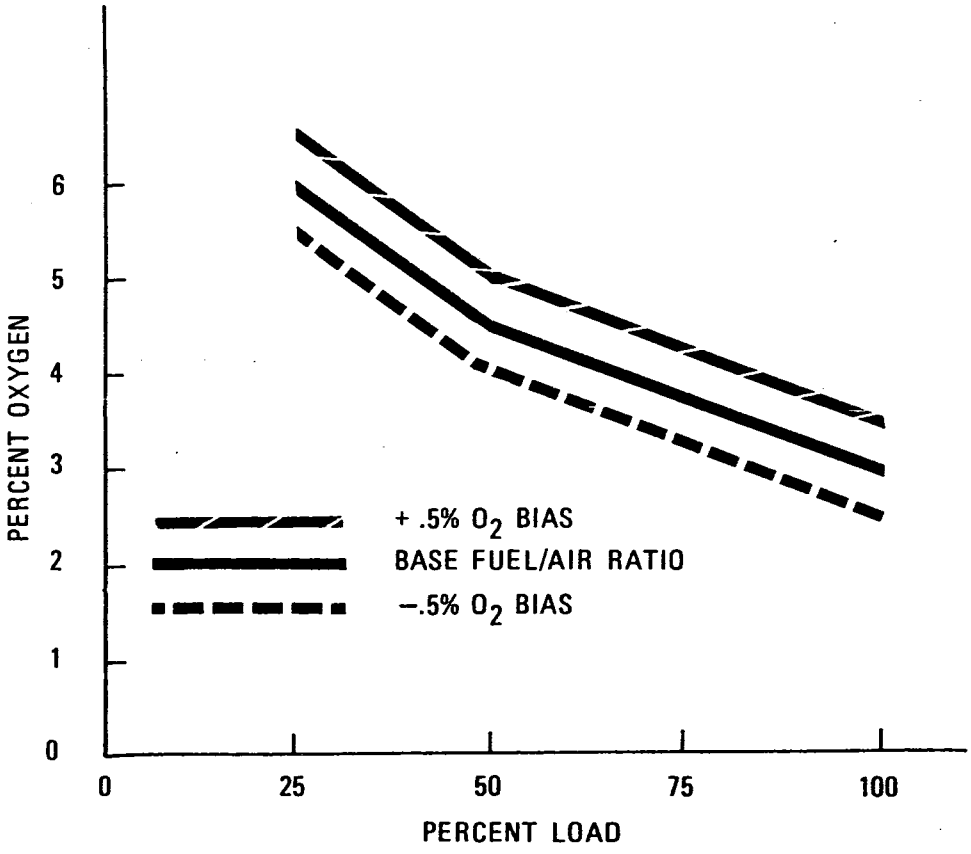


FIGURE 3-5. FUEL/AIR RATIO BIASING

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.

a. Operation. To start a direct-acting steam pump, drain the steam line and ensure that no water is present. Open the drain cocks on steam cylinders. Ensure that valves on the 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.

b. 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.

c. Duplex Pump Adjustment. A duplex pump will strike its heads if there is too much lost motion in the valve gear and will short stroke if there is too little. If the crosshead of a duplex pump slips, the pump may strike the head on one end and short stroke on the other end. Reference figures 2-105, 2-106, and 2-107. To adjust the steam valves of a duplex pump, proceed as follows:

(1) Remove steam-chest cover.

(2) Locate midposition of one piston by moving it to alternate ends of its stroke and marking the rod at same edge of the same stuffing box. Locate and mark the center of the distance between the two previous marks and move the piston until this third mark is in line with the indicated outside edge of the stuffing box. The piston is now in its midposition. Note: Use a very light marking to prevent scoring the rod during operation. A very light scratch with a sharp pointed tool is best.

(3) Check position of rocker arm. Correct position is at a right angle; relocate spool on the rocker arm operating rod to achieve this position.

(4) Repeat steps (2) and (3) on the other piston.

(5) Locate valves in their midposition.

(6) Adjust the effective length of the valve rod to obtain the same amount of lost motion on either side. With an arrangement as shown in Figure 2-106A, this is done by disconnecting the valve and pusher rods and turning the valve rod until the lost motion is equally divided, then reconnecting the valve and pusher rods. With an arrangement as shown in figure 2-106B, the nuts on the valve stem may be relocated. Care must be taken not to change the amount of lost motion while relocating these nuts.

(7) Move one valve off midposition before the steam chest is covered. The pump will not start unless this is done and it will be necessary to pry one side of the pump off dead center by hand.

d. 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.

e. 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 the 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.

3-24. 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.

3-25 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 the use of forced and induced draft fans.

a. 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 the rings to turn and carry oil to the bearing. It is important that proper oil levell 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 six months to one year, depending on service. Use of manufacturer's recommended grease only and use care to prevent overgreasing.

b. 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. Bearing operating temperature of 130° F or less is considered satisfactory.

c. 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. The dampers may be manually or automatically controlled. In either case, means are provided to regulate air flow to meet system requirements.

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

(1) Vibration caused by unbalanced rotor.
(2) Misalignment resulting in vibration, overheating of bearings and wear of couplings.
(3) Incorrect or insufficient lubrication resulting in failure or overheating of bearings.
(4) Improper regulation due to fouled or worn control vanes, dampers, and control mechanisms.
(5) Reduced fan efficiency and capacity due to blades fouled with dust, dirt, or grease.
(6) Fan rotor and casing erosion due to handling air or gases laden with fly ash and other abrasive material.

3-26. 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° F to 220° F. More involved systems for feedwater heating, deaerating, and treatment are discussed in chapter 4. Reference chapter 4, Section III for operating recommendations.

3-27. 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 the individual items of equipment and for the overall boiler installation. When sootblowers 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 (reference figure 2-18) 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 two days, clean the fire side to minmize corrosion problems.

3-28. 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.

a. 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 all 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.

b. 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 two 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.

3-29. 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 rapidity with which the fire can be extinguished.

a. 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.

(1) Shut off fuel.

(2) 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 non-return valve will automatically isolate the disabled boiler from the header.

(3) 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.

(4) Maintain minimum air flow through the boiler setting to carry away steam discharged from the leak.

(5) After 15 or 20 minutes, shut down the forced-draft fans.

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

(7) Inspect the boiler and all 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.

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

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

(2) Close the steam outlet valves.

(3) 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.

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

(5) 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.

3-30. EMERGENCY PROCEDURE — FAN FAILURE

The flow of air and gases through the boiler depends upon the action of the forced and induced draft fans. The greatest difficulty occurs when induced draft fans stop for any reason. If the combustion system continues to operate when the induced draft fan fails, smoke, combustion gases, or fire are discharged into the boiler room. The forced draft fan and fuel feed should be immediately stopped when the ID fan trips. Most boilers are equipped with safety interlocks which do this automatically. Safety interlocks are also normally provided to stop the fuel feed if the forced draft fan fails. If such interlocks are not provided, the operator must take these actions manually. If the induced draft fans have tripped for any reason, slowly open all dampers in the air and flue gas passages to their wide open position in order 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 fifteen minutes. At the end of this period, close the flow control dampers and immediately start the fan(s). Gradually increase the air flow to at least 25 percent of full load flow and purge the setting for five minutes. These general recommendations should be adhered to unless adequate tests on a specific boiler demonstrate that different values should be used.

3-31. EMERGENCY PROCEDURE — ELECTRIC SYSTEM FAILURE

Auxiliary equipment in some plants is equipped with both steam and electric drives. In case of failure of one, the other can be quickly put into service. If all 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 all 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 induced draft fan.
c. Fuel supply to the furnace.
d. Combustion sir supply.
e. Operation of automatic controls.
f. Operation of valves and safety devices.

3-32. EMERGENCY PROCEDURE — FLAME FAILURE

Oil- and gas-burners are provided with flame scanners and safety controls which will safely shut down a burner within two to four seconds of flame failure, and post purge the furnace before shutting off the fans. Manual systems require that the operator take these actions. If the fans are operating after a safety shutdown, continue the operation. Do not immediately increase the air flow. If the air flow is above 25 percent of full load flow, it should be gradually decreased to this value for a post-firing purge of at least five minutes. If the flow is below 25 percent at the time of the shutdown, it should be continued at that rate for five minutes, then increased to the 25 percent level, and held there for an additional five minutes. Reference NFPA 85 standard series for additional information.

3-33. 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 all 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 air flow 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 vacuum which 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 per instructions in paragraphs 5-11 and 4-12. If storage is planned, follow the instructions in paragraph 4- 18 to protect the water side.

Procedures for removing low pressure steam and low temperature water heating boilers from service can be found in ASME Code Section VI.

SECTION III. OPTIMIZING CENTRAL PLANT EFFICIENCY

3-34. OPTIMIZING COMBUSTION EFFICIENCY

With the 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 chapter 1. To optimize boiler efficiency the combustion efficiency must first be optimized. We have seen in paragraph 1-11 and tables 1-4, 1-5, 1-6, 1-7, and 1-8 that combustion efficiency is a function of the type of fuel burned, the flue gas temperature, and the amount of excess air in the 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.

a. Sootblowing/Cleaning to Reduce Flue Gas Temperatures. On all boilers equipped with sootblowers, they should be operated as needed to maintain clean heat transfer surfaces. Once a shift is the recommended internal 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 scootblowing. A reduction in temperature of 35° F to 40° F corresponds to an efficiency improvement of one percent. Reference tables 1-5 through 1-8 for the specific improvement at the actual temperatures and excess air levels at which you are operating. For fire tube boilers not equipped with sootblowers, a record of flue gas temperatures at the normal firing rate of the boiler should be kept. When the flue gas temperature exceeds the clean boiler flue gas temperature by more than 70° F, the boiler should be taken out of service and cleaned. Fire-tube boilers should, as a minimum, be cleaned during the quarterly inspection.

b. 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. Maintain aproper water treatment program as described in chapter 4. 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.

c. 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. Reference paragraph 5-11. The operator should ensure that all doors, ports, and openings into the furnace are closed tightly. The furnace draft should be maintained at a slightly negative level of -0.03s to -0.10 inches of water. This practice helps to minimize air leaks. When the draft is increased for sootblowing, take care to return it to its normal level after sootblowing 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.

d. 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. The 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.

e. Fuel/Air Ratio Optimization. Reference paragraph 3-20a, Combustion Controls-Fuel/Air Ratio Adjustment. 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 3-1 gives recommended oxygen, carbon dioxide, and excess air levels at full load, 50 percent load, and 25 percent load for typical equipment. All 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 3-1. Flue Gas Analysis at 25%, 50%, and 100% Load
For Natural Gas, No. 2 Oil, No. 6 Oil, and Stoker Coal

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

3-35. OPTIMIZING BOILER EFFICIENCY

Boiler efficiency accounts for the energy loss included in combustion efficiency plus the 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.

a. 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 temperture at which standby boilers are maintained. For some plants operating with non-critical 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 air flow which will cool the boiler.

b. 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 side maintenance. Blowdown is a form of preventive maintenance that should be carefully controlled (reference paragraph 4-8). 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 make-up water. Automatic control of continuous blowdown is also recommended to improve the accuracy of the blowdown procedure and help minimize losses.

c. 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. Reference operation procedures in paragraph 3-17.

d. Stabilize Combustion Controls. The combustion control system must accurately establish the correct fuel/air ration to optimize combustion efficiency. Combustion controls are designed to regulate fuel and air flows 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.

3-36. OPTIMIZING CENTRAL BOILER PLANT EFFICIENCY

Overall plant efficiency is always less than boiler efficiency. Reference paragraph 1-13 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.

a. 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 3-6 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 #1 and #2 would be most economical. If efficiency of particular boiler is good over a very small range, it ma 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 Standing Operating Procedure should be developed establishing which boilers should operate for a given load.

b. Deaerator Control. Reference paragraphs 4-6g and 4-16c. 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 one-tenth percent to one 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.

c. 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 non-condensing steam turbine is only about 20 percent. Suitable uses for the exhaust steam must, therefore, be developed if steam turbines are to be used effectively Operate steam drives only when a use for the low pressure exhaust steam is available.

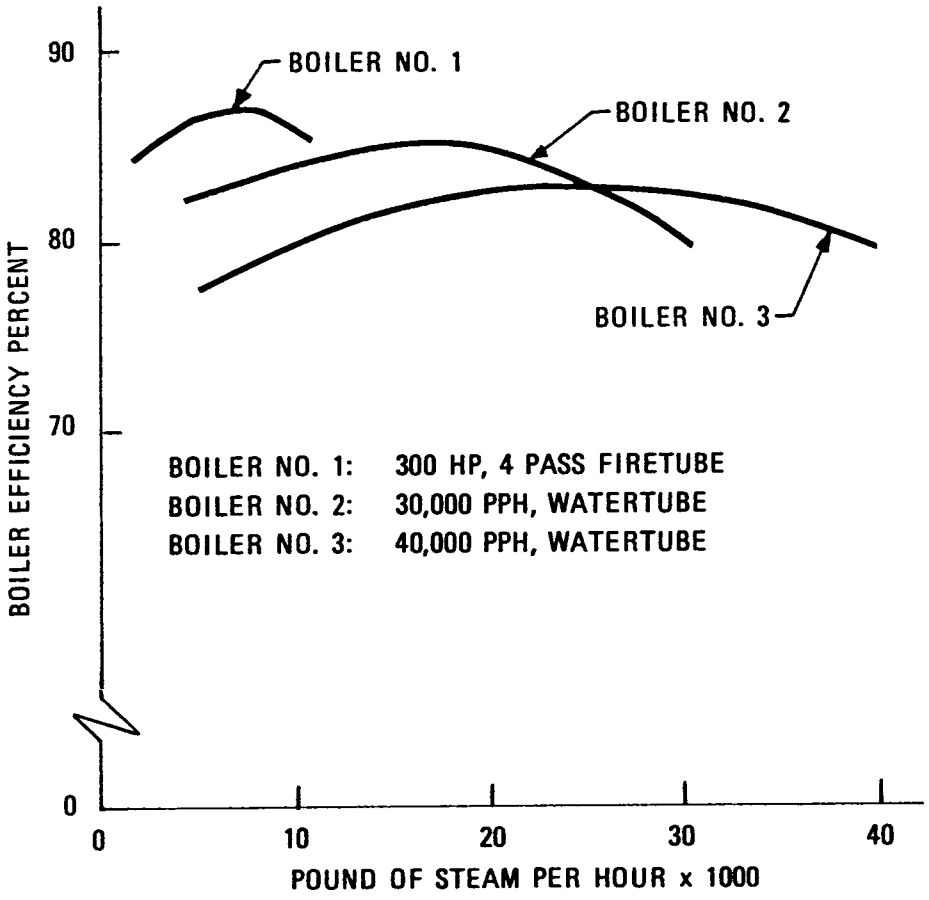


FIGURE 3-6. BOILER EFFICIENCY VERSUS LOAD

d. 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 all 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. Reference paragraph 1-2b(1) Energy Losses.

e. Equipment Modifications or Additions. Existing equipment which does not operate efficiently should be modified or replaced if economically justified. Economizers or air heaters should be considered for boilers that normally operate with flue gas temperatures above 500° 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 quantities can be realized. The addition of a blowdown heat recovery system should be considered. The use of vent condensers, condensate heat recovery systems, improved steam traps, and upgraded boiler combustion controls should also be considered. 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.

f. 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. Make-up water must be heated from its supply temperature, usually about 60° F, while condensate return water needs only to be heated from its already elevated temperature of 150 to 180° 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 five to ten percent of supplied flow in a steam system and one percent in a hot water system.

CHAPTER 4

WATER TREATMENT FOR BOILER PLANTS

SECTION I. INTRODUCTION

4-1. OBJECTIVES OF WATER TREATMENT

This chapter is an introduction to boiler water treatment. Boiler water requires treatment to protect both the boiler and the distribution system. Professional help will occasionally be required to solve specific problems. Further assistance may be obtained from the United States Army Engineering and Housing Support Center (USAEHSC), Fort Belvoir, Virginia 22060. The material in this chapter is designed to acquaint the operator with the reasons for treatment and the techniques available. There are four primary reasons for treatment of boiler water.

a. Minimize Corrosion of Boiler and Distribution System. Corrosion of the steam distribution system is the result of carbon dioxide and oxygen released from the boiler water. The carbon dioxide condenses to form carbonic acid which combines with the oxygen to attack the distribution system piping. Iron and copper particles are returned to the boiler as suspended solids which collect as boiler scale and sludge and promote corrosion in the boiler. Leaks in distribution system piping result in energy lost as steam or hot water. Additional raw water must also be treated to replace the water or steam lost, adding to the water treatment cost and quantity of impurities added to the system. Figure 4-1 illustrates oxygen pitting of a condensate pipe.

b. Minimize Boiler Scale Deposits. Boiler scale deposits act as insulation which can result in overheating of the tubes and subsequent tube failures. Deposits also reduce heat transfer through the tubes, causing higher boiler exit gas temperatures and lower boiler efficiency while promoting corrosion by allowing the concentration of impurities under the scale. Figure 4-2 illustrates a boiler tube which has failed due to scale.

c. Improve Efficiency of Operation. As noted above, control of boiler scale and system leakage due to corrosion helps to maintain a plant's operational efficiency. Effective boiler water treatment also reduces the energy lost in blowdown. Treatment chemical quantities are reduced and appreciable energy savings are realized when blowdown is reduced and condensate return quantities are increased.

d. Control Carryover. In steam boilers, water may, under some conditions, leave the boiler with the steam. This can result in deposits in superheater tubes as shown in figure 4-3, or in piping and turbines. Corrosion is encouraged under such deposits. Water carried over in steam can also lead to water hammer which can be extremely damaging to piping and equipment.

4-2. IMPURITIES IN WATER

Absolutely pure water is not found in nature. The impurities in water include dissolved gases, chemical compounds, and suspended solids. Some of these impurities can be seen, while others can be detected by taste or odor and still others can be detected only by laboratory test. Potable water contains impurities that make it unsatisfactory for boiler use including hardness components, dissolved minerals, alkalinity, dissolved gases, suspended solids, and oils. Uncontrolled concentrations of these impurities in only parts per million ranges can cause major problems, while concentrations of oxygen in parts per billion cause corrosion problems.

a. Hardness. Hardness in water is the result of the presence of calcium and magnesium, which may be deposited as scale. Most of the calcium and magnesium entering the boiler or boiler water treatment system is combined with either a carbonate or a bicarbonate and is referred to as "carbonate hardness." Hardness is generally expressed in terms of equivalent calcium carbonate. Hardness ions may also be combined with sulfates, nitrates, or chlorides in which case they are referred to as "noncarbonate hardness." Calcium and magnesium are positively charged ions or "cations" when dissolved in water. Carbonate and sulfate are negatively charged ions, called "anions." Table 4-1 lists some of the cations and anions which are common to boiler water.

Table 4-1. Common Cations and Anions

Positive Ions (Cations)		Negative Ions (Anions)	
Al^{+++}	Aluminum	Cl^-	Chloride
Ca^{++}	Calcium	CO_3^{--}	Carbonate
Fe^{++}	Ferrous Iron	HCO_3^-	Bicarbonate
Fe^{+++}	Ferrous Iron	HCO_3^-	Bicarbonate
H^+	Hydrogen	PO_4^{---}	Phosphate
K^+	Potassium	SO_4^{--}	Sulfate
Mg^{++}	Magnesium	SO_3^{--}	Sulfite
Na^+	Sodium	SiO_3^{--}	Silicate

(1) Calcium Carbonates.

Calcium bicarbonate is soluble and common in natural waters. It can decompose with the addition of heat or an increase in pH to form calcium carbonate and carbon dioxide. The reaction is:

$$Ca(HCO_3)_2 = CaCO_3 + CO_2 + H_2O$$



FIGURE 4-1. CONDENSATE PIPE CORROSION



FIGURE 4-2. BOILER TUBE FAILURE CAUSED BY SCALE



FIGURE 4-3. SUPERHEATER TUBE SHOWING CARRYOVER DEPOSITS

Calcium carbonate formed in the above reaction has a low solubility and forms a tenacious scale. The carbon dioxide is carried from the boiler with the steam. When the steam condenses, the carbon dioxide is dissolved in the condensate forminge a weak carbonic acid solution which can corrode the metals in the condensate system and contaminate the condensate with dissolved metals.

(2) **Calcium Sulfates.** Various forms of calcium sulfate scale are found in boiler systems, the most important of which is gypsum, $CaSO_4 \cdot 2H_2O$. The solubility of gypsum increases until the temperature reaches approximately 100° F and then gradually decreases. This scale has more than one hundred times the solubility of calcium carbonate at normal boiler temperatures.

(3) **Magnesium Bicarbonate.** Magnesium bicarbonate differs from calcium bicarbonate, in that it decomposes with the addition of heat to form magnesium hydroxide and carbon dioxide. The reaction is: $Mg(HCO_3)_2 = Mg(OH)_2 + 2CO_2$

The magnesium hydroxide may form a sticky sludge or deposit as boiler scale. If silica is in the water, the magnesium hydroxide will react with the silica to precipitate magnesium silicate, which may be removed as sludge.

(4) **Magnesium Chloride.** Magnesium chloride, $MgCl_2$, is very soluble. It reacts with water at the water-metal interface to produce magnesium hydroxide and hydrochloric acid. The reaction is:

$$MgCl_2 + 2H_2O = Mg(OH)_2 + 2HCl$$

The hydrochloric acid is a gas which can leave the liquid water and corrode the boiler just above the water line.

b. Silica. Silica or silicon dioxide, SiO_2, is found in abundance in nature. Common forms of silica include sand and quartz. Silica in boiler feedwater may precipitate and form a hard, glassy coating on the boiler surfaces. In boilers operating above 400 psig, silica vapor is carried over with the steam and deposited on turbine blades or piping. In treated boilers operating below 400 psig, silica is not troublesome because silica vapor is not formed. Phosphate treatment will prevent calcium silicate from forming scale by combining with the calcium, while sufficient alkalinity will keep the silica soluble. Excessive concentrations of silica can be limited by external treatment or continuous blowdown.

c. Iron and Other Suspended Solids. Iron corrosion products are probably the single largest cause of deposit problems in boiler systems. Condensate systems which have been attacked by carbon dioxide and oxygen are the major source of iron deposited in boilers. Iron from this source is a fine suspended solid. Other suspended solids which may enter the boiler and form porous deposits in low flow areas include copper, mud, sand, silt, clay, and dirt. Localized corrosion damage is encouraged at these deposits.

d. Dissolved Gases/Oxygen and Carbon Dioxide. Water that comes in contact with air will absorb oxygen and carbon dioxide. Raw water typically contains about nine parts per million of dissolved oxygen. While many impurities would be acceptable at this level, oxygen is not and treatment must be applied to reduce the oxygen levels a thousand times. Oxygen levels of less than seven parts per billion are necessary to avoid the pitting corrosion common to oxygen attack. Carbon dioxide may come either from air or from the reaction of carbonates with water. The reaction is:

$$CO_3— + H_2O = CO_2 + 2OH-$$

This reaction creates two important results. First, carbon dioxide has been produced which may later present a corrosion problem in the condensate system. Carbon dioxide and oxygen are more corrosive in combination than they are separately. Secondly, hydroxide (OH-) has been produced, and thus the alkalinity and causticity of the water have been increased.

e. Alkalinity/Causticity. The alkalinity of water tells the amount of acid that the water can neutralize. Alkalinity is the result of bicarbonates, carbonates, hydroxide, and other negative ions present in the water. Total alkalinity, or "M" alkalinity, is the amount of alkalinity that will react with acid as the pH of the sample is reduced to the methyl orange endpoint, approximately 4.3 pH. "P" alkalinity is the amount of alkalinity that will react with acid as the pH of the sample is reduced to the phenolphthalein endpoint, approximately 8.3 pH. Alkalinity is reported as parts per million of calcium carbonate, while causticity is the portion of the total alkalinity related to hydroxide ions (OH-). Maintaining causticity within limits in boiler water is important to avoid corrosion from acids, promote good reactions between impurities, maintain impurities as dissolved solids, and ensure the desired relationship between calcium and phosphate. Alkalinity or causticity above desired limits can cause corrosive attack or carryover. Increasing causticity decreases the amount of hydrogen ions and acidity of water, as will be seen in the following discussion of pH.

f. pH. The pH is a measure of acidity or alkalinity of water. The test specifically measures the concentration of hydrogen ions in the water. A very small portion of pure water will ionize into equal parts of hydrogen (acidic) and hydroxide (alkaline) ions. The reaction is:

$$H_2O = H+ + OH-$$

There will be .0000001 or (1×10^{-7}) grams per liter of each ion. Pure water thus said to have a pH of 7. Values of pH less than 7 are said to be acidic (contain more H+ ions), while values greater than 7 are said to be alkaline (contain more OH- ions). The pH scale is logarithmic. A pH of 5 is ten times as acidic as a pH of 6, while a pH of 4 is ten times more acidic than a pH of 5 and

a hundred times as acidic as as pH of 6. This is important to consider when adding a strong acid to a system, because 0.1 N sulfuric acid will have almost 100,000 times the acidity of neutral water. Adding one gallon of .1 N sulfuric acid to a system of 100,000 gallon capacity will double the acidity in the system. The pH of water is a very important factor in controlling corrosion. Very small changes in pH can significantly affect the solubility, reactions, and precipitation of impurities. Table 4-2 illustrates the relationships between pH, normality, and hydrogen ion concentration.

Table 4-2. Water pH

Hydrogen Ion Concentration

Nature	pH	Normality		H+ppm
Very Acidic	0	10+(1)	1000	
(pH = 0 to 3)	1	10-1	100	
	2	10-2	10	
	3	10-3	1	
Acidic	4	10-4		.1
(pH = 4 to 6)	5	10-5		.01
	6	10-6		.001
Neutral (pH = 7)	7	10-7		.0001
Basic	8	10-8		.00001
(pH = 8 to 10)	9	10-9		.000001
	10	10-10		.0000001
Very Basic	11	10-11		.00000001
(pH = 11 to 14)	12	10-12		.000000001
	13	10-13		.0000000001
	14	10-14		.00000000001

4-3. RESULTS AND REACTIONS OF BOILER WATER IMPURITIES

Scale, sludge, corrosion, and carryover are the results of boiler water impurities. The reactions of the impurities are discussed below.

a. Scale. Scale or sludge may be formed from either dissolved or suspended solids. In steam boilers impurities are concentrated in the boiler water as steam is produced. At a given temperature, pressure, and pH, a fixed amount of water can hold in solution only a fixed amount of any given substance. This is called the solubility of that substance. Water can hold great quantities of soluble substances like common salt, while less soluble substances like calcium carbonate, $CaCO_3$, are not held in large quantity. If water holds too many Ca++ and CO_3 — ions, the excess calcium carbonate will precipitate out as either a scale on metal surfaces or as a sludge. When boiler water is treated with phosphate, the calcium hardness precipitates out as a calcium phosphate sludge because the calcium phosphate is less soluble than the calcium carbonate. This sludge can be removed with bottom blowdown. As scale is formed, it may collect suspended sludge or solids such as iron rust or silica. Typical scales may include calcium carbonate ($CaCO_3$), calcium sulfate ($CaSO_4$), calcium silicate ($CaSiO_3$), or magnesium hydroxide ($Mg(OH)_2$). Scale may encourage corrosion, and may range from soft, porous, and easy to remove, to hard and extremely difficult to remove. Thickness and insulating effects of scales will also vary. Water treatment is used to minimize scale deposits by reducing hardness and other solids through external treatment and blowdown. Internal treatment is then used to promote favorable reactions and improve solubility.

b. Sludge. Sludge is an accumulation of suspended solids. These solids may have entered with the feedwater or precipitated from hardness ions in the water. Sludge is found in less turbulent sections of boilers and distribution systems. It may be sticky, and unless removed regularly, may settle on metal surfaces and form a scale. Excessive sludge may cause plugging in water wall headers, tubes, mud drums, blowdown lines, and gage glass connections. Calcium phosphate, iron rust, and silica are commonly found in sludge. Internal treatment with dispersants, like tannin, is used to keep sludge finely divided and fluid. Blowdown is used to remove the sludge.

c. Corrosion. Iron is found in its natural state as an oxidized compound, Fe_2O_3, FeO, or Fe_3O_4. Corrosion is an electrochemical reaction, and is nature's way of returning processed metals like steel, copper, and zinc to their natural states. The iron in steel boiler parts gives up two electrons as it goes into solution as Fe++ ions. The area where iron goes into solution is called the anode. Damaging corrosion will not occur unless the electrons released by the iron are removed from the steel by oxygen or hydrogen. The area where the electrons are removed is called the cathode. The fact that water can hold only certain amounts of iron ions in solution limits corrosion. Unfortunately, oxygen in water with Fe++ and OH- ions can form ferric hydroxide (Fe(OH)3) which precipitates out of the water. This reaction is:

$$4\ Fe(OH)_2 + 2H_2O + 0_2 = 4\ Fe(OH)_3$$

This reaction occurs in both cold and hot water and allows more iron ions to enter the water. At higher temperatures, ferrous hydroxide reacts in water to form magnetic iron oxide or magnetite. Heating surfaces of boilers are usually black because of this insoluble black oxide which precipitates out of the water. The reaction is Ferric hydroxide can give up water to form insoluble ferric oxide, or hematite. Although many intermediate reactions occur, the final reaction is:

$$3\ Fe(OH)_2 = Fe_3O_4 + 2H_2O + H_2$$

Ferric hydroxide can give up water to form insoluble ferric oxide, or hematite. Although many intermediate recations occur, the final recation is:

$$2\ Fe(OH)_3 = Fe_2O_3 + 3H_2O$$

To protect boilers and distribution piping from rusting, both external and internal water treatment is used to keep

oxygen levels in the parts per billion range or less. This stops corrosion by preventing electrons from being removed from the steel. Corrosion can also damage idle boilers if they are not protected by maintaining a high pH anddeaerating the water.

(1) **Pitting.** Pitting is corrosion in a small area of a metal surface, often caused by oxygen in the water. These areas may be metallurgical defects, cuts, scratches, or crevices, either on the metal surface or under scale or sludge deposits. Oxygen reacts with ferrous ions to form insoluble ferric hydroxide. The ferric hydroxide forms a small hood (or "tubercule") over the area and induces an electrolytic current to flow through the metal. The current causes more iron to be converted to ferrous ions. The hood then grows as oxygen reacts with the ferrous ions, causing more ferric hydroxide to be precipitated. This action may continue until the metal is pitted completely through. Pits are usually started when the boiler is idle. Pitting is the most destructive type of corrosion that occurs in boilers or distribution systems.

(2) **Condensate Line Grooving.** Carbon dioxide leaving a steam boiler will condense with the steam, and carbonic acid will be formed as shown below:

$$CO_2 + H_2O = H_2CO_3$$

This weak acid will lower the pH of the condensate and make hydrogen ions available to encourage corrosion. Ferrous ions will be removed from the steel and returned to the boiler plant as ferrous bicarbonate Fe $(HCO_3)_2$ or rust particles. Iron is typically removed from the bottom of the condensate pipe, causing a general thinning of the pipe wall, or grooving along the bottom of the pipe. Corrosion is most active where the steam condenses. Oxygen either from the boiler or from raw water entering the distribution system (e.g., through a leaking heat exchanger) will add to the corrosion problems. Raw water leakage can also cause scale and sludge problems in the boilers, and corrosion in the condensate return system.

(3) **Copper and Brass Corrosion.** Copper and brass corrosion is an electrochemical corrosion. In preventing this type of corrosion, it is important to protect distribution system heat exchangers from exposure to excessively high or low pH levels.

(4) Caustic Corrosion/Caustic Embrittlement. Excessive amounts of hydroxide in the boiler water can cause even higher concentrations of hydroxide to occur under scale deposits or at mechanical joints and can result in pitting corrosion or "caustic embrittlement." Caustic embrittlement is a specialized type of corrosion occurring at stressed points in the boiler. Once a common cause of boiler failure, improved fabrication techniques and better water treatment have made it rare.

d. Carryover. In steam boilers, poor boiler water quality can produce "carryover" of water droplets with the steam. These water droplets will contain any impurities found in the boiler water. The contaminants in this carryover can cause fouling, blockage of equipment and corrosion. Carryover can occur in three ways: (1) foaming, (2) misting, and (3) priming. Foaming involves the production of a foam at the liquid- steam interface which is carried out with steam. High concentrations of dissolved and suspended solids, including alkalis, oils, fats, greases and organic matter, can cause foaming. Misting is characterized by fast-rising steam bubbles which burst and entrain water into the steam line. Priming involves a sudden surge of boiler water level, causing some of the water to be carried over into the steam. Mechanical causes of priming include carrying the water level too high, uneven fire distribution, and load characteristics or boiler design. Priming is also aggravated by impurities. Elimination of mechanical causes may require redesign of the boiler or steam drum internals, installation of steam purifiers, lowering of the boiler water level, better firing methods, or better boiler load regulation.

4-4. CONTROLLING IMPURITIES

Treatment of boiler water falls into three areas: external treatment, internal treatment, and blowdown. External treatment involves the pretreatment of makeup water to remove hardness, alkalinity, dissolved gases, and other impurities before the water enters the boiler. Internal treatment involves the introduction of chemicals directly into either the boiler feedwater just before it enters the boiler, or into the boiler drum itself. Impurities which enter a steam boiler from any source are concentrated as steam is produced. Blowdown involves the intermittent or continuous removal of this concentrated boiler water and sludge. A combination of external treatment, internal treatment, and blowdown must be used to effectively control impurities and resulting scale, sludge, corrosion, and carryover.

a. External Treatment. External treatment equipment and chemicals are available to remove impurities from the water before it enters the boiler. External treatment is discussed in Section II of this chapter. Removing impurities before they enter a boiler is the most effective way to protect the boiler and reduce water problems. Effective external treatment also helps to reduce internal treatment costs and improves boiler operating efficiency by reducing blowdown requirements.

b. Internal Treatment. The purpose of internal treatment is to prevent any problems in the boiler or distribution system caused by the impurities remaining after external treatment. Many methods of internal treatment are in use. The Army uses carefully controlled boiler water alkalinity, phosphate treatment to remove hardness, and an organic dispersant to condition suspended solids. The chemicals

used for internal boiler water treatment are inexpensive and readily available. Those most commonly used in Army boilers are caustic soda, a sodium phospohate, and quebracho tannin. Sodium sulfite is used to remove dissolved oxygen, while in steam plants, neutralizing amines are used to control condensate line corrosion. The amount of internal treatment is based upon maintaining the chemical within specified control limits. Continuous feeding of chemicals is recommended for best and most consistent control.

c. Blowdown. As steam leaves a boiler, the dissolved solids are concentrated in the remaining water. If this concentration were allowed to continue without control, the dissolved solids in the water would eventually precipitate out as scale or sludge and carryover could result. To prevent these problems, sludge is removed by intermittent bottom blowdown and dissolved solids are removed by continuous or intermittent blowdown from the boiler water line.

(1) **Rate of Blowdown.** The amount of feedwater to a boiler during a given period divided by the amount of blowdown during the same period gives the number of times the feedwater has been concentrated in a steam boiler called "cycles of concentration" or simply "concentration." Blowdown calculations are presented in appendix D. The rate of blowdown is controlled such that the concentration is as high as practical. The concentration that can be safely carried depends upon the particular installation. To determine the optimum concentration for a given plant, the concentration is gradually built up with the boiler operating on a typical load profile. Samples of condensed steam and boiler water are taken for analysis at the same time. The concentration of dissolved solids in the boiler water at the time that carryover first appears in the steam establishes the upper limit of concentration. Normally, however, it is not necessary to perform these tests. For average conditions, blowdown rate should be sufficient to maintain dissolved solids between 3,000 and 3,500 ppm. In addition, the rate of blowdown must be sufficient to prevent sludge accumulation, or problems from excess causticity or silica. Five percent blowdown (or 20 concentrations) are typical of a plant with good external treatment. In cases where this is not possible, consult the operating agency commander. The amount of blowdown must be adjusted in accordance with the load. As the boiler load increases or decreases, blowdown should be increased or decreased proportionately. If for any reason the percentage of condensate being returned to the boiler drops so that more makeup water is needed for the same load, a higher rate of blowdown may be required to maintain proper limits.

(2) **Continuous and Intermittent Blowdown.** Blowdown can be performed either continuously or intermittently. Continuous blowdown is generally preferred because it allows closer control of boiler water solids and energy savings through reduced blowdown quantities. Blowdown can be controlled either manually or automatically based on boiler load or by using a conductivity monitor to actuate a throttling valve. Automatic blowdown control saves fuel and treatment chemicals by reducing boiler makeup requirements. Automatic blowdown controls can usually be justified for boilers with capacities of 10,000 pounds of steam per hour or more. Intermittent blowdown is less desirable and less economical because the solids concentration is allowed to fluctuate about the optimum level. However, the reduced equipment requirements may justify intermittent blowdown on small boilers having relatively low load requirements.

(3) **Location of Blowdown.** The location of blowdown is also a factor to consider in determining optimum blowdown rates. Bottom blowdown is necessary to remove settled sludge. Frequent bottom blows of short duration are more effective in sludge removal than occasional blows of longer duration. Long blows from bottom connections should also be avoided due to the danger of starving and overheating generating tubes. Blowdown for control of dissolved solids or other impurities is normally taken near the water level. Water is removed through a nozzle located about six inches below normal operating water level in an area away from the feedwater inlet.

(4) **Economics of Blowdown.** If the rate of blowdown is excessively high, heat (fuel), treatment chemicals, and water are all wasted. The most significant of these losses comes from the heat that is lost with the blowdown. Up to two percent of the total boiler heat input may be lost to blowdown. Heat exchangers which return part of this heat to the makeup water are recommended for all boilers operating with continuous blowdown. The high costs associated with wasted fuel can also justify upgrading of external treatment equipment to reduce blowdown requirements.

d. Factors Affecting Boiler Water Treatment. Many mechanical activities including operation of deaerators, water softeners, and blowdown systems affect boiler water treatment. Efficient operation of deaerators and venting of corrosive gases will help to control corrosion in boilers and condensate return systems, and reduce cheical tretment requirements. Efficient operation of water softeners will assure an almost hardness-free feedwater, further reducing the internal treatment requirements. Proper control of blowdown will also result in savings of treatment chemicals as discussed above. In addition, mechanical maintenance affects the boiler water treatment program. For example, maintaining a tight distribution system with little steam or condensate leakage results in a minimum of makeup requirements and consequently less chemical treatment.

The aims of boiler water treatment are achieved, therefore, by controlling the mechanics of treatment, maintenance, and chemicals.

e. Technical Assistance. Technical assistance is available from operating agency commanders for training of personnel in control of chemical treatment, testing procedures, related problems such as return-line corrosion, deaerator operation, and any other problems pertaining to water treatment.

4-5. TREATMENT REQUIREMENTS

Proper boiler water treatment is necessary to prevent scale, sludge, and corrosion within the boiler and distribution system. The type and extent of treatment required is determined by the nature of the raw water, the type of boiler, and the end use of the steam or hot water produced. Boilers are classified as follows:

Low Temperature Water	LTW (up to 250° F, less than 160 psi)
Medium Temperature Water	MTW (251° F to 350° F)
High Temperature Water	HTW (351° F to 450° F)
Low Pressure Steam	LPS (up to 15 psig)
High Pressure Steam	HPS (above 15 psig)

a. Treatment Requirements for Steam Boilers. Central boiler plants should be equipped with external treatment systems to reduce the sludge and scale potential of the boiler water, and with deaerators capable of delivering feedwater with low oxygen content at all operating loads. Where external treatment is not available, special precautions must be taken to blow down the boiler sufficiently to keep suspended solids at a low level, prevent sludge from forming on boiler surfaces and keep silica concentrations low enough to prevent deposits. Water treatment for high pressure steam boilers consists of caustic soda, sodium sulfite, sodium phosphate, and tannin, and must be lmaintained within control limits at all times. The deaerator should be operated to give dissolved oxygen values in the feedwater below 0.005 cc 0_2 per liter (seven parts per billion) and a boiler water sodium sulfite residual should be maintained. Low pressure steam boilers may require water treatment based on size, makeup rate, age, type of boiler, local makeup water characteristics, and scale or corrosion problems. Where caustic soda, sodium sulfite, phosphates, and tannin are added to low pressure steam boilers, treatment is generally controlled to the same limits as in high pressure boilers. The desired boiler water limits for steam boilers producing saturated steam for heating or humidification only at less than 300 psig are given below. Comments on these limits and special cases are presented in the following paragraphs.

Causticity	20-200 ppm
Total Alkalinity	900-1200 ppm (CaCO3), see paragraph (10
Phosphate	30-60 ppm
Tannin	Medium
Dissolved Solids	3,000-3,500 ppm, see paragraph (1,2)
Suspended Solids	100 ppm max, see paragraph (3)
Sodium Sulfite	20-40 ppm
Silica	Less than 150 ppm, see paragraph (10)
Dissolved Oxygen	Less than 7 ppb
Iron	10 ppm

(1) Maximum values may not be achievable in practice. The need to maintain causticity or suspended solids limits may override the total alkalinity and dissolved solids criteria.

(2) Current ABMA guidelines for total dissolved solids allow concentrations up to 5,000 ppm for boilers producing saturated steam at less than 250 psig for heating only. For boilers producing superheated steam, follow the manufacturer's recommendations for dissolved solids limits.

(3) For boilers designed to operate at moderate or low heat transfer rates, a suspended solids limit of 30 ppm is acceptable if the steam is used only for heatin and if excessive sludge does not develop. This generally includes boilers generating steam up to approximately 50 psig, especially those constructed prior to the mid- 1970's. For boilers producing higher pressure steam, or steam to be used to drive a turbine or other process, much lower limits, between 10 and 25 ppm are recommended. Follow the manufacturer's recommendations. Suspended solids are increased in the boiler by the use of phosphate chemistry (paragraph 4-7b). Phosphate ions which are introduced internally combine with residual calcium ions, under conditions of high pH, to form tricalcium phosphate. Since tricalcium phosphate is insoluble, it is retained in the boiler water as a sludge or suspended solid which must be removed by blowdown. The 30 to 60 ppm phosphate residual noted on the previous page is the soluble phosphate present over and above that required to precipitate out the calcium. This is sometimes called "excess phosphate." Since each ppm of calcium essentially reacts to form one ppm of suspended solid, it is important to size and operate softening equipment so as to minimize residual calcium hardness and therefore internal phosphate requirements.

(4) Low-pressure cast-iron steam boilers are not treated. If scale formation is observed, use inhibited sulfamic acid, as required, to remove the deposits.

(5) For steam boilers used in conjunction with cascade type hot water distribution systems, the limits are:

pH	9.3-9.9 (All steel systems may use a higher pH)
Causticity	20-30 ppm
Sodium Sulfite	30-60 ppm

The recirculating hot water distribution system limits are:

ph	9.3-9.9
Hardness	Less than 2 ppm

(6) When water-tube boilers of 35,000 pounds of steam per hour or greater capacity are operated at high loads, tannin may not be stable in the boiler water, and its use may lead to furnace tube deposits. In this case, it is preferable to operate without tannin. A lignin type dispersant may be used instead.

(7) Anti-foaming agents may be necessary in some cases.

(8) Low capacity steam boilers rated at capacities less than approximately 60 horsepower or 1,500 pounds of steam per hour need only be treated with caustic soda. A pH of 10 to 12 should be maintained. Boilers rated at 10 horsepower or less need not be treated unless warranted by local conditions.

(9) In boilers operating at less than 300 psig, silicate scale forms mostly as calcium silicate. Softening of the water to remove the calcium ions is generally sufficient to control this type of scaling.

(10) The 150 ppm limit for silica is a suggested guideline. Higher levels may be maintained provided that causticity is maintained at high enough levels to ensure silica solubility. The maximum silica level that is acceptable for an individual installation must be determined in the boiler plant, and should not exceed a level at which a buildup of sludge or scale occurs.

b. Treatment Requirements for Steam/Condensate Systems. For steam systems where amine treatment is economically justified, minimum condensate limits should be maintained between pH of 7.5 and 8.0. Higher values of pH may be required at some points in the system in order to maintain this limit.

c. Treatment Requirements for HTW and MTW Boilers. Treatment requirements of hot water systems differ greatly from those of steam systems. These systems are closed so that the only makeup water needed is to replace the water lost at pump glands and valve stems. Since makeup requirements are small, the accumulation of impurities is so small that blowdown is rarely needed. Makeup requirements even in the largest systems should not exceed 200-1,000 gallons per day. All makeup water introduced into a hot water system must be treated to remove the hardness. The water softening system should normally consist of dual zeolite tanks, brine solution tank, manually operated multi-port control valve, bell alarm water meter, and water distribution manifold. A deaerator is not required. Sodium sulfite is used to remove dissolved oxygen. The desired boiler water limits for hot water systems are:

pH	9.3-9.9 (All-steel systems may have pH above 9.9)
Sodium Sulfite	20-40 ppm
Hardness	Less than 2.0 ppm

d. Treatment Requirements for LTW Boilers. LTW boilers may be treated as noted in paragraph c for HTW and MTW systems. Alternatively, all-steel LTW systems may be treated with borax-nitrite or, if copper piping is present, borax-nitrite with a copper inhibitor. The desired boiler and distribution water limit for this alternate is 1,500-2,500 ppm of borax-nitrite.

SECTION II. EQUIPMENT AND CHEMICALS

4-6. EXTERNAL TREATMENT EQUIPMENT

External treatment equipment includes water softeners, dealkalizers, degasifiers, demineralizers, and deaerating equipment. Some type of external treatment equipment is generally required for any central plant operating above 15 psig. In selecting external treatment equipment, table 4-3 and the information presented in this section may be used as a guide. This manual does not, however, provide guidance for many water treatment problems. Furthermore, the information presented is of a general nature, and must be supplemented by a qualified water consultant to select the optimum system for a given set of raw water and feedwater conditions. Consult your operating agency commander for further assistance. The common systems used in Army boiler plants are capable of furnishing water to the boilers with a remaining alkalinity, expressed as $CaCO_3$, of less than 20 ppm when a hydrogen zeolite or chloride anion exchanger is used. Average hardness should not exceed 2 ppm $CaCO_3$ when sodium zeolite or hot lime plus hot sodium zeolite is used or 25 ppm when a lime soda softener is used. Figure 4-4 illustrates the effects of these various external treatments on raw water.

a. Sodium Zeolite Softeners. The sodium zeolite process is the most common and simplest system for softening hard water, and is the one normally referred to when the term "zeolite softening" is used. The primary purpose of sodium zeolite softening is the removal of the scale-forming ions of calcium and magnesium and replacement of them with an equivalent amount of sodium ions. It consists of a zeolite tank with attached regeneration control mechanism, a salt storage tank, and a brine solution measuring tank. Raw water under pressure enters the top through the control valve, hits a splash plate, and drops onto the zeolite bed. Layers of graded gravel support the bed. In the zeolite bed, calcium and magnesium ions are replaced with sodium ions. There is an underdrain system beneath the gravel that collects the softened downflow water and discharges backwash water upward during regeneration. Above the zeolite bed, an arrangement of laterals collects the backwash water and sprays the brine solution over the zeolite bed during regeneration. The space above the top of the zeolite bed is called the free-board. Its function is to provide room for expansion of the zeolite bed and to prevent loss of zeolite during backwashing. The bed is compressed during the softening run. Control of the softening and regeneration cycles may be either manual or automatic. In a manual system, a valve nest or a multiport valve is provided to control the regeneration steps. A fully automatic sodium zeolite softener is illustrated in figure 4-5. In a unit with automatic operation, a meter on the soft water effluent line actuates the control valve after a predetermined quantity of water has been softened. This action takes the softener unit off the line and starts the regeneration cycle. On completion of regeneration, the unit reverts to the softening cycle. The heart of regeneration control, either for automatic or manual operation, is the multiport valve, which opens and closes ports, admitting regenerants and rinse water for the various operations of regeneration. Additional control is provided by wash water and rinse water rate-of-flow controllers. These controllers are either float-operated butterfly valves in sumps or automatic-throttling backwash outlet valves. Brine may be transferred from the brine measuring tank to the zeolite tank either by pump or hydraulic ejector. The disadvantage of the sodium zeolite process is that it does not reduce total solids, alkalinity, and silica. Ion exchange materials may also be degraded or blocked by suspended matter and other impurities present in the incoming water.

b. Hot Process Lime-Soda Softeners. Lime-soda softening is used to precipitate hardness. It also can remove silica, provide deaeration of the boiler makeup water, and provide filtration of suspended matter. It has the advantage of being able to treat large quantities of water in a relatively compact unit. Figure 4-6 illustrates this equipment. The general procedure for this type of softening is to heat the water to 212° F or higher, using live or exhaust steam in a deaerating section. The deaerating section is thoroughly vented at all times to remove gases. High operating temperatures promote maximum treatment efficiency. A mixture of lime ($Ca(OH_2)$) and soda ash (Na_2CO_3) is added to the hot water to remove both carbonate and noncarbonate hardness. Calcium bicarbonate and magnesium bicarbonate react with lime, producing insoluble calcium carbonate and magnesium hydroxide, respectively. Typical reactions to remove non-carbonate hardness include converting calcium sulfate to calcium carbonate and sodium sulfate and converting magnesium sulfate to insoluble magnesium hydroxide and sodium sulfate. The hardness precipitates as a sludge and settles to the bottom of the tank from which it is periodically removed. The softened water settles to the bottom of the tank, then rises to the tank discharge, and flows to a filter. This process requires one to two hours. The filter removes the remaining precipitate, leaving a clear effluent. The lime-soda softening process does not reduce hardness of a softened water to as low a value as do the ion-exchange softening processes. Hardness can be reduced to approximately 10 to 30 ppm as calcium carbonate, depending upon the temperature of the operation and the alkalinity maintained. Consequently,

Table 4-3. Guide for Selection of External Treatment Equipment

Makeup Requirements	Steam Pressure	Alkalinity	Turbidity	Recommended External Treatment Equipment
GPM	PSIG	PPM-C_aCO_3	PPM	
All	Less than 15	All	Less than 10	Normally internal treatment only.
			Over 10	Filtration plus internal treatment.
Less than 100	15-200	Less than 75	Less than 10	Sodium Zeolite.
			Over 10	Filtration plus sodium zeolite.
		Over 75	Less than 10	1. Sodium zeolite plus hydrogen zeolite (3). 2. Sodium zeolite plus chloride/anion exchange. 3. Hydrogen zeolite (3, 5).
			Over 10	1. Filtration plus sodium zeolite plus hydrogen zeolite. 2. Hydrogen zeolite (3, 5).
	200-650	Less than 35	Less than 10	Sodium zeolite.
			Over 10	Filtration plus sodium zeolite.
		Over 35	Less than 10	1. Sodium zeolite plus hydrogen zeolite (3). 2. Demineralization.
			Over 10	1. Filtration plus sodium zeolite plus hydrogen zeolite. 2. Filtration plus demineralization.
Over 100	15-200	Less than 75	Less than 10	Sodium zeolite.
			Over 10	1. Filtration plus sodium zeolite. 2. Hot lime soda.
		Over 75	Less than 10	Sodium zeolite plus hydrogen zeolite (3).
			Over 10	1. Filtration plus sodium zeolite plus hydrogen zeolite (3). 2. Filtration plus demineralization.
	200-650	All	Less than 10	1. Sodium zeolite plus hydrogen zeolite (3). 2. Demineralization.
			Over 10	1. Filtration plus sodium zeolite plus hydrogen zeolite (3). 2. Filtration plus demineralization. 3. Hot-lime hot-sodium zeolite. Above psig.
All	Over 650 (Normally Superheated)	All	Less than 10	Demineralization.
			10-400	Filtration plus demineralization.
			Over 400	1. Filtration plus demineralization. 2. Reverse osmosis. 3. Electrodialysis.

NOTES

1. The above chart provides general guidelines only. Final choice of treatment system must be based upon complete raw water analysis, feedwater requirements, and overall economics, including both external and internal treatment and blowdown. External treatment may be desirable to reach recommended levels of TDS without exceeding other parameter limits for causticity, silica, or suspended solids.
2. Separate deaeration is required to all boilers over 15 psig pressure, except where lime-soda softeners are designed to provide adequate deaeration as well as softening.
3. Degasification is required after hydrogen zeolite treatment.
4. Filtration process may require clarification and aeration.
5. Flows less than 10 gpm or very low sulfate plus chloride content.

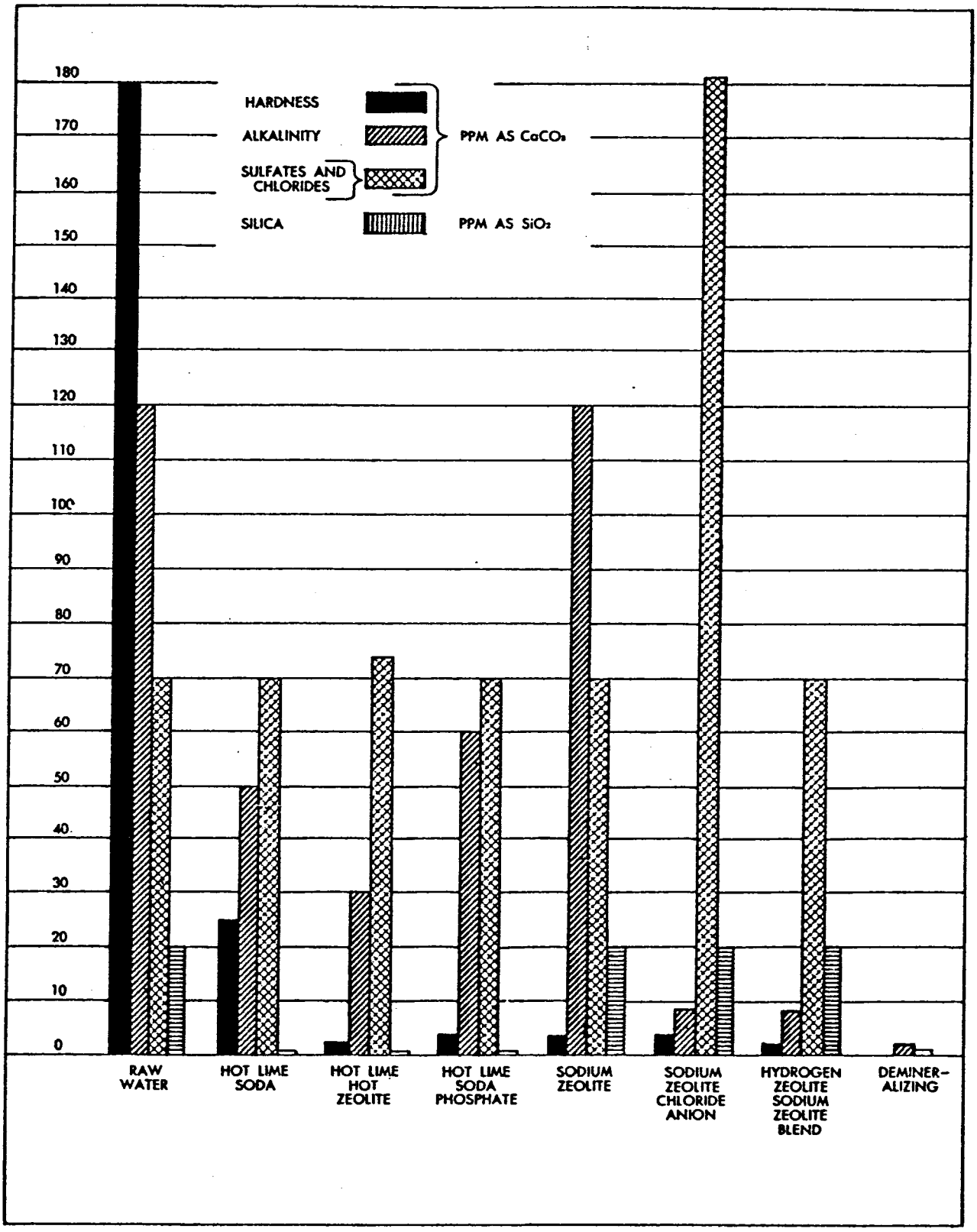


FIGURE 4-4. EFFECTS OF TREATMENT ON RAW WATER

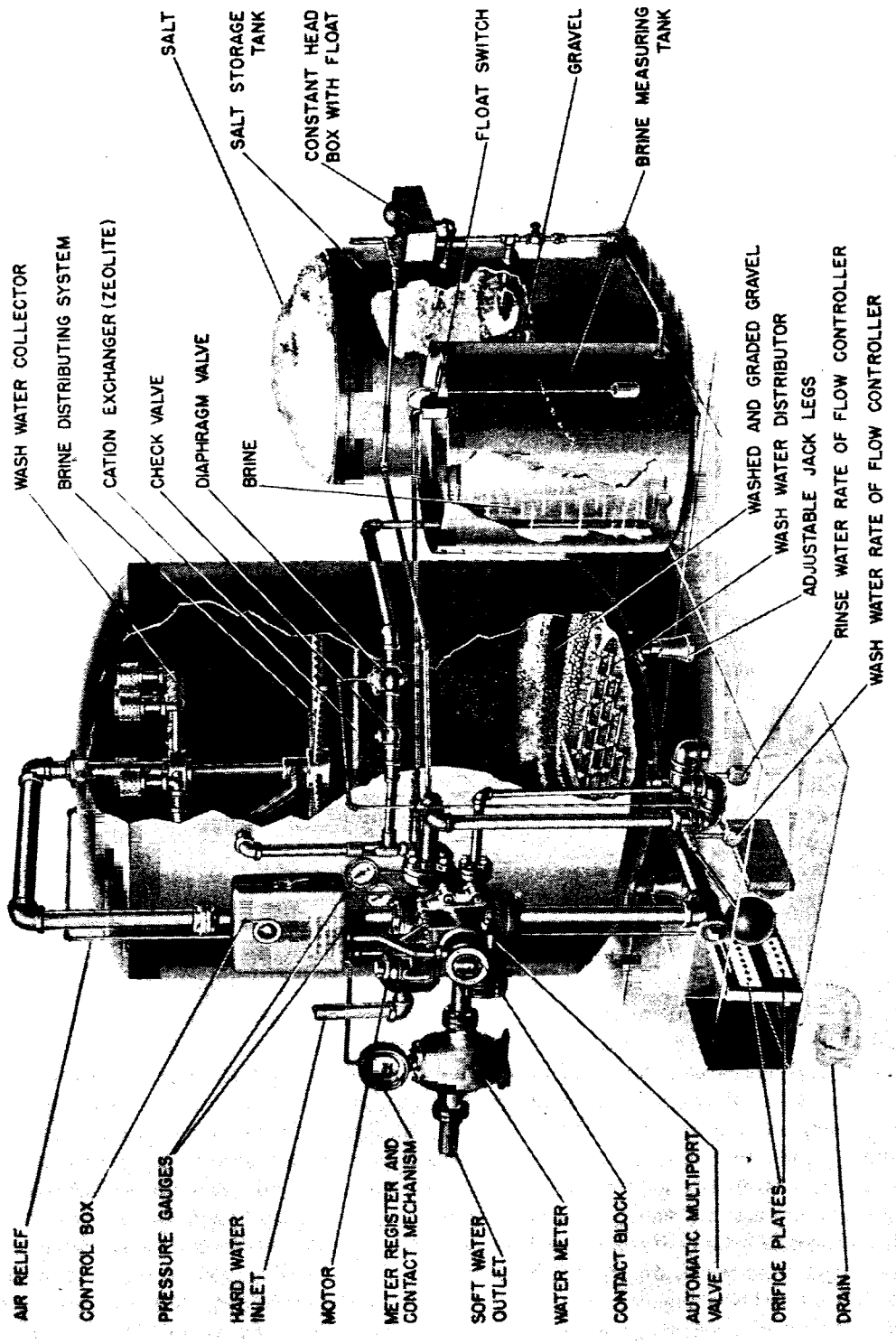


FIGURE 4-5. SODIUM ZEOLITE SOFTENER

where lime-soda softened water is used for boiler makeup water, internal chemical treatment requirements are higher than if ion-exchange softened water is used. Because hardness can be reduced to no lower than 10 to 30 ppm, there is little advantage to this process where raw water hardness is already less than 50 ppm. On waters of high non-carbonate hardness, there will be no decrease in solids content, and under some conditions there may actually be an increase. Finally, control of the process is more difficult than control of ion-exchange softeners, and more frequent testing of the effluent is required. Because of these limitations, lime-soda softening is rarely used alone in modern Army boiler plants.

c. Hot-Lime Hot-Sodium Zeolite Softeners. Combination hot-lime hot-sodium zeolite softening is used for treatment of makeup supply to boilers operating above 400 psig when the makeup is high in calcium and magnesium bicarbonate hardness. The equipment used in this process is a combination of hot process lime-soda and sodium zeolite softening with minor modifications. Figure 4-7 shows a flow diagram of a typical hot-lime hot-sodium zeolite system. The process involves the softening of raw water with lime. After settling and filtering have occurred, the hot filtered effluent is passed through a sodium zeolite water softener. The chief advantage of this method of treatment is that it almost completely removes hardness and reduces alkalinity. In plants operating at lower boiler pressures with a reasonable quantity of return condensate however, the installation of a hot-lime hot-ion exchange system represents a considerable expense that may not be economically justified. The limitations of the system must be thoroughly studied and evaluated to ensure that it is practical and economic for a given set of plant requirements.

d. Hydrogen Zeolite Softeners. The hydrogen zeolite process reduces hardness in a manner similar to that of the sodium zeolite process. It differs however, in that acid is used instead of salt for regeneration and hydrogen instead of sodium is exchanged for the cations calcium and magnesium. The salts of these cations are converted into their corresponding acids. The carbonic acid resulting from the hydrogen exchange in carbonates and bicarbonates breaks down into carbon dioxide gas which can be liberated by aeration. Thus, this process not only softens the water but also removes alkalinity, and can result in a marked decrease in solids content. It is primarily used in boiler feedwater conditioning where the makeup water is low in hardness and high in bicarbonate alkalinity. It is necessary to neutralize the acid effluent from the hydrogen zeolite unit. This is done in one of two ways: blending the hydrogen zeolite effluent with the effluent of a sodium zeolite unit operating in parallel (figure 4-8) or adding an alkali such as caustic soda (figure 4-9). The correct proportions of water to pass through the two zeolite systems depend upon the following factors: the alkalinity of the raw water; the free acid contained in the hydrogen zeolite effluent (which in turn depends upon the sulfate, nitrate, and chloride content of the raw water); and the alkalinity desired in the final mixed effluent. Adjustments can easily be made for correct proportions of effluents from the hydrogen and sodium zeolite units. In the absence of a sodium zeolite blend, the use of an alkali is economical when either the quantity of the water to be treated or the sum of the sulfates and chlorides present is so small that only negligible quantities of alkali are required.

(1) When the hydrogen zeolite becomes exhausted, it is backwashed with makeup water, and regenerated with a dilute solution of acid. This restores hydrogen to the zeolite and simultaneously removes the calcium, magnesium, and sodium which were taken up by the zeolite during the softening run. After the calcium, magnesium, sodium, and any excess acid are rinsed out of the softener, the unit is restored to service. In rinsing, free mineral acidity (FMA) is used as an indication of the end of the rinse cycle. FMA will vary according to characteristics of the raw water supply, and the amount of rinsing required will vary accordingly.

(2) The neutralized effluent of the hydrogen zeolite unit is pumped to a closed degasifier (figure 4-10) to scrul out carbon dioxide. This is done by forcing air into the bottom of the degasifier. The air rises past the falling water and absorbs the dissolved carbon dioxide. Water leaving the degasifier is oxygen saturated and must be deaerated before going to the boilers. General precautions for periodic inspections and care of hydrogen zeolite units are the same as for sodium zeolite units. Particular care must be given to the rate of flow and exhaustion points of acid-regenerated units, since excessive flow rates and overrunning of the unit will destroy the softening material. Before a definite recommendation for this type of equipment can be made, it is necessary to make a thorough study of its economics and practicality. In general, such a study will show that the hydrogen zeolite system is more expensive and unwarranted for Army central boiler plants.

e. Chloride Anion Exchanger/Dealkalizer. The chloride anion exchange process reduces alkalinity in makeup water without acid treatment or hydrogen zeolite, and is often used in series with a sodium zeolite unit. It is regenerated with salt and a small percentage of caustic soda. While not as economical or efficient as acid tretment or hydrogen zeolite, it has the advantage of obtaining similar reductions in alkalinity without the necessity of handling acids. Chloride anion exchanger units are used most frequently in relative small boiler plants. The principle involved is the exchange of bicarbonate ions in the makeup water for the chloride of a resinous chloride material. The whole process is similar to the cation exchange in the sodium

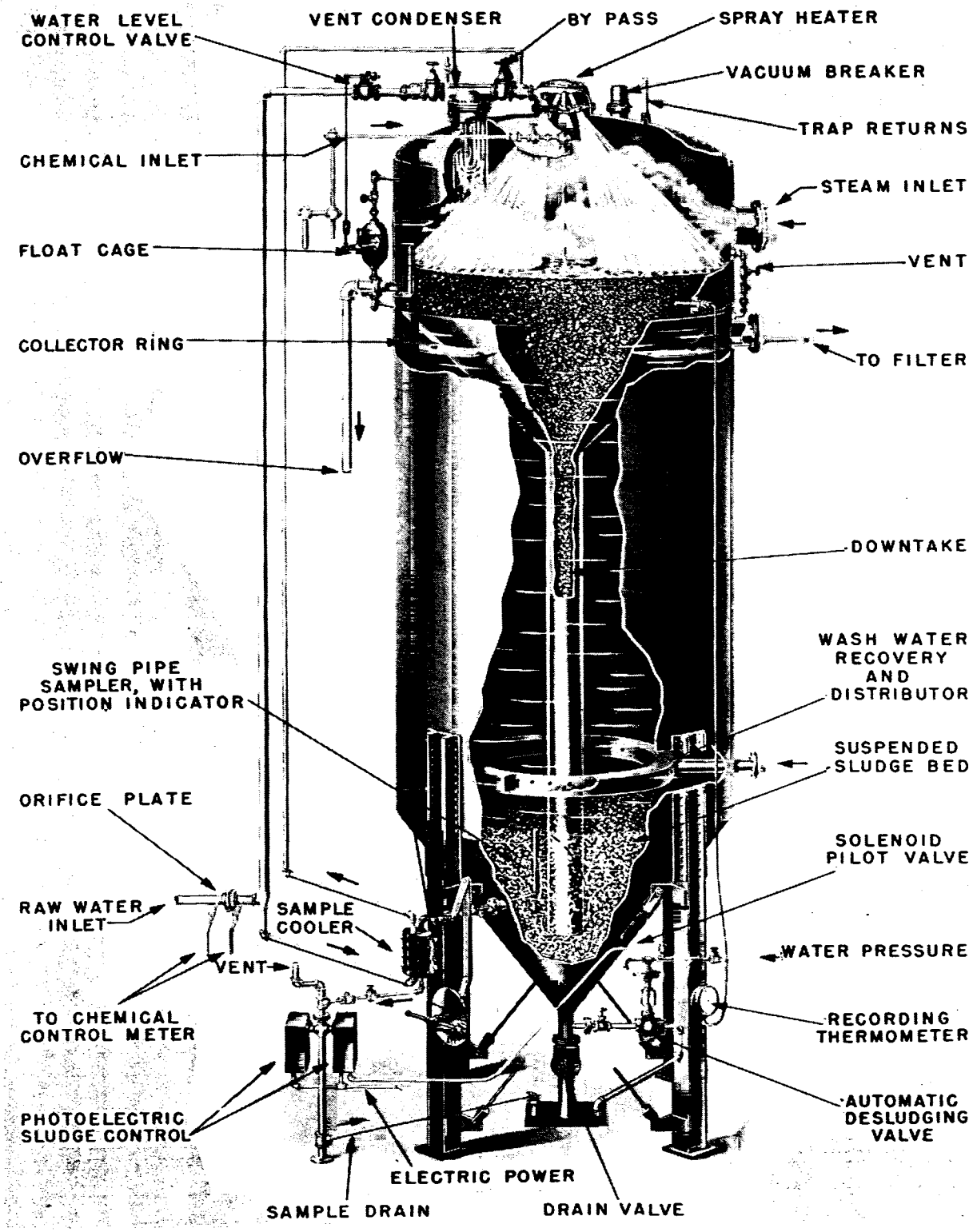


FIGURE 4-6. HOT PROCESS LIME SODA SOFTENER

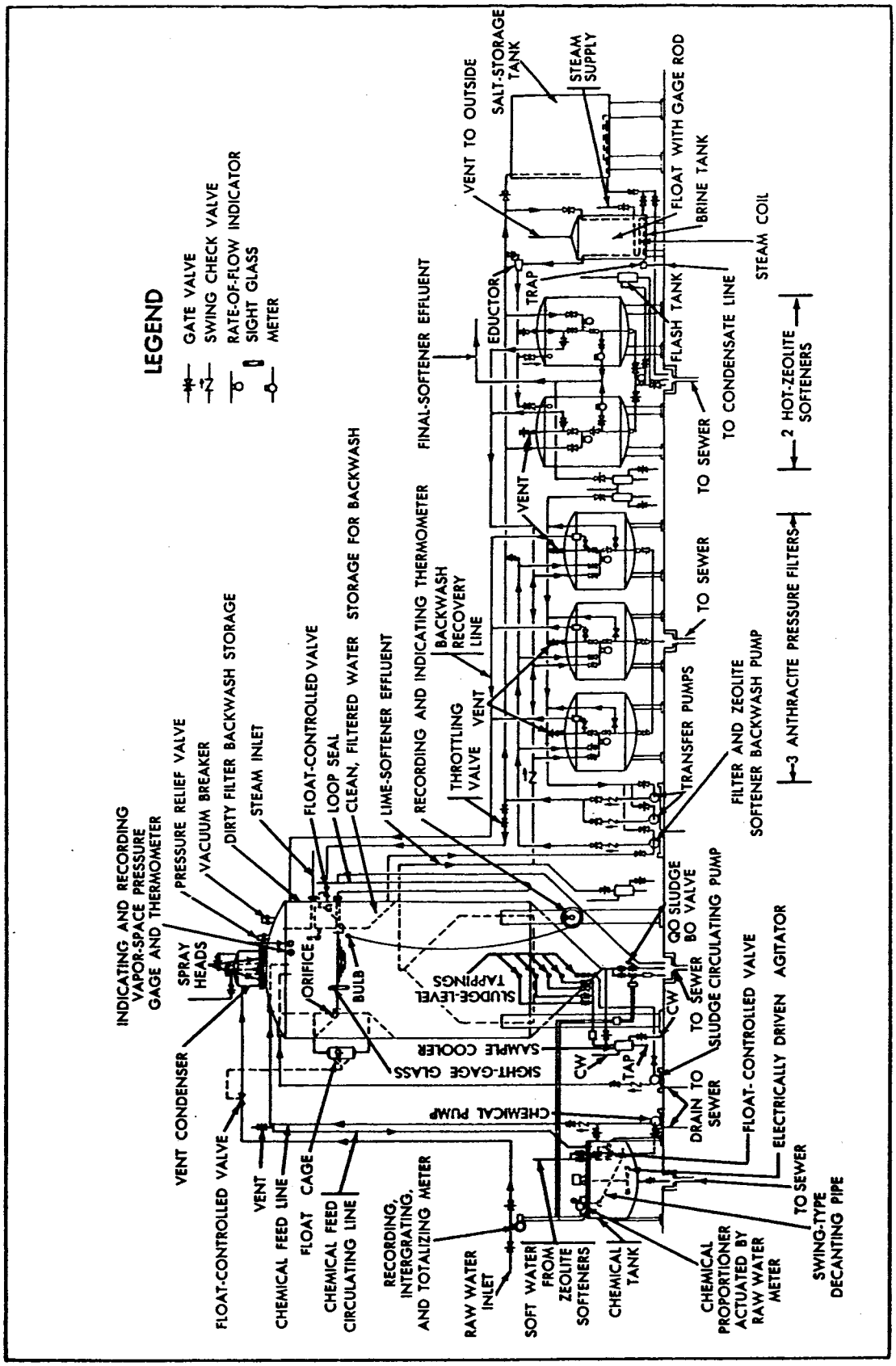


FIGURE 4-7. HOT-LIME HOT-SODIUM ZEOLITE SOFTENER

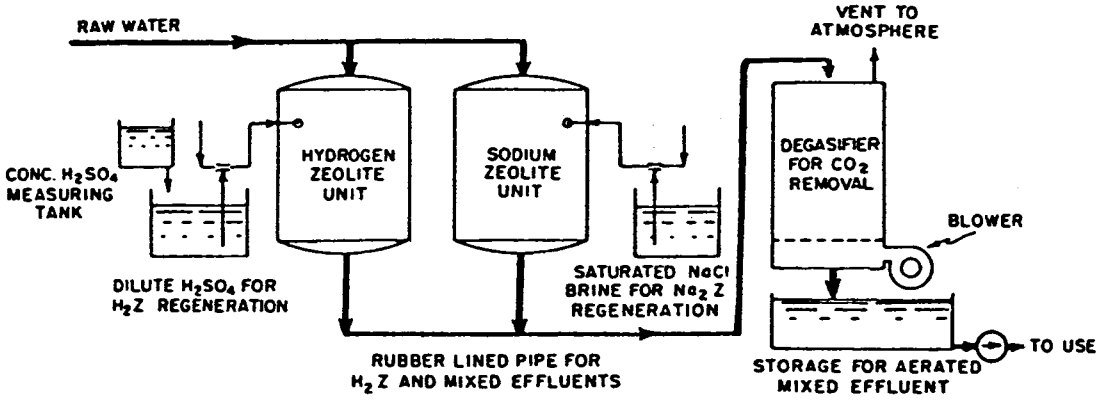


FIGURE 4-8. HYDROGEN AND SODIUM ZEOLITE SOFTENERS OPERATING IN PARALLEL

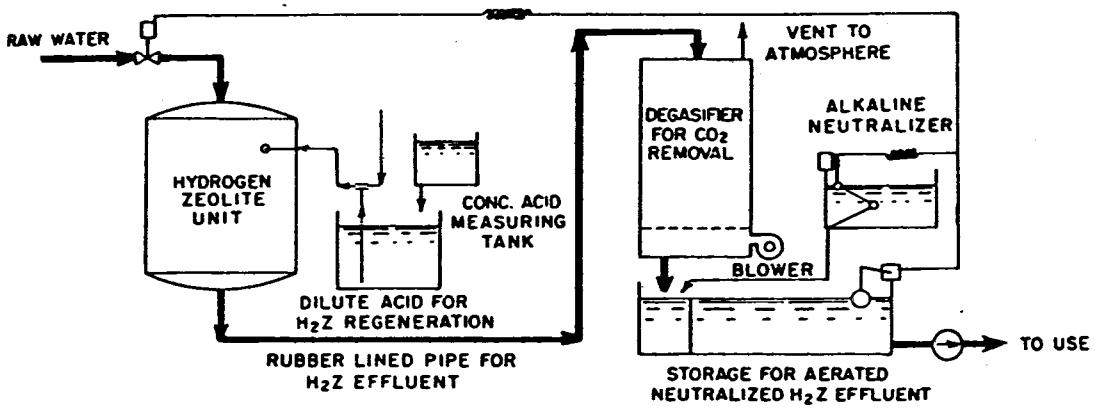


FIGURE 4-9. HYDROGEN ZEOLITE WITH ALKALINE NEUTRALIZATION

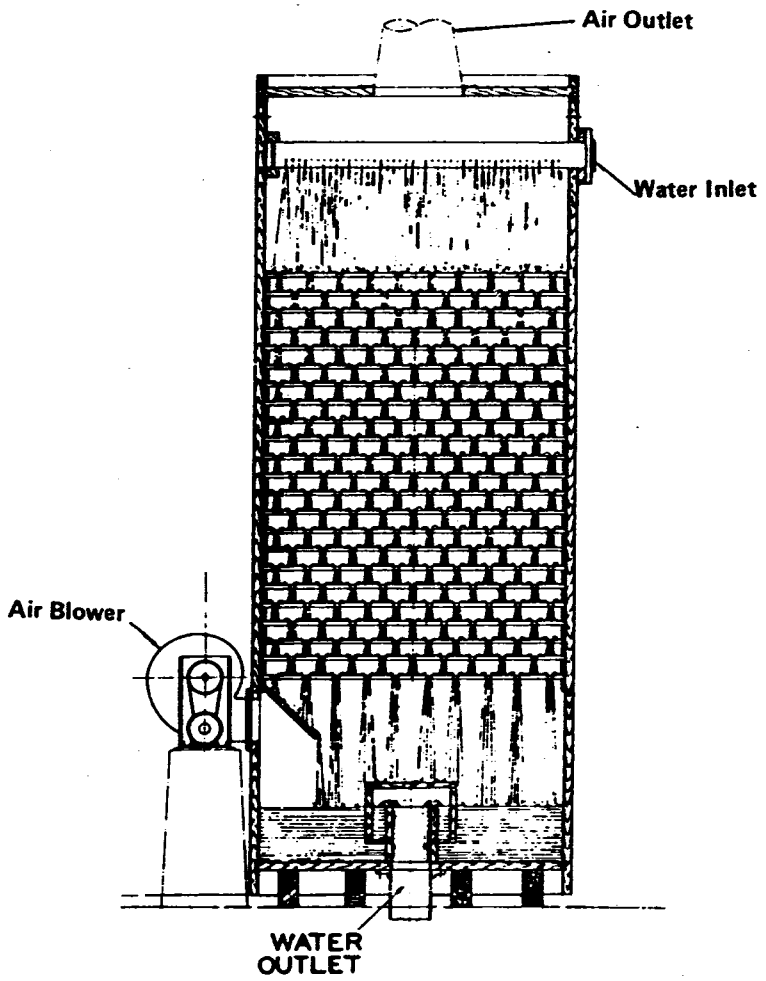


FIGURE 4-10. DEGASIFIER/DECARBONATING TOWER

cycle, except that anions are exchanged instead of cations. The equipment involved, method of operation, and regeneration are the same as for the zeolite softener. This process should not be used on dirty makeup water, because dirt cannot be removed easily by backwashing. When this method is combined in series with a sodium zeolite unit and degasifier, both hardness and alkalinity are reduced. Figure 4-11 shows a typical system. The main disadvantages of the process are that it does not reduce silica, and that salt is added, thereby increasing the conductivity which may result in increased blowdown. Demineralization is frequently a more economical approach for treating high impurity water.

f. Demineralizers. Unlike the zeolite softeners which remove only cations, demineralizers remove both cations and anions. These ions are replaced by hydrogen and hydroxide ions which combine to form water. The resulting effluent is equal to or better than distilled water. Demineralizers, which are also commonly called "deionizers," are generally used with high or medium pressure boilers or in plants requiring high-purity water.

(1) Demineralization is most often accomplished by first passing the water through a column of cation exchange resin. As water moves through the resin, it leaves its cations on the resin while it picks up hydrogen ions. Next, the water passes through a column of anion exchange resin. Here, the water leaves its anions on the resin and picks up hydroxide ions. The hydroxide ions then combine with the hydrogen ions to form essentially pure water. Another arrangement which is sometimes used is mixed bed demineralization. This combines the cation and anion resins in a uniform mixture in one column, resulting in an effective infinite series of cation-anion exchange systems. Figure 4-12 illustrates a mixed bed demineralizer unit and its regeneration cycle. There are many variations of these arrangements. Either strong or weak cation or anion resins can be used, and the equipment can be arranged in two-ed, three-bed, or mixed-bed configurations. Strong cation resin has the ability to remove sodium whereas weak cation resin does not. Strong anion resin has the added ability over weak anion resin to remove carbon dioxide, carbonate, bicarbonate, and silica.In some cases, degasifiers are also added to the system. When the acids generated in the cation column react with alkalinity in the raw water, carbon dioxide can form. This can be removed by ion exchange or by degasification, depending on the system.

(2) After an ion-exchange resin has exhausted the amount of ions it has available for exchange, it must be regenerated. The regeneration process starts by loosening the bed by reverse flow of water through the column. The resin is then regenerated with a downward flow of regenerants. An acid solution is used for a cation resin and a caustic solution for an anion resin. The regenerant chemical is finally displaced by a slow flow of water through the resin followed by a rapid rinse to remove all traces of the regenerant chemical. Demineralization produces better makeup water than any of the methods discussed previously. It is an extremely versatile process, and the resins can be adjusted to suit almost any combination of raw water quality and makeup chemistry requirements. Choice of demineralization over other systems is more a function of makekup water requirements than raw water quality. Its advantages include reduced boiler blowdown and resulting reduced makeup requirements, and a big assist in the production of high quality steam. Its main drawback is its higher equipment and operating cost. It is usually difficult to justify a demineralization system unless the plan operates in the range of 600 psig or above, a pressure at which few Army boiler plants operate.

g. Electrodialysis and Reverse Osmosis. The softeners and demineralizers discussed previously are the normal choices for common water sources, including city systems, rivers, streams, and wells. Industrial plants, and in some cases Army boiler plants, may also be required to operate on less pure water such as brackish or high turbidity sources from a deep well or estuary with several thousand parts per million or greater solids. Various membrane and distillation techniques are available to handle these special situations. Electrodialysis and reverse osmosis are two of these having the longest development history. Electrodialysis operates by passing the water between sets of parallel membranes carrying an electric field. The charged field causes the cations to migrate toward the negatively charged electrode, and the anions in the opposite direction. The membranes used are selectively permeable to allow the passage of ions from the "pure" stream to the "brine" stream. Reverse osmosis systems operate on the principle that when two salt water solutions of different concentrations are separated by a semipermeable membrane, water will be transported from the dilute to the more concentrated side. When pressure is applied to the concentrated side, the water will flow in the reverse direction. The process is thus one of concentration, resulting in one stream more concentrated in salt than the original feed, and one that is purer. These treatments, and other similarly exotic systems, are generally expensive, and have high operation costs. They may be applied, however, either by themselves or in combination with one of the other systems discussed to meet specialized treatment requirements. Assistance should be obtained from the operating agency commander.

h. Deaerating Heaters and Deaerators. Deaerating heaters and deaerators are used in steam boiler plants to remove oxygen and other dissolved non-condensible gases from the boiler feedwater and also to minimize the amount of internal treatment required for oxygen control. This

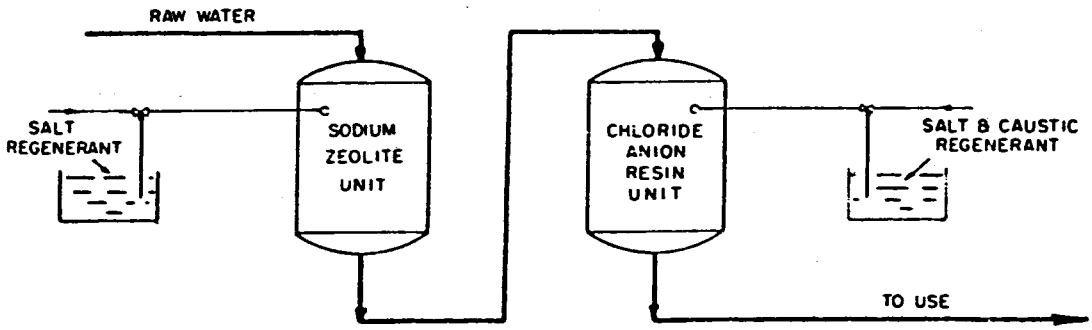
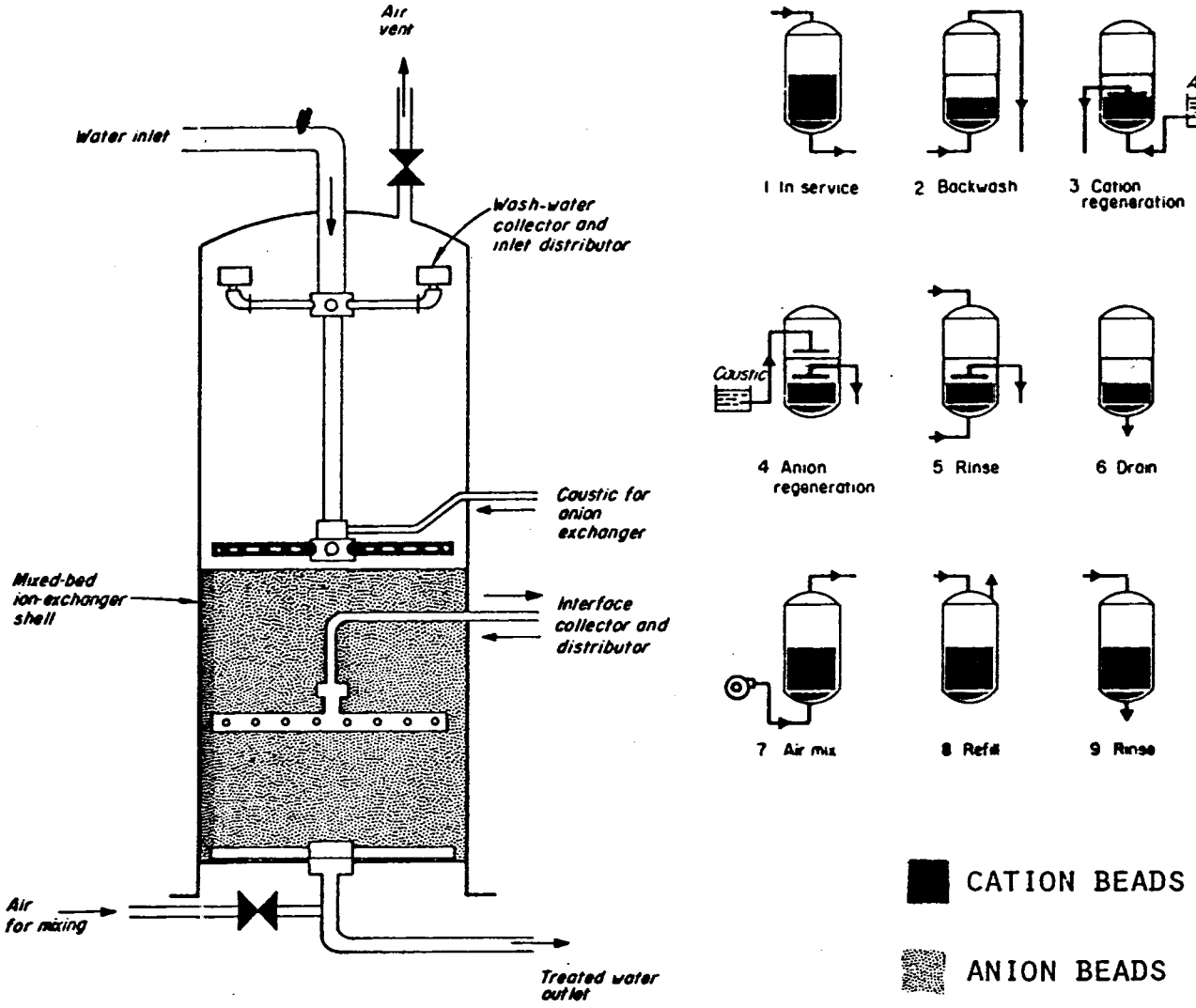


FIGURE 4-11. SODIUM ZEOLITE-CHLORIDE ION EXCHANGE SYSTEM



A. MIXED BED DEMINERALIZER

B. REGENERATION CYCLE

FIGURE 4-12. DEMINERALIZER

deaeration is necessary to minimize corrosion in the boiler and steam distribution system. The other major function of the deaerating heater and deaerator is to heat the boiler feedwater to a temperature at which it can be fed to the boiler without causing thermal shock. Boiler plant efficiency can be improved if turbine exhaust or other waste steam is available for heating the feedwater. Deaerating heaters and deaerators can serve to receive and store condensate. All steam plants operating above 15 psig with an installed capacity of more than 100 horsepower or 3,500 pounds per hour should be equipped with a deaerating heater, deaerator, or a hot lime-soda softener which includes a deaerating section. Hot water plants do not normally reqluire deaerating equipment. Plants not equipped with some type of deaerating equipment will usually have a feedwater heater. Feedwater heaters are discussed in paragraph 2-36. Deaerators operate by heating the water to the boiling temperature. Since the solubility of any gas in water is zero at or above the boiling point, oxygen and other noncondensible gases come out of solution and can be vented to atmosphere. The maintenance of proper temperature is critical and provisions must be made to supply live steam to the deaerating section if sufficient exhaust steam is not available. See paragraphs 4-16c(1) and (2) which further discuss deaerator operation.

(1) **Types of Deaeration Equipment.** The three types of deaeration equipment are deaerating heaters, tray deaerators and spray deaerators. Newer boiler plants are equipped with tray or spray type deaerators because of their ability to reduce dissolved oxygen levels to less than seven parts per billion compared with approximately forty parts per billion for a deaerating heater. The deaerating heater is an open vented tank in which the feedwater is heated to above 212° F by a steam coil in the bottom of the tank. In the tray deaerator, shown in figure 4-13, water enters at the top and cascades down through a series of trays or baffles while steam enters at the side and passes upward through the falling water droplets, heating the water. The water droplets expose a large surface area to the steam, aiding the heating process. The dissolved gases are expelled from the water through the deaerator vent. The spray deaerator atomizes the incoming water into fine droplets and mixes this spray with steam for heating and deaeration. The spray deaerator is shown in figure 4-14.

(2) **Typical Deaerator Installations.** Deaerators are installed on elevated structures above the boiler feed pump suction to provide sufficient NPSH and prevent flashing at the pump inlet under the feed temperature conditions. With a feedwater temperature of 214° F and a back pressure on the deaerator of approximately 0.5 psig, the hydrostatic head on the feed pumps should be approximately seven feet. If the boiler feedwater temperature is held above 214° F, the hydrostatic head must be increased proportionately. The three common types of deaerator installations are described below.

(a) Type I. Type I (figure 4-15), is the most common. All returns are pumped to the surge tank where makeup is added as needed and the water controlled by the load demand, is allowed to flow by gravity to the deaerator. Storage at the deaerator for this type of installation is small (generally not over a 3-minute plant supply), because the primary reserve is maintained in the surge tank which also takes care of sudden surges of condensate. Feedwater enters and leaves this type of deaerator uniformly at a rate equal to the feedwater requirements of the boilers. The makeup level in the surge tank should be as low as is consistent with safe operation (minimum of 10-minute supply — total space for 30-minute supply) to permit ample storage space for sudden surges of return condensate.

(b) Type II. In Type II deaerator installations (figure 4-16), all condensate returns are pumped directly to the heater. Storage space is maintained after the deaerator compartment. Makeup is added as required directly through the deaerator, also maintaining as low a makeup level as is safe (minimum 10-minute supply — total space for 30-minute supply) to permit storage space for sudden surges of condensate. This type of installation can impose high intermittent loads on the deaerator as area condensat pumps start and stop, and requires a deaerator of greatei capacity to handle the same average load as Type I. As pumps normally operate approximately 25 percent of the time, a load three to four times the average load is imposed when all of the condensate return pumps happen to be operating at the same time. Therefore, feedwater enters this type of deaerator intermittently at a rate of three to four times the rate of feed to the boilers.

(c) Type III. Type III deaerator installations (figure 4-17) are an adaptation of Type I installations. These installations use a transfer pump to pump water from the surge tank to the deaerator, because sufficient head room is not available for gravity flow. Most transfer pumps are steam driven, providing an even flow of water to the deaerator at a rate equivalent to the output of the boilers. Where electric- driven transfer pumps are used, it is essential that they be of the continuous operating type, pumping feedwater to the deaerator by action of float-operated water level control. If low and high water floats are used to start and stop the pump, intermittent loads equivalent to the capacity of the transfer pump are imposed on the deaerator; unless the deaerator is sized accordingly, overloading will result.

(3) **Deaerator Auxiliary Equipment.** Deaerators are equipped with some or all of the following auxiliary equipment.

(a) Surge Tanks. Steel surge tanks, installed ahead of the feedwater heaters, should be provided for the storage

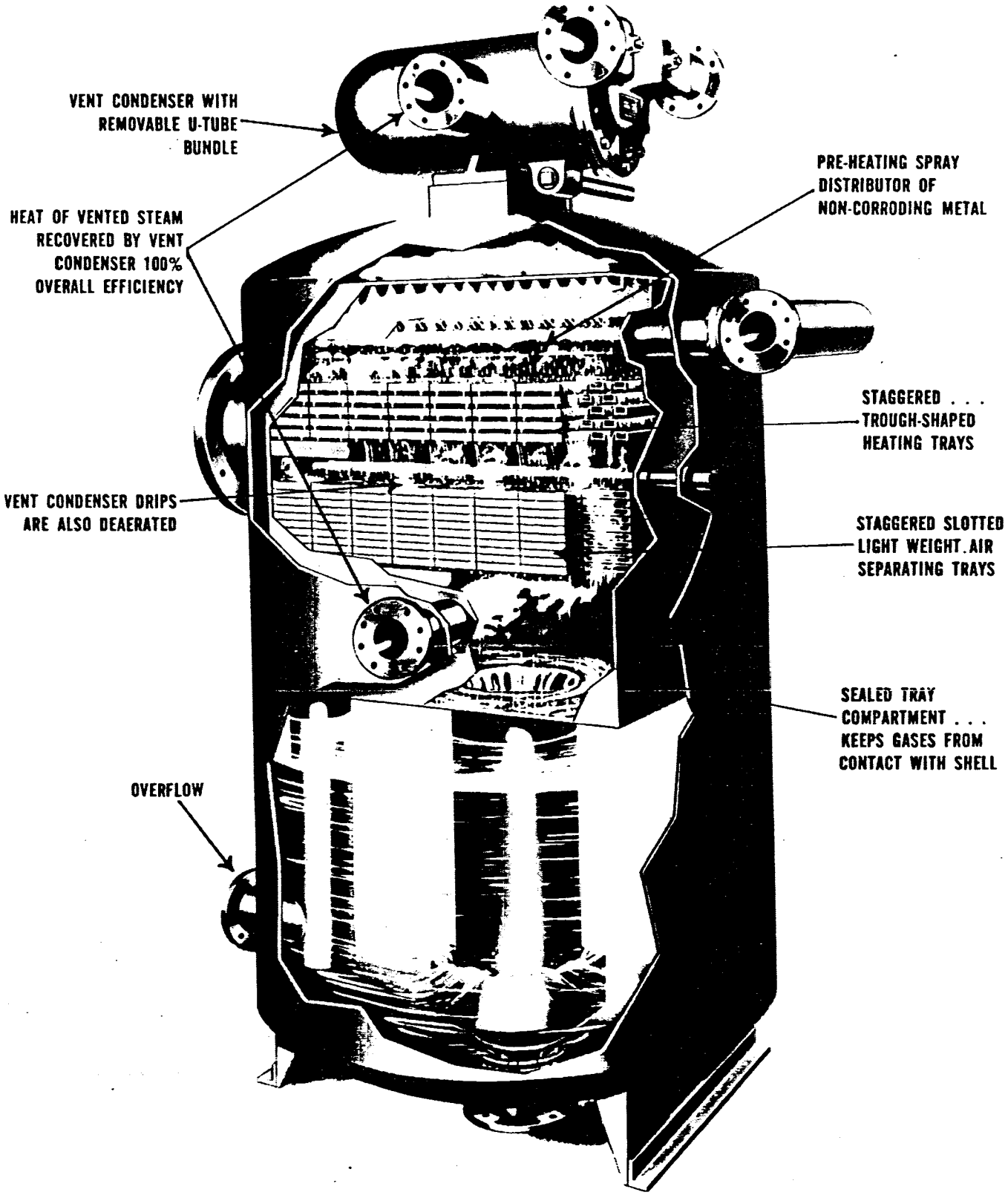


FIGURE 4-13. TRAY DEAERATOR

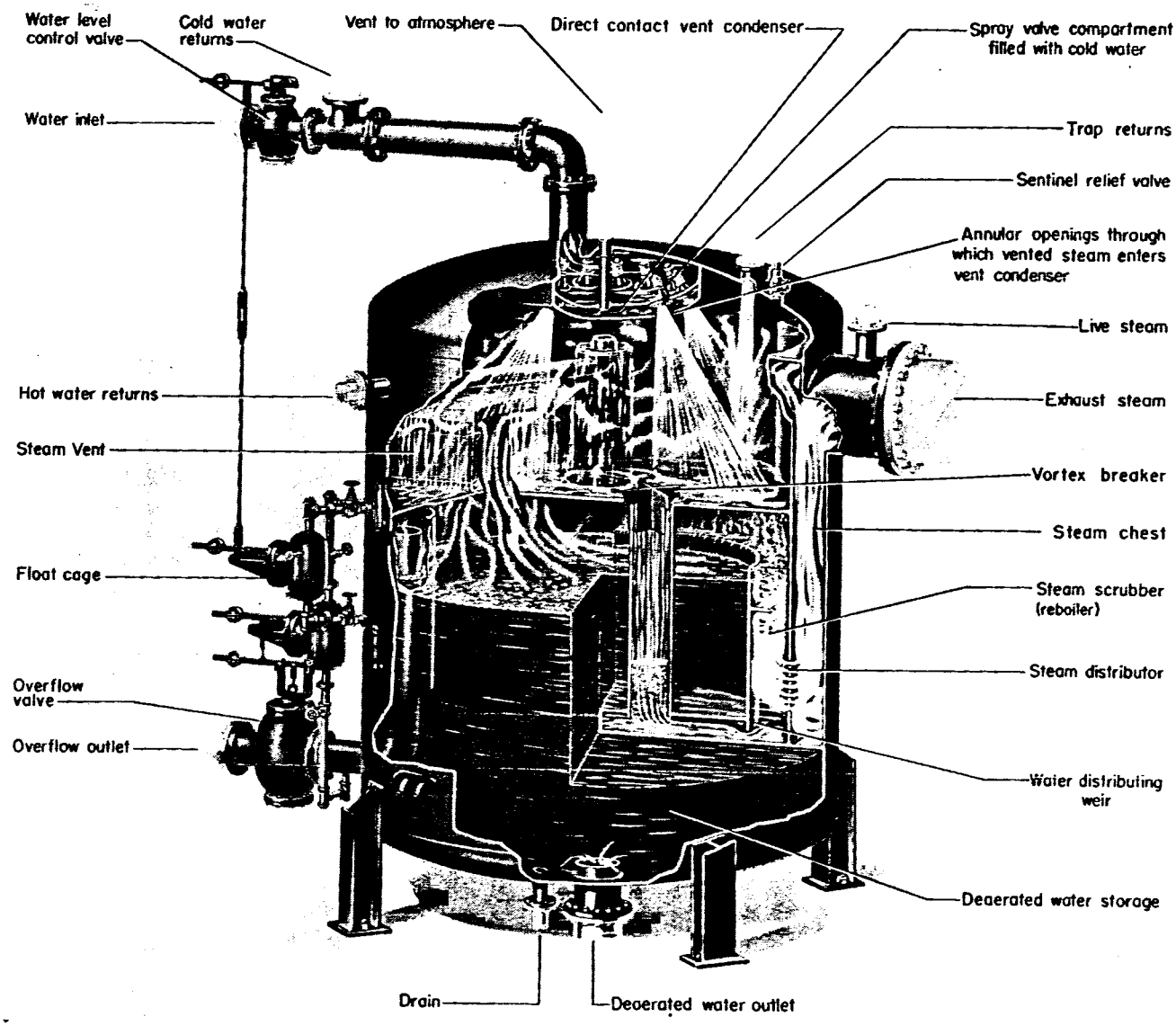


FIGURE 4-14. SPRAY DEAERATOR

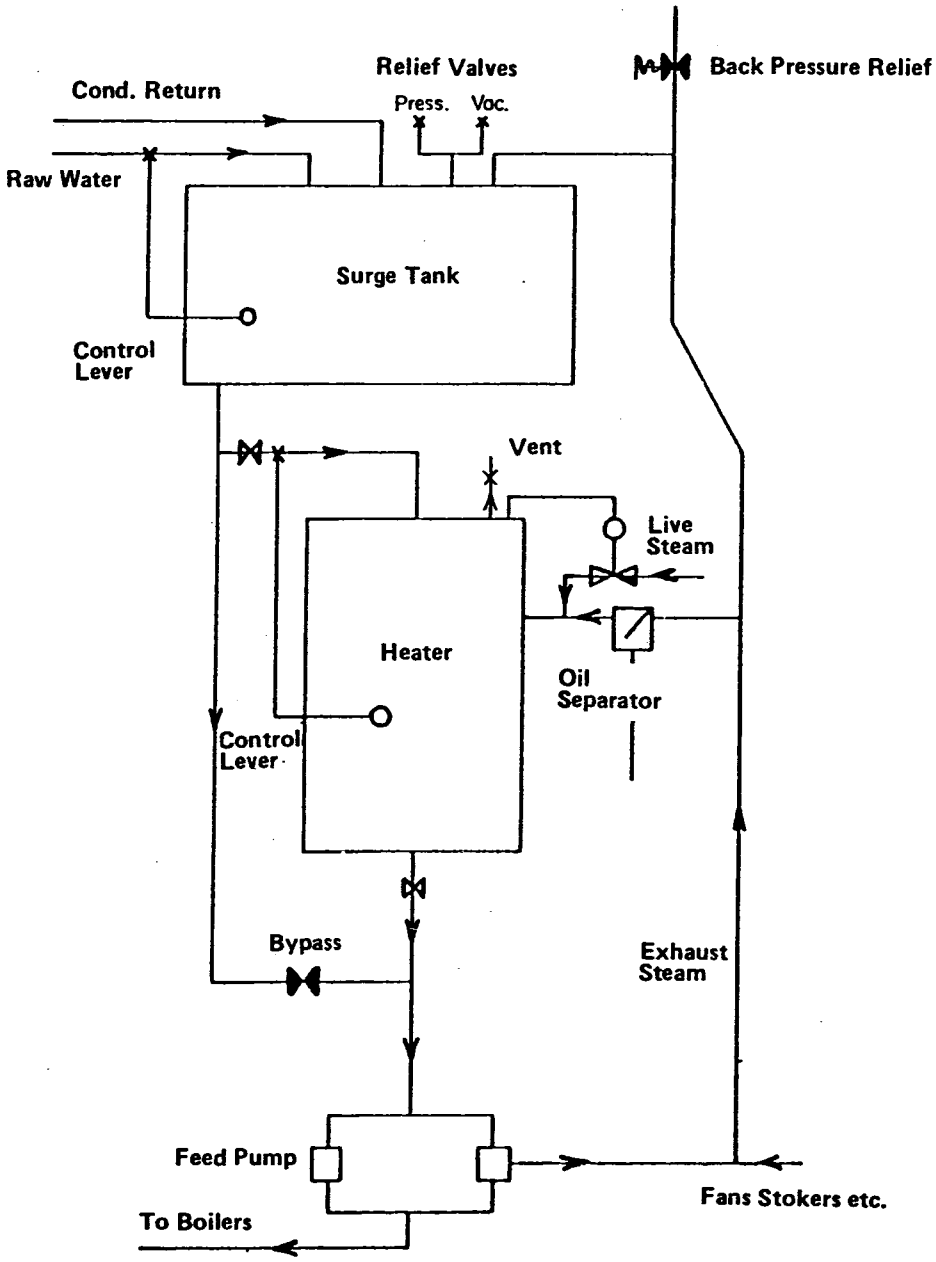


FIGURE 4-15. TYPE I DEAERATOR INSTALLATION

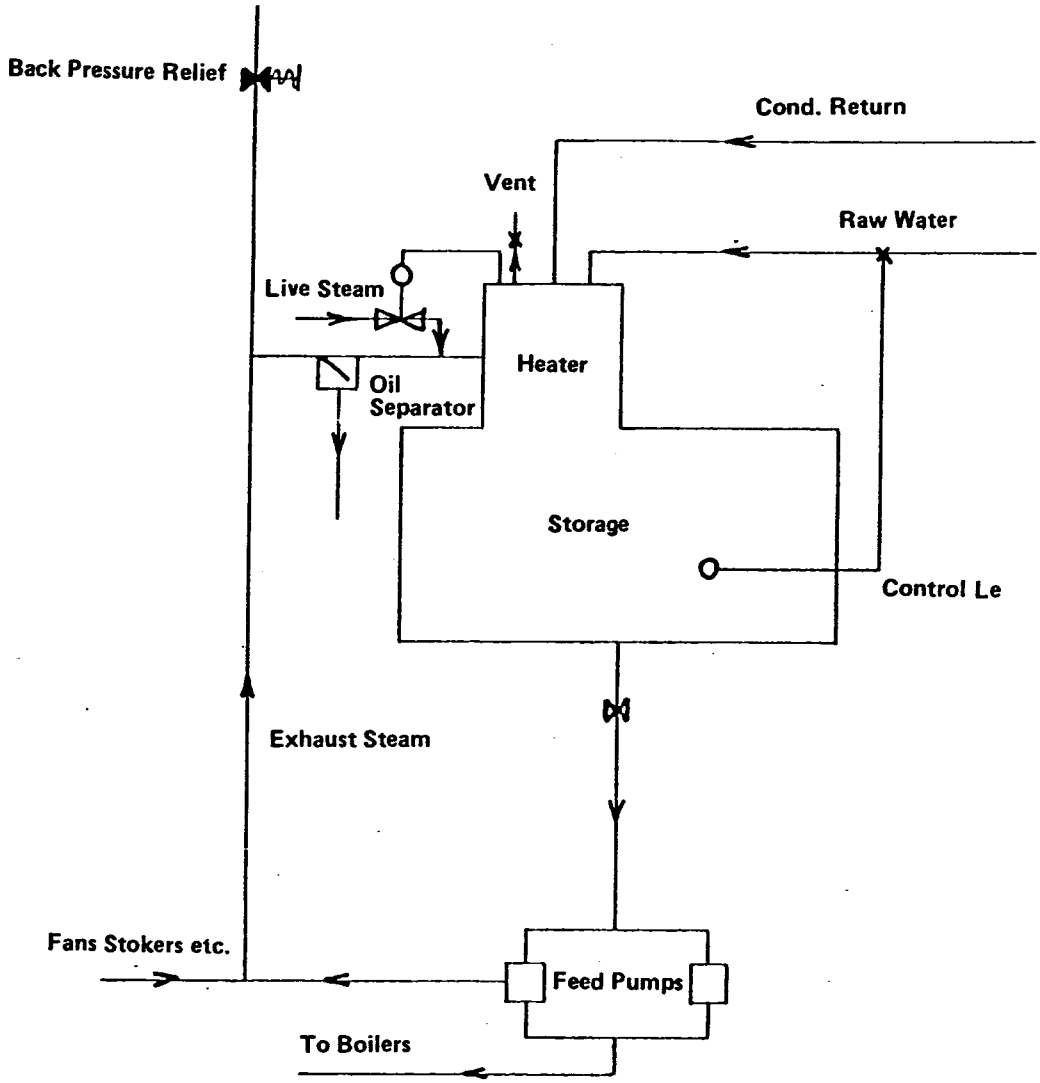


FIGURE 4-16. TYPE II DEAERATOR INSTALLATION

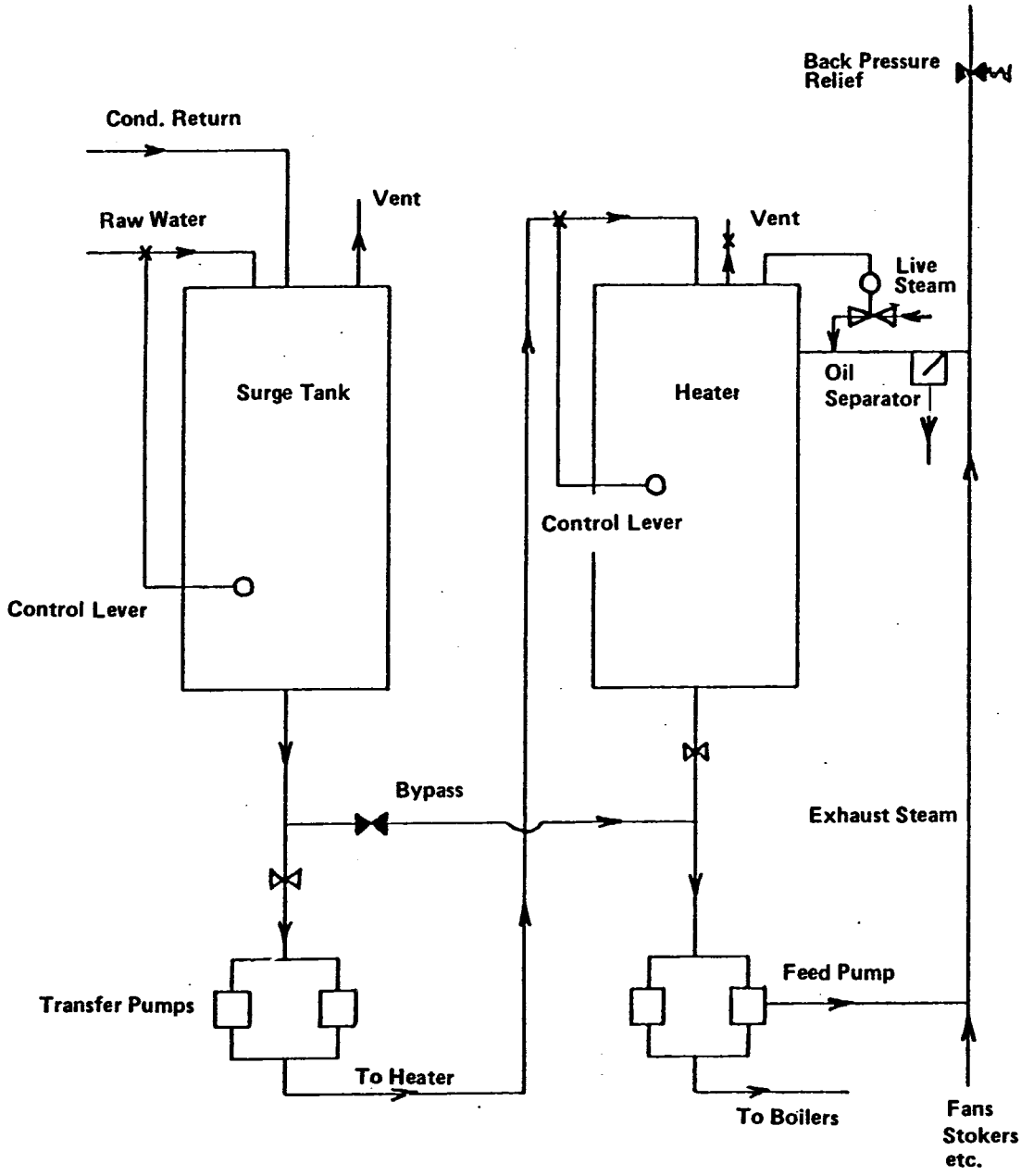


FIGURE 4-17. TYPE III DEAERATOR INSTALLATION

of condensate where the boiler load is primarily for space heating, or where large quantities of condensate are returned by the condensate pumps. Where steam-driven auxiliaries are used in the boiler plant, surge tanks should provide a minimum of 10 minutes storage of makeup water plus 20 minutes storage of condensate, based upon connected load.

(b) Vent Condenser. Deaerators are generally equipped with a vent condenser. Its purpose is to condense the vented vapors and to preheat the water before it enters the deaerating chamber, thus increasing the efficiency of the deaerator. A vent condenser is a tube-type heater mounted on top of the deaerating heater. It condenses most of the vented steam, leaving a higher percentage of oxygen to escape through the vent. The resulting condensate is returned to the deaerating section. The heat recovery secured through the use of a vent condenser permits a larger amount of steam to be vented from the deaerating section without loss of heat.

(c) Deaerator Bypass. Deaerators should be providedwith a valved bypass to permit operation of the boilers when the deaerator is being serviced.

(d) Instruments. Every deaerator must be equipped with a direct reading thermometer and pressure gage properly located and accessible for reading. Deaerator operation may also be checked continuously using a temperature and pressure recording instrument installed on the deaerator. The thermometer bulbs should be installed in the water space of the heater approximately four inches below the lowest water level. The pressure elements should be connected into the steam space. A makeup flow meter should be installed in the makeup water line to the heater and a condensate flow meter(s) should also be installed.

(e) Accessories. The use of a highly efficient oil separator is of primary importance if the exhaust steam from equipment in the steam plant contains oil. Sources of oil may be reciprocating pumps, engines, or compressors. Some deaerating heaters are equipped with oil separators, while they are offered as optional equipment on others.

4-7. INTERNAL TREATMENT

The following chemicals and equipment are used to control impurities inside a boiler or distribution system.

a. Maintenance of High pH.

(1) Caustic Soda. Caustic soda (NaOH) is used to increase the pH of feedwater. It provides alkalinity in the form of free hydroxide ions (OH-) to neutralize acidity of the boiler water. The proper pH provides the proper conditions for the precipitation of desirable sludges. Phosphate precipitates of calcium and magnesium formed when the pH of the water is less than 10.5 tend to be sticky, whereas if the alkalinity is higher the precipitates are in the form of a soft, finely divided sludge which can be easily removed by blowdown. Causticity of boiler water also raises the solubility of silica, helping to prevent the formation of silica deposits, and protects the boiler against corrosion by neutralizing the acids.

(2) **Soda Ash.** Use of soda ash (Na_2CO_3) is not authorized for boilers because it breaks down when heated to form hydroxide ions and carbor dioxide. It may be used however, when caustic soda is not available and alkalinity adjustment is necessary.

(b) Phosphate Chemistry. Phosphate in boiler water at the proper alkalinity (pH greater than (10.5) combines preferentially with calcium to precipitate a calcium phosphate, primarily tricalcium phosphate. Since tricalcium phosphate is insoluble in water, it is retained in suspension as a finely divided and fluid sludge which is easily removed by blowdown. One of many possible reactions can be represented as follows:

$$10Ca^{++} + 6PO_4 \text{---} + 2OH^- = Ca_{10}(PO_4)_6(OH)_2$$

While possessing many advantages when properly employed, phosphate internal treatment also has the disadvantage of increasing the tendency of boiler water carryover. This is due to the suspended calcium phosphate particles which tend to stabilize boiler water foam. Any of the sodium phosphate salts listed in Table 4-4 may be used. They all release phosphate ions in hot boiler water, which will react with calcium. Various factors must be considered before determining which of the phosphates listed in the table is best for a given plant.

(1) **Types of Sodium Phosphates.** The two basic groups of sodium phosphates are "orthophosphates" and "molecularly dehydrated polyphosphates." The orthophosphates react readily with calcium to form a precipitate. Orthophosphates must be fed directly to the boiler to avoid scale and plugging of the feedwater line. The dehydrated polyphosphates will not react with calcium until the molecule picks up water and is rehydrated. This is delayed reaction and in most cases it is possible to feed polyphosphates into the boiler feed pump suction or the feed line without the reaction occurring until the water is in the boiler. It is safest, however, to feed any phosphate directly into the boiler. Under no circumstances should any phosphate be injected ahead of or into a deaerating heater.

(2) Cost. The relative cost of phosphates may be evaluated on the basis of cost per pound of phosphorous pentoxide (P_2O_5). Column 4 of table 4-4, multiplied by cost per pound of the phosphate chemical, gives the cost per pound of P_2O_5 in that phosphate chemical. Hexametaphosphate is the most commonly used polyphosphate.

(3) **Alkalinity.** The alkalinity of the phosphate in boiler water must be considered in phosphate selection. Alkalinity is controlled with caustic soda which is inexpensive

Table 4-4. Common Sodium Phosphates

Name of Phosphate	Symbol	pH*	Percent P_2O_5 Content	Pounds Chemical Per Pound P_2O_5
	(1)	(2)	(3)	(4)
ORTHOPHOSPHATES				
Monosodium phosphate:				
Anhydrous	NaH_2PO_4	4.6	59	1.70
Monohydrate	NaH_2PO	4.6	52	1.92
Disodium phosphate:				
Crystalline	$Na_2HPO_42H_2O$	9	39	2.57
Anhydrous	Na_2HPO_4	8.8	48	2.08
Trisodium phosphate:				
Crystalline	$Na_3PO_412H_2O$	11.8	18.5	5.40
Monohydrate	$Na_3PO_4H_2O$	12	39	2.57
MOLECULARLY DEHYDRATED POLYPHOSPHATES				
Hexametaphosphate	1.1 Na_2:1 P_2O_5	6.7	67.5	1.48
Tetraphosphate	1.37 Na_2O:1 P_2O_5	8.5	62.5	1.60
Septaphosphate	1.2 Na_2O:1 P_2O_5	7.2	63.5	1.57
Sodium Tripolyphosphate	$Na_5P_3O_{10}$	9.5	57.8	1.73
Tetrasodium Pyrophosphate	$Na_4P_2O_7$	10.2	53	1.89

* One percent solution

compared with sodium phosphate. One of the reasons for the common use of hexametaphosphate is that it is almost neutral and therefore simplifies boiler treatment by not affecting alkalinity.

c. Oxygen Control. Although oxygen can be reduced to less than seven parts per billion in modern deaerators, it must be reduced even further with chemical scavengers. Sodium sulfite is the most common scavenger used. Oxygen is removed by producing soluble sodium sulfate. The reaction is:

$$Na_2SO_3 + \tfrac{1}{2}O_2 = Na_2SO_4$$

The reaction is slow at moderate temperatures. Catalysts such as copper and cobalt are sometimes added to the sulfite to enhance reaction in room temperature water. Catalyst feed is not necessary during normal unit operation because the trace metal content of makeup water is sufficient to catalyze the reaction. It is important to feed sodium sulfite at the earliest practical point in the system (preferably the deaerator storage section), to feed continuously, and to maintain sulfite residual according to levels recommended in paragraph 4-5. One disadvantage of sulfite treatment is that dissolved solids are added to the water. Oxygen control is as important in idle boilers as it is in operating boilers, and it is necessary to maintain proper sulfite residual while a boiler is shut down or in storage.

d. Dispersants. Unless the amount of material precipitated is very small, it is necessary to add dispersants to prevent the precipitated material from growing into aggregates. At high pressures, aggregates may become baked onto boiler tubes or form deposits that can lead to under-deposit corrosion.

(1) **Quebracho Tannin.** Quebracho tannin is often used as as dispersant in Army boilers. After calcium and magnesium have been precipitated as sludge, tannin keeps the sludge from jelling into large solid masses so that it can be carried by the circulating water and removed by blowdown. This decreases sludge accumulation and scale formation. Tannin also has a corrosion control property in that it absorbs some of the dissolved oxygen and forms a protective film on steel. Finally, quebracho tannin provides smoother boiling with less carryover. Although other organic chemicals, such as extracts from other woods and seaweed have also been used as sluge conditioners, quebracho tannin is recommended for use in Army steam boilers operating under 400 psig.

(2) **Sulfonated Lignins.** Sulfonated lignins, which are by-products of the paper industry, are economical disperants for phosphates and iron. They act by coating the particles to produce a clarified colloidal solution that can be controlled by continuous blowdown.

(3) **Synthetic Polymers.** During the past several years, a large number of polymer materials have been developed which can effectively and economically replace the natural disperants and coagulants. Polymers having properties of either cations or anions are available, as well as non-ionic materials. All of these materials may work effectively as dispersants, buy may also be effective coagulant aids depending upon the concentration in which they are employed. Care must be exercised in the selection of polymers and the concentration used to assure optimum use of the materials and avoid coagulation-related problems.

e. Carbon Dioxide Control. Condensate line corrosion is one of the most severe corrosion problems faced by the Army. Carbon dioxide control, along with oxygen control, is important in preventing condensate return line corrosion. Carbon dioxide corrosion usually grooves and channels the bottom of the pipe. Frequently, it is most pronounced just beyond the traps of hot-water generators or radiators. The problem of internal corrosion of condensate return lines would not exist if carbon dioxide and oxygen could be kept out of the lines. Unfortunately, this is not possible. Carbon dioxide may enter the system as free carbon dioxide in the makeup water or it may be generated in the boiler by the decomposition of carbonates and bicarbonates of sodium, calcium and magnesium. A typical reaction is:

$Ca(HCO_3)2$	+ heat =	$CaCO_3$	+ H_2O	+ CO_2
soluble calcium bicarbonate		calcium carbonate	water	carbon gas dioxide

The carbon dioxide is discharged from the boiler with the steam. It then redissolves, either in pockets of condensate in the steam line or in the return condensate and forms carbonic acid. Carbon dioxide and oxygen become more corrosive when combined than they are individually. Both external treatment in the form of ion exchangers or degasifiers and internal treatment using neutralizing amines can be used to control carbon dioxide corrosion. Filming amines, such as octadecylamine, are not authorized. As stated in Army Regulation 420-49, steam treated with authorized neutralizing amines (morpholine and cyclohexylamine) must not be used directly for humidifcation or cooking purposes. A steam generating heating exchanger must be installed to provide amine-free steam at all locations where steam is used for direct contact cooking or humidification. Before amine treatment begins, all possible water and steam losses must be eliminated.

(1) **Reduction of Water Losses.** The amount of bicarbonate and carbon dioxide entering the boiler can be reduced by minimizing condensate losses, and therefore makeup rate. The makeup rate for a well-operated heating plant should not exceed ten percent of total boiler steam generation. Poorly operating steam traps waste steam and cause losses which must be replaced by makeup water. Piping leaks should be located and repaired immediately.

Makeup can also be reduced by careful control of blowdown. Reduction of water losses is also important because it allows recycling of the amine treatment chemicals, thus reducing chemical quantities asnd costs.

(2) **Morpholine and Cyclohexylamine.** These amines are alkaline chemicals which volatize with the steam and combine with the carbon dioxide in sthe condensate to neutralize its acidity and protect against CO_2 corrosion. They are the only two amines presently authorized. They are usually used in 40 percent concentrations to minimize fire hazards. Distribution ratio (the ratio of concentration of the amine in steam to its concentration in water) is used as one means of selecting the proper material. At approximately 100 psia, a common distribution system pressure, ammonia has a distribution ratio of 10, cyclohexylamine about four and morpholine only about four-tenths. When steam first condenses, morpholine will be present in a larger concentration, due to its favorable distribution ratio, while at more distant points in the distribution system, cyclohexylamine will be available in large concentrations. These two chemicals are often used together to provide maximum protection. The proportion of the chemicals is determined by trial and error, starting with a mixture of 75 percent morpholine and 25 percent /clohexylamine. Tests required are described in paragraph 4-15. If corrosion or a low pH is found toward the end of the distribution system, the percentage of cyclohexylamine is increased. If corrosion or low pH is found toward the beginning of the distribution system, the percentage of morpholine is increased. If the corrosion is found in the middle of the distribution system, additional quantities of both morpholine and cyclohexylamine may be required. Feeding to an operating boiler must be continuous and at a rate sufficient to maintain a minimum pH of 7.5 to 8.0 at all points in the distribution system. Testing for condensate corrosion is discussed in paragraphs 4-14 and 4-15.

f. Low Temperature Water Treatment. For low temperature water systems operating at 250° F or less, there are a number of treatments which can be employed. In fact, treatments which are commonly used in cooling water systems can provide excellent corrosion control in LTW systems as well. A treatment which will generally provide good corrosion control is one employing borax and nitrite. This treatmentl is normally applied with levels of 1,500 to 2,500 ppm (or as recommended by the chemical supplier) as formulated compound maintained in the loop to be treated. Borax-nitrite treatment is easy to control in a water system which has little leakage and low makeup. Periodic analyses should be performed. Weekly tests are suggested with the nitrite residual being measured. The chemical concentration should be readjusted to maintain residuals in the range of 1,500-2,500 ppm. Nitrite reducing bacteria can periodically infest a system and rapidly deplete the nitrite in the water. Depending on the operating temperature of the system, these bacteria may or may not be sterilized. If they are not sterilized, rapid depletion of nitrite will occur and the solution will not adequately protect the system from corrosion. Weekly tests will indicate this condition. Copper corrosion inhibitors are frequently added with the borax-nitrite when copper alloy heat exchangers are included in the distribution system.

4-8. BLOWDOWN

The following equipment is used to provide an economical, continuous blowdown system on steam boilers.

a. Flash Tank with Heat Exchanger System. When blowdown water leaves the boiler, whether from a bottom purge or a continuous surface blowoff, it is a hot, pressurized liquid. The sudden reduction to atmospheric pressure causes some of this liquid to flash into steam. For safety reasons, this change of phase must occur in a specially designed vessel called a flash tank. The steam from the flash tank can then be passed through the feedwater heater. The hot water flowing from the flash tank usually contains enough heat to justify passing it through a heat exchanger to preheat makeup water. Reference figure 4-18. This equipment is economical to install on any size boiler or group of boilers. For boilers operating below 15 psig, and some boilers operating at higher pressures and makeukp water rates, the heat exchanger alone is sufficient to cool the blowdown water to the point at which it can be discharged into the sewer.

b. Conductivity Meter and Automatic Controls. Blowdown can be automatically controlled through the use of a conductivity sensor. The conductivity sensor works on the principle that ionizable solids in the boiler water cause the solution to conduct electricity. The higher the concentration of ionizable salts present, the greater will be the conductance of the sample. The controller opens and closes the blowdown valve as required to maintain the proper conductivity. Figure 4-19 diagrams the automatic continuous blowdown controls. This equipment is economical to install on many boilers, especially where chemistry and dissolved solids are difficult to control. A conductivity meter should preferably have a minimum range of 0 to 5,000 micromhos. This will allow analysis of either boiler water or condensate. Automatic or manual temperature compensation should also be included. The meter shown on Figure 4-20 is available from USAEHSC on "Order Blank - For Boiler Water Testing Equipment," Form No. 278. This meter has a five-position switch which allows for five ranges, 0 to .5, 0 to 5, 0 to 50, 0 to 500, and 0 to 5,000 micromhos. Conductivity meters with scales showing total dissolved solids (TDS) should not be used

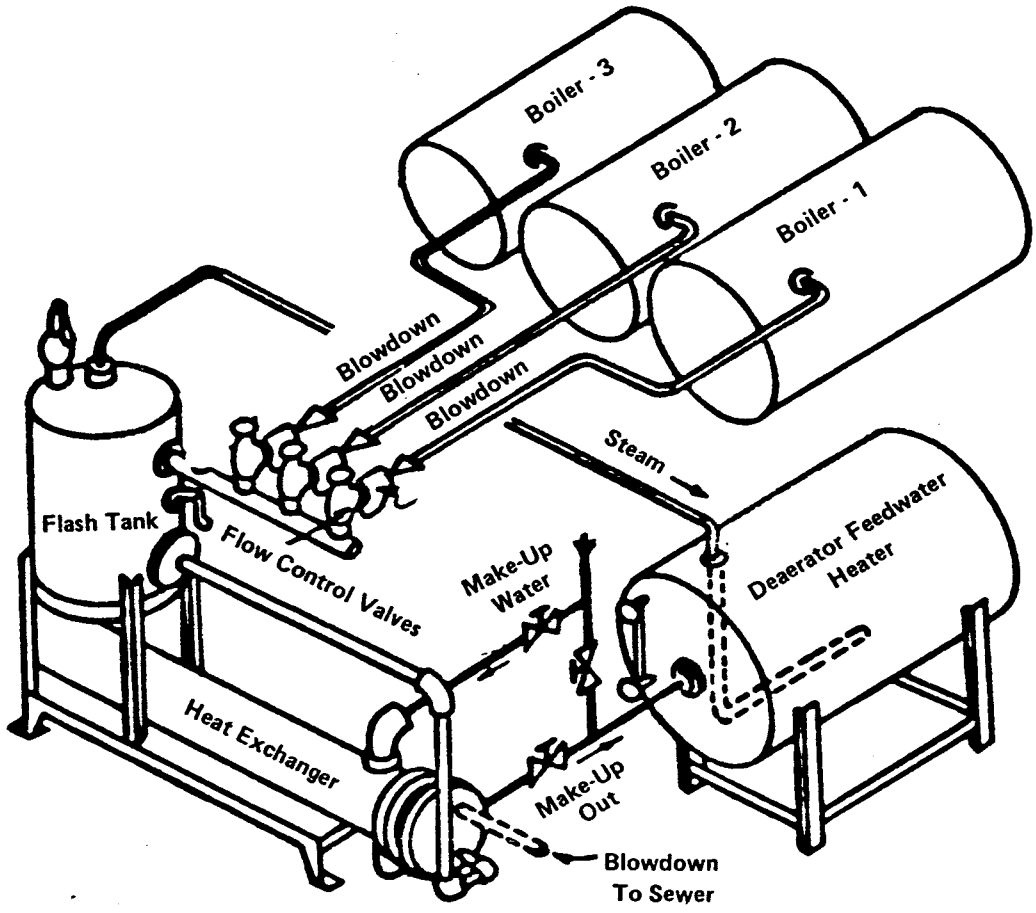


FIGURE 4-18. BLOWDOWN SYSTEM WITH FLASH TANK AND HEAT EXCHANGER

since the conversion factor from micromhos to TDS is unknown and must be adjusted for different boiler waters and condensate. Reference appendix B, paragraph B02e for conductivity test procedure for boiler water.

SECTION III. OPERATION

4-9. BOILER WATER TREATMENT OPERATING LOG

An example of the monthly Repair and Utilities Operating Log (Boiler Water Treatment), DA Form 4367, is shown in figure 4-21. Regulation requires this log to be maintained in plants operating above 15 psig steam or 300 psig water with an output capacity above 3.5 MBtu/hr or 100 horsepower. This log provides a record of boiler, makeup and condensate water treatment and test results. The data obtained from this log makes an accurate analysis of plant operation possible. Entries are made in columns. An explanation on the use of each column is on the back of the form. One log should be maintained for each boiler and one for plant makeup water data. Columns 19 and 20 may be used to record condensate conductivity and hardness. If a boiler is secured in a wet condition, causticity and sodium sulfite residual should be indicated in the remarks block. If the boiler is secured dry, the frequency of desiccant inspection should be indicated. Organized operating logs should also be maintained for low pressure boilers and for HTW, MTW, and LTW systems. The logs should contain the following information: results of all chemical tests, dates tests performed, amounts of chemicals added, dates chemicals added, and amount and time blowdown performed. Periods of boiler layup and downtime maintenance should also be recorded.

4-10. PROCUREMENT OF STANDARD AND SPECIAL TREATMENT CHEMICALS

Prescribed chemicals for boiler plant water conditioning may be procured as listed below.

a. Caustic Soda. Specify: "Caustic soda for boiler feedwater treatment; to contain not less than 76 percent sodium oxide (Na_2O) and be in flake form." As it absorbs moisture readily and becomes sticky, specify shipment of the chemical in 100-pound steel drums. This chemical may be procured from commercial sources.

b. Sodium Phosphate. Sodium phosphates may be specified with reference to table 4-4. Example: For sodium metaphosphate specify "Compound, boiler feed water, Type II sodium phosphate, glassy, 67 percent P_2O_5." The chemical is shipped in 100-pound bags and may be procured from the Federal Supply Schedule.

c. Quebracho Tannin. Specify: "Quebracho tannin, solid, for boiler feedwater conditioning; suitably processed to obtain easy solubility; shall be of the following composition: shall contain not less than 65 percent quebracho tannin, not more than 17 percent non-tannin, nor more than 1 percent insoluble, and not more than 20 percent water; packed in 100-pound bags." This chemical may also be procured from the Federal Supply Schedule.

d. Sodium Sulfite. Specify: "Sodium sulfite (Na_2SO_3), anhydrous, for boiler feedwater treatment; to contain at least 90 percent Na_2SO_3, the remainder to be primarily sodium sulfate (Na_2SO_4), sodium carbonate (Na_2CO_3), with less than 1 percent moisture; a 10 percent solution to be alkaline to phenolphthalein."

e. Antifoams. For antifoam or other special water treatment chemicals, consult the operating agency commander for the proper chemical to use and the correct method of application.

f. Rock Salt. A good grade of rock salt is preferable sto granulated salt for regeneration purposes. Rock salt does not cake, as do many grades of granulated salt, and it is equally effective as a regenerating agent. The salt should contain not less than 98 percent sodium chloride with a minimum of calcium and magnesium salts, contain less than 1.5 percent of dirt or other insoluble matter, and have a grain size within the 10 to 50 mesh range.

g. Morpholine. Specify "Morpholine (C4H9NO), boiler feedwater compound, used to control carbon dioxide corrosion in steam condensate lines; 40 percent morpholine content; all drums to bear adequate caution labels to protect against fire, poison, and caustic burn hazards; packed in 480 pound drums (55 gallon drums)." Available from the Federal Supply Schedule.

h. Cyclohexylamine. Specify "Cyclohexylamine ($C_6H_{11}NH_2$) boiler feedwater compound, used to control carbon dioxide corrosion in steam condensate lines; 40 percent cyclohexylamine content; all drums to bear adequate caution labels to protect against fire, poison, and caustic burn hazards; packed in 420 pound drums (55 gallon drums) or packed in 40 pound drums (5 gallon drums.)" Available from the Federal Supply Schedule.

i. Proprietary Compounds. As a general policy, use of premixed chemical compounds is not authorized. Such compounds, if proportioned correctly for a specific water, generally cannot be used advantageously without change for water of a different analysis. As the boiler compound is a fixed mixture of chemicals, there is no way to adjust the dosages of individual chemicals for maintaining the desired concentrations of each in the boiler. Exceptions

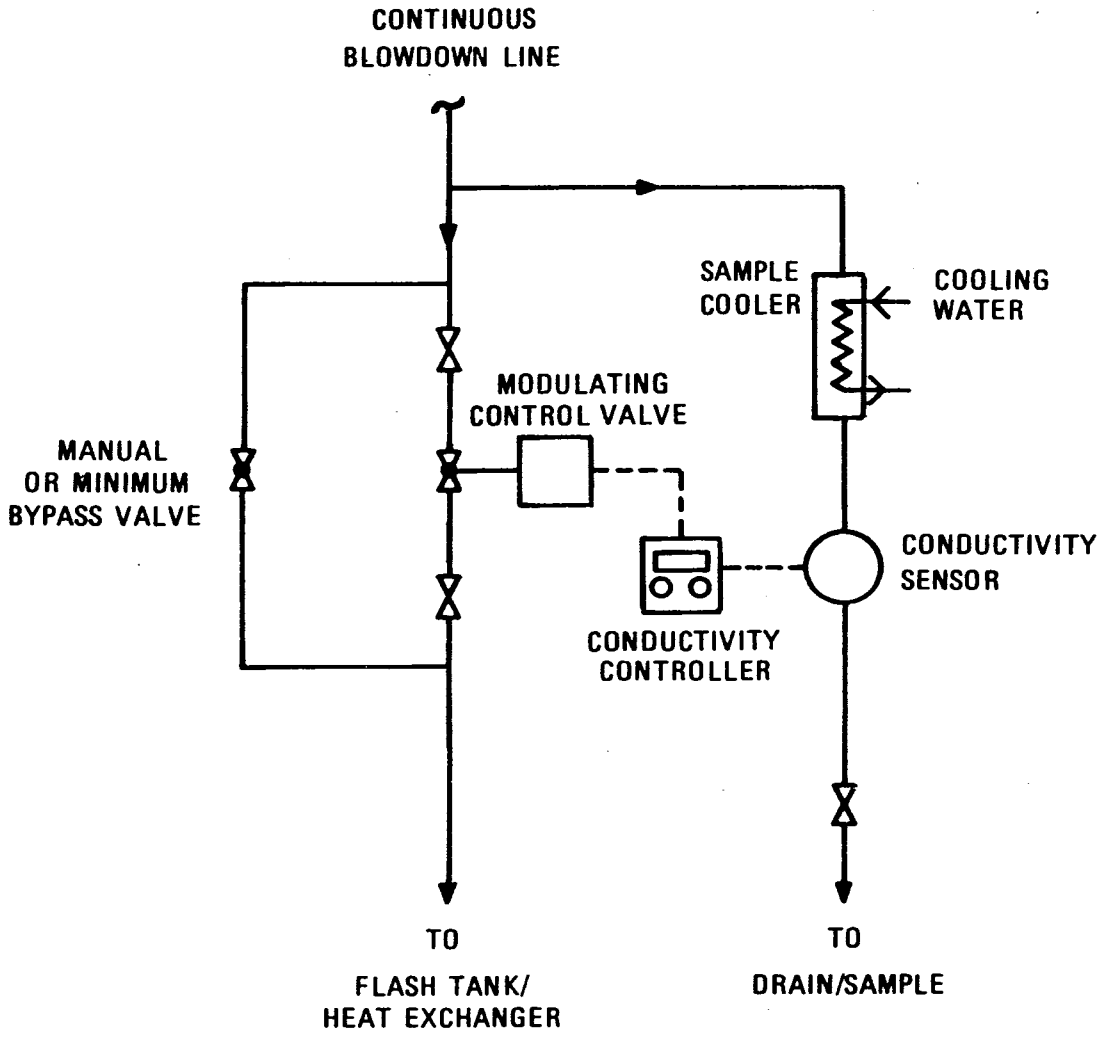


FIGURE 4—19. AUTOMATIC CONTINUOUS BLOWDOWN CONTROLS



FIGURE 4-20. CONDUCTIVITY METER

REPAIRS AND UTILITIES OPERATING LOG
(Boiler Water Treatment)
For use of this form, see AR 420-52; the proponent agency is Office of the Chief of Engineers.

INSTALLATION: FT. GOOD | PLANT: CENTRAL | BUILDING NUMBER: 1520 | MONTH OF: APRIL, 1988

DAY OF WEEK	BOILER NO.	CHEMICAL ANALYSES – BOILER WATER: PHOSPHATE Limits 30 - 60 P.P.M.(PO4)	CAUSTICITY Limits 20 - 200 P.P.M.(CaCO3)	TANNIN Limits M (V. LT., LT., D., DK., V. DK.)	SODIUM SULFITE Limits 20-40 P.P.M.(residual)	TOTAL DISSOLVED SOLIDS Limits 3000 - 3600 P.P.M.	BLOW DOWN BOILER SYSTEM: INCHES GAGE GLASS	CHEMICALS ADDED BOILERS: CAUSTIC SODA	PHOSPHATE	TANNIN	SODIUM SULFITE	CHEMICAL ANALYSIS – CONDENSATE: STEAM HEADER pH	RETURN SYSTEM pH	CHEMICALS ADDED – CONDENSATE RETURN SYSTEM: NAME OF CHEMICAL: CYCLO HEXAMINE LBS.	PINTS	WATER SOFTENED: SOD. CYCLE ZEOLITE 1,000 GAL.	SALT ADDED LBS.	HYD. CYCLE ZEOLITE 1,000 GAL.	H2SO4 ADDED LBS		
		P.P.M.	P.P.M.		P.P.M.	P.P.M.	SECONDS	(X or OZ)	OZ	OZ	OZ										
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
F	1	50	140	M	35	3200	30	4	4	6	8	11.0	8.0		4	6760	160				
Sa	1	60	180	M	40	3000	30	4	4	6	8	11.1	8.2		4	5700					
S	1	70	220	DK	45	2800	30	3	3	4	8	11.1	8.3		4	5760					
M	1	70	200	DK	40	3100	30	3	3	4	8	11.0	8.0		4	4500					
T	1	60	180	M	35	3500	30	3	3	6	8	11.1	8.2		4	6590					
W	1	50	160	M	40	3800	30	4	3	6	8	11.0	8.0		4	6600					
Th	1	40	140	M	35	3400	30	4	3	6	8	11.0	7.8		4	6710					
F	1	40	140	M	30	3100	30	4	4	6	8	10.9	7.8		4	6640	160				
Sa	1	50	160	M	35	3000	30	4	4	6	8	11.0	8.0		4	5540					
S	1	50	160	M	40	2700	30	4	4	6	8	11.1	8.2		3	5540					
M	1	40	140	M	40	3100	30	4	4	6	8	10.9	7.8		4	6600					
T	1	40	120	LT	35	3300	30	4	4	8	8	10.9	7.6		4	6510					
W	1	30	100	M	35	3300	30	4	4	6	8	11.0	8.0		3	6400					
Th	1	30	120	M	30	3200	30	4	4	6	8	11.1	8.2		3	6450					
F	1	30	100	M	35	3400	30	4	4	6	8	11.1	8.0		3	6390					
Sa	1	40	120	M	40	3300	30	3	3	6	6	11.1	8.2		3	5200	160				
S	1	40	140	M	45	3200	30	3	3	4	4	11.2	8.4		3	5010					
M	1	30	120	M	35	3500	30	3	3	4	6	11.2	8.4		3	5300					
T	1	40	100	M	30	3600	30	3	3	4	6	11.0	8.0		3	5150					
W	1	40	100	M	35	3400	30	3	3	4	6	11.0	8.0		3	4310					
Th	1	40	120	M	35	3400	30	3	3	4	6	11.0	7.8		3	4200					
F	1	40	100	M	30	3300	30	3	3	4	6	11.0	7.8		3	4150					
Sa	1	50	120	M	35	3100	30	3	3	4	6	11.0	8.0		3	4010					
S	1	60	120	DK	40	3000	30	3	3	2	6	11.1	8.2		3	4050					
M	1	60	100	DK	35	3000	30	3	3	2	6	11.0	8.0		3	4100					
T	1	50	80	M	30	3100	30	4	3	4	6	11.0	7.8		3	4070					
W	1	40	100	M	25	3400	30	4	3	4	8	11.0	8.0		3	4090	160				
Th	1	40	120	M	25	3500	30	3	3	4	8	10.9	7.8		3	4050					
F	1	30	120	M	30	3400	30	3	4	4	6	11.0	7.8		3	3830					
Sa	1	30	140	M	30	3400	30	3	4	4	6	11.0	8.0		3	3710					

REMARKS

WENT TO SUMMER OPERATING MODE 4/16 CLOSED SOUTH HEADER 4/19

SEE REVERSE SIDE FOR INSTRUCTIONS | PREPARED BY: Gary Clark | DATE: 5/2/88 | APPROVED BY: Robert L Greene | DATE: 5/3/88 | POST ENGINEER: James R Lobb | DATE: 5/6/88

DA FORM 1 APR 75 4367 REPLACES DA FORM 8-97, 1 JUN 50, WHICH WILL BE USED.

FIGURE 4-21. BOILER WATER TREATMENT OPERATING LOG

may be authorized by Office Chief of Engineers. Also, exceptions are made in the use of proprietary briquettes for power plant water conditioning in a theater of operations.

j. Magnetic and Electromagnetic Descaling Devices. A variety of magnetic and electromagnetic devices are currently manufactured that claim to reduce both corrosion and scale with substantially no technical control. Several commercial units were evaluated under field and laboratory conditions. These tests did not provide any indication that the devices were effective in preventing or reducing scale, or in improving boiler efficiency. Army-wide use of magnetic descalers is not recommended, based on these findings. Moreover, current operation of such devices at Army facilities should be quantified and validated.

4-11. CARE AND MIXING OF TREATMENT CHEMICALS

Chemicals are received in a dry state, and must be properly stored to prevent contamination and absorption of water. Precautions must be taken in mixing and handling chemicals to ensure that accurate quantities are used, and to prevent contact with chemicals which could cause injury.

a. Storage. Store all chemicals in a dry place, at floor level, free from contact with foreigh substances.

b. General Precautions. Avoid getting chemicals on the skin. Wear work gloves and eye protection while handling chemicals, either in dry form or in solution. Add chemical solutions to the feeding device immediately after preparation. The use of a properly designed screen to remove foreign material from the solution before feeding is desirable to prevent line stoppages. If chemicals such as flake caustic contact the skin, they must be rinsed with large quantities of water. If any chemical solutions splash in the eyes, rinse immediatley with large quantities of water. Refer to paragraph 4-18 for additional safety precautions.

c. Methods of Mixing/Makeup of Chemical Dosage.

CAUTION

Mix chemicals at floor level or in an approved open feeder to avoid injury to eyes or face.

Do not mix batches of chemicals in advance of immediate requirements, as this defeats the purpose of the treatment and complicates control of the individual chemical concentrations in the boiler water. Individual chemicals are used in boiler water treatment rather than ready-mixed compounds because they permit better control of concentration. Improper chemical concentrations are not effective in protecting the internal water-contacted surfaces of the boiler against scale and corrosion. A chemical analysis of boiler water should be made so that the chemical demand of the water may be determined. The treatment requirements are described in paragraph 4-5.

(1) **Solution of Tannin and Phosphate.** Tannin is dissolved in hot water at approximately 160° F to 180° F in a clean metal container. Stir until the tannin is completely dissolved. Mix phosphate separately in water at approximately 150° F in a clean metal container, and stir until all phosphate is dissolved. Mix the two solutions before placing in chemical feeding device.

(2) **Solution of Caustic Soda.**

CAUTION

Do not use hot water for the solution of caustic soda, as splashing and possible serious injury will result. Wear goggles and rubber gloves when mixing this chemical. Do not pour cold water on caustic soda as splashing and possible serious injury can result. Add the caustic soda gradually, with constant stirring, to an adequate quantity of cold water.

(3) **Solution of Sodium Sulfite.** Mix sodium sulfite solution just before use in cold water and with minimum exposure to air. If mixed too soon, the chemical is useless for boiler water treatment because it will react with oxygen from the air which dissolves in the solution. Use the minimum amount of mixing to dissolve the chemical.

4-12. INITIAL FLUSHING AND CLEANING

Contracts for installation of new boilers generally require removal of all foreign material followed by an initial boiling-out period with a chemical solution. If chemical cleaning is considered necessary after acceptance of the boiler, follow the steps below.

a. Before the boiling-out procedure has begun, replace high pressure gage glasses with temporary glasses to prevent attack on the glass by the boil-out mixture.

b. Chemicals in the following proportions should be thoroughly dissolved in the water before being placed in the boilers:

24 pounds caustic soda
24 pounds disodium phosphate (anhydrous)
8 pounds sodium nitrate
½ pound suitable wetting agent
1,000 gallons water

c. Fill the boiler with the above solution and operate at approximately 30 to 50 psig for a period of 24 to 48 hours, exhausting the steam to atmosphere.

d. Open and drain the boiler. Remove any loose material.

e. Flush the boiler thoroughly to ensure that none of the chemicals used in the boiling-out process remain in the boiler.

f. To remove oily residue which will cause foaming in the boiler water and contamination of steam, provide

adequate blowdown during the first week of boiler coperation.

4-13. FLUSHING AND CLEANING OF SCALED AND CORRODED BOILERS

Many used boilers are scaled and corroded upon installation. If corrosion appears to be serious, make an immediate boiler inspection. If the scale is moderate or light, remove as follows:

a. Clean out all loose scale, and any scale adhering to the boiler which can be removed manually.

b. Place in the boiler approximately 15 pounds of caustic soda and 10 pounds of phosphate for each 100 horsepower or 3450 pounds of steam per hour boiler capacity. Seal the boiler openings and open all vents. Fill the boiler approximately three-quarters full with water.

c. Use a small fire in the furnace and raise the temperature of the water in the boiler to approximately 200° F. Maintain this temperature for 24 to 48 hours. Add makeukp water as required during this period to fill the boiler to the base of the safety valves.

d. Analyze the boiler water during the boil-out period and add caustic soda and metaphosphate to maintain the following concentrations:

Hydroxide: 300 to 500 ppm
Phosphate: 100 to 150 ppm

e. Open the boiler at the end of the boil-out period and clean out the sludge and loose scale. Pay particular attention to removing scale and sludge from water legs in fire-tube boilers. Flush the boiler thoroughly.

f. If, at the end of the boil-out period, inspection shows that heavy or hard scale was not removed, use of an acid to remove the scle is indicated. Notify the operating agency commander. Due to the hazards involved and the possibility of damage to the boiler when acid cleaning large steel boilers, use firms specializing in this type of work.

g. If extensive corrosion is exposed when scale is removed, have a boiler inspection made by an approved agency.

h. When the boiler is operated, any residual scale may cause faulty operation. Sufficient and frequent blowdown must be used to maintain dissolved solids at a maximum of 3,500 ppm. take the boiler out of service at frequent intervals to remove sludges formed from disintegrated scale.

4-14. SAMPLING

Samples are obtained and tested so that treatment chemicals can be maintained within proper limits and blowdown can be controlled. The samples should be representative of the water to be tested. This can be accomplished by using proper sampling points asnd methods. All samples must be drawn before chemicals are added to determine the minimum concentrations of the chemicals available in the boiler. Samples must be drawn before the bottom is blown down to determine the maximum total dissolved solids content of the boiler water.

a. Samples for Check Analysis. Army Regulation 420-49 requires samples to be submitted to an adequately equipped laboratory for check analysis. The samples are submitted to assist operating personnel in correcting faulty analytical techniques, in providing a quality check of reagents, and in making available a basis for evaluation of compliance with residual requirements. The USAEHSC Laboratory, Fort Belvoir, Virginia, performs the check analyses on samples submitted from Army installations. In overseas commands where shipment of samples to the United States is not feasible or expeditious, samples will be sent to a central laboratory established by the command. Reports on sample analyses are returned through command channels asnd include appropriate technical comments.

(1) Each operating boiler plant equipped with hot water or steam boilers with one or more boilers of 3.5 MBtu/hr or 100 horsepower or greater capacity must submit a sample for check analysis each month.

(2) Each operating boiler plant equipped with hot water or steam boilers of less than 3.5 MBtu/hr or 100 horsepower capacity shall submit a sample for check analysis once every three months.

(3) Submit a 32-ounce sample for all high pressure (15 psig or greater) boilers and low pressure boilers treated with caustic, phosphate, tannin, and sodium sulfite.

(4) Submit a 4-ounce sample for low pressure boilers (less than 15 psig) treated with caustic only.

(5) Submit a 32-ounce sample for hot water boilers.

(6) Sample shipping containers and bottles for submission of boiler water for check analyses are obtained by direct request to USAEHSC. In overseas areas when the command has established a central laboratory for the analysis of boiler water, sample containers and bottles should be obtained from that source. Containers for high-pressure boiler water samples are designed to ship a 32-ounce plastic bottle. Containers for water samples from low-pressure boilers treated with caustic soda are designed to ship a 4-ounce plastic bottle. Pack the bottle carefully so that it will not leak in shipment. A data sheet is enclosed in each sample container. Completely fill out the data sheet and ship it with the sample.

b. Water Sample Collection. A water sample should be drawn through a cooling coil that prevents the flashing of the boiler water into steam. An air-cooled coil can be used if the sample is drawn slowly, but best results are obtained by using a water-cooled coil such as the one shown in figure 4-22. If boiler water is taken without cooling, it becomes concentrated because a portion of the water flashes into steam. Blowdown based on the testing of a

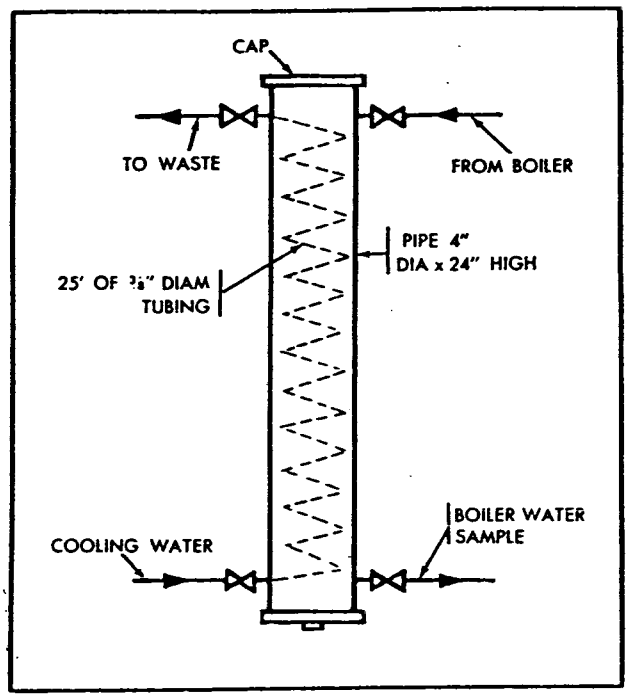


FIGURE 4-22. WATER COOLED SAMPLE COOLER

concentrated sample will be too high, resulting in unnecessary chemical and energy costs. It is important to flush the sample line and cooler thoroughly before taking a sample.

c. Location and Sizing of Lines. Use the manufacturer-supplied sample connection when provided. Water column connections may be used if sample connections are not provided. Blow the water column down several times and draw a sample from a ¼-inch sampling connection installed ahead of the water column blowdown valve. Properly located continuous blowdown connections can also make good sampling points. If the sample connection is close to the feedwater inlet, be sure that the sample is not diluted by feedwater. Pipe all sample connections to floor level for convenience and safety. Connect the sample cooler to the sample line. It is desirable to locate the sample cooler near the laboratory sink where tests for boiler water residuals are made.

d. Steam Sampling Nozzle. A separate steam sampling nozzle is desirable to ensure that a representative sample is obtained from each individual boiler. The nozzle and method of connection should conform to the American Societey for Testing and Materials (ASTM) Method D1066. A sample cooler other than the one used for sampling boiler water must be used for steam sampling because of the possibility of collecting residual boiler water solids. All piping, connections, and valves conveying the steam to the sample cooler must be corrosion-resisting material, such as copper, brass, or stainless steel. The steam sample is taken in the following manner:

(1) Flush the sample line and cooler thoroughly. Flush out new steam sampling equipment for 24 hours before using it to collect steam samples.

(2) Draw the sample slowly and bring it to about 70° F. (unless the test calls for a higher temperature) by regulating the flow of cooling water.

(3) Rinse the collecting container at least three times with the sampling water before collecting the sample.

(4) Collect about a pint (500 ml) of sample in a thoroughly cleaned glass container. Note that a sample of steam drawn when the velocity of the steam in the main is high is more representative than a sample drawn when the velocity is low.

4-15. CHEMICAL ANALYSIS

The chemical analysis performed on boiler water has the purpose of accurately determining the chemical makeup of the water. Accurate analysis is important step in protecting equipment from excessive corrosion and scale, and at the same time maintaining the most economic production of steam or hot water.

a. Authority for Tests. Test kits and analysis equipment are provided by the Army for regular use with each boiler. The equipment and tests have been developed by the boiler manufacturers and government chemical analysis laboratories to give accurate and timely information on boiler water conditions that are unique to each installation. There may be other tests for a given parameter of boiler performance; however, a good general rule is, "If the equipment and the test procedures are not discussed by this manual, THE TEST IS NOT AUTHORIZED." Other procedures may be too costly or time-consuming to perform on a regular basis and the results of such unauthorized tests can require an extraordinary level of training for proper interpretation.

b. Test Scheduling. Tests should be run according to the schedule below. The procedures for these tests are outlined in appendix B.

(1) **Boiler Water.** All boilers of 100 horsepower or more are tested daily. Boilers less than 100 horsepower are tested twice weekly, or more often if necesssary to maintain the specified chemical limits. High pressure steam boilers are tested for causticity, phosphate, tannin, sodium sulfite, and conductivity. Low pressure steam boilers treated for corrosion with caustic soda only are tested for pH and conductivity. Hot water boilers are also tested daily, for pH, hardness, and sodium sulfite. LTW boilers are tested for nitrite. Boiler water samples from all hot water and steam boilers are submitted to the USAEHSC Laboratory for check analysis at intervals specified in paragraph **4-14a.**

(2) **Condensate.** Condensate is sampled daily at its return to the plant and weekly at the end and midpoint of the distribution system. The parameters tested are pH and conductivity. Hardness is tested if a change in conductivity is noticed, or routine hardness testing may be substituted for conductivity testing. Hardness indicates a leakage of raw water into the system. This leakage must be found and corrected.

(3) **External Treatment Plants.** Water samples from external treatment plants should be tested daily (each operating unit) or more frequently based on manufacturer's instructions. The parameters tested are hardness, free mineral acidity, and/or alkalinity, depending upon the particular equipment. The operating pressure and temperature of all deaerator units should be checked and recorded once a shift, and adjustments made, if required.

c. Instrumentation. Instrumentation has been developed which can accurately, reliably, and continuously monitor the conductivity of boiler water. This instrumentation is economical for testing and for use in continuous steam boiler blowdown systems to control dissolved and suspended solids. Daily testing of conductivity is still required. Reference paragraph **4-8b** which discusses conductivity meters.

d. Special Corrosion Testing. Corrosion testing assemblies are installed at various points in the condensate system for three month test periods to study corrosion. Tests should be performed once a year in each condensate system. The corrosion coupons, which are machined and weighed prior to installation, are removed at the end of the test and forwarded to USAEHSC for analysis. Loss of weight, thickness, and amount of channeling and pitting are measured and general appearance is evaluated. USAEHSC then prepares a report noting corrosion rates of the piping tested and recommending changes in water treatment procedures. Reference figure 4-23 which shows the corrosion tester. The USAEHSC form supplied with the corrosion tester should be completely filled out and returned with the coupons.

4-16. GENERAL OPERATION OF EXTERNAL TREATMENT EQUIPMENT

Complete operational instructions for external treatment equipment are contained in the manufacturer's manuals. The following information should not be regarded as a substitute for the individual manufacturer's instructions.

a. Zeolite Softeners. For proper operation of all softening units, post the manufacturer's instructions conspicuously near the softening units. Follow these instructions in the regeneration, rinse, and operation of these units. Keep a careful record of salt consumption of the softeners, and periodically compare this consumption to that specified by the manufacturer. Salt comsumption per unit volume of water softened is an excellent index of softener performance. An increase in the quantity of salt used between regenerations of a given unit indicates a deterioration in performance.

(1) **Rates of Flow.** To obtain continued satisfactory performance of zeolite treatment equipment, it is essential that flow rates be maintained at all times within the limits set by the manufacturer. Figure 4-24 illustrates schematically the normal up- and down-flows of a zeolite unit. The down-flow represents the service, regenerant solution, and rinsing flows; the up-flow represents the backwash.

(a) Service Flow. When the recommended service flow rate is exceeded, both excessive pressure drop and loss of impurity removal efficiency occur. These are the results of forcing the water to channel through the paths of least resistance in the softener material, thereby reducing the necessary contact with the zeolite. Reference figure 4-25 which illustrates the effects of excessive flow rates.

(b) Backwash Flow. In this operation, the zeolite bed is raised so that the individual grains of zeolite are suspended in water. Packing of the bed which may have occurred during the service operation is broken up, and dirt or other foreign matter that may have collected on top of the bed is washed out. If the backwash rate is too low, the packing is not broken up and the zeolite bed is not properly suspended. Under these conditions, the fine foreign material and dirt do not wash out of the bed. Fine particles, if not washed out of the bed, act as an abrasive on the zeolite grains. The abrasive action may cause the zeolite grains to break up, leading to increased pressure drop and breakthrough in subsequent washings. If this occurs, the entire contents of the unit may have to be removed, the gravel regraded, and the bed relaid. Backwashing at an insufficient rate of flow over an extended period does not accomplish the desired results because, even though the water to waste appears fairly clear, only the dirt and fines capable of being lifted by a low flow rate are removed, while other objectionable heavier particles remain. If the wash rate is too high, the zeolite washes out, reducing the capacity of the unit. Backwashing for too short a period does not complete the operation, because a minimum length of time and volume of water are required to lift the zeolite before the zeolite fines and other foreign matter are removed. Backwashing for too long a period at the proper flow rate is a waste of water. Care must be taken to avoid sudden shocks to the bed while backwashing. Shocks may be caused by water entering the unit too rapidly, by pumps being started while the unit is backwashing, or by bubbles of air entering the unit. Any of these may cause gravel hills or upsetting of the bed.

(c) Regenerant Solution Flow. In this operation, the impurities attached to or combined with the zeolite are removed, and the zeolite is reactivated by passing a regenerant solution through the bed. The solution enters through the distribution laterals at the top of the unit, passes through the bed and leaves at the bottom. Its strength, whether made up of brine, sulfuric acid, or caustic soda, is most important, and the manufacturer's instructions for preparation must be followed. If the proper solution strength or solution volume is not maintained, the unit will operate at reduced capacity.

(d) Rinse Flow. To obtain the correct rate of flow, the rinse flow control device must operate freely and be adjusted in accordance with the manufacturer's instructions. If the rinse rate is too high, the bed tends to pack. If the rate is too low, the rinse time is prolonged, or the excess regenerant solution and impurities are not properly washed out.

(2) **Check for Efficiency.** After the zeolite unit has been installed, the installing contractor will test it for performance. The quantity of treated water that a unit can deliver can be easily checked if the exchange capacity and the number of cubic feet of zeolite contained in the softening unit are known. For example:

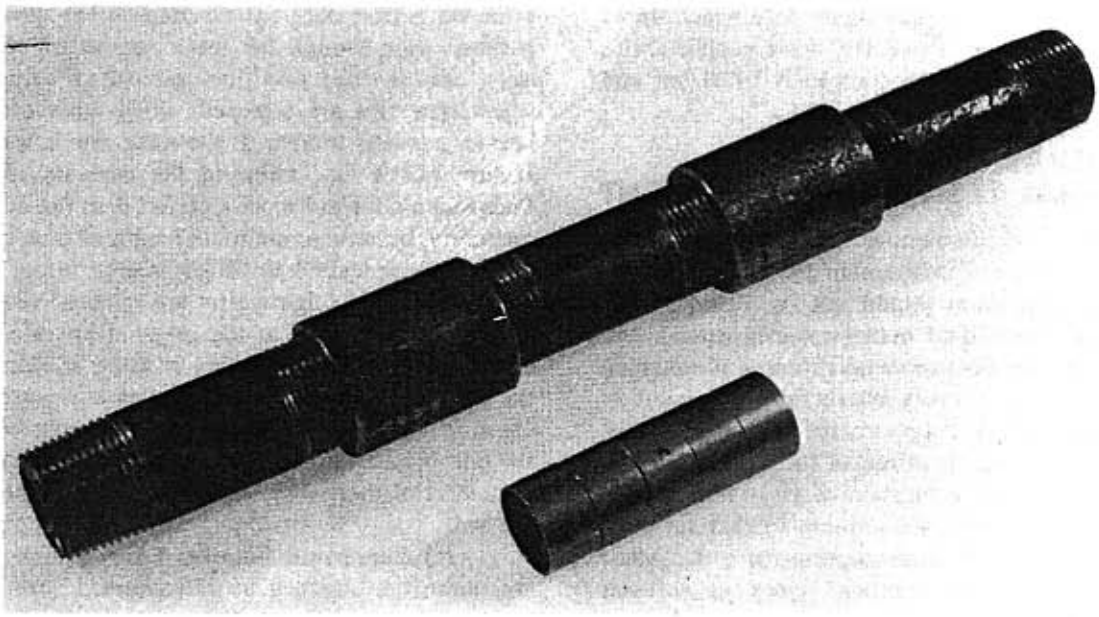


FIGURE 4-23. CONDENSATE CORROSION TESTER

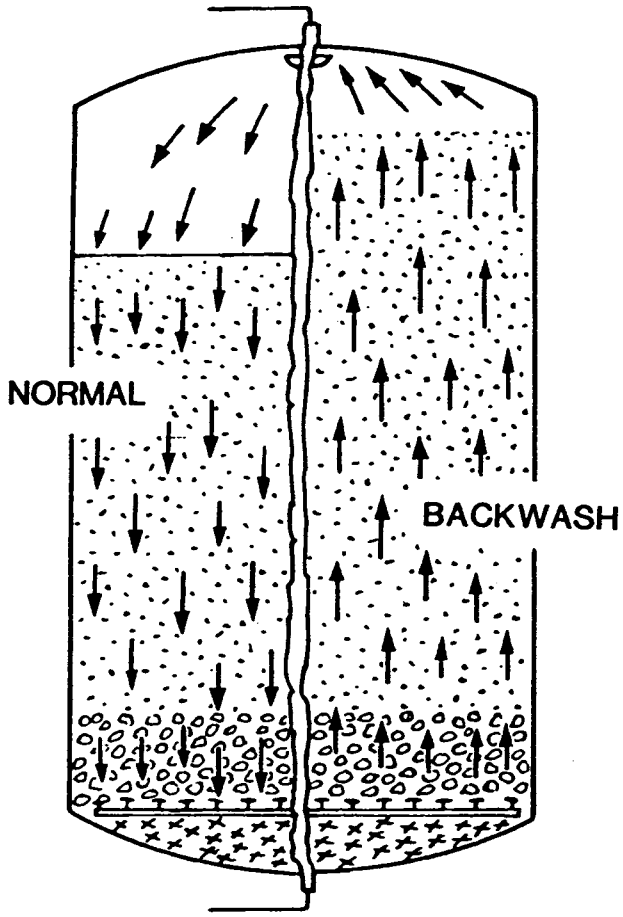


FIGURE 4-24. ZEOLITE SOFTENER WATER FLOWS

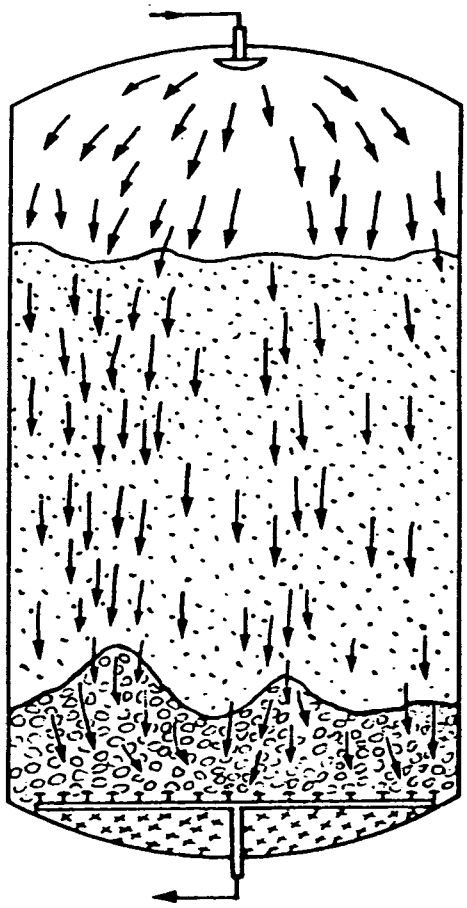


FIGURE 4-25. EFFECT OF EXCESSIVE WATER FLOW RATES

$$\text{Capacity (gallons)} = \frac{\text{Cubic Feet of Zeolite x Exchange Capacity of Zeolite in Grains per Cubic Foot}}{\text{Hardness of Water as } CaCO_3 \text{ in Grains per Gallon}}$$

If a sodium zeolite unit has an exchange capacity of 250,000 grains and the raw water has a hardness of 10 grains per gallon, the unit can soften 250,000/10 = 25,000 gallons between regenerations. If the unit requires regeneration after softening 20,000 gallons with the same 10 grain hardness water, the unit's efficiency is then 20,000/25,000 X 100 = 80 percent. But, if the raw water analysis shows a change, such that its hardness is increased from 10 grains to 12.5 grains, then 20,000 gallons softened between regenerations shows no loss in efficiency because 250,000/12.5 = 20,000 gallons. It is necessary to check softener efficiency periodically. If it shows a marked decrease, the operator should go through the foregoing procedure to determine if the loss in efficiency is due to a change in the raw water analysis. If it is due to other factors, the flow rates during service and regeneration should be checked to determine if the recommended rates are being properly maintained. The surface of the zeolite should also be checked. A hilly appearance gives evidence of channeling and packing of the bed and furnishes a clue to the condition of the gravel bed surface beneath. A check on the depth of the zeolite bed indicates whether zeolite has been washed out. Measurements should be taken at several points to assure an average depth. They are taken by inserting a small-diameter rod or a 6-foot metal rule through the zeolite until the gravel is felt and then noting the distance the rod or rule was inserted. Make probings at approximately the points indicated in figure 4-26, and enter the measurements in the corresponding circles. Another way to determine the depth is by comparative measurements of the distance from the zeolite surface to the backwash and brine distributor fittings or some other fixed point. If a loss of zeolite material is evident, the cause must be found and the zeolite replenished, with care taken to avoid repetition of the loss. In addition to washing out, loss may be caused by a defective underdrain system or by a clogged and defective brine distributor system. Another cause may be a change in the water undergoing treatment. Its constituents may be incompatible with the zeolite being used. If the cause of the failure cannot be determined, consult the manufacturer's service representative. When maintenance recommendations fail to correct operational difficulties, refer the matter to the operating agency commander.

(3) **Check of Salt Requirements.** Approximately one-half pound of salt is required per 1,000 grains of hardness removed for each regeneration. The following calculation is used to determine actual salt consumption of a salt regenerated unit:

$$\text{Salt (NaCl) required (lbs)} = \frac{\text{Gallons of Water Softened x Hardness of Water as CaCO3 in Grains per Gallon}}{2{,}000}$$

A saturated solution of brine, necessary for proper regeneration of a softening unit, has a Baume gravity of 23° and contains 2.5 pounds of salt per gallon.

(4) **Parallel Operation.** Best results and most efficient operation are obtained if all installed units are operated in parallel. Regardless of the load imposed on the softening plant, all units should be operated simultaneously. If more than one softening unit is installed in a plant, regenerations of the units should be staggered.

b. Hot-Process Lime Soda Softeners. In the operation of hot-process plants, the following minimum requirements for proper performance must be carefully observed.

(1) **Steam Pressure and Temperature.** A positive steam pressure must be maintained within the reaction and sedimentation tank at all times to ensure venting of oxygen and other non-condensible gases. The minimum water temperature in the sedimentation tank must not be more than 5 to 10° F below the temperature of the steam in the tank. This temperature is necessary to promote softening reactions and to ensure complete settling of the precipitate. When insufficient exhaust steam is available to maintain this temperature, live steam must be supplied and controlled from the steam space so that a positive pressure is maintained within the tank.

(2) **Chemical Control Tests.** Chemical tests must be made regularly in accordance with the manufacturer's recommendations. Satisfactory results cannot be expected if the operator cannot be certain at all times that the water everywhere in the plant is of the best quality obtainable.

(3) **Chemical Tanks.** Chemical tanks must be charged regularly with the correct amounts of the proper chemicals. At the time of charging, the operator must examine the proportioning equipment to ensure that moving parts operate freely.

(4) **Sludge Blowdown.** The sedimentation tank must be blown down regularly, the frequency depending on the character of the raw water. If this practice is not followed, the sludge cone fills with sludge, and an excessive amount of suspended matter can be carried upward into the clarified water zone, overloading the filters.

(5) **Filter Backwash.** The filters must be backwashed regularly to ensure ample hydraulic head on the booster or the boiler feedwater pumps. Proper backwashing will also help to prevent suspended matter from accumulating to the point at which it passes through the filtering material and contaminates the feedwater.

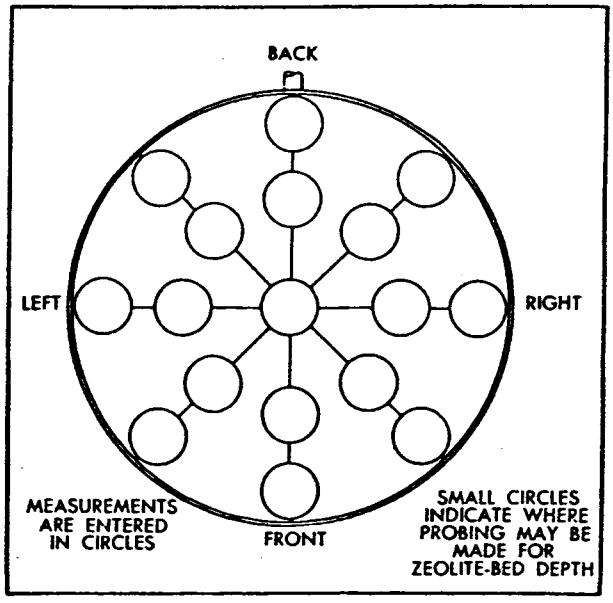


FIGURE 4-26. ZEOLITE BED INSPECTION POINTS

(6) **Overload.** To assure proper operation of the softener and filters in providing a high quality boiler makeup, the rated capacity of the softener must not be exceeded.

c. Deaerators. The operating procedure for efficient deaeration involves keeping the deaerator vent open at all times, keeping the live steam regulator on at all times, using as much exhaust steam as possible, maintaining the water at boiling temperature, keeping makeup water to a minimum, cleaning the deaerator at least every six months, checking trap operation on the oil separator daily, and checking the surge tanks and deaerator for overflow due to leaking valves. The reasons for these actions are described in the following subparagraphs. It is important that a properly located and calibrated thermometer and pressure gage be installed on each deaerator. Only with accurate temperature and pressure information is proper deaerator operation possible.

(1) **Relationship of Temperature, Pressure and Solubility.** In order to secure good deaeration, the temperature of the feedwater must be continuously maintained at the saturation temperature corresponding to the steam pressure maintained on the deaerator. The proper relationship between water temperature and the steam pressure is shown in table 4-5. The difference between the saturation temperature (corrected for altitude) and the feedwater temperature should not be more than one degree.

(a) For example, assume the following conditions: a boiler plant located at an elevation of 1,000 feet above sea level, the steam pressure in the deaerator is 2 psig, and the feedwater temperature in the heater storage compartment is 216° F. As indicated in table 4-5, the temperature difference is not more than 1° F; therefore, the heater is efficiently removing dissolved gases. In this example, merely maintaining temperatures above 212° F will not give good deaeration, since a significant amount of oxygen may still be dissolved in the water.

(b) For an example of solubility, assume the following conditions. A deaerator is operating at 7 psig pressure and the feedwater temperature is 218° F. By following the temperature line of figure 4-27 for 212° F vertically up to the 7 psig pressure curve intersection and then moving to the left to the oxygen content table, it is noted that solubility of oxygen under these conditions is 1.8 cc per liter or 2.5 ppm (cc O_2 per liter X 1.4 = ppm O_2). This is too high and indicates inadequate deaeration. Good deaeration should reduce oxygen to between 7 and 40 parts per billion, a thousand times less than in this example. To assure good deaeration, the proper feedwater temperature for 7 psig steam pressure is found to be 233° F (at sea level). It must also be remembered that adequate vent flow must be maintained if optimum deaeration is to be accomplished. See subparagraph (3) for further information.

(2) **Methods of Maintaining Temperatures.** All possible exhaust steam should be used for deaerator operation. Where a large amount of exhaust steam is available from boiler plant auxiliaries such as fans, turbines, stokers, and pumps, the back pressure should be set as high as the particular installation will permit without causing feedwater pump trouble. Temperatures of 230° to 240° F are not unusual for this type of operation. Live steam regulators or reducing valves are used to supply the necessary steam when sufficient exhaust steam is not available. They should be kept turned on at all times because they use steam only as required. Live steam to a deaerator cannot be controlled by hand due to fluctuating loads; such a procedure would cause either too much or too little steam to be used. Proper deaeration requires the proper amount of steam a the right time. Live steam regulators must be properly sized asnd controlled. Heavy intermittent loads will require larger regulators than steady loads. Where it is necessary to install a larger regulator for more capacity to handle an occasional intermittent load, a smaller regulator should be installed in parallel with the large one. This will provide better control since the larger one can be shut down during periods of light loads such as the summer season. Large regulators have a tendency to chatter or groove the seat and generally do not control well on very light loads. Regulators of a type to give close control in the pressure range of ½ to 5 psig should be installed. This generally calls for a large diaphragm (12 to 16 inches diameter) or a pilot controlled valve. Regulators should be installed with their outlet as close as possible to the deaerator and the outlet line slhould normally be increased to larger line size. A long line from the regulator to the deaerator should be avoided as it slows the action of the regulator and gives poor control. The control line on the regulator should be piped directly to the deaerator shell since the pressure to be controlled is in the deaerator, not in the line to the deaerator. Instant action of the regulators is required to ensure that steam is provided instantly, and that deaeration takes place as the water flows into the deaerator. This response can only be obtained if the regulator sensing line actually senses pressure in the deaerator shell proper. Control lines connected close to the regulator or in the line are not effective.

(3) **Venting of Gases.** Gases that are released from the water must be properly vented. Failure to obtain the proper water temperature is often due to insufficient venting. This can be done in two ways: directly to the atmosphere or through a vent condenser to the atmosphere. Venting directly to the atmosphere is effective but results in wasted steam. Venting through a vent condenser is better since much of the heat in the vent steam can be recovered.

Table 4-5. Deaerator Temperature Versus Pressure

Pressure in heater psig	Boiling Points Corresponding to Various Elevations												
	Sea level	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000
.0	212*	211	210	209	208	207	207	206	205	204	203	202	201*
.5	214	213	212*	211	210	209	208	208	207	206	205	204	203
1.0	215	215	214	213	212*	211	210	209	208	208	207	206	205
1.5	217	216	215	215	214	213	212*	211	210	209	208	208	207
2.0	219	218	217	216	215	215	214	213	212*	211	210	209	208
2.5	220*	219	219	218	217	216	215	215	214	213	212*	211	210
3.0	222	221	220*	219	219	218	217	216	215	215	214	213	212*
3.5	223*	222	222	221	220*	219	219	218	217	216	215	215	214
4.0	224	224	223*	222	222	221	220*	219	219	218	217	216	215
4.5	226	225	224	224	223*	222	222	221	220*	219	219	218	217
5.0	227	227	226	225	224	224	223*	222	222	221	220*	219	219
5.5	229	228	227	227	226	225	224	224	223*	222	221	222	220*
6.0	231	230	229	228	227	226	225	224	223	222	221	220	219
6.5	232	231	230	229	228	227	226	225	224	223	222	221	220
7.0	233	232	231	230	229	228	227	226	225	224	223	222	221
7.5	234	233	232	231	230	229	228	227	226	225	224	223	222
8.0	235	234	233	232	231	230	229	228	227	226	225	224	223
8.5	236	235	234	233	232	231	230	229	228	227	226	225	224
9.0	237	236	235	234	233	232	231	230	229	228	227	226	225
9.5	238	237	236	235	234	233	232	231	230	229	228	227	226
10.0	240	239	238	237	236	235	234	233	232	231	230	229	228
10.5	241	240	239	238	237	236	235	234	233	232	231	230	229
11.0	243	242	241	240	239	238	237	236	235	234	233	232	231

*Exact

Temperatures are shown to the nearest whole degree

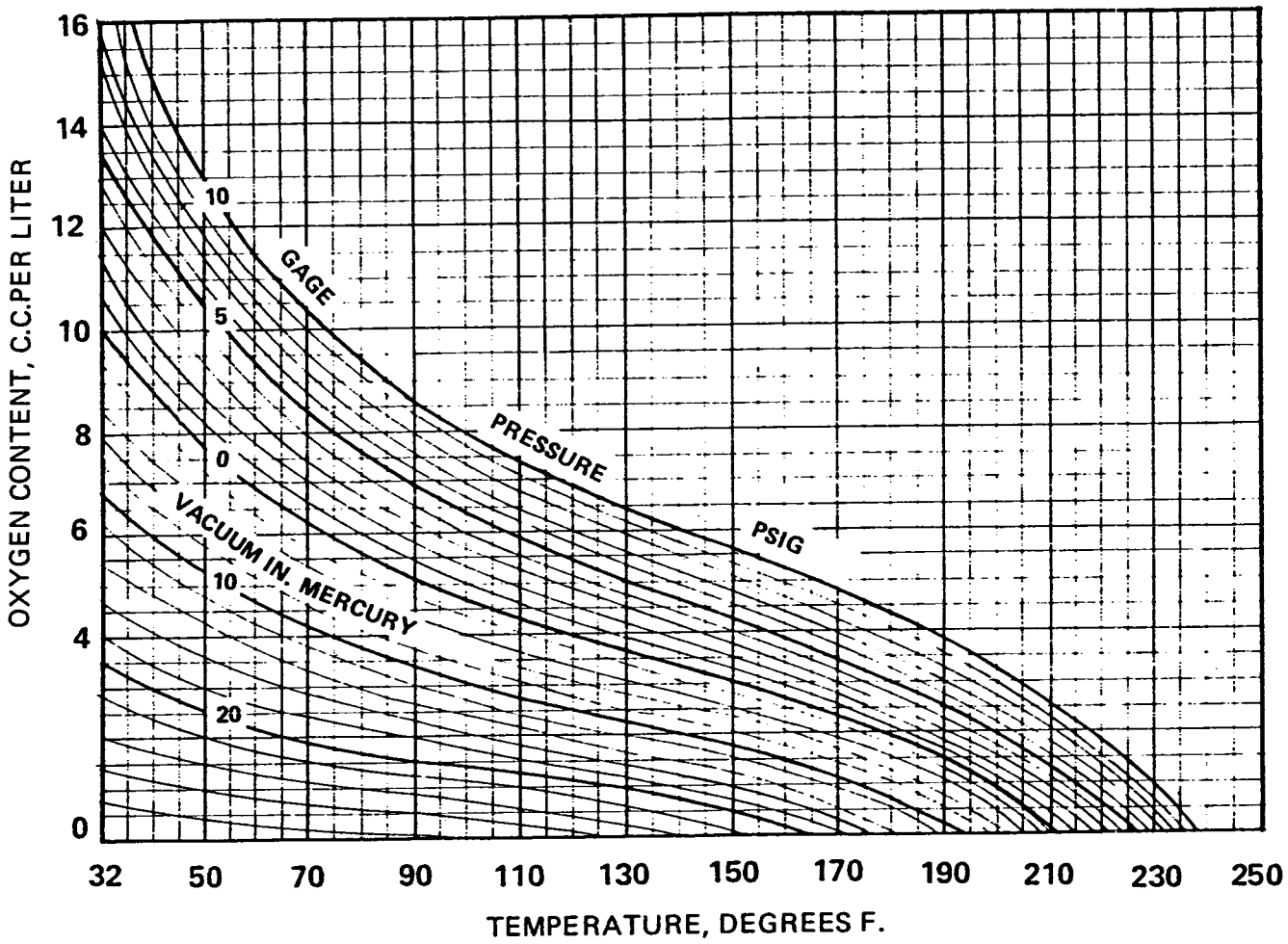


FIGURE 4-27. SOLUBILITY OF OXYGEN IN WATER

Conventional heaters are vented from either the top or sides of the shell. Thermostatic traps should not be used. The best vent for a heater is as ½- or ¾-inch gate valve with an ⅛-inch hole drilled through the seat, permitting positive venting at all times in case the valve is inadvertently closed. The amount of valve opening depends upon load conditions and the size of the heater. Approximately one-tenth to one percent of plant load is usually required to be vented at all times, but the actual amount requires trial and error determinations and a series of oxygen analyses on water from the deaerator. Oxygen content of the water is the final criteria for proper deaeration. Vent lines should be installed to permit visual observation of the amount of venting.

d. Corrections for Improper Deaerator Operation. Operational and mechanical changes to correct deaerator troubles are described below. Changes should be made in a systematic, step by step procedure because more than one of them may correct the adverse condition.

(1) **Surge Tank Problems.** Surge tank problems may occur where water has a tendency to hold up in the tank.

(a) Install a vacuum breaker on closed surge tanks which are under pressure. This can be a 1½-inch or 2-inch flapper type check valve. Vacuums sometimes are caused when a sudden heavy load of cold condensate or raw water enters the hot surge tank.

(b) Lower the pressure maintained on the deaerator and operate at the lowest pressure required for uniform temperature control.

(c) If the surge tank is constructed for pressures up to at least 15 psig, and if the condensate return pumps discharging to it have sufficient head capacity, an equalizing line may be installed between the top of the surge tank and the deaerator to maintain the same pressure on both. Install a line of ample size to equalize the pressures.

(d) Install a feed line of ample size between the surge tank and the deaerator. Streamline as much as possible the fittings and turns which could retard the flow.

(e) Where headroom permits and condensate return pumps have sufficient head capacity, raise the surge tank to provide at least 3 psi dynamic head difference between the water level in the surge tank and the top of the deaerator. Example: A deaerator operating at 3 psig will require that the surge tank water level be at least (3 psig + 3 psi) x 2.31 feet per psi or 13.8 feet above the water inlet to the deaerator. Consideration must be given to friction loss in straight piping and fittings, as well as control valves, type of vent condenser, and type of deaerator to arrive at the proper height of the surge tank. Where an equalizing line is used between the surge tank and deaerator, the minimum distance is 3 psi x 2.31 feet per psi, or 6.93 feet.

(f) Where there is insufficient head between the deaerator and boiler-feed pump and it would be uneconomical to raise the deaerator, install a low-head booster pump between the deaerator and feedwater pumps to prevent vapor binding. Select a pump with adequate capacity and discharge pressure sufficient to maintain 3 psi dynamic head on the suction side of feedwater pumps when at full capacity of the plant.

(2) **Lack of Adequate Head on Boiler Feed Pumps.** Lack of adequate head between the deaerator and the boiler-feed pumps is one of the most common sources of trouble.

(a) Check the feed pumps for proper packing, valve settings, slippage, etc.

(b) For reciprocating pumps where normal operation uses one pump at a high rate, use two pumps at a lower speed instead. This will give the cylinders more time to fill, thereby decreasing the tendency of the water to flash.

(c) Install a vertical storage chamber on the suction side of the feed pump. This chamber should be constructed of pipe one or two sizes larger than the pump suction and equalized with the heater by running a 1- to 1¼-inch line from the top of the chamber to the steam space of the deaerator.

(d) A ½- or ⅜-inch line may be run from the top of the water cylinder on the feed pump or bleed cock to the steam space on the deaerator to act as a bleed line for any steam vapor formed. This can be especially useful on centrifugal pumps.

(e) Piping connections between the deaerator and feed pumps should be as direct as possible, of ample size, and at least one size larger than the pump inlet. Any reductions in size should be made at the pump inlet. Avoid numerous fittings and 90° turns.

(f) Lower the operating pressure of the deaerator as much as possible but always operate with some continuous positive pressure, even it is only ½ psig. Deaeration is only successful when the temperature is above the boiling point of water, which can only occur if there is a positive pressure on the deaerator.

(g) Where construction permits, give consideration to the possibility of lowering the boiler-feed pumps into a pit or raising the deaerator in order to obtain the necessary head on the pump suction. This should be considered only after all other means of correction have been exhausted.

(3) **Feedwater Temperature Fluctuations.** If feedwater temperature varies widely from that expected for a given set of conditions, one of the following problems may exist.

(a) The deaerator may be insufficiently or improperly vented.

(b) The thermometer or pressure gage may be inaccurate. Check the instruments periodically for accuracy.

(c) Pressure gage readings must be corrected for

hydrostatic head, if any. Make a correction of +-0.43 psi for each foot of static head due to a water leg. For example, a gage installed 10 feet below the level of the gage connection to the heater would require a correction of 4.3 psi (6.3 psi gage reading - 4.3 psi = 2 psi in the deaerator). The shell of the deaerator is the most satisfactory location for a gage installation.

(d) The deaerator may require cleaning.

(e) The deaerator trays may be misaligned.

(f) The thermometer bulb may not be submerged in the circulating water. It is important that the bulb be submerged about four inches.

If the bulb is out of the water, it will measure steam temperature rather than water temperature and proper control will be impossible.

(g) The deaerator may not be of succifient capacity for the amount of water being heated.

(h) The live steam supply may be insufficient.

(i) The pressure regulating valve may be misadjusted or improperly sized for close control.

4-17, GENERAL OPERATION OF INTERNAL TREATMENT EQUIPMENT

Boiler water is treated to control corrosion and scale deposits in the boiler and distribution system. Internal treatment chemicals should be maintained within the limits established in paragraph 4-5. Failure to maintain proper treatment levels can result in excessive corrosion and scale, tube failure, leaks, energy losses, and excessive maintenance and operating expenses. The chemicals and feed equipment used in internal treatment are discussed in paragraph 4-8. The feeding procedures and precautions are discussed below.

a. Chemical Feed Equipment. Internal treatment chemicals can be fed into the system through either closed or open feeders. All steam boilers operating above 15 psig should be provided with equipment to add chemicals directly to the boilers. The point of chemical admission varies with the specific chemical, the individual boiler plant, and operating conditions. Use the chemical feed connection provided by the boiler manufacturer, if possible.

(1) **Closed Feeder.** The pressure-pot feeder is a simple chemical feeder that can be fabricated from a piece of 6- or 8-inch pipe 18 to 24 inches long. Both ends are sealed by capping or welding and suitable valving and funnel are installed for admission and discharge. Feeders fabricated in accordance with the ASME code are commercially available. Military Specification MIL-F-18113 shows a pressure-pot feeder which is illustrated in figure 4-28. Before entering the pressure-pot feeder, the chemicals must be mixed or dissolved in a mixing tank. For small installations, the mixing tank may consist of a steel barrel. A small steam jet in the bottom of the mixing tank can be used to facilitate mixing. Chemicals such as phosphate and tannin can be dissolved in a fine-mesh basket suspended just beneath the surface of the water in the mixing tank. Figure 4-29 illustrates a more elaborate dissolving tank and pressure feeder.

(2) **Open Feeder-Chemical Mixing Tank/Chemical Feed Pump.** For larger chemical dosages it is more convenient to use an open feeder with chemical feed pump as shown in figure 4-30. The use of this arrangement is usually justified for boilers using more than one thousand dollars worth of chemicals per year, because it improves results and reduces chemical costs. The chemical-dissolving tank should be large enough to hold about one gallon of solution for each pound of chemical used per day. Many commercial chemical mixing tanks are made of fiberglass, although for many installations a 55-gallon drum is suitable. Tanks should not be made of galvanized or tinned iron or aluminum. The open feeder has a valved line near the bottom to carry the chemical solution to the pump, a gage glass, agitator, safety relief valve and cover. A screen or dissolving basket is suspended at a point about a foot below the top of the tank. Donut floats should be used when sodium sulfite is being prepared to avoid oxidation of the solution. No direct connection between a potable water supply and the chemical tank is permitted. Figure 4-31 illustrates a plunger/diaphragm type pump which is suitable for chemical feed applications.

b. Feeding Procedure. Chemicals should be fed after making tests for boiler water chemical residuals. If the test for total dissolved solids indicates that blowdown is necessary, blow the boiler down before feeding the chemicals. If certain residuals are low, proceed as follows:

(1) Determine the required amount of treatment chemicals by study of chemical residual test results and boiler operation.

(2) Weigh the total amount of each required chemical.

(3) Dissolve the chemical in the mixing or dissolving tank by adding sufficient water and using a wooden paddle reserved for this purpose.

(4) Allow the solution to flow to the chemical pump (or place it in the pressure-pot feeder) in proportion to the requirements of each boiler.

(5) When only one boiler is involved, all required chemical solutions may be mixed and fed as a single solution.

(6) Where feedwater deaerating heaters or deaerators are installed, feed sodium sulfite continuously to the reservoir of the heater or the deaerator.

c. Feeding Precautions. When feeding chemicals, use the following precautions.

(1) Do not feed any chemical ahead of the feedwater heater or deaerator.

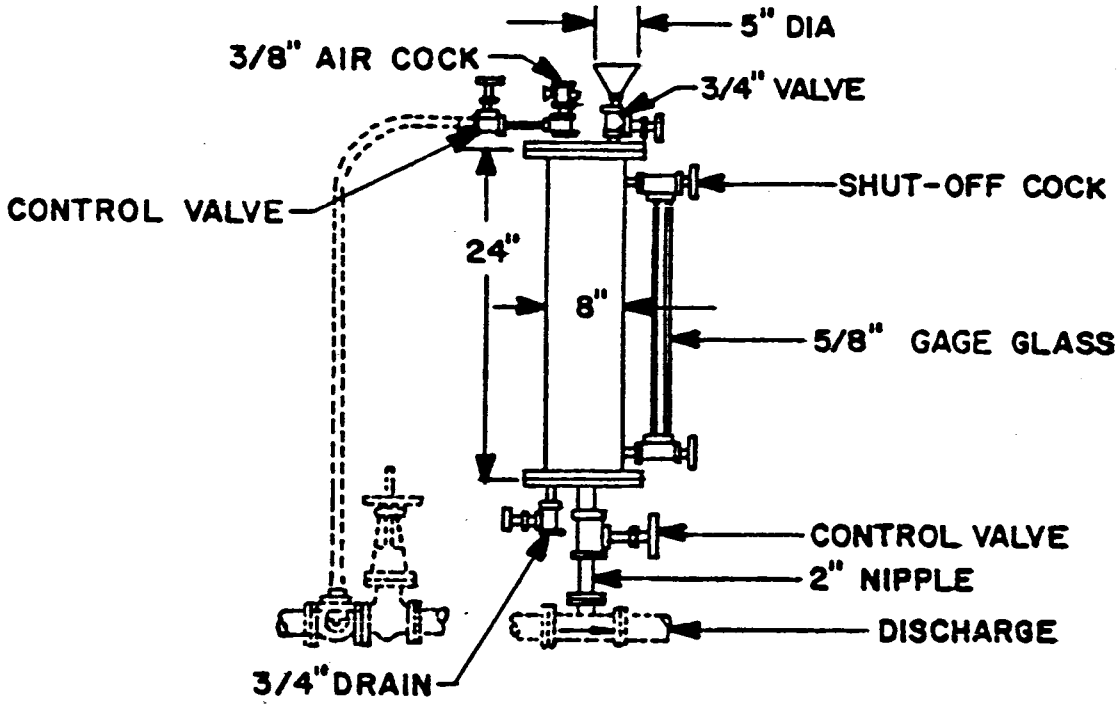


FIGURE 4-28. PRESSURE POT FEEDER

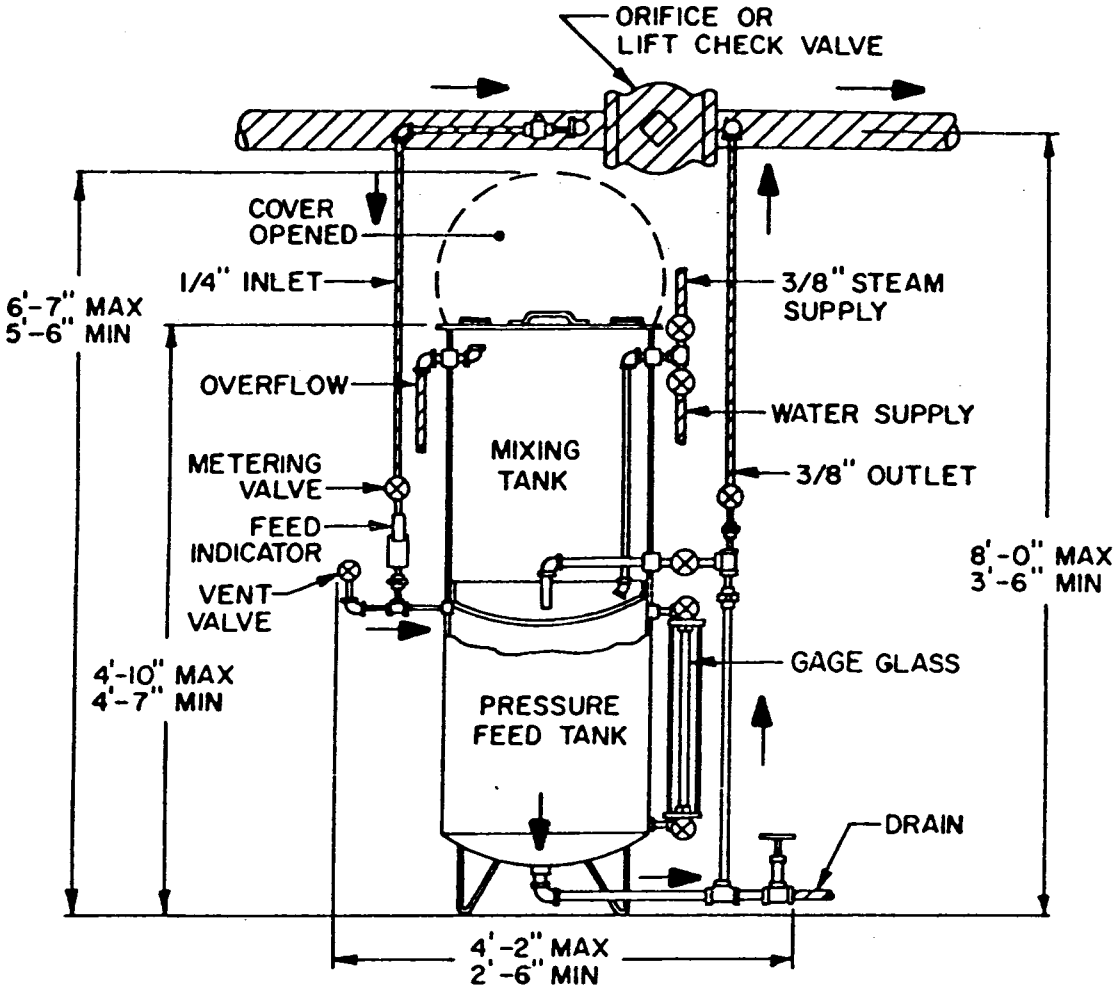


FIGURE 4-29. AUTOMATIC PROPORTIONING FEEDER

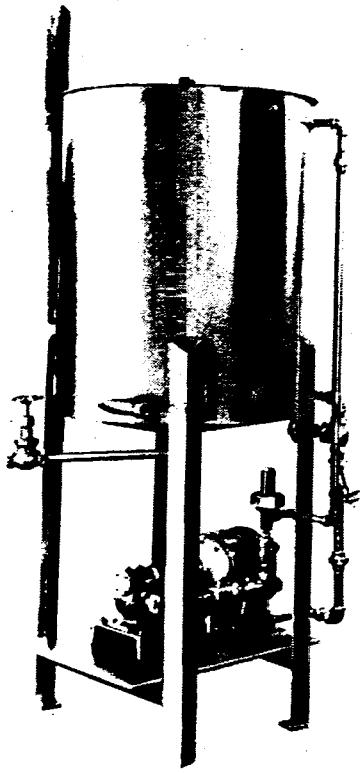
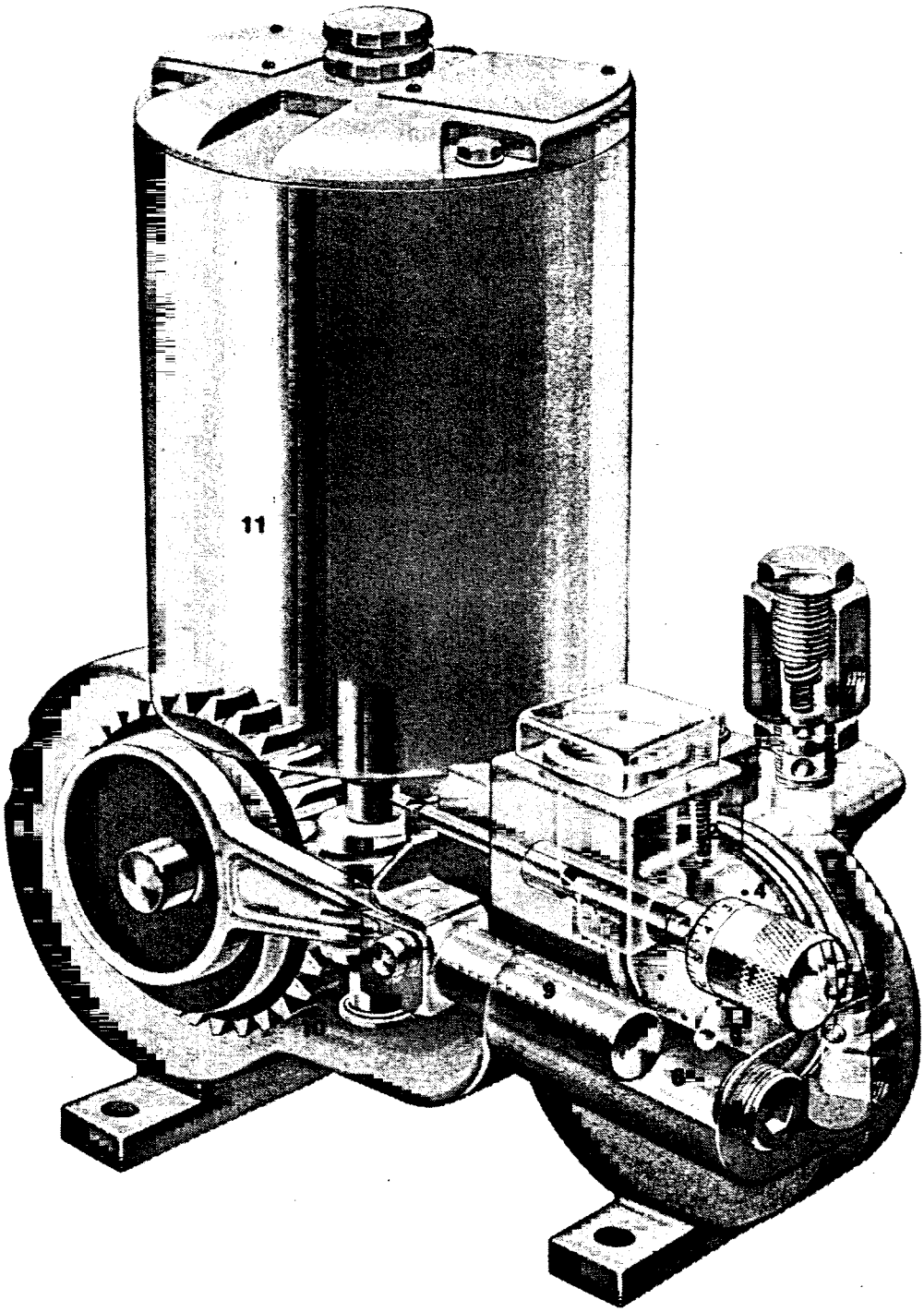


FIGURE 4-30. CHEMICAL MIXING TANK WITH CHEMICAL FEED PUMP



1. Repetitive accuracy guaranteed by automatic air venting on each pump stroke to prevent vapor accumulation.
2. Built-in relief valve prevents pump damage if discharge system is blocked during operation.
3. Dependable double ball check valves in easily replaceable cartridges for simplified maintenance.
4. Proven Teflon[1] diaphragm design is fatigue-resistant and leakproof under normal operation.
5. Diaphragm head can be remotely located for submerged tank pumping of dangerous liquids.
6. Self-compensating hydraulic system — no vacuum breakers or refill valves to adjust.
7. Positive capacity adjustment over full flow range during operation. Electric or pneumatic capacity adjustment options available for remote or process instrument control.
8. Hydraulically actuated diaphragm is not pressure loaded, acts only as separating membrane between liquids.
9. Precise plunger-bore fit with generous bearing area eliminates plunger packing, extends service life.
10. All moving parts are continuously submerged in lubricating oil to assure long, efficient pump life.
11. Compact design with self-contained totally enclosed motor[2] and drive allows installation in almost any location or environment.

FIGURE 4-31. CHEMICAL FEED PUMP
PLUNGER/DIAPHRAGM TYPE

(2) Do not feed sodium orthophosphates unless authorized by the operating agency commander.

(3) Do not feed sodium orthophosphate into the feedwater system. Feed it directly into the boiler.

(4) Never place dry chemicals in a chemical feeder or pump. This practice will plug the chemical feed lines in a short time.

(5) Make sure all piping and valve installed with chemical feeders or pumps are designed to withstand the boiler pressure.

(6) Drain the feeder before introducing chemicals. When draining the feeder, close all pressure connections to the feeder before opening the drain valve to prevent injury to the operator by hot water or chemcials.

4-18. SAFETY PRECAUTIONS

The primary requirements for safety in boiler plant water conditioning are the same as those for the operation of any other plant or process: good maintenance, proper procedures, and good housekeeping. If the plant is not kept clean and orderly, the chances for accidents multiply. Treatment of water involves the use of chemicals, some of which are dangerous if not handled properly. All safety data sheets must be thoroughly read and strictly followed.

a. Acids. The tests for chemical residuals involve negligible quantities of acid, and the risk is small if spillage is avoided and bottles containing acid are not broken. Greater risks are involved in the handling of sulfuric acid in the hydrogen zeolite, demineralizing, and direct-acid treatment processes. The Manufacturing Chemists Association has published a Chemical Safety Data Sheet, SD-20, dealing with the methods of handling sulfuric acid. The following excerpt from the bulletin lists some of the recommended precautions.

(1) Do not permit dilute or strong sulfuric acid to come in contact with the eyes, skin, and clothing.

(2) When handling the acid, always wear goggles, face shields, gloves, and protective clothing.

(3) Never add water or caustic solutions to sulfuric acid; violent reactions can take place. Spattering must be avoided. If it is necessary to mix acid and water, always add the acid cautiously to the water; never add water to strong acid.

(4) Cleaning or repairing tanks should be performed under proper supervision of a foreman. Instructions relative to entering and cleaning of tanks and exact steps to be taken must be observed. Emergency equipment must be immediately available before workers are allowed to enter tanks for making repairs.

(5) Wash down spills immediately with plenty of water. Never use combustibles such as cloths, sawdust, or other organic materials for mopping up spilled sulfuric acid.

(6) In the event of accidental contact, all contaminated clothing should be removed immediately and affected areas washed with plenty of water for a least 15 minutes. This is especially important when the eyes are affected.

b. Caustic Soda. The Manufacturing Chemists Association has issued a Chemical Safety Data Sheet, SD-9, on handling caustic soda. The following quotation from it illustrates the need for safety measures. "Caustic soda is dangerous when improperly handled. Whether in solid form or in solution, marked corrosive action results from contact will all tissues of the body. Since signs and symptoms of irritation are frequently not evident immediately after contact with caustic soda, injury may result before one realizes that the chemical is in contact with the body. Therefore, adequate protection against such exposure should be provided for all parts. If such precautions are ignored and carelessness is tolerated, caustic soda is capable of producing serious injury . . ." The same precautionary measures indicated for sulfuric acid also apply to the handling of caustic soda.

c. First Aid. The following safety equipment should be readily available.

(1) **Eyewash Fountain.** Have an eyewash fountain, detailed in figure 4-32, or a ready source of running tap water, such as a bubbler drinking fountain or hose with a soft, gentle flow of water, available for eye irrigation. If even minute quantities of sulfuric acid or caustic soda enter the eyes, irrigate the eyes immediately and flush the eyes with a large amount of water for a minimum of 15 minutes.

(2) **Safety Shower.** Have a readily accessible, well-marked, rapid-action safety shower available in the area where sulfuric acid or caustic soda is being handled. A suggested type is illustrated by figure 4-33.

(3) **Safety Inspection.** Inspect all safety equipment regularly to ensure it is in working condition at all times. Place clearly marked signs near the emergency eyewash fountain and the safety shower to indicate their methods of use.

d. Chemical Spill Kits. Each boiler plant should be equipped with the appropriate chemical spill kits. These kits are commercially available to clean up acids, bases, and solvents. It is best to be prepared for the spill that never happens. The moments after a spill has occurred are not the time to decide how to handle the spill.

4-19. CARE OF IDLE STEEL BOILERS

Serious corrosion, caused by oxygen dissolved in water, can occur while a boiler is idle. If oxygen is permitted to dissolve in even small pools of boiler water, concentrated localized corrosion will result. It is not always possible to eliminate air from the boiler, but it is possible to dry

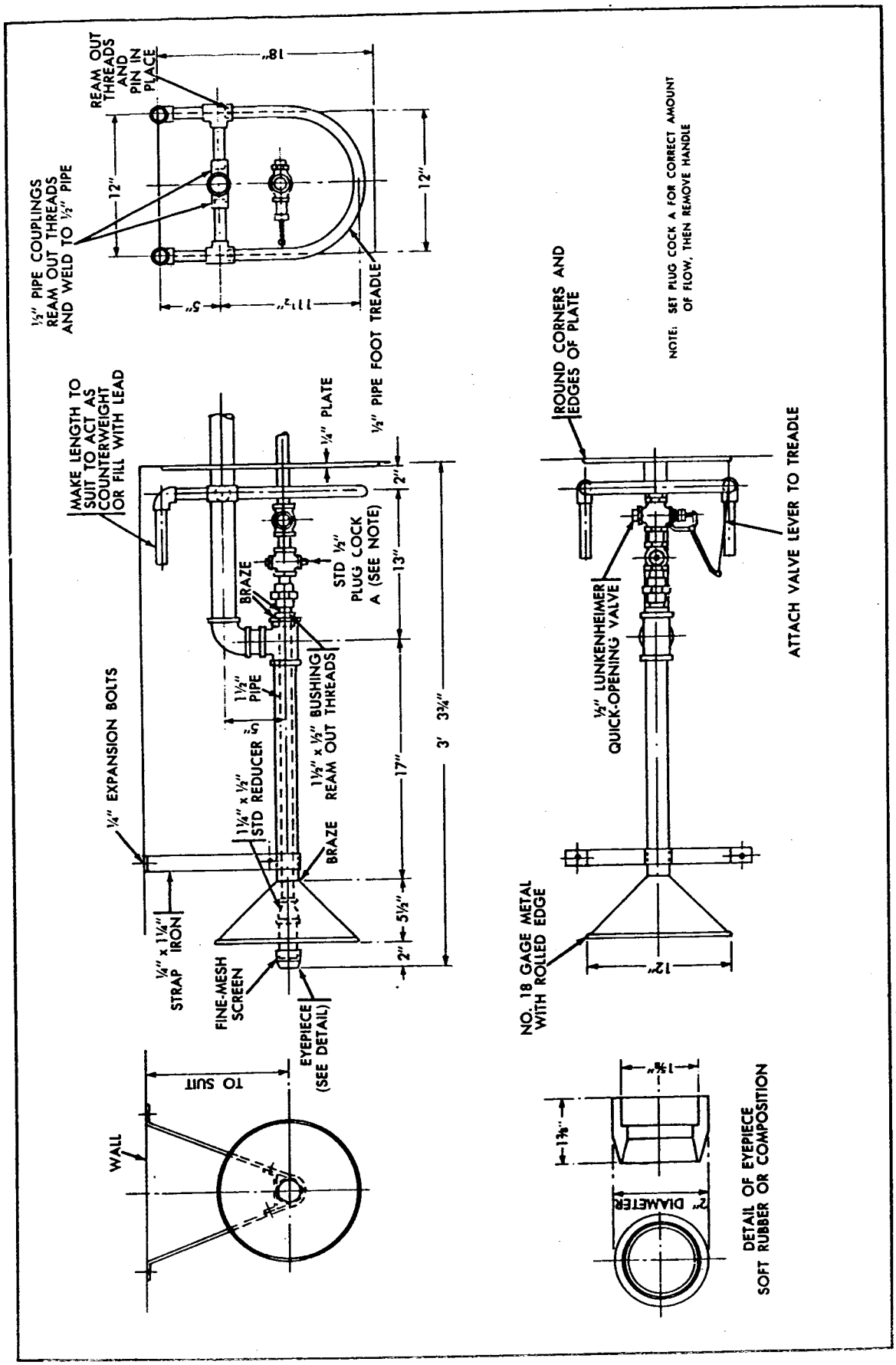


FIGURE 4-32. EYEWASH STATION

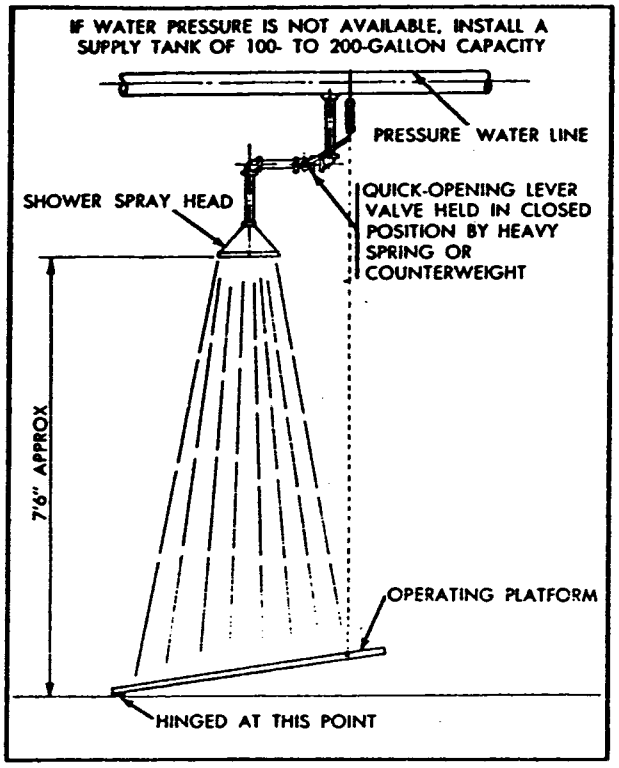


FIGURE 4-33. SAFETY SHOWER

the boiler and follow other procedures which will protect the metal surfaces. Standby boilers may be called upon to resume operation within four to six hours. Under these conditons, it is not practical to drain the boiler and an alternate wet method of boiler layup is recommended. Note that the dry methods should not be used on cast-iron boilers. The following procedures will protect boiler metal against corrosion during out-of-service periods:

One to Three Days. Boilers that will not be used for one to three days should be maintained in a hot standby condition. Steam boilers should have their outlet valves shut. Sludge should be blown down before shutdown. Combustion equipment should be fired as needed to maintain the boiler under pressure. Take care to not allow the boiler to cool and pull a vacuum that would draw air into the boiler and damage gaskets. Normal boiler water treatment limits are maintained.

Four to 30 days. The boiler should be filled with water treated with caustic soda and sodium sulfite. See Procedure a.

Thirty to 150 Days. The boiler should be laid up by either the "wet" or 'dry" method. "Wet" see Procedure b. "Dry" see Procedure c or d.

In Excess of 150 Days. The boiler should be laid up by the "quicklime" or "silica gel" method. See Procedure d.

a. Wet Method-Short Periods. Procedure a — Load conditions may make it necessary to shut a boiler down for relatively short periods yet maintain it in a standby condition. Corrosion will result if the normal water level in the boiler is maintained during the standby period. Proceed as follows to avoid corrosion:

(1) Approximately one hour before taking the boiler off line, introduce enough caustic soda and sodium sulfite to increase causticity to approximately 500 ppm hydroxide and to provide 200 ppm sodium sulfite concentration as Na2SO3.

(2) When the boiler is off line, fill it completely with deaerated water or condensate.

(3) Before operation is resumed, drain the water to the proper level and make chemical tests for causticity, phosphate, tannin, and total dissolved solids. Blow down the boiler or feed chemicals as indicated by the test results.

b. Wet Method. Procedure b — If a boiler is not on standby service the following wet layup method is recommended:

(1) Drain the boiler completely. Ensure that water walls and gage columns are not overlooked. Next, open the boiler and wash the inside of loose scale and sediment by flushing thoroughly with strong water pressure. Use a stiff brush to clean all internal surfaces of the boiler that can be reached. Break the feedwater and steam connections to the boiler and blank the connections if other boilers in the plant are operating.

(2) If the boiler plant is equipped with a deaerator, fill the boiler with deaerated water. If no deaerator is installed, use either condensate or raw water for this purpose. While the boiler is being filled, add enough caustic soda to give a hydroxide content of 500 ppm in the boiler water (about eight pounds of caustic soda per thousand gallons holding capacity of the boiler), and enough sodium sulfite to give 200 ppm concentration (about 2 pounds of sodium sulfite per thousand gallons holding capacity of the boiler).

(3) Start a small fire in the furnace. Open the vent or safety valve and boil the water within the boiler under atmospheric pressure for two hours to ensure circulation of chemicals and deaeration. When the water in the boiler has cooled, fill the boiler to the top, overflowing the vent or safety valves to ensure complete filling.

(4) Make periodic inspections to ensure maintenance of water level. Replace any water lost from the boiler. It may be necessary under these conditions to add additional chemicals to the boiler. Maintain hydroxide and sodium sulfite concentration at about 500 ppms and 200 ppm, respectively.

(5) To facilitate inspections, a small steel tank equipped with a gage can be installed above the top of the boiler, as shown in figure 4-34. This tank can be filled with water and connected to a steam takeoff tap, vent, or safety valve connection. A glance at the water level in the small drum will quickly tell whether or not the boiler is completely filled.

c. Dry Method. Procedure c — Boilers equipped with manholes may be laid up for 30 to 150 days using the dry method described below.

(1) Take the boiler out of service and drain it completely while still warm. Ensure that water walls and gage columns are not overlooked. Next, open the boiler and wash the inside of all loose scale and sediment by flushing thoroughly with strong water pressure. Use a stiff brush to clean all internal surfaces of the boiler that can be reached. Break the feedwater and steam connections to the boiler and blank connections if other boilers in the plant are operating.

(2) If the boiler room is dry and well-ventilated, the boiler may be left open to the atmosphere. If not, use Procedure d.

d. Quicklime or Silica-Gel Method. Procedure d — This method applies only to boilers equipped with manholes.

(1) Take the boiler out of service and drain completely while still warm. Check to ensure that water walls and gage columns are not overlooked. Next, open the boiler and wash the inside of all loose scale and sediment by flushing thoroughly with strong water pressure. Use a stiff brush to clean all internal surfaces to the boiler and blank

the connections if other boilers in the plant are operating.

(2) Start a very light fire in the furnace. Maintain this fire for at least two hours or until inspection shows no moisture on internal sections of the boiler.

(3) Place quicklime **(not hydrated lime)** or silica-gel in one or more metal or fiber trays in the boiler. Place the trays on wood blocks so that air can circulate beneath them. The amount of lime or silica-gel required is about 50 pounds per 3,000 pounds of steam per hour boiler capacity.

NOTE

It is important that the quicklime or silica-gel does not contact the metal surface of the boiler.

(4) Seal the boiler tightly.

(5) Open and inspect the boiler every two months. Carefully reseal immediately after the inspection. If the lime or silica-gel is found to be wet upon inspection, replace it with dry material.

(6) To resume operation, reopen the boiler, remove the trays of quicklime or silica-gel, reseal all drumheads and manholes, and replace all piping removed and blanked.

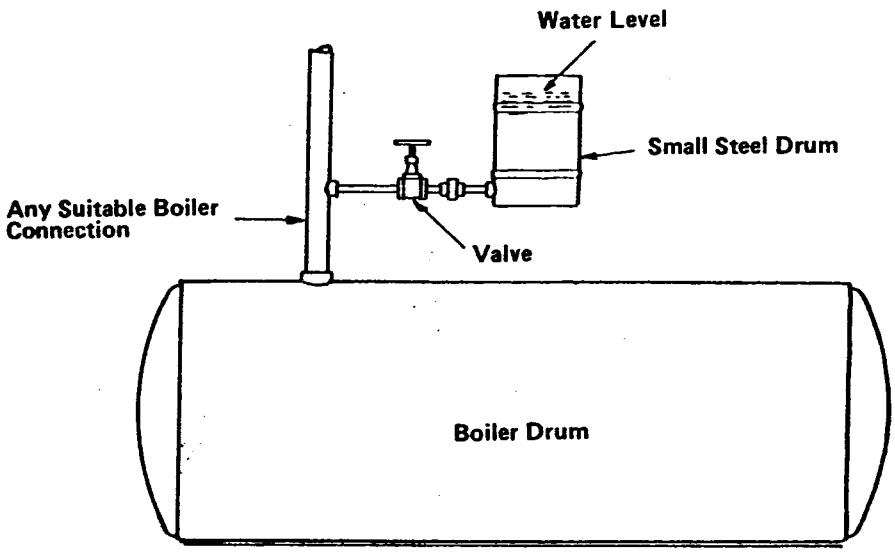


FIGURE 4--34. WET STORAGE METHOD

CHAPTER 5
INSPECTION AND PREVENTIVE MAINTENANCE

SECTION I. INTRODUCTION

5-1. PURPOSE AND SCOPE.

This chapter is presented for the information and guidance of those responsible for maintenance of boiler plant equipment. It establishes a complete preventive maintenance system. The use of DA Form 4177, the Utilities Inspection and Service Record, is described. This system of maintenance assignments and records is sufficiently flexible to be applicable to most boiler plant installations. Although this manual 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 manufactuerer's instruction file on all installed equipment.

5-2. TYPES OF MAINTENANCE.

a. Forced Maintenance. Forced outages for the 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:

— Sustained and frequent overloading of fuel burning equipment
— Operating with improper air flow conditions
— Fouling of external heating surfaces
— Inadequate water conditioning
— Improper lubrication

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

b. Preventive Maintenance. Preventive maintenance can be defined as the systemic and periodic inspection and servicing required to keep equipment in proper operating condition. It 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 worker morale.

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 preventive maintenance. The chief operator should assign to himself responsibility for all 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 by the preventive maintenance record card system. 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 for which he is 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 all 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 all enemies of mechanical and electrical equipment. Stop leaks as soon as they are detected. Unrepaired leaks 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 Director of Engineering and Housing ensure that all personnel are carrying out their responsibilities and that equipment is being properly maintained. DA Form 4177, shown in figure 5-1, is the basic card from which the record system is assembled. Two separate cards, a field card and a master card, are made up for each major piece of plant equipment. A complete set of master c ards is kept in a loose-leaf binder in the plant office, which the field card becomes a written assignment of work for the operator. The record is complete within itself and is available for inspection by the Director of Engineering and Housing or Army command inspector. A copy of this manual should be kept in each plant to fa cilitate references to the items listed on the cards.

a. Record Card Entries. Care is required to initially fill in the cards properly. Each entry is discussed below.

(1) **Equipment Number.** The equipment number entry is made up of three parts separated by dashes. The first part is the boiler plant building number. The second part may refer to the paragraph in this chapter which discusses the equipment, or it may be a number assigned by the Director of Engineering and Housing, or an equipment classification code. The third part distinguishes between a number of identical or similar pieces of equipment.

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

(3) **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.

(4) **Work To Be Done.** Study this manual and the equipment manufacturers manual, noting all 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 all necessary inspections and services are shown on the record card. List operations in order of frequency of performance, with daily service first.

(5) **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".

(6) **Reference.** Insert paragraph numbers to facilitate reference to the appropriate manual.

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

(8) **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.

(9) **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.

(10) 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 t complete Item 51 — commutator grooved. The work order number is entered under the column headed Signed and is initialed. When all spaces on the Service Record are filled in, a blank card should be stapled to the original.

b. 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 all 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.

(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.

(2) **Regulag 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.

(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.

c. Record Card Example. Figure 5-1 illustrates a Master Record Card for a typical boiler. In this example the boiler is the No. 2 boiler located in building NN11. A Field Record Card would be similar, but would also include initials for all daily inspection and servicing performed.

d. Use of the Record Card System. The Record Card System consists of duplicate sets of the DA Form 4177 card, one set making up a Field File and the other the Master File. The Field File is made up of the forms forwarded to the operator who maintains the equipment. A copy of this manual is maintained in the plant to explain duties. The assigned operator makes all service entries and keeps his copies of the forms up to date. Forms in the Field File are kept in the operator's possession except at the beginning of the month, when they are sent to the supervisor for transfer of consolidated data to the Master File. Record cards in the Master File are arranged by equipment number and kept in the work supervisor's office. A movable tab is placed on the tab index of each card, above the month during which maintenance for the unit is next scheduled. When operators turn in the Field File at the beginning of the month, entries are checked to ensure that all work was done and a summary of the entries is transferred to the Master File. The summary includes any special difficulties encountered by the operator, work orders required for maintenance, and the consolidated entry of items checked. After all entries are made, movaable tabs are then shifted to the next month when maintenance is scheduled and Field File cards are returned to the operator. Any tabs in the Master File that are not moved are readily apparent. Since they indicate that a Field File card was not turned in or that work was not completed, immediate follow-up is essential. Careful supervision and attention to detail in setting up the system will pay dividends in accomplished maintenance and more efficient operation.

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 machinists vise, and a tool board.

a. Special Tools. Some maintenance operations require tools which 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 post; otherwise, requisition them. Indicate on the maintenance card the department from which they may be borrowed.

b. Care of Tools. Maintain all tolls 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.

c. Tool Board. Keep all tools on a well-planned tool board or tool box, not in binx, 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. A board made of wood is especially sattisfactory since it is easily constructed and special hangers and brackekts required for the tools can easily be fastened to it. Steel tool boards are mor durable and are also frequently used. 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 all 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.

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

a. Lubricants. Lubricants are frequently referred to in the Scheduled Preventive Maintenance section. Because of the extreme variations in equipment and service

JAN 2	FEB	MAR	APR SA 2	MAY	JUN	JUL 2	AUG	SEP	OCT A 2	NOV	DEC

EQUIPMENT NUMBER NN11-511-2 DESCRIPTION IRON CITY BOILER #2, 350 HP FIRETUBE

PREVENTIVE MAINTENANCE TO BE DONE BY C. JONES, CHIEF OPERATOR

ITEM NR	WORK TO BE DONE	REFERENCE	FREQUENCY	TIME
1	EXTERNAL INSPECTION	5-11a	Daily	
2	TEST BOILER WATER SAMPLES	5-11a	Daily	AM
3	BOTTOM BLOWDOWN	5-11a	Daily	PM
4	CLEAN BOILER EXTERIOR	5-11a	Daily	
5	LEVER TEST SAFETY VALVES	5-11b	Monthly	2nd Monda
6, 7	CHECK BOILER DRAIN VALVES & FLOOR DRAINS	5-11b	Monthly	
8	INTERNAL & EXTERNAL INSPECTION	5-11c	Quarterly	
9	CLEAN FIRESIDE OF BOILER	5-11c	Quarterly	
10	EXTERNAL INSPECTION	5-11d AR420-49	Semi-Annual	APR
11	ANNUAL INSPECTION	5-11e,f AR420-49	Annual	OCT

SCHEDULE INSPECTION AND SERVICE ON THIS SIDE. RECORD INSPECTION AND SERVICE ON REVERSE SIDE.

DA FORM 1 OCT 73 4177 REPLACES DA FORM 9-34.

UTILITIES INSPECTION AND SERVICE RECORD

For use of this form, see TM 5-600 series, the proponent agency is Office of the Chief of Engineers.

RECORD OF INSPECTIONS AND SERVICE

DATE	WORK DONE	INITIAL	DATE	WORK DONE	INITIAL
1/11/82	Item 5,6 & 7	CJ	10/11/82	Item 5,6 & 7	CJ
1/13/82	Item 8 & 9	CJ	10/13/82	Item 9 & 11 Annual Inspection	CJ
2/8/82	Item 5,6 & 7	CJ	10/14/82	Brush & Wash Waterside	CJ
2/18/82	Reseat blowdown valve	CJ	10/14/82	Replace fusible plug	CJ
3/8/82	Item 5,6 & 7	CJ	11/8/82	Item 5, 6 & 7	CJ
4/12/82	Item 5,6,7 & 10	CJ	12/13/82	Item 5, 6 & 7	CJ
4/14/82	Item 8 & 9	CJ			
4/27/82	Repack mainsteam valve	CJ			
5/10/82	Item 5,6 & 7	CJ			
6/14/82	Item 5,6 & 7	CJ			
7/12/82	Item 5,6 & 7 J.T. 7/12/82	CJ			
7/15/82	Item 8 & 9 J.T. 7/15/82	CJ		This illustrates a master	
7/19/82	Repair refractory front wall	CJ		recorder card which has consoli-	
7/20/82	Work Order No. 261	SB		dated the daily and other	
8/9/82	Item 5,6 & 7	CJ		entries from the field record	
9/13/82	Item 5,6 & 7	CJ		card.	

FIGURE 5-1. RECORD CARD EXAMPLE

conditions, the types of lubricants required for a given plant must be determined locally. The equipment manufacturers instructions, advice from lubricant manufactuerers, and advice of the Director of Engineering and Housing help to determine the lubricant requirements. Tables 5-1 and 5-2 are provided to list stock numbers and uses for standard Army lubricants.

b. 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. When using cleanilng solvents, be sure the solvent is completely evaporated before placing the equipment back into service. When using solvents for cleaning electrical equipment, first remove all 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 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 tor remain exposed to air after cleaning.

SECTION II. SCHEZDULED PREVENTIVE MAINTENANCE

5-10. 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 manufacturers operating and maintenance instructions and add additional required items. Review the applicable ASME Code and the National Board Inspection Code published by the National Board of Boiler and Pressure Vessel Inspectors, 1055 Crupper Avenue, Columbus, Ohio 43229, 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.

5-11. 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 both involve the 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 per chapter 4. 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) Item 5. Lever test all safety valves. Reference paragraph 5-15.

(2) Item 6. Check all boiler drain valves for proper opening and closing.

(3) Item 7. 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) Item 8. Internally and externally inspect the boiler. Reference semi-annual and annual procedues.

(2) Item 9. Clean the fireside of the boiler.

d. Semi-Annually. Semi-annually or as required by AR 420-49 an external inspection of the boiler by an Authorized Inspector is required. Item l0. 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.

Table 5-1. Lubricating Oils, Greases, and Preservatives

Product	Military Specification Number	Symbol	Approximate SAE Grade(1)	National Stock Number(2)	Temperature Above
Lubricating oil, general purpose	MIL-L-15016A	2075	20W		-10°F
		2110(3)	10W-75W	9150-00-223-4137	0°F
		2135	20W-75W	9150-00-231-6664	0°F
		2190	30W	9150-00-231-6639	35°F
		2250	40W		35°F
		3050(3)	20W	9150-00-223-4138	0°F
		3065	30W-80W		5°F
		3080	40W-90W	9150-00-223-8890	15°F
		3150	140W	9150-00-240-2258	25°F
Lubricating oil, compounded	MIL-L-15019B	4065	40W	9150-00-243-3196	35°F
		6135	140W	9150-00-231-6645	60°F
		8190	30W	9150-00-231-9033	35°F
Lubicating oil, mineral, cylinder	MIL-L-15018B	5190	140W	9150-00-240-2260	60°F
Lubicating oil, steam turbine (noncorrosive)	MIL-L-17331B	2190TEP	30W	9150-00-235-9061	60°F
Lubricating oil, internal combustion engine, subzero	MIL-L-10295A	OES		9150-00-242-7603	-65° to 0°F
Lubricating oil, instrument jewel-bearing, nonspreading low temperature	MIL-L-3918	OCW		9150-00-2270-0063	-40°F
Lubricants; chain, exposed-gear and wire rope	VV-L-751A	CW-11B		9150-00-246-3276	All
Lubricating oil, internal combustion engine	MIL-L-2104A	OE-10	10W	9150-00-265-9425	20°F
		OE-30	30W	9150-00-265-9433	0°F
		OE-50	50W	9150-00-265-9440	15°F
Grease, automotive and artillery	MIL-G-10924A	GAA		9150-00-190-0907	-65° to 125°F
Grease, ball and roller bearing	MIL-G-18709	BR		9150-00-249-0908	125° to 200°F
Grease, graphite	VV-G-471C	GG-1		9150-00-272-7652	125° max.
Lubricating oil, internal combustion, preservative	MIL-L-21260	PE-1		9150-00-111-02-1 9150-00-111-0208	
Lubricating oil, preservative, medium	PL-MED			9150-00-231-2356	
Corrosive preventive, petroleum,hot application	MIL-G-11796A	CL-3		8030-00-231-2353	
Corrosion preventive, compound, solvent cutback, cold application	MIL-C-16173B	CT-1		8030-00-231-2362	

NOTES

(1) SAE numbers 10W through 50W are for crankcase lubrication. SAE numbers 75W through 140W are for transmission lubrication.

(2) National stock numbers are for 5-gallon containers for lubricating oils and 35-pound containers for grease, except 1/2-ounce can for MIL-L-3918. For other containers, see Federal Supply Catalog.

(3) Quenched.

Table 5-2. Lubricating Oil and Grease Uses

Equipment	Oil or Grease Symbol
Air compressors	
Vertical with splash lubrication	
Gage pressure less than 100 psi	2110, 3050
Gage pressure greater than 100 psi	2135, 2190, 3050
Horizontal	2135, 2190, 3050
External lubrication, sight feed, wick feed, hand oiling	2135, 2190, 3050
External lubrication, circulating systems or splash type crankcase	2110, 2135, 3050
Cylinders: Wet conditions	8190
Dry conditions	2190, 2250, 3065
Bearings:	
Ball, all temperatures to 200°F	BR
Ball, low-pitch line speed	
Operating temperature below 32°F	2075
Operating temperature 32° to 150°F	2190, 2250, 3065
Ball, medium-pitch line speed	
Operating temperature below 32°F	2075
Operating temperature 32° to 150°F	2135, 3050
Ball, high-pitch line speed	
Operating temperature below 32°F	2075
Operating temperature 32° to 150°F	2110, 3050
Ring-oiled, small, miscellaneous	2110
Kingsbury thrust bearing	2190TEP
Thrust (other than Kingsbury, subject to water)	4065
Thrust (other than Kingsbury, not subject to water)	2135, 2190
Bronze guide	GAA
Countershaft	CG 1
Differential (enclosed)	3150, 5190, 6135
Eccentric	3065
Guide	GAA, CG 1
Oilite bronze bushings	OE10, OE30
Pillow block	GAA
Underwater-babbitted	GAA, CG 1
Universal joint, slip splines	BR
Chain Drives	
Roller	3080, GAA, CG 1
Roller (enclosed)	Winter, 2075; Summer, 3065
Roller (semienclosed)	Winter, 3080; Summer, 6135
Slow-speed	CW-IIB
Medium-speed	5190
Chemical feeders	See manufacturer's instructions
Clarifier equipment	Do.
Couplings	6135
Drive jaw clutch	OE30
Gear case or gear head	Low temperature, 3080, high temperature, 5190
Gears	
Herringbone	Winter, 2075; Summer, 3065
Helical	Do.
Motor reducers	Winter, 3050; Summer, 2135
	5190
Open	Winter, 2075, 2110; Summer, 2135
Planetary	Winter, 3080; Summer, 6135
Worm and pump transmission	OCW
Instruments	See manufacturer's instructions
Motors	4065, 6135
Packing, Sludge Pumps	See manufacturer's Instructions
Pumps	GAA
Seal packings	
Shafting	2190, 3065
Large	2110, 2135, 3050
Small	WB
Shear pins	CG 1, GAA
Sheaves	3050
Solenoid oilers	GAA
Valve stems	

(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 AR 420-49. 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, DA Form 416, must be posted for each boiler in the plant.

(1) Item 11. 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) All 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, settlemlent, loose bricks, spallilng, 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 Code or 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 or National Board Inspection Codes.

(a) Where sootblowers are installed, blow soot before reducing boiler load below 50 percent.

(b) Shut down the boiler per paragraph 3-33. 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. All 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 handholes, and suitable wrenches for removing and replacing covers.

(h) Replace fusible plugs.

(i) If insulation conceals manufactuerers 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 all 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 two 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.

5-12. ECONOMIZERS.

Reference paragraph 2-7.

a. Daily: Inspect for leaks in piping, valves, packings, gasketed joints, handhole openings, casing, etc. Make repairs as required.

b. Monthly. Check the following under identical load conditions:

(1) Item 2. Water pressure drop through the economizer.

(2) Item 3. Draft losses across the economizer.

(3) Item 4. 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. AR 420-49 and ASME Boiler and Pressure Vessel Code requires inspection of the economizer in addition to the boiler.

(1) Item 5. Externally look for signs of overheating, leakage, wear, or corrosion in pressure parts. Check the baffles and tubes in the area of sootblowers for signs of abrasion caused by fly ash or steam cutting. Check the elements of the sootblower.

(2) Item 6. Internally look for corrosion, erosion, scale, sludge deposits, or oil in tubes and headers.

5-13. AIR HEATERS.

Reference paragraph 2-8.

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 the manufacturers recommendations.

b. Monthly: Item 5. Check the following under idential 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 heaters, if supplied.

(4) Establish a lubrication schedule for rotary air heaters in accordance with the manufacturers recommendations.

b. Monthly: Item 5. Check the following under identical load conditions:

(1) Air and gas side draft losses.

(2) Gas temperature drop through the air heater.

(3) 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.

(4) Make an orsat or oxygen analysis of the 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) Item 6. During the boiler overhaul, clean and inspect the air heater. Look for indications of corrosion, erosion, leakage, and wear.

(2) Item 7. 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) Item 8. Check the condition of sootblowers and washing equipment.

5-14. WATER COLUMNS.

Reference paragraph 2-11.

a. Daily.

(1) Blow down and inspect all 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: Item 4. During annual boiler overhaul, or more often if necessary, dismantle, clean, and inspect all parts such as valves, alarm linkages, floats, chains, alarms, glasses, diaphragms, or electrodes. Replace or repair damaged or worn parts are required to ensure proper functioning.

5-15. SAFETY VALVES.

Reference paragraph 2-13.

a. Daily.

(1) Check for steam leakage indicating damaged seat, defective parts or lodged scale. Correct immediately 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: Item 4. Check each safety valve by raising the valve off the seat by listing the lever. Keep the valve wide open for at least l0 seconds to blow dirt and scale clean from the seat. Close the valve by suddenly releasing the lever.

c. Annually: Item 5. Before and after the annual steam generator inspection and overhaul, test the operation of all safety valves. Testing is also required whenever the spring or blow back ring has been reset or adjusted.

5-16. FUSIBLE PLUGS.

Reference paragraph 2-16. 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: Item 2. Replace fusible plugs at least once a year.

5-17. SOOTBLOWERS.

Reference paragraph 2-17b.

a. Daily.

(1) Check for leaks. Repair if required.

(2) Check for correct operation of the system components.

b. Semi-Annually.

(1) Item 3. 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 sootblower piping system.

(h) Evidence of abrasion caused by impingement of the jet.

(2) Item 4. Repack and adjust glands to prevent leakage.

5-18. STOKERS.

Reference paragraph 2-18.

a. Daily.

(1) Clean exposed parts of the stoker.

(2) Inspect all accessible parts. Pay special attention to bolts and connections in shear pins or safety release mechanisms. Be sure there is no binding which may keep the 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 the manufacturers requirements.

b. Quarterly. Make the following general inspection and overhaul whenever a boiler is removed from service.

(1) Item 4. Inspect the complete stoker. Check for wear on surfaces of feeder-box sides, conveyor areas, and all 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 all 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) Item 5. Remove slag from furnace walls adjacent to stoker or fuel-bed surface. Take care to avoid injury to the brickwork.

5-19. PULVERIZED COAL EQUIPMENT.

Preventive maintenance procedures for pulverized coal equipment may be found in manufacturers instructions and Navy Manual MO-205.

5-20. COAL HANDLING EQUIPMENT.

Reference paragraph 2-19.

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 manufacturers instructions.

(3) Inspect scales for zero load balance.

b. Monthly: Item 4. 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. Semi-Annually: Item 5. Inspect for the following:

(1) Corrosion or erosion of hoppers, chutes, and gates.

(2) Lining and protective coatings for damage.

(3) Scale levers, knife edges, and bearings for wear or damage. Repair or replace as required.

(4) Concrete structures for cracks or other damage.

d. Annually: Item 6. Prepare applicable metal surfaces and repaint.

5-2l. ASH HANDLING EQUIPMENT.

Reference paragraph 2-20.

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 wsher, if provided.

(d) Proper operation of ash gates and clinker grinders.

(e) Proper operation of automatic steam valves and automatic controls, ilncluding maintenance of correct steam pressue.

b. Quarterly.

(1) Item 2. Inspect conveyor piping, especially at elbows, for accumulated ash and erosion. Rotate, repair, or replace as necessary.

(2) Item 3. Inspect steam exhauster for corrosion and erosion.

(3) Item 4. Inspect wsher internals for wear, ash accumulation, and nozzle condition. Clean and repair as necessary.

5-22. OIL BURNERS.

Reference paragraphs 2-21 and 3-18.

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) Item 5. Completely remove and clean the burner and igniter.

(2) Item 6. Inspect all air register and burner parts for freedom of movement, warpage and wear. Repair or replace as required. Adjust all parts for proper operation. The services of a burner servicemen may be required.

(3) Item 7. Replace atomizer tips or nozzles that have been in normal service with new tips or nozzles.

(4) Item 8. Calibrate burner pressue and t emperature gages.

5-23. OIL HANDLING EQUIPMENT.

Reference paragraphs 2-22 and 3-18.

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 paragraphs 5-34, 5-35, and 5-36.

b. Annually.

(1) Item 5. 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) Item 6. Inspect for damage to protective coatings or paint. Repair or repaint as required.

(3) Item 7. Test relief valve settings and operation.

(4) Item 8. Clean, inspect, and calibrate all controls and instrumentation.

5-24. GAS BURNERS.

Reference paragraphs 2-23 and 3-19.

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.

(l) Item 2. Completely remove and clean the burner and igniter.

(2) Item 3. Inspect all burner parts for freedom of movement, warpage, and wear. Inspect gas nozzles. Repair or replace as required. Adjust all parts for proper operation. The services of a burner serviceman may be required.

(3) Item 4. Calibrate burner pressure gages.

5-25. FEEDWATER/DRUM LEVEL CONTROLS.

Reference paragraph 2-25. a. Daily.

(1) Inspect for water leaks. Repair immediately.

(2) Observe operation of all control devices. Report and repair any malfunction immediately.

(3) Establish a lubrication schedule for all components in the control system in accordance with manufacturers recommendations.

b. Annually.

(1) Item 4. During the boiler overhaul, or more often if necessary, clean and inspect all control components. Look for signs of corrosion, erosion, or wear and for deposits, leaks, and defective parts. Repair as required.

(2) Item 5. Check settings, adjustments, and operation of all components.

5-26. COMBUSTION CONTROLS.

Reference paragraphs 2-26 and 3-20.

a. Daily.

(1) Inspect for air, oil, gas and water leaks. Repair immediately.

(2) Blow down compressed air drip legs and filters.

(3) Check jackshafts, 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 the manufacturers instructions.

b. Monthly: Item 7. Replace or clean all system filters.

c. Annually.

(1) Item 8. Inspect and completely clean all control devices internally. Replace any worn, corroded, or damaged parts.

(2) Item 9. Test for correct calibration. Adjust as required.

(3) Item 10. Test control settings under operating conditions. Optimize control function to improve plant efficiency.

(4) Item 11. Obtain the assistance of a fully trained combustion control service engineer as required to calibrate, clean and adjust the controls.

5-27. BOILER SAFETY CONTROLS.

Reference paragraphs 2-27 and 3-21.

a. Daily.

(1) Inspect all 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) Item 3. Inspect all 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) Item 4. Test all safety controls for proper calibration and operation.

5-28. INSTRUMENTATION.

Reference paragraph 2-28.

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 all instruments and gages for corrosion, deposits, or other defects. Item 4. Inspect carefully for the following:

(1) Ruptured or distorted pressue 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.

5-29. MECHANICAL COLLECTORS.

Reference paragraph 2-32.

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) Item 3. Check all gasketed joints for leaks. Replace damaged or defective gaskets as required.

(2) Item 4. Check the interior of dust collector for caked deposits, corrosion, erosion, loose parts, and other damage. Clean and repair as required.

(3) Item 5. Check the exterior of dust collector for damaged parts, paint, corrosion, etc. Clean and repair as required.

c. Annually: Item 6. Paint the entire assembly.

5-30. STACKS.

Reference paragraph 2-40.

a. Daily: Inspect for possible defects, leaks, damage, deterioration of lining, cracks, or settlement in foundation.

Report promptly any such observation.

b. Quarterly.

(1) Item 2. 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) Item 3. Remove soot and fly-ash accumulation from base of stack.

(3) Item 4. 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. Semi-Annually: Item 5. 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: Item 6. Clean and inspect the stack internally and externally. Inspect lightning rod tips and ground connections. Paint.

5-3l. ZEOLITE WATER SOFTENERS.

Reference paragraph 4-6a and 4-l6b.

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. Semi-Annually.

(1) Item 3. Inspect ion exchange vessel, valves, and piping for corrosion, rust, and peeling of paint.

(2) Item 4. 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: Item 5. Calibrate instruments annually or more often as required.

5-32. HOT LIME-SODA SOFTENERS.

Reference paragraph 4-6b and 4-16b.

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° 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) All lilnes and valves for leakage. Repair or replace immediately.

(2) Blow down rection tank daily or more often according to sludge accumulation.

(3) Lubricate motors and pumps according to manufacturers directions and schedule.

b. Monthly.

(1) Item 4. Clean chemical solution tank. Clean outlet strainer.

(2) Item 5. Clean and flush chemical feed pump.

(3) Item 6. Lubricate and adjust chemical proportioner.

c. Semi-Annually.

(1) Item 7. 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) Item 8. Open, examine, clean, and recharge filters in accordance with manufacturers recommendations.

d. Annually.

(1) Item 9. 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) Item 10. Dismantle, clean, overhaul, and repack pumps.

(3) Item 11. Repack valves.

(4) Item 12. Paint exposed surfaces.

5-33. DEAERATING HEATERS AND DEAERATORS.

Refernce paragraph 4-6h and 4-16c.

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: Item 3. 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 prssure 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.

5-34. PUMPS.

Reference paragraph 2-37.

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. Item 2. Inspect all external gear and bearing housings for correct lubricant condition. Establish lubrication requirements and schedule in accordance with the manufacturers recommendations.

c. Annually. Item 3. 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.

5-35. CENTRIFUGAL PUMPS.

Reference paragraph 2-37b.

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. Semi-Annually.

(1) Item 2. Check alignment of pump and driver with the unit at stand-still and normal operating temperature.

(2) Item 3. Check shaft sleeves for scoring.

(3) Item 4. Replace packing if required.

(4) Item 5. Drain the oil from oil-lubricated bearings, flush, and refill with clean oil.

(5) Item 6. 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: Item 7. Completely disassemble, clean, and inspect the pump. Check for the following:

(1) Wearing ring clearances according to manufacturers instructions. Diametric clearance between 0.005 and 0.025 inch is usual.

(2) Bearing wear and clearances. Overhaul if required, according to manufacturers 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 flowmeters.

(6) Suction and discharge strainers for cleanliness.

5-36. RECIPROCATING PUMPS.

Reference paragraph 2-37c.

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 manufacturers instructions.

b. Monthly: Item 3. 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) Item 4. Dismantle the pump once a year or more often if required; clean and inspect the poump.

(2) Item 5. 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.

(2) Item 6. Also look for corrosion, erosion, or excessive wear of parts, and for transmission of strains from piping to pump.

(3) Item 7. 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.

(4) Item 8. Check for plugged steam passages in steam chest, scoring of shoulders or cyliners, corrosion, erosion, and excessive wear of parts.

(5) Item 9. Calibrate instruments.

(6) Item 10. Replace packings.

5-37. STEAM INJECTORS.

Reference paragraph 2-37e.

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: Item 5. 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.

5-38. STEAM TURBINES (NON-CONDENSING).

Reference paragraph 2-41. Institute preventive maintenance schedule in accordance with manufacturers recommendations. The following program is suggested for a singel stage impulse non-condensing steam turbine typically used at Army installations 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 all ilnstruments, gages, and throttle valve.

(2) Establish lubrication requirements and schedule in accordance with manufacturers instructions.

b. Weekly.

(1) Item 3. Blow down steam strainer connection.

(2) Item 4. Lubricate governor and overspeed trip linkages.

(3) Item 5. Trip emergency valve by hand trip lever to check its operability.

c. Monthly.

(1) Item 6. Change bearing oil and clean reservoir.

(2) Item 7. Make visual inspection of governor parts, bearings, and linkage for lost motion.

(3) Item 8. Check coupling for looseness, wear, and alignment.

d. Annually: Item 9. 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 manufacturers 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 opoeration. 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.

5-39. AIR COMPRESSORS.

Reference paragraph 2-45.

a. Daily.

(1) Inspect for the following:
(a) Unusual noise or vibration.
(b) Abnormal temperature and prssure 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 manufacturers recommendations.

b. Quarterly: Item 3. Inspect for the following:

(1) Compressor valves for wear, dirt, and improper seating.

(2) Operation of all 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) Item 4. Check cylinders for wear, scoring, corrosion, and dirt.

(2) Item 5. Inspect pistons and rings for leakage, wear, scoring, security to the piston rod, and head clearances.

(3) Item 6. Inspect crank shaft and crank shaft bearings for wear and proper operation.

(4) Item 7. Check alilgnment of the compressor with respect to the driver.

5-40. STEAM TRAPS.

Reference paragraph 2-46. Establish a comprehensive and coordinated maintenance and inspection program for all 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) Item 2. Blow down steam trap to eliminate dirt accumulations.

(2) Item 3. Open the air vents on float traps to vent accumulated air.

(3) Item 4 Test traps for correct operation.

c. Annually.

(1) Item 5. Completely disassemble all 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) Item 6. Replace or repair all defective gaskets, linkages, and orifices.

(3) Item 7. Reassemble and test for proper operation.

5-41. ELECTRIC MOTORS.

Reference paragraph 2-42. Also reference TM 5-683 entitled Facilities Engineering Electrical Interior Facilities.

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 manufacturers recommendatins.

b. Annually.

(1) Item 3. Inspect squirrel cage rotors for broken or loose bars. Check for loose or broken fan blades.

(2) Item 4. Thoroughly inspect all ball, roller, and sleeve bearings for wear and dirt.

(3) Item 5. Check and record insulation resistance.

(4) Item 6. Check windings for dirt, moisture, cracks, and loose wedges.

(5) Item 7. Check coupling alignment.

5-42. FORCED DRAFT AND INDUCED-DRAFT FANS.

Reference paragraphs 2-38 and 2-39.

a. Daily.

(1) Inspect for the following:

(a) Abnormal noises.

(b) Abnormal vibration.

(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 manufacturers recommendations.

b. Quarterly.

(1) Item 3. Examine water cooling system for corrosion and clogging.

(2) Item 4. Clean rotor and casing and inspect for corrosion, erosion, and damage. Check clearances between rotor and casing.

(3) Item 5. Check alignment of shaft and coupling; inspect coupling.

(4) Item 6. Check condition of foundation and tightness of bearing and foundation bolts. Defective foundation or loose bolts may promote heavy vibration.

(5) Item 7. Inspect bearings.

c. Annually: Item 8. Annually, or more often if required, inspect and perform the following maintenance work:

(1) Complete by 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.

5-43. 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.

a. Procedure. Command inspections are made on accessible central boiler plant equipment at any time that causes the least possible interference with boiler plant routine. All 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:

(1) Cleanliness of equipment, pipes, walks, floors, walls, and instruments.

(2) Any leaks from water, steam, oil, or air equipment.

(3) Neat and orderly storage tools, spare parts, upplies, and fuel.

(4) Deficiencies of equipment, working order of parts.

(5) Prompt notification to the Director of Engineering and Housing of all opoerating deficiencies.

(6) Methods and procedures used in hazardous opertions.

b. Follow-Up. After inspections have been completed, personnel are advised of the deficiencies and irregularities noted.

5-44. TECHNICAL INSPEZCTION.

Technical inspections are made by the Director of Engineering and Housing or designated personnel of his organizatrion to determine the general condition of boiler plant equipment, effectiveness of preventive maintenance , and need for additional instruction or training of maintenance personnel.

a. 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 ollowing are checked at each piece of boiler plant equipment inspected.

(1) All items included in command inspections. (See paragraph 5-43.)

(2) Adequacy of preventive maintenance as it is being performed.

b. Follow-Up. On completion of the technical inspection, the Director of Engineering and Housing 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.

5-45. MAJOR ARMY COMMAND INSPECTIONS.

Major Army Command Inspections are made by technical personnel to determine effectiveness of preventive maintenance and to ensure uniform procedures at all posts. They include examination of preventive maintenance inspection records.

a. General Inspections. Technical personnel make general inspections at least four times a year. Inspectors check the following:

(1) Preventive maintenance record system.

(2) Familiarity of maintenance personnel with equipment duties.

(3) Promptness of corrective action when Director of Engineering and Housing is notified of defects.

b. Follow-Up. Errors and oversights are reported to the proper authority. The Major Army Command maintains suitable records of inspections. These records include a list of equipment inspected, findings, recommendations, and other pertinent data.

APPENDIX
REFERENCES

Government Publications.

Department of the Army

MIL-F-18113	Pressure Pot Feeder
AR-420-49, Sect. VI	Boiler Inspection
TM 5-576	Coal Handling, Storage and Sample Preparation
TM 5-680G	Additional Information on Electrical Equipment
TM 5-682	Electrical Safety Regulation
TM 5-683	Facilities Engineering Electrical-Interior Facilities
TM 5-684	Facilities Engineering Electrical-Exterior Facilities April 1979
TM 5-810-2	High Temperature Water Heating Systems
TM 5-810-4	Compressed Air
TM 5-815-1	Air Pollution Control Systems for Boiler and Incinerators

Department of the Navy Manuals

MO-205 Vol. I	Pulverized Coal Systems

Department of the Air Force Manuals

85-12, Chapt. 1	Information on LPG

Nongovernment Publications.

American National Standards Institute (ANSI), 1430 Broadweay, New York, NY 10018

ANSI B16	Pipe, Flanges, and Fittings
ANSI B31.1	Power Piping
ANSI B36	Iron and Steel Pipe

American Society of Mechanical Engineers (ASME), United Engineering Center, 345 East 47th Street, New York, NY 10017

ASME Boiler and Pressure Vessel Code

Section I	Rules for Construction of Power Boiler
Section IV	Requirements for Heating Boilers
Section VI	Recommended Rules for Care and Operation of Heating Boilers
Section VII	Recommended Rules for Care of Power Boilers
Section IX	Welding Qualifications

American Society of Testing and Materials (ASTM), 1916 Race Street, Philadelphia, PA 19103

ASTM D388	Coal Classification
ASTM D396	Standard Classification for Fuel Oils
ASTM D1066	Steam Sampling Nozzle and Method of Connection

Boiler Efficiency Institute, P.O. Box 2255, Auburn, AL 36830

Boiler Efficiency Improvement

National Board of Boiler and Pressure Vessel Inspectors, 1055 Crupper Avenue, Columbus, OH 43229

National Board Inspection Code

National Fire Protection Association (NFPA), Batterymarch Park Quincy, MA 02269

NFPA 13	Installation of Sprinkler System

NFPA 14	Standards for the Installation of Standpipe and Hose Systems.
NFPA 30	Flammable and Combustible Liquids Code
NFPA 31	Standards for the Installation of Oil Burning Equipment
NFPA 85A	Standards for Prevention of Furnace Explosions in Fuel Oil and Natural Gas-Fired Single Burner Boiler-Furnances.
NFPA 85B	Standards for Prevention of Furnace Explosions in Natural Gas-Fired Multiple Burner Boiler-Furnaces
NFPA 85D	Standards for Prevention of Furnace Explosions in Full Oil-Fired Multiple Burner Boiler-Furnances
NFPA *5E	Standards for Prevention of Furnace Explosions in Pulverized Coal-Fired Multiple Burner Boiler-Furnances
NFPA 85F	Standards for the Installation and Operation of Pulverized Fuel Systems

APPENDIX B

CHEMICAL ANALYSIS PROCEDURES

B-1. EXTERNAL TREATMENT PLANTS

a. Test for Hardness (Colorimetric Titration Method). This test is based on determination of the total calcium and magnesium content of a sample by titration with a sequestering agent in the presence of an organic dye sensitive to calcium and magnesium ions. The end point is a color change from red to blue. It occurs when all the calcium and magnesium ions are sequestered. NOTE: If the testing procedure of the equipment and/or reagent supplier differs from the following procedure, the supplier's procedure must be used.

(1) **Equipment.** These are supplied by commercial concerns as test kits.

Equipment includes:

(a) One 25-ml burette, automatic, complete.

(b) One 210-ml casserole, porcelain.

(c) One 50-ml cylinder, graduated.

(d) One stirring rod, glass,

(2) Reagents.

(a) Hardness indicator.

(b) Hardness buffer.

(c) Hardness titrating solution, 1 ml = 1 mg $CaCO_3$.

(3) **Procedure.** Measure 50 ml of the sample in the graduated cylinder and transfer it to the casserole. With the calibrated dropper, add 0.5 ml of hardness buffer reagent to sample and stir. Add 4 to 6 drops of hardness indicator.If hardness is present, the sample turns red. Add the hardness titrating solution slowly from the burette, with continued stirring. When approaching the end point, the sample begins to show some blue coloration, but a definite reddish tinge can still be seen. The end point is the final discharge of the reddish tinge. More hardness titrate solution does not produce further color change. In using this procedure, the hardness titrating solution must be added slowly because the end point is sharp and rapid. For routine hardness determination it is suggested that 50 ml of the sample be measured, but only approximately 40 to 45 ml be added to the casserole at the start of the test. Add the hardness buffer reagent and the hardness indicator as directed, and titrate the mixture rapidly to the end point. Then add the remaining portion of the sample. The hardness present in the remainder of the sample turns the contents of the casserole red again. Titrating is continued slowly until the final end point is reached. Keep a record of the total milliliters of hardness titrating solution used.

(4) **Calculation of results.** The ppm hardness is calculated by the equation:

$$ppm\ hardness\ as\ CACO_3 = \frac{mil\ titrating\ solution\ x\ 1{,}000}{ml\ sample}$$

Using a 50-ml sample, the hardness in ppm as $CaCO_3$ is equal to the ml of titrating solution employed, multiplied by 20.

b. Test for Alkalinity. This test is based on determination of the alkaline content of a sample by titration with a standard acid solution. The end points are taken as points of change in color of the organic indicators, phenolphthalein (approximately pH 8.3) and methyl orange (approximately pH 4.3) representing definite points to which the alkalinity of the sample has been reduced by adding standard acid solution.

NOTE: If the testing procedure of the equipment and/or reagent supplier differs from the following procedures, the supplier's procedure must be used.

(1) **Equipment.**

(a) One 25-ml burette, automatic, complete.

(b) One 210-ml casserole, porcelain.

(c) One 50-ml cylinder, graduated.

(d) One stirring rod, glass.

(2) **Reagents.**

(a) Acid, sulfuric, N/50.

(b) Phenolphthalein indicator. 0.5%.

(c) Methyl orange indicator, 0.05%

(3) **Procedure.**

(a) Measure a clear, 50-ml sample of water in the graduated cylinder and transfer it to the casserole. Add 4 to 5 drops of phenolphthalein indicator. If the sample is alkaline water, which is usual in boiler water, it turns red. If the sample is raw or natural water, it usually remains colorless.

(b) Add the standard N/50 sulfuric acid from the burette drop by drop to the sample in the casserole, stirring constantly until the point is reached at which 1 drop removes the last trace of red and the sample becomes colorless. Stop and record the total milliliters to this point as the P reading.

(c) Add 4 drops of methyl orange indicator. (If no red developed when the phenolphthalein indicator was added to the original sample, the titration may be started with the methyl orange indicator at this point.) Again add the acid, drop by drop, until 1 drop changes the color from yellow to salmon-pink. Record the final burette reading as the M reading. This is a difficult end point to achieve accurately, and some practice may be necessary.

The general tendency is to add too much acid, which changes the sample from salmon-pink to definite red. Record the titration to the P point and the total titration to the M point, as the P and M readings respectively. (Note that M is always greater than P because P is included in M.) If the water sample does not settle clearly, the M reading can best be determined on a filtered sample. However, make the P reading on an unfiltered sample to ensure an accurate result.

(4) **Calculation of Results.** Phenolphthalein and methyl orange alkalinity are calculated by the equations:

$$P\ Alk\ as\ ppm\ CaCO_3 = \frac{ml\ of\ H_2SO_4 \times 1{,}000}{ml\ sample}$$

$$M\ Alk\ as\ ppm\ CaCO_3 = \frac{ml\ of\ H_2SO_4\ 1{,}000}{ml\ sample}$$

Using a 50-ml sample, P Alk in ppm $CaCO_3$ equals the ml of N/50 sulfuric acid recorded for the P reading multiplied by 20. The M Alk (total alkalinity) equals the ml of N/50 sulfuric acid recorded for the M reading multiplied by 20.

B-2. BOILER WATER.

a. Test for Sodium Sulfite. It is important that sodium sulfite be the first boiler water test performed on any set of samples. Sample exposure to air must be minimized, and test must be performed immediately after collection for accurate results. Cool the sample to 70° F, or below, and expose to the air as little as possible, because oxygen in the air combines with sodium sulfite in the sample and causes low readings. It is desirable to collect a separate sample, using the boiler water sample cooler,with the line reaching to the bottom of the sampling bottle. Allow the boiler water to run until a few bottlefuls overflow to waste. A USAEHSC test kit is used.

(1) Equipment.

(a) Two marked test tubes.

(b) Two plain test tubes.

(c) One stopper for plain test tubes.

(d) One stirring rod.

(e) One 7-in. dropper.

(f) One ¼ teaspoon.

(g) One 50-ml beaker.

(h) One 100-ml beaker.

(i) One 30-ml acid dropping bottle, with dropper marked at ½ mil for hydrochloric acid 3N.

(j) sOne 30-ml starch dropping bottle, with dropper marked at ½ ml for starch indicator.

(2) **Reagents.**

(a) One 2-oz. bottle of potato or arrowroot starch.

(b) One 8-ml vial of thymol.

(c) One 32-oz. bottle of hydrochloric acid 3N.

(d) One 1-pt. amber bottle of standard potassium iodate-iodide reagent.

(3) **Preparation of Starch Indicator.** This indicator must be prepared locally in the following manner.

(a) Measure out a level ¼ teaspoonful of potato or arrowroot starch and transfer to the 50-ml beaker.

(b) Add a fe3w milliliters of distilled water and stir the starch into a thin paste, using the glass end of the stirring rod.

(c) Put 50 ml of distilled water into the 100-ml beaker. (It is convenient in this step to have the 100-ml beaker marked at the point where it holds 50 ml, or one of the marked test tubes can be used by filling it with distilled water to the fourth mark above the long mark.)

(d) Bring the water in the 100-ml beaker to a boil by any convenient method.

(e) Remove the source of heat and immediately pour the starch paste into the boiling water while stirring the solution.

(f) Put a crystal of thymol into the starch solution and stir. After the solution has cooled, pour off any scum on the surface and transfer 30 ml to the indicator dropping bottle.

(g) The starch solution loses its sensitivity as a indicator after a time. Addition of the thymol preserves it for about two weeks. Date the starch when prepared.

(4) **Procedure.**

(a) Transfer 1 ml of hydrochloric acid 3N to a clean, marked test tube by measuring out two ½-ml portions with the dropper of the acid dropping bottle.

(b) From the starch dropping bottle, transfer ½ ml of starch to the marked test tube.

(c) Without disturbing any settled sludge in the sample, pour enough sample into the marked test tube to bring the level up to the first mark (25 ml). Stir the mixture in the tube with the plunger end of the stirring rod.

(d) To add the standard potassium iodate-iodide reagent to the mixture in the marked test tube, it is convenient to have the marked test tube supported and the stirring rod placed in the tube, so that the reagent can be added with one hand while the mixture is stirred with the other. Fill the 7-in. dropper with standard potassium iodate-iodide reagent from the stock bottle by sucking it up with the rubber bulb. (The dropper must be kept clean and reserved for this test only).

(e) Add the reagent to the mixture in the marked test tube, one drop at a time, counting the number of drops and stirring after each is added until a permanent blue color, which is not removed by stirring, is obtained. The standard iodate-iodide reagent reacts with sodium sulfite in the mixture, and formation of the permanent

blue color from the action of excess reagent with the starch shows that all the sodium sulfite in the mixture has been consumed by the iodate-iodide reagent.

(f) Each drop of iodate-iodide reagent used (except the last one) indicates 5 ppm of sodium sulfite in the boiler water sample. To figure the concentration of sodium sulfite in the boiler water, multiply the total number of drops of the standard iodate-iodide reagent used, less one, by 5.

(5) **Recording the Results.** Record the results of the test as ppm in column (4), DA Form 4367, Boiler Water Treatment Log.

b. Test for Causticity (OH-) Without Tannin. This test must be run immediately after the sodium sulfite test for any set of boiler water samples. Sample exposure to air must be minimized before this test is performed. The boiler water sample is collected at a temperature of 70° F, or below. The USAEHSC test kit is used.

(1) **Equipment.**

(a) Two 8-in. droppers with bulbs.

(b) Four marked test tubes, 22 mm x 185 mm.

(c) Three plain test tubes, 22 mm x 175 mm.

(d) Two rubber stoppers, No. 3.

(e) One 14-in. test-tube brush.

(f) One test-tube clamp.

(g) Two 9-in. stirring rods.

(h) One 1-oz. indicator dropping bottle for phenolphthalein.

(i) One test-tube rack.

(2) Reagents.

(a) One 32-oz. bottle causticity reagent No. 2

(b) One 32-oz. bottle causticity reagent No. 1

(c) One 4-oz. bottle of phenolphthalein indicator.

(3) **Procedure.** In conducting a test for causticity when tannin is not used, follow the procedure outlined below. NOTE: Avoid exposure of sample to air as much as possible to minimize absorption of CO_2. If the sample in the tube is warm, cool it by flowing cold water on the outside of the tube.

(a) Without disturbing any settled sludge, fill a marked test tube exactly to the first mark (25 ml) with some of the original boiler water sample.

(b) Shake causticity reagent No. 1 (barium chloride solution saturated with phenolphthalein) thoroughly and add enough to the graduated tube to bring the level exactly to the second, or long mark (30 ml). Stir the solution with the stirring rod which must be kept clean and reserved for the causticity test only. Do not strike the end of the stirring rod against the bottom of the test tube, as it is easily punctured. If the mixture remains colorless or does not turn pink, the causticity in the boiler water is zero. In this case the test is finished.

(c) If the mixture turns pink, causticity is present. (If the pink color is not very deep, intensify it by adding two drops of phenolpthalein indicator to the mixture in the tube). Add causticity reagent No. 2 (standard 1/30 normal acid), using the dropper, which must be kept clean and reserved for the causticity test only. Causticity reagent No. 2 is sucked from the reagent bottle into the dropper by its rubber bulb and added, drop by drop, to the test tube. After each addition, stir the mixture with a stirring rod. After sufficient reagent has been added, the pink color disappears, the change point usually being very sharp. As soon as the pink color just fades out, stop adding reagent.

(d) The amount of causticity reagent No. 2 required to make the pink color disappear indicates the concentration of hydroxide (OH-) or causticity in the boiler water. The amount of reagent used is shown by the marks on the test tube above the long mark (30 ml). The distance between any two marks on the test tube equals 5 ml, and readings less than 5 ml can be estimated. For example, of only 3/5 the distance between the long mark and the next mark above was filled, then 3 ml were added. If the distance filled was past one mark plus 3/5 the distance to the next, then 5 + 3 = 8 ml were used. To obtain the actual ppm of hydroxide or causticity shown by the test, multiply the number of ml by 23. Thus, for 8 ml of causticity reagent No. 2, there are 8x23=184 ppm hydroxide or causticity in the water.

(4) **Recording the Results.** Record the results of the test as zero or in ppm, as the case may be, in column (2) of DA Form 4367, Boiler Water Treatment Log.

c. Test for Causticity (OH-) With Tannin. This test must be run immediately after the sodium sulfite test for any boiler water samples. Sample exposure to air must be minimized before this test is performed. For this test, it is desirable to start with a warm sample at about 160° F. It may be reheated by placing the sample-collecting container in a stream of hot boiler water drawn through the boiler water cooler connection. NOTE: Avoid exposure of sample to air a much as possible to minimize absorption of CO_2.

(1) **Equipment and Reagents.** These are the same as B-2a((1) and (2) where tannin was not used.

(2) **Procedure.** In conducting a test for causticity when tannin is used, follow the procedure outlined below.

(a) Fill two test tubes to the first mark (25 ml) with some of the original boiler water sample, taking care not to disturb the settled sludge in the container. (It is important that as little sludge as possible be transferred from the sample-collecting container to the test tubes).

(b) Shake causticity reagent No. 1 thoroughly and add enough to each of the two marked tubes to bring the levels up to the second, or long, mark (30 ml). Stir both with the stirring rod, which must be kept clean and

reserved for the causticity test only. Stopper both tubes and let them stand until any sludge formed has settled to the bottom. The sludge carries with it much of the tannin or other colored matter in the solution. Settling takes a few minutes if the sample is warm. Without disturbing the sludge at the bottom, pour enough solution from the tubes into the third marked tube to fill it to the second, or long, mark. Discard the mixture left in the first two. If the sample in the third is still warm, cool it by letting cold water run on the outside of the tube. It is sometimes possible to intensify the pink color by adding two drops of phenoplhthalein from the indicator dropping bottle to the sample in the tube. Stir the solution. If it is not pink, the causticity in the boiler water is zero and the test is finished.

(c) If the mixture turns pink, proceed in the same manner as B-2**a** (3) **(c)**, **(d)**, and **(e)** when no tannin is used.

(3) **Alternate Procedure.** Use a graduated cylinder, marked for 50 or 60 ml., instead of two standard marked test tubes used in steps B-2**a(a)** and **(b)**. With the graduated cylinder, the warm (160° F) sample is added up to 50-ml mark and causticity reagent No. 1 up to the 60-ml mark. Stir the mixture and lightly stopper the tube or graduated cylinder. After the sludge settles, pour off enough of the solution into one of the standard marked test tubes to fill it to the long mark (30 ml). If the sample is warm, cool it by letting cold water run on the outside of the tube. The pink color may be intensified by adding two drops of phenolphthalein. If the solution is not pink, the causticity in the boiler water is zero. If it turns pink, proceed in the same manner as B-2**a** (3) **(c)**, **(d)**, and **(e)**, when no tannin is used.

(4) **Titrimetric Method.** Use the titrimetric method of determining causticity when greater accuracy is desired than is given by either of the above methods. This method utilizes a burette which permits measuring very small quantities of causticity reagent No. 2. Procedure is as follows:

(a) Admit 40 ml of hot boiler-water sample to a graduated cylinder. Shake causticity reagent No. 1 thoroughly and add 10 ml of reagent to the graduated cylinder. Stir the mixture and lightly stopper the graduated cylinder. Permit precipitate to settle and then transfer 30 ml of clear solution to a white casserole or other suitable vessel. Add 2 to 3 drops of phenolphthalein indicator.

(b) Add causticity reagent No. 2 from the burette drop by drop until the pink color disappears.

(c) Read the number of ml of causticity reagent No. 2 used directly from the burette. Multiply this figure by 23 to find ppm of causticity of hydroxide.

(5) **Recording of Results.** Record the results on DA Form 4367, Boiler Water Treatment Log, after the test is complete.

d. Test for Phosphate. This is a colorimetric test fo phospohate, employing a decolorizing carbon for remova. of tannin. Carbon absorbs the tannin, and the carbon and tannin are then filtered out. When tannin is not present,the use of carbon is not required. The USAEHSC Kit is used.

(1) **Equipment.**

(a) One Taylor Comparator Phosphate Slide, 5 to 100 ppm, #9110.

(b) One Taylor Slide Base, #9190.

(c) One Taylor Dalite Lamp, #9195.

(d) Four combination comparator mixing tubes, each marked at 5, 15, and 17.5 ml, with stoppers.

(e) Two short comparator tubes marked at 5 ml.

(f) One filter funnel, 65 mm diameter.

(g) One package filter paper, 11 cm diameter, very fine.

(h) One 15 ml bottle.

(i) One ½ ml dropper.

(j) One ¼ teaspoon measuring spoon.

(k) Two plain test tubes, 22 mm x 175 mm (about 50 mm).

(l) Two rubber stoppers, No. 3.

(2) **Reagents.**

(a) One 32-oz. Comparator Molybdate.

(b) One 2-oz. Concentrated Stannous Chloride.

(c) One Standard Phosphate Test Solution (45 ppm of phosphate, PO_4).

(d) One lb Decolorizing Carbon. (This special grade of decolorizing carbon has been tested to ensure that it does not affect the phosphate concentration in the sample.)

(3) **Preparation of Dilute Stannous Chloride.** For test purposes, the stannous chloride is supplied in concentrated form. Dilute and prepare the reagent from the concentrated stannous chloride on the day it is to be used, because the diluted solution deteriorates too rapidly for supply by a central laboratory. If not fresh, dilute stannous chloride gives low test results. Concentrated stannous chloride also deteriorates in time and should not be used if more than two months old. Unopened bottles of concentrated stannous chloride are good for six months. Dilute stannous chloride is made by the following method:

(a) Fill the ½-ml dropper up to the mark with the concentrated stannous chloride.

(b) Transfer it to a clean 20-ml bottle.

(c) Add distilled water up to the shoulder of the bottle, then stopper and mix by shaking.

(d) Any dilute stannous chloride not used the day it is made should be discarded.

(4) **Procedure.** The test for phosphate is outlined below.

(a) Without disturbing any settled sludge, transfer sufficient of the sample to the test tube to fill it about

half full.

(b) If tannin is present in the sample, add ¼-teaspoonful of decolorizing carbon. Stopper the tube and shake vigorously for about 1 minute. The carbon absorbs the tannin so that it can be filtered out.

(c) Fold a filter paper and place it in the filter funnel. Do not wet down the filter paper with water. Filter the shaken sample using a combination mixing tube as a receiver. Avoid jiggling the funnel, as unfiltered boiler water may overflow the edge of the filter paper and go into the tube. The operator may provide a support for the funnel. Filtering is slow because of the action of the carbon.

(d) After 5 ml of sample has filtered through, as indicated by the level in the tube, discard it. Continue filtering to bring the level in the test tube again up to the 5 ml mark. The sample should come through clear and free, or nearly free, of any color resulting from tannin. If it does not, refer to paragraph **(i)** which describes retesting procedures for cases where more Decolorizing Carbon is needed to remove tannin from the sample.

(e) Add comparator molybdate reagent to bring the level up to the second mark (15 ml). Stopper and mix by inverting the tube several times.

(f) Add fresh dilute stannous chloride up to the third mark (17.5 ml). Stopper and mix by inverting. If phosphate is present, the solution in the mixing tube turns blue.

(g) Place the tube in the center opening in the slide base. Fill the two short comparator tubes with distilled water and insert them into the two holes adjacent to the center hole. Place the base on the Dalite lamp and turn on the lamp.

(h) Find the best match between the sample and the color standards of the phosphate slide by moving the slide along the slide base. Concentrations between those of two color standards can be estimated. Note the reading within one minute after adding the dilute stannous chloride since the color can fade rapidly.

(i) If the color obtained is darker than the 60 ppm standard, the sample should be diluted and tested again. After filtering 5 ml of sample, add 5 ml distilled water and mix. Use 5 ml of this diluted sample to perform the test. Multiply the result by two to obtain the concentration of the original undiluted sample.

(j) Where the use of a ¼-teaspoon of Decolorizing Carbon does not give a filtered sample which is free or nearly free of color due to tannin, the test can be repeated using more Decolorizing Carbon, say ½—Teaspoon. Add it in ¼-teaspoon portions. Stopper and shake sample for one minute after each addition. With some grades of Decolorizing Carbon, more than this mount should not be used as it can remove phosphate from solution and give low results.

(5) **Testing the Reagents.** Test the comparator molybdate and concentrated stannous chloride reagents at frequent intervals, at least twice a week, to ensure they are giving a correct blue color development in the test. This is done by testing for the phosphate concentration in the standard phosphate test solution. Add sufficient standard phosphate solution (45 ppm PO_4) to a combination mixing tube to bring the level up to the first mark. Add comparator molybdate and stannous chloride reagents as described in the test above. The color obtained should be about midway between 40 and 50 ppm color standards of the comparator. If the color is outside the 40 to 50 ppm range of the standards, the reagents must be replaced.

(6) **Recording the Results.** Record the results on DA Form 4367, Boiler Water Treatment Log, after the test is complete.

e. Test for Tannin. When boiler water is treated with tannin, the dosage can be controlled satisfactorily by the depth of brown formed in the boiler water by the tannin. To estimate the depth of the color, which is necessary in addjusting tannin dosages, a sample of the boiler water is compared with the series of brown color standards of successively increased depths of color. The tannin color comparator used for the comparison has five glass color standards: No. 1, very light; No. 2, light; No. 3, medium; No. 4, dark; and No. 5, very dark.

(1) **Equipment.** This test employs a USAEHSC Kit. Required equipment includes:

(a) One tannin color comparator.

(b) Two square tubes, 13 mm view depth.

(c) One plain test tube, 22 mm x 175 mm.

(d) One filter funnel, 65 mm x 65 mm.

(e) One package filter paper, 11-cm. diam.

(2) **Procedure.**

(a) Without disturbing any settled sludge in the sample, fill the test tube to within 1 or 2 inches of the top with the boiler water being tested.

(b) Place a square test tube into a slot of the comparator, and set the filter funnel in the tube. Fold a filter paper and place it in the funnel without wetting it down. Filter sufficient sample from the plain test tube into the square tube so that it is nearly full.

(c) Remove the square test tube from the comparator and note the appearance of the filtered boiler water. It should be free of suspended solids and sludge.

(d) If the sample does not come through free of suspended solids or sludge, refilter it, using the same funnel and filter paper. Repeat, using double filter paper if necessary, until it is free.

(e) Set the square tube of filtered sample in the middle slot of the comparator. Compare the color of sample with the five color standards, viewing it against a source of fairly bright daylight.

(f) The color standard most closely matching the color of the filtered sample gives the tannin concentration of the boiler water. For most boiler water conditions, the tannin dosage is usually satisfactory if it maintains a medium (No. 3) tannin color in the boiler water. When boiler water causticity is high, the tannin dosage may be adjusted to maintain a dark (No. 4) tannin color.

(3) **Recording the Results.** Record the results on DA Form 4367, Boiler Water Treatment Log, after the test is complete.

f. Test for Total Dissolved Solids (TDS). The electrical conductivity method is a simple and rapid way to determine TDS content.

(1) **Equipment and Reagents.**

(a(Myron L model EP meters can be provided via lateral transfer by USAEHSC which should be contacted for details. This instrument operates from two 9V transistor batteries and has a built-in cell. It has automatic temperature compensation from 32 to 120°F (0-48°C). A variable range selection (0-0.5, 0-5, 0-50, 0-500, 0-5000 micromhos) permits its use for condensate as well as for boiler water. The base temperature of the Myron L is 77°F (25°C). The instrument comes with complete directions for use and these should be followed for general operation.

(b) Alternatively, a Solu-Bridge, Model RD-P4 or SD-P104, for a 105 to 120- V, 50- to 60-cycle AC outlet and one polystyrene dip cell, Model L CEL-52 or CEL-VS2S is required. This Solu-Bridge model has a range of 500 to 7,000 micromhos and a temperature compensation device which adjusts the reading to a base temperature of 64° F. The SD-P104 has a base temperature of 77 . . . F (25° C). This instrument and dip cell may be procured from commercial sources. Note that this conductivity meter can only be used for testing boiler water. To test both condensate and boiler water, an SD-406A range 0-5,000 micromhos meter and CEL-VS2S cell or the 0-5,000 micromhos meter from USAEHSC would be required.

(c) The following equipment and reagents are also needed for TDS testing. They can be obtained from USAEHSC and are referred to as "Equipment used with Conductivity Meter":

One thermometer, armored.

Four test tubes, 200 mm x 38 mm.

One pint conductivity neutralizing solution.

One 1-oz. indidcator dropping bottle with ½-ml dropper.

One quart conductivity meter test solution, 2,000 micromhos/cm at 64° F.

One quart 3N hydrochloric acid solution (not required with Myron L type meters).

One quart distilled water.

Two rubber stoppers, No. 8.

Four ounces of phenolphthalein solution.

(2) **Procedure for Myron L Type Instrument.**

(a) Without disturbing settled sludge, first rinse a clean 200 mm x 38 mm test tube with the sample, then pour in about 60 ml of the sample. The tube can be marked with a file or crayon at the point where it holds 60 ml. This point is about 5 inches from the top of the tube. The test tube rack provided with the causticity test kit can be used to support the tube. Add 1 to 2 drops of phenophthalein solution, and ½ ml of conductivity neutralizing solution to the sample. Stopper and invert several times to mix. If pink color persists, an additional amount of neutralizing solution should be added until the pink color disappears. In the presence of a dark tannin color, a pink color may not be clearly distinguished but a deepening of the original color will be observed. Upon complete neutralization, the original color will be restored.

(b) Rinse the built in cell cup three times with the sample to be tested, then fill with the sample to at least ¼ inch above the top electrode. NEVER FILL THE CELL BY DIPPING THE INSTRUMENT INTO WATER! DO NOT USE WITH SAMPLES HOTTER THAN 120° F (48° C).

(c) Select the desired range.

(d) Push the button; the pointer immediately indicates the specific conductivity of the sample in micromhos.

(e) When finished with the instrument, rinse the cell cup with clean water, preferably deionized. Be certain that all tannin is removed from the cup and electrodes. A wash bottle containing deionized water is helpful for cleaning the cell. When there are visible films of oil, dirt, or scale in the cell cup or on the top electrode, scrub lightly with a small brush and household cleaner. Rinse out the cleaner and the instrument can be used.

(f) The specific conductance reading is converted to TDS concentration in parts per million by multiplying by one of the following conversion factors, depending on the tannin number of the samaple.

Tannin Number	*Factor*
0	0.7
1	0.8
2, 3	0.9
4.5	1.0

Note the conversion factor for condensate is 0.6. The change in condensate conductivity is important. The TDS number is relative.

(g) Check calibration of the cell at least weekly. This is done by measuring the temperature and specific conductance of the calibration solution, using the same procedure as described above for boiler water and rinsing the cell cup with the calibration solution. Use of the neutralizing solution is omitted. If the reading does not correspond to the specific conductance of the calibration solution at the temperature given on the solution bottle,

adjust the calibration control (accessible through the fingerhole in the bottom cover) until the reading agrees with the micromho value of the standard solution. Measure a fresh sample of the standard solution. The meter reading must again indicate the micromhos value of the standard solution; the instrument is now calibrated on all ranges.

(3) **Procedure for Solu-Bridge Type Instrument.**

(a) Without disturbing settled sludge, first rinse a clean 200 mm x 38 mm test tube with the sample and then pour in about 60 ml of the sample. The tube can be marked with a file or crayon at the point where it holds 60 ml. This point is about 5 inches from the top of the tube. If desired a rack or other support for the tube can be made at the boiler plant. Add to the sample two dropperfulls (filled to the mark) of conductivity neutralizing solution. Stopper and invert several times to mix.

(b) Connect the terminals of the cell to the conductivity meter. Fill a clean 200 mm x 38 mm test tube about half full with distilled water. Wash the cell by immersing in distilled water. Do not immerse the cable. Move the cell up and down several times in the distilled water. Remove the cell and shake to remove any distilled water. Discard the distilled water in the tube. Immerse the cell in the solution being tested up to a point where the level of the solution is at lest ½ inch above the vent holes. Move up and down several times to release any bubbles which may adhere to the cell. Set the thermometer in the solution in the test tube.

(c) Plug the instrument cord into a 105 to 120V, 50-60 cycle AC outlet and turn on the instrument switch.

(d) After the thermometer reading has come to rest, set the temperature adjustment knob of the instrument to the same reading as the thermometer. Remove the thermometer from the solution. Set the cell so that it is centered in the test tube.

(e) After the instrument has warmed up, as indicated by the brightness of the electron tube (RD-P4 only), rotate the dial of the instrument until the dark segment of the electron tube reaches its widest opening and a sharp shadow is obtained. The RD-P4 Solu-Bridge reads specific conductance in micromhos/cm at 64° F. With the SD-P104, rotate the dial until both the red and green lamps are lit. The SD-P104 reads specific conductance at 77° F (25° C).

(f) Clean the cell by rinsing in fresh distilled water. When not in use, immerse the cell in distilled water in a 200 mm x 38 mm test tube.

(g) Note that each small division on the scale between 500 and 4,000 represents 100 micromhos/cm and each small division between 4,000 and 7,000 is 200 micromhos/cm on the RD-P4 meter.

(h) The specific conductance reading is converted to TDS concentration in parts per million by multiplying by one of the following conversion factors depending on the tannin number of the sample:

Tannin Number	*Factor with 64° F Base Temperature*	Factor with 77° F Base Temperature
0	0.8	0.7
1	0.9	0.8
2,3	1.0	0.9
4,5	1.1	1.0

Example: If the sample has a tannin number of 1, and a specific conductance of 3100 micromhos/cm is obtained, the concentration in the sample is 3100 x 0.9 = 2800 ppm with a 64° F base temperature meter. Record the results of the test as ppm in column (5), DA Form 4367, Boiler Water Treatment Log.

Note the conversion factor for condensate is 0.6 for either base temperature. The change in condensate conductivity is important. The TDS number is relative.

(i) Inspect the cell at intervals for the following: is wear or cracking noted; is there foreign material on the electrodes; is shield in position, intact, and are electrodes in position; are vent holes free of obstruction; is the black platinum coating present over all the electrode surfaces? If a mechanical defect is noted in the cell or if loss of the black platinum coating on the electrodes is noted, the cell can be returned to the manufacturer for repair or replatinizing of the electrodes. When not in use, the cell can be stored submerged in distilled water..

(j) Clean a cell used frequently every few weeks. This may be done by dipping in 3N hydrochloric acid for about two minutes, followed by washing in running tap water, and inverting the cell to wash the electrodes. If any deposits remain in the cell, clean further by swishing in soapy water followed by washing in running tap water and inverting the cell to wash the electrodes. If the dark segment of the electron tube becomes hazy, this condition can sometimes be corrected by cleaning the cell. Where cleaning does not improve the hazy condition, this may mean the black platinum coating on the electrodes has become worn. In this case, return the cell to the manufacturer for replatinizing and calibration.

(k) Check calibration of the cell once a week. This is done by measuring the specific conductance of the calibration solution, using the same procedure as described above for boiler waters, including setting the temperature adjustment to the temperature of the solution. Use of the neutralizing solution is omitted. Glassware, cell, and thermometer must be thoroughly cleaned and rinsed first with calibrting solution. The reading obtained should correspond to that of the calibrating solution at the temperature given on the solution bottle. If the reading is low, try cleaning the cell with 3N acid. If the reading

remains appreciably outside the range, return the cell to the manufacturer for repair.

B-3. MISCELLANEOUS TESTS.

a. Test for pH. The value of pH indicates the degree of acidity or alkalinity of a sample. A pH of 7.0 represents the neutral point, lesser values denote acidity, and greater values denote alkalinity. The test is made as soon as possible after taking the sample. Avoid exposure to air as much as possible to minimize absorption of CO_2. Several methods are available for pH determination.

(1) Colorimetric Method. This is represented by the Taylor comparator,which is sold by chemical supply sources in kit form. The method is simple, but to assure accuracy the indicator fluid must be standardized periodically.

(2) **USAEHSC Test Kit Method for pH of Boiler Water.** The test kit includes:

(a) Two vials indicator paper, hydrions pH 10 to 12.

(b) Two vials indicator paper, hydrions pH 11 to 12.

(c) One 50-ml beaker.

(d) One 2-oz. bottle

(3) **Procedure.**

(a) Remove a strip of pH 10 to 12 indicator paper from the vial and dip it into the sample in the beaker. Keep the paper immersed for 30 seconds and then remove it. If the sample does not change the color of the paper, or colors it yellow or very light orange, the pH of the sample is too low and the test is finished. If the paper turns orange or red, the pH is either satisfactory or too high.

(b) In that case, remove a strip of paper of pH 11 to 12 from the vial and dip it into the sample in the beaker. Keep the paper immersed for 30 seconds and then remove it. If the sample does not change the color of the paper, or colors it a light blue, the pH is satisfactory. If the paper turns deep blue, the pH is higher than necesssary.

(c) Adjusting the Chemical Dosage. For most cases, a satisfactory pH determined by these directions indicates a pH in the boiler water in the range of about 10.5 to 11.5. If caustic soda treatment is being used to build up pH, a low pH indicates too little chemical is being used. The pH can be built up by increased treatment with the chemical. Too low a pH can also be brought about by excessive blowdown, excessive loss of condensate or improper operation of a zeolite softener. If the pH of the boiler water samples is high and caustic soda is being used, the dosage can be reduced.

b. USAEHSC Test Kit Method for Condensate pH.

(1) **Applicability.** This kit is designed for controlling the dosage of volatile neutralizing amines such as morpholine or cyclohexylamine which are currently used to raise pH of the condensate, thereby reducing corrosion due to carbon dioxide.

(2) **Equipment.** The test kit includes the following:

(a) One Dalite Lamp, Taylor #9195*

(b) One base, Taylor #9190

(c) One pH Slide Comparator (pH range 6.0 to 7.6), Taylor #9066

(d) Two four-ounce bottles of Bromthymol Blue, indicator for #9066 slide, Taylor #R-1003 K-D

(e) One pH slide comparator (pH range 7.2 to 8.8), Taylor #9068

(f) Two four-ounce bottles of Cresol Red, indicator for #9068 slide, Taylor #R-1003H-D

(g) One pH slide comparator (pH range 8.0 to 9.6), Taylor #9070

(h) Two four-ounce bottles of Thymol Blue, indicator for #9070 slide, Taylor #R-1003M-D

(i) Five combination mixing tubes marked at 5, 15, 17.5 ml and #2 rubber stoppers.

(j) One Test Tube Brush

(k) One Stirring Rod

(l) Three Plastic Droppers marked at 0.5 ml

(m) Two 100 ml Beakers marked at 50 ml

(3) **Taking the Sample of Condensate.** Condensat return samples should be taken at the following points:

(a) Daily at the boiler plant main return to test for pH. Preferably, conductivity and hardness should also be checked on this sample.

(b) Samples should be taken at least once a week from the endpoints and midpoints of a large distributions system and tested for pH, hardness, and conductivity.

(c) In a system with several branches, samples should be taken weekly from alternate branches so that condensate chemistry (pH, hardness, conductivity) can be monitored and properly maintained. These samples are in addition to those specified in paragraphs **(a)** and **(b)** above.

(d) A sample should not be taken from a collecting tank if other water such as makeup is received in the tank.

(e) A sample is collected in the beaker up to the 50 ml mark. Cooling the condensate is not necessary. However, it should be collected slowly to reduce flashing. In the distribution system, the sample should be taken from a running stream from a heat exchanger.

(f) If the pH is not to be measured immediately, the sample should be collected in a glass bottle which should be completely filled and tightly sealed.

(4) **Operating Limits.** A minimum pH range of 7.5-8.0 is considered adequate for controlling corrosion. If morpholine is used, the minimum pH is to be maintained near the end of the distribution system. If cyclohexylamine is used, the minimum pH point will be observed closer

to the boiler. For the most satisfactory performance, especially in large steam distribution systems, it is recommended that both morpholine and cyclohexylamine be used in a 75/25 or 50/50 ratio of morpholine/cyclohexylamine. When using a mixture of amines, the minimum pH point must be determined locally through on-site chemical analysis of the condensate throughout the system.

(5) **Procedure.**

(a) Rinse three of the combination mixing tubes with the sample to be tested. Fill them to the first mark (5 ml) with the sample, wipe dry, and place in the holes back of the three slots in the Taylor base. The two outside tubes act as blanks to eliminate the effect of color and turbidity on the sample.

(b) To the middle tube add 0.5 ml of Cresol Red. (Taylor #R-1003K-D).

(c) Remove the tube from the base and mix thoroughly, using a clean stirring rod. Replace the tube in the middle hole.

(d) Place the Cresol Red pH slide comparator (pH 7.2 to 8.8) on the base so that one of the white lines on the slide is directly above the line on the base.

(e) Make comparison with the standards by holding the comparator toward a window or, perferably, placing it on the shelf in front of the Taylor Dalite lamp. Do not use fluorescent light.

(f) If the color of the middle tube does not match the color of either of the standards, or lies between the colors of the two standards, move the slide to the right or left, as required, until the next line on the slide is directly above the line on the base.

(g) If the color of the middle tube exactly matches one of the standards, read the pH value directly from the slide. If, however, the color of the sample lies between the colors of two consecutive standards, the pH is taken as an average of the two.

(h) Never consider a match with the lowest or highest standard as an accurate determination. The actual pH may be beyond the range of the indicator.

(i) Should a match appear to be likely with the lowest or highest pH color standard on the slide, repeat the test using a fresh sample and using Bromthymol Blue (Taylor #R-1003H-D) indicator and Bromthymol Blue pH slide (pH range 6.0 to 7.6) or Thymol Blue (Taylor #R-1003M-D) indicator and Thymol Blue pH slide (pH range 8.0 to 9.6).

(6) NOTE: Do not filter any samples for pH test. If the sample is too cloudy or turbid, allow it to stand in a closed bottle until the liquid is clear. Decant required amount of sample carefully.

APPENDIX C HEAT BALANCE CALCULATIONS

C-1. 100PSIG STEAM HEAT BALANCE

Reference figure C-1. (Note that this figure is a duplicate of figure 1-1.) The following assumptions have been made:

—100 lb of steam at 100 psig saturated conditions will heat water from 50° F to 140° F.

—Percent energy is based on the energy in the steam input to the heat exchanger.

—Negligible heat is lost from the insulated piping, heat exchanger, vent condenser, or condensate tank.

—The vent condenser condenses 91% of the flash steam and cools the condensate to 100° F.

—The amount of flash steam released is not effected by the water returned from the vent condenser. With this assumption our example serves to establish flash steam losses for systems without vent condensers.

a. The following steam table enthalpies in Btu/lb have been utilized:

For 100 psig steam hg100 = 1189.7 and hf100 = 309.0
For 0 psig steam hg0 = 1150.4 and hf0 = 180.0
For water at 50° F hf50 = 18.0
For water at 100° F h100 = 68.0
For water at 140° F hf140 = 107.9
For water at 198° F hf198 = 166.0

b. Percent energy in saturated water at the heat exchanger outlet is calculated as follows:

Base Energy = M x hg100 = 100 lb x 1189.7 Btu
Energy at heater exchanger outlet = M x hf100 = 100 lb x 309.0 Btu/lb = 309,000 Btu

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%

c. Energy from the 100 psig saturated water at 309 Btu/lb and 338° F reaches a new equilibrium after it exits the steam trap at 0 psig, 180 Btu/lb, and 212° F by flashing a portion of its mass to steam at 0 psig. The pounds of flash steam Fs released is calculated as follows:

M x hf100 = Fs x hg0 + (M-Fs) x hfo

to the boiler. For the most satisfactory performance, especially in large steam distribution systems, it is recommended that both morpholine and cyclohexylamine be used in a 75/25 or 50/50 ratio of morpholine/cyclohexylamine. When using a mixture of amines, the minimum pH point must be determined locally through on-site chemical analysis of the condensate throughout the system.

(5) **Procedure.**

(a) Rinse three of the combination mixing tubes with the sample to be tested. Fill them to the first mark (5 ml) with the sample, wipe dry, and place in the holes back of the three slots in the Taylor base. The two outside tubes act as blanks to eliminate the effect of color and turbidity on the sample.

(b) To the middle tube add 0.5 ml of Cresol Red. (Taylor #R-1003K-D).

(c) Remove the tube from the base and mix thoroughly, using a clean stirring rod. Replace the tube in the middle hole.

(d) Place the Cresol Red pH slide comparator (pH 7.2 to 8.8) on the base so that one of the white lines on the slide is directly above the line on the base.

(e) Make comparison with the standards by holding the comparator toward a window or, perferably, placing it on the shelf in front of the Taylor Dalite lamp. Do not use fluorescent light.

(f) If the color of the middle tube does not match the color of either of the standards, or lies between the colors of the two standards, move the slide to the right or left, as required, until the next line on the slide is directly above the line on the base.

(g) If the color of the middle tube exactly matches one of the standards, read the pH value directly from the slide. If, however, the color of the sample lies between the colors of two consecutive standards, the pH is taken as an average of the two.

(h) Never consider a match with the lowest or highest standard as an accurate determination. The actual pH may be beyond the range of the indicator.

(i) Should a match appear to be likely with the lowest or highest pH color standard on the slide, repeat the test using a fresh sample and using Bromthymol Blue (Taylor #R-1003H-D) indicator and Bromthymol Blue pH slide (pH range 6.0 to 7.6) or Thymol Blue (Taylor #R-1003M-D) indicator and Thymol Blue pH slide (pH range 8.0 to 9.6).

(6) NOTE: Do not filter any samples for pH test. If the sample is too cloudy or turbid, allow it to stand in a closed bottle until the liquid is clear. Decant required amount of sample carefully.

APPENDIX C HEAT BALANCE CALCULATIONS

C-1. 100PSIG STEAM HEAT BALANCE

Reference figure C-1. (Note that this figure is a duplicate of figure 1-1.) The following assumptions have been made:

—100 lb of steam at 100 psig saturated conditions will heat water from 50° F to 140° F.

—Percent energy is based on the energy in the steam input to the heat exchanger.

—Negligible heat is lost from the insulated piping, heat exchanger, vent condenser, or condensate tank.

—The vent condenser condenses 91% of the flash steam and cools the condensate to 100° F.

—The amount of flash steam released is not effected by the water returned from the vent condenser. With this assumption our example serves to establish flash steam losses for systems without vent condensers.

a. The following steam table enthalpies in Btu/lb have been utilized:

For 100 psig steam hg100 = 1189.7 and hf100 = 309.0
For 0 psig steam hg0 = 1150.4 and hf0 = 180.0
For water at 50° F hf50 = 18.0
For water at 100° F h100 = 68.0
For water at 140° F hf140 = 107.9
For water at 198° F hf198 = 166.0

b. Percent energy in saturated water at the heat exchanger outlet is calculated as follows:

Base Energy = M x hg100 = 100 lb x 1189.7 Btu
Energy at heater exchanger outlet = M x hf100 = 100 lb x 309.0 Btu/lb = 309,000 Btu

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%

c. Energy from the 100 psig saturated water at 309 Btu/lb and 338° F reaches a new equilibrium after it exits the steam trap at 0 psig, 180 Btu/lb, and 212° F by flashing a portion of its mass to steam at 0 psig. The pounds of flash steam Fs released is calculated as follows:

M x hf100 = Fs x hg0 + (M-Fs) x hfo

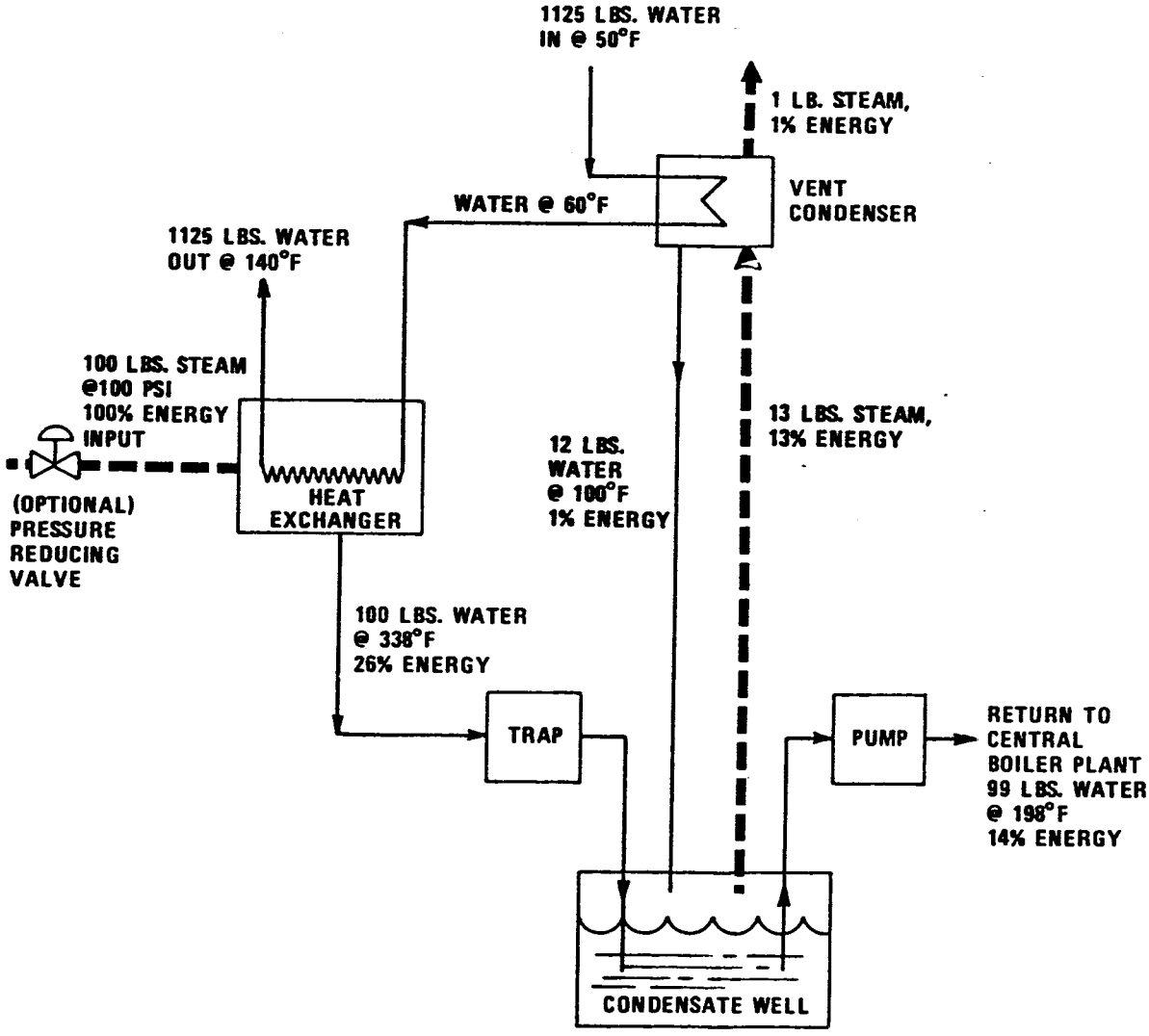


FIGURE C-1. 100 PSIG STEAM HEAT BALANCE

100 lb x 309.0 Btu/lb = Fs = (100 lb-Fs 1150 Btu/lb = (100 lb-Fs) x 180 Btu/lb
30,900 Btu = 1150 Btu/lb x fs + 18,000 Btu + 180 Btu/lb x Fs
12,900 Btu = 970 Btu/lb x fs
13.3 lb = Fs Use Fs = 13 lb for Figure C-1.

d. Percent energy in flash steam is calculated as follows:

Energy in flash steam = MF x hg0 = 13.3 lb x 1150 Btu/lb = 15, 295 Btu

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%
Use 13% in Figure C-1.

e. Pounds of flash steam lost = .09 x 13.3 lb = 1.2 lb. Use 1 lb.

f. Percent energy in flash steam lost = (MFlost x hg0 divided by base energy) x 100 = (1.2 lb x 1150 Btu/lb divided by 118970 Btu) x 100 = 1.16%. Use 1%.

g. Pound of condensate returned from vent condenser = .91 x 13.3 lb = 12.1 lb. Use 12 lb.

h. 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%. Use 1%.

i. Condensate return to the Central Boiler Plant will nave characteristics calculated as follows:

—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.

—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° F = 12.1 lb of condensate from the vent condenser at 68 Btu/lb and 100° F = (86.7 lb x 180 Btu/lb = 12.1 lb x 68 Btu/lb) = (15,606 + 823) = 16,428 Btu.

—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° F.

—Percent energy in the condensate return is (energy in condensate divided by base energy) x 100 = (16,428 Btu divided by 118970 Btu) x 100 = 13.8%. Use 14%.

j. The amount of water heated from 50° F to 140° F in the heat exchanger and vent condenser is calculated as follows:

The energy available for heating the water equals the energy in the incoming steam (base energy) minus the energy lost by vented steam (paragraph f) minus energy return (paragraph i) = (118,970 Btu — 1,380 Btu — 16,428 Btu) = 101,162 Btu.

The energy required to heat water from 50° F to 140° F is (hf140-hf50) =)107.9 Btu/lb) — 18 Btu/lb = 89.9 Btu/lb.

The pounds of water heated is (101,162 Btu divided by 89.9 Btu/lb) = 1,125 lb.

k. The temperature at the outlet of the vent condenser is calculated:

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

h50 + 10.44 = 18 Btu/lb + 10.44 Btu/lb = 28.44 Btu/lb. From the steam tables this coresponds to a temperature of 60° F.

C-2. 15 PSIG STEAM HEAT BALANCE

Reference figure C-2. (This figure is a duplicate of figure 1-2.) This heat balance is based on the same assumptions listed in paragraph C-1 except now 15 psig saturated steam is utilized for heating the water.

a. The following steam table enthalpies in Btu/lb have been utilized:

For 15 psig steam hg15 = 1164.0 and hf15 = 219.0
For water at 50° F hf50 = 18.0
For water at 140° F hf140 = 107.9
For water at 208° F mf208 = 176.0

b. Percent energy in saturated water at the heat exchanger outlet is calculated as follows:

Base Energy = M x hg15 = (100 lb x 1164.0 Btu/lb = 116,400 Btu

Energy at heat exchanger outlet = M x hf15 = (100 lb x 219.0 Btu/lb) = 21,900 Btu

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%
use 19%.

c. Energy from the 15 psig saturated water at 219 Btu/lb and 250° F reaches a new equilibrium after it exits the steam trap at 0 psig, 180 Btu/lb, and 212° F by flashing a portion of its mass to steam at 0 psig. The pounds of flash steam F_s released is calculated as follows.

M x hf15 = F_s x hg0 + (M-F_s) x hf0

100 lb x 219.0 Btu/lb = F_s x 1150 Btu/lb = (100 lb-F_s) x 180 Btu/lb

21,900 Btu = 1150 Btu/lb x F_s + 18,000 Btu-180 Btu/lb x F

3,900 Btu = 970 Btu lb x F_s

4.0 lb = F_s

d. Percent energy in flash steam is calculated as follows:

Energy in flash steam = M_F x hg0 = 4.0 lb x 1150 Btu/lb = 4,600 Btu

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%.

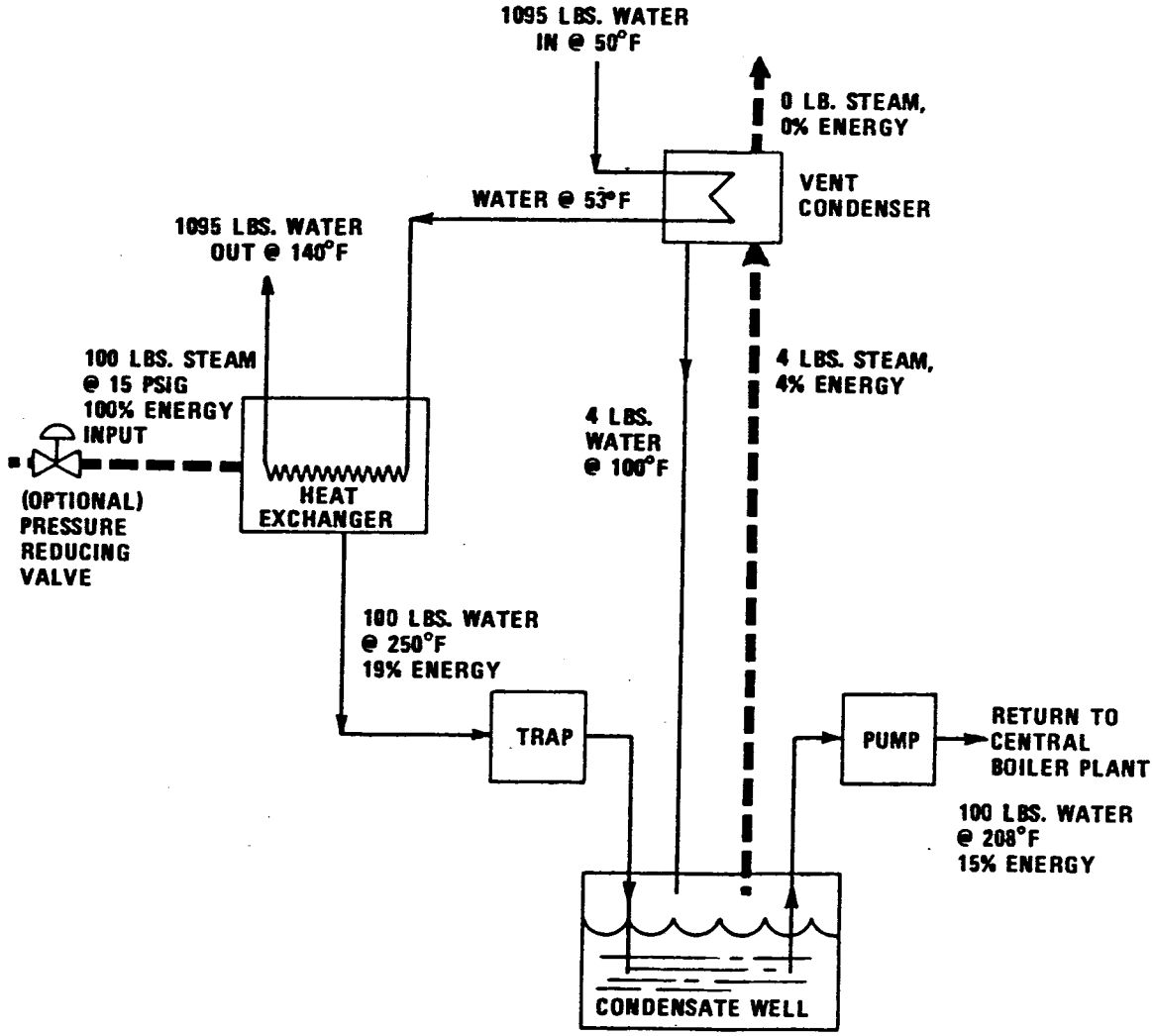


FIGURE C-2. 15 PSIG STEAM HEAT BALANCE

e. Pounds of flash steam lost = .09 x 4.0 lb = .36 lb.

f. Percent energy in flash steam lost = (Flost x h_g0 divided by base energy) x 100 = (.36 lb x 1150 Btu/lb divided by 116,400 Btu) x 100 = .36%.

g. Pound of condensate returned from vent condenser = .91 x 4.0 lb = 3.64 lb. Use 3.6 lb.

h. Percent energy in condensate return from vent condenser = (MMCR x $_h$f100 divided by base energy) x 100 = 3.64 lb x 68 Btu/lb divided by 116,400 Btu) x 100 = .21%

i. Condensate return to the Central Boiler Plant will have characteristics calculated as follows:

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.

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° F + 3.6 lb of condensate from the vent condenser at 68 Btu/lb and 100° F = (96.0 lb x 180 Btu/lb + 3.6 lb x 68 Btu/lb) + (17,280 + 245) = 17,525 Btu.

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° F.

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%.

j. The amount of water heated from 50° F to 140° F in the heat exchanger and vent condenser is calculated as follows:

The energy available for heating the water equals the energy in the incoming steam (base energy) minus the energy lost by vented steam (paragraph f) minus energy return (paragraph i) = (116,400 Btu — 414 Btu — 17,525 Btu) = 98,461 Btu.

The energy required to heat water from 50° F to 140° F is (hf140°-hf50) = (107.9 Btu//lb-18 Btu/lb) = 89.9 Btu/lb.

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:

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

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° F.

C-3. HIGH TEMPERATURE WATER HEAT BALANCE

Reference figure C-3 (identical to figure 1-3). The following assumptions are made so we can compare the high temperature water system with the 100 psig steam system:

—1125 lb of water will be heated from 50° F to 140° F.

—The heat exchanger will be designed to heat the water with a 400° F inlet and 240° F outlet high temperature water.

—Negligible heat is lost from the insulated piping and heat exchanger.

a. The following steam table enthalpies in Btu/lb have been utilized:

Water at 50° F hf50 = 18.0
Water at 140° h140 = 107.9
Water at 240° F h240 = 208.3
Water at 400° F hf400 ° 375.0

b. Energy added to water is calculated: M_w x (hf140-hf50) = 1125 lb x (107.9 Btu/lb-18.0 Btu/lb) = 101,138 Btu.

c. High temperature water (HTW) flow rate is calculated by the following energy balance:

Energy added = Energy released by HTW

101,138 Btu = MHTW x (hf400 - (hf240) = MHTW x (375.0 Btu/lb-208.3 Btu/lb)

MHTW = 606.7 lb. Use 607 lb.

d. 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%. Use 56%.

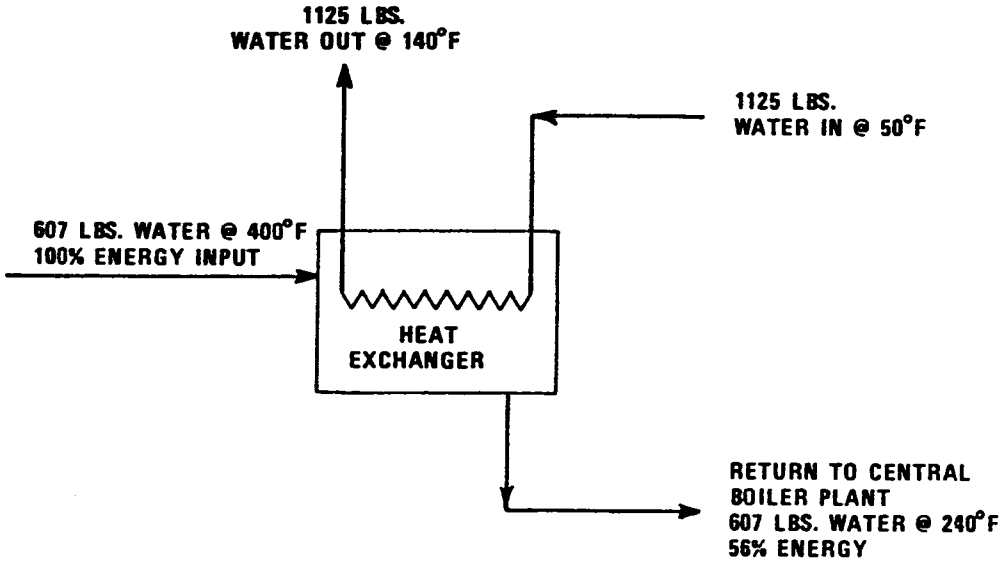


FIGURE C-3. HIGH TEMPERATURE WATER HEAT BALANCE

APPENDIX D BOILER WATER CALCULATIONS

D-1. BOILER BLOWDOWN CALCULATIONS

The rate of blowdown from a boiler is a critical operating control on total dissolved solids (paragraph 4-4c).

a. The water added to the boiler must equal water lost from the boiler

$$F = E + B$$

Where: F = Feedwater, pounds/hour
E = Steam generation, pounds/hour
B = Blowdown, pounds/hour

b. The blowdown can be related to the feedwater using the cycles of concentration:

$$C + \frac{F}{B} \text{ or } F = B \times C$$

Where: C = Cycles of concentration, no units
F = Feedwater, pound/hour
B = Blowdown, pound/hour
It is common to express blowdown as a present.

$$\%B = \frac{100}{C}$$

c. The relationship between feedwater,blowdown, steam generation, and cycles is represented as:

$$B = \frac{E}{(C\text{-}1)}$$

This is derived as follows:

(1) $F = B \times C$ (paragraph C-1b)
(2) $F = E + B$ (paragraph C-1a)
(3) $B \times C = E + B$ (Replacing F in Equation 2 with Equation 1)
(4) $B \times C - B = E$ (Rearranging Equation (3))
(5) $B \times (C\text{-}1) = E$ (Rearranging Equation (4))
(6) $B = \frac{E}{(C\text{-}1)}$ (Rearranging Equation (5))

b. Blowdown is never metered, but it can be calculated if any two of the feedwater, cycles,or steam generation quantities are known. Steam is usually metered. The cycles of concentration can be determined by comparing the concentration of dissolved solids in the boiler water to the concentration in the feedwater. Cycles can than be calculated (note that the blowdown concentration is the same as the boiler concentration):

$$C = \frac{Bs}{Fs} \text{ or } C = \frac{B \text{ mmho}}{F \text{ mmho}}$$

Where: C = Cycles of concentration, no unit
Bs = Blowdown TDS, ppm
Fs = Feedwater TDS, ppm
B mmho = Blowdown conductivity, micromho
F mmho = Feedwater conductivity, micromho

D-2. DETERMINING FEEDWATER REQUIREMENTS

The blowdown calculations in paragraph D-1 can be used to determine feedwater requirements. Note that feedwater means the water that is fed to the boiler from the deaerator and includes makeup plus condensate return.

a. Example D-1. A 250 psig boiler operates at a conductivity level of 5500 mmho (see paragraph 4-5a for guidance on the maximum allowable level). The boiler feedwater has a conductivity of 275 mmho. The cycles of concentration is calculated as follows:

$$C = \frac{B}{F} = \frac{5500}{275} = 20$$

b. The percent blowdown is:

$$\%LB = \frac{100}{C} = \frac{100}{20} = 5\%$$

D-3. DETERMINING MAKEUP REQUIREMENTS

Makeup is the water from the external water treatment system provided to the deaerator. The criteria for treating makeup is covered in section 4-II.

a. Makeup is the difference between the condensate return and the feedwater.

$$M = F\text{-}R$$

Where: M = Makeukp, pounds/hour
F = Feedwater, pounds/hour
R = Condensate return, pounds/hour

b. The condensate will not contain any appreciable level of dissolved solids (or conductivity) unless there is a source of contamination within the system. This allows the determination of percent makeup using the equation:

$$\%M = \frac{F}{M} \times 100$$

Where: %M = Percent makeup
F mmho = Feedwater conductivity, micromho
F mmho = Makeup conductivity, micromho

c. Example D-2. Makeup conductivity is 610 mmho for the boiler in example 4-1. The percent makeup is calculated:

$$\%M = \frac{F}{M} \times 100 = \frac{275}{610} = \frac{275}{610} \times 100 = 45\%$$

(1) This means that the makeup is 45% of the feedwater. The condensate return percent is calculated:

$$\%R = 100 - \%M = 100 - 45 = 55\%$$

(2) The quantity of makeup is calculated:

$$M = \frac{\%M}{100} \times F = \frac{45}{100} \times 42,105 = 18,947 \text{ pounds/hour}$$

(3) The condensate return quantity is calculated:

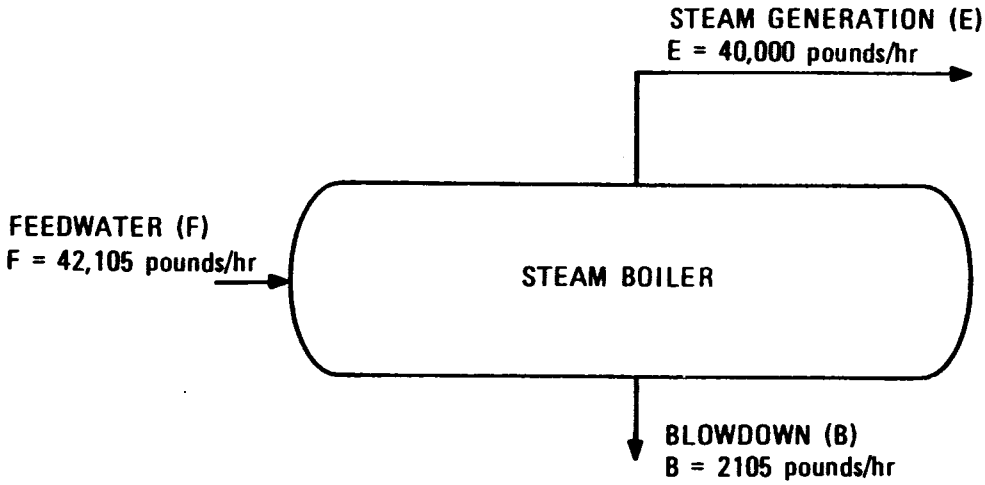


FIGURE D-1. EXAMPLE OF BOILER FEEDWATER, STEAM GENERATION AND BLOWDOWN RELATIONSHIPS

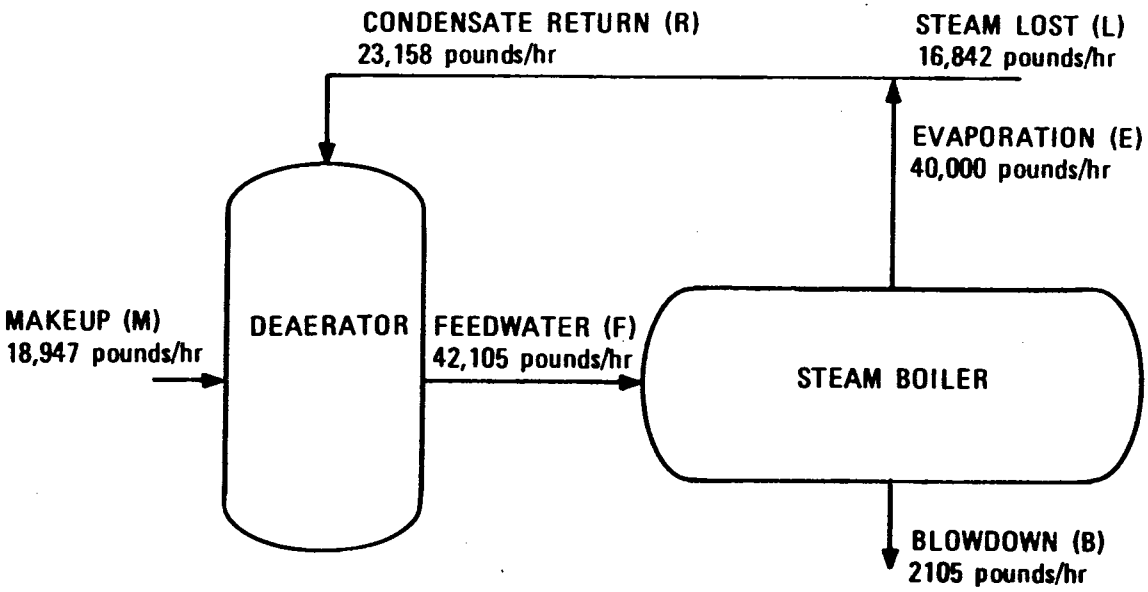


FIGURE D-2. EXAMPLE OF BOILER CALCULATIONS

R = F - M = 42,105 - 18,947 = 23,158 pounds/hour

d. The difference between steam produced and the condensate returned is due to steam or condensate lost in the system. These losses may include leaks or consumption of steam by the process equipment. The losses can be calculated as follows:

L = E - R

Where: L = Steam or condensate losses, pounds/hour
E = Steam generated, pounds/hour
R = Condensate return, pounds/hour

e. Example D-3. The steam and condensate losses for the boiler described in Examples D-1 and D-2 can be calculated:

L = E - R = 40,000 - 23,158 = 16,842 pounds/hour

(1) This relationship and the information from the previous examples are presented in figure D-1 and figure D-2.

f. Monitoring the system for steam generated and dissolved solids, and performing these calculations on a regular interval will give a basis for evaluating boiler system performance. An increase in steam and condensate loss may indicate the development of a new leak or an increase in existing leaks. These calculations can provide a good basis for estimating steam savings from maintenance efforts.

D-4. DETERMINING CHEMICAL TREATMENT REQUIRED

Chemical treatment programs involve selecting the type of chemical to be used and establishing a treatment level. These factors are discussed in paragraph 4-7. Blowdown calculations can be used to determine the amount of chemical that needs to be added to meet the treatment objectives.

a. Example D-4. The boiler in examples D-1, D-2, and D-3 is to be operated with a phosphate level of 60 pm in the boiler water. The blowdown has been determined to be 2,105 pounds per hour. The required phosphate addition on a daily basis must equal the phosphate that is discharged with the blowdown. This is calculated as follows:

Phosphate Loss = B x Level

$$= \frac{(2{,}105 \text{ lb/day} \times 24 \text{ hr/day} \times 60 \text{ ppm}}{1{,}000{,}000}$$

= 3.03 pounds phosphate/day

The treatment chemical contains 40% phosphate, which means there is 0.4 pounds phosphate per pound of chemical:

Chemical Required = Phosphate Loss divided by 0.4

$$= \frac{3.03}{0.4} = 7.58 \text{ pounds/day}$$

GLOSSARY

ABATEMENT	The reduction in degree of intensity of pollution.
ABSOLUTE PRESSURE	Pressure above zero pressure, the sum of the gage and atmospheric pressures.
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 U.S., 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 blow-off discharge before it enters the building drain.
AGGLOMERATING	A caking characteristic of a coal.
AIR ATOMSIZING 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 combusion of the fuel.
AIR DRIED	Condition of coal after sample has been exposed to 85F to 95F 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.
AIR VENT	A valved opening for venting air from the top of the highest drum of a boiler or pressure.

ALARM	A suitable horn, bell, light or other device which when operated will give notice of malfunction or off-normal condition.
ALLOWABLE WORKING PRESSURE	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.
AMBIENT AIR	The air that surrounds the equipment.
AMBIENT TEMPERATURE	The temperature of the air surrounding the equipment.
ANALYSIS, PROXIMATE	Analysis of a solid fuel determining moisture, volatile matter, fixed carbon and ash expressed as percentage of the total weight of sample.
ANALYSIS, ULTIMATE	Chemical analysis of a fuel determining carbon, hydrogen, sulfur, nitrogen, chlorine, oxygen, and ash as percentages of the total weight of sample.
ANTHRACITE	ASTM coal classification by rank: Dry fixed carbon 92% or more and less than 98%; and dry volatile matter 8% or less and more than 2% on a mineral- matter-free basis.
AQUIFER	An underground bed or layer of earth, gravel, or pourous stone that contains water.
AREA SOURCE	In air pollution, any small individual fuel combustion source, including vehicles. A more precise legal definition is available in Federal Regulations.
ARCH-FURNACE	A substantially horizontal structure extending into the furnace, to serve as a deflector of the gases.
AS-FIRED FUEL	Fuel in the condition as fed to the fuel burning equipment.
ASH	The incombustible solid matter in fuel.
ASH BED	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%.
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	sA 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 all 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.
BARETUBE 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 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% or more and less than 86%; and dry volatile matter 22% or less and more than 14%. 2. MEDIUM VOLATILE: Dry fixed carbon 69% or more and less than 78%; and dry volatile matter 22% or less and more than 31%. 3. HIGH VOLATILE (A): Dry fixed carbon less than 69% and dry volatile matter more than 31% Btu value equal to or greater than 14,000 moist, mineral- matter-free basis. 4. HIGH VOLATILE (B): Btu value 13,000 or more and less than 14,000 moist, mineral- matter-free basis. 5. HIGH VOLATILE (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.
BLOWDOWN 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 disproportionately large quantity of air passes.

BLOWOFF SEPARATOR — A vented and drained container equipped with internal baffles or an appratus for the purpose of separating moisture from flash steam as it passes through the vessel.

BLOW-OFF 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 pressure in excess of 15 pounds per square inch or hot water at temperatures in excess of 250F 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 250F or steam at pressures not more than 15 pounds per square inch.
3. HIGH-TEMPERATURE WATER — A water heating boiler operating at a pressure exceeding 160 psig or temperatures exceeding 250F.
4. WATERTUBE — A boiler in which the tubes contain water and steam, the heat being applied to the outside surface.
5. BENT TUBE — A watertube boiler consisting of two or more drums connected by tubes, practically all of which are bent near the ends to permit attachmen to the drum shell on radial lines.
6. HORIZONTAL — A watertube 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. 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.
9. 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.
10. LOW HEAD — A bent tube boiler having three drums with relatively short tubes in a vertical plane.
11. FIRETUBE — A boiler with straight tubes, which are surrounded by water and steam and through which the products of combustion pass.
12. HORIZONTAL RETURN TUBULAR — A firetube boiler cosisting 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.
13. 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.

BOILER (Cont'd)	14. 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. 15. 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. 16. 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. 17. 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. 18. 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 (see Boiler Dry-Back and Boiler Wet-Back). In Marine Service, the boilers are generally of the Wet-Back Type.
BOILER BLOW-OFF PIPING	The piping connections from the boiler to the blow-off valves.
BOILER BLOW-OFF TANK	A vented and drained container into which water is discharged above atmospheric pressure from a boiler blow-off line. Also called Flash Tank.
BOILER CONVECTION BANK	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.
BOILER DRY-BACK	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 refratory and insulating material).
BOILER EFFICIENCY	The ratio of the net energy output of the boiler fluid divided by the input of the primary energy source(s).
BOILER HORSEPOWER	The evaporation of 34½ pounds of water per hour from a temperature of 212F into dry saturated steam at the same temperature. Equivalent to 33,472 Btu/hr.
BOILER WET-BACK	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.
BOND	A retaining or holding high-temperature cement for making a joint between brick or adjacent courses of brick.
BONE COAL	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% fixed carbon.
BOOSTER FAN	A device for increasing the pressure of flow of a gas (see Blower).
BOSS	A raised portion of metal of small area and limited thickness on flat or curved metal surfaces.
BOTTOM AIR ADMISSION	A method of introducing air to a chain or traveling grate stoker under the stoker.
BREECHING	A duct for the transport of the products of combustion between parts of a steam generating unit or to the stack.
BRIDGEWALL	A wall in a furnace over which the products of combustion pass.
BRIDGING	The accumulation of non-combustible 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 32F to 212F 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 4⅜", over 3¼" 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", over 5/16" round mesh screen. 2. Number 2 (Rice) — through 5/15", over 3/16" round mesh screen. 3. Number 3 (Barley) — through 3/16", over 3/32" round mesh screen. 4. Numbver 4 — through 3/32", over 3/64" round mesh screen. 5. Number 5 — through 3/64", 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 farbrication, 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 manufacturers stated output rate over a period of time for which the boiler is designed to operate.
CAPACITY FACTOR	The total outpout over a period of time divided by the product of the boiler capacity and tehe time period.
CARBON	An element. The principal combustible constituent of most fuels.
CARBON CONVERSION EFFICIENCY	An indictor of the degree to which the fuel carbon compounds are oxidized to CO_2.
CARBONIZATION	The process of converting coal to carbon by removing other ingredients.

CARBON LOSS	The loss representing the unliberated thermal energy occasioned by failure to oxidize some of the carbon in the fuel.
CARBON RESIDUE	The carbon residue of a fuel is a measure of the carbonaceous material left after all the volatile compounds are vaporized in the absence of air.
CASING	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.
CENTRIFUGAL COLLECTOR	A mechanical system using centrifugal force to remove aerosols from a gas stream or to de-water sludge.
CENTRIFUGAL FAN	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.
CHAIN GRATE STOKER	A stoker which has a moving endless chain as as grate surface, onto which coal is fed directly from a hopper.
CHECKER WORK	An arrangement of alternately spaced brick in a furnace with openings through which air or gas flows.
CHEMICAL FEED PIPE	A pipe inside a boiler drum through which chemicals for treating the boiler water are introduced.
CHIMNEY LINING	The material which forms the inner surface of the chimney.
CINDER	Particles of partially burned fuel from which volatile gases have been drive off, which are carried from the furnace by the products of combustion.
CIRCULAR BURNER	A liquid, gaseous, or pulverized fuel burner having a circular opening through the furnace wall.
CIRCULATOR	A pipe or tube to pass steam or water between boiler drums or headers. Also used to apply to tubes connecting headers of horizontal watertube boilers with drums.
CLASS	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.
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 all 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 all 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°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 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 contgrol responsive to changes in liquid level, pressure, or temperature or position for limiting the operation of the controlled equipment.
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 are intended to prevent unsafe operation of the controlled equipment.
CONTROL UNIT	A device designed to regulate the fuel, air, water, or electerical supply to the controlled equipment. It may be automatic, semi-automatic or manual.
CONTROL VALVE	A valve used to control tehe 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 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 air flow 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.

DAMPER (Cont'd)	2. Curtain Type — A damper, composed of flexible material, moving in a vertical plane as it is rolled. 3. Flap Tpye — 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 air flow 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	Gass 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

DISTRIBUTED DIGITAL CONTROL (Cont'd)	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 CAGE	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 all 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	All 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	Non-combustible 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%.
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%.
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%.
DRY STEAM	Steam containing no moisture. Commercially dry steam is usually said to contain not more than one half of one 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	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 all 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 setpoint. This error calculation is usually an integral part of an automatic controller.
EVAPORATED MAKE-UP	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 air flow 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 make-up 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 D 197).
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 as plane parallel to the wall.
FIREBOX	The equivalent of a furnace. A term usually used for the furnaces of locomotive 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 all 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.
FALMMABILITY	Susceptability to combustion.
FLAMMABILITY LIMITS	The limiting (upper & 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

FLAMMABILITY LIMITS (Cont'd)	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 Blow-Off 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 NOx control.
FLULIDIZED 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 COLLECTEOR	A device designed to remove fly ash in dry form from the flue gas.
FOAMING	The continuous formation of bubbles which have sufficiently high surface tension to remain as bubbles beyond the disengaging surface.
FORCED DRAFT FAN	A fan supplying air under pressure to the fuel burning equipment.
FORCED DRAFT 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 contining 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 D 396.
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. It is 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

FUEL OIL GRADES (Cont'd)	it to be pumped and atomized at relatively low storage temperatures. Thus, in all but extremely cold weather it requiresl 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. Tha 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 sub-classification 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" 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 a boiler water. Usually expressed as grains per gallon or ppm as $CaCO_2$.
HARD WATER	Water which contains calcium or magnesium in an amount which requires an excessive amount of soap to form a lather.
HEADER	A chamber for the collection and/or distribution of fluid to or from a multiplicity of parallel flow parts.
HEAT AVAILABLE	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.
HEAT BALANCE	An accounting of the distribution of the heat input and output.
HEAT EXCHANGER	A vessel in which heat is transferred from one medium to another.
HEATING SURFACE	That surface which is exposed to the heating medium for absorption and transfer of heat to the heat medium.
HEAT RECOVERY BOILER	See Wasteheat boiler.
HEAVY METALS	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.
HIGH GAS PRESSURE SWITCH	A switch to stop the burner if the gas pressure is too high.
HIGHER HEATING VALUE	The total heat obtained from the combustion of a specified amount of fuel which is at 60F when combustion starts, and the combustion products of which are cooled to 60 F before the quantity of heat released is measured (see also Calorific Value and Lower Heat Value).
HOPPER	A changer or bid used for holding solid fuel or refuse.
HOPPER BOTTOM FURNACE	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.
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 increase 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 FAN	A fan exhausting hot gases from the heat absorbing equipment.
INHIBITOR	A substance which selectively retards a chemical action.
INJECTOR	A device utilizing a stem 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.
INSPECTION DOOR	A small door in the outer enclosure so that certain parts of the interior of the apparatus may be observed.
INSULATION	A material of low thermal conductivity used to reduce heat losses.
INTEGRAL (RESET) CONTROLLER	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.
INTERLOCK	A device to prove the physical state of a required condition and to furnish that proof to the primary safety control circuit.
INTERMITTENT BLOWDOWN	The blowing down of boiler water at intervals.
INTERMITTENT IGNITION	An igniter which burns during light-off and while the main burner is firing, and which is shut off with the main burner.
INTERNAL-MIX OIL BURNER	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.
INTERNAL TREATMENT	The tratment of boiler water by introducing chemicals directly into the boiler.
INTERRUPTED IGNITION	An igniter which burns during light-off, and which is shut off (interrupted) during normal operation of the main burner.
INTERTUBE BURNER	A burner which terminates in nozzle discharging between adjacent waterwall tubes.
INERT GASEOUS CONSTITUENTS	Incombustible gases such as nitrogen which may be present in a fuel.
ION	A charged atom or radical which may be positive or negative.
ION EXCHANGE	A reversible process by which ions are interchanged between solids and a liquid with no substantial structure changes of the solid.
JUMPER TUBE	A short tube connection for bypassing routing, or directing the flow of fluid as desired.
LAGGING	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.

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 acteual instantaneous outpout rate of a boiler.
LONG FLAME BURNER	A burner in 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	The higher heating value 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.
LUG	Any projection used for supporting or grasping.
LUMINOSITY	Emissive power with respect to visible radiation.
MAKE-UP	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 outpout 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, distribute 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

MECHANICAL STOKER (Cont'd)

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 discharge 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 othter than the normal action of the coal feeding and agitating mechanism.

META-ANTHRACITE — Highest coal classification according to rank. Dry fixed carbon 98% or more and dry volatile matter 2% 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 all necessary control system instructions in what is called memory. Usually, all 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%.

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.

MUD OR LOWER DRUM	A pressure chamber of a drum or header type located at the lower extremity of a watertube boiler convection bank which is normally provided with a blow-off 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, asnd 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.
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.
NOx	A notation meaning oxides of nitrogen.
NOx PORT AIR	Air that is added downstream of the primary combustion zone to achieve off-stoichiometric combustion and reduce NOx 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.
NUT	Anthracite coal designation through 1⅝" over 15/16" round mesh screen. Bituminous coal size designation by some chosen screen mesh size. as 2" x ¾".
NUT AND SLACK	A combination of Nut and Slack coal, such as 2" x ¾" Nut plus ¾" x Slack (see Slack).
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%. At 0%, light is completely unobstructed and at 100%, 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 the liquid fuel is discharged. 2. A delvice 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.
OVERFIRE AIR FAN	A fan used to provide air to a combustion chamber above the fuel bed.
OXIDANT	A substance containing oxygen that reacts chemically in air to produce a new substance.
OXIDATION	Chemical combination with oxygen.
OXIDIZING ATMOSPHERE	An atmosphere which tends to promote the oxidation of immersed materials.

OXYGEN ATTACK	Corrosion or pitting in a boiler caused by oxygen.
PACKAGED STEAM GENERATOR	A boiler equipped and shipped complete with fuel burning equipment, mechanical draft equipment, automatic controls and accessories.
PACKED TOWER	A pollution control device that forces dirty air through a tower packed with loose pellete-like material of various shapes or a fixed grid type material, while liquid is sprayed over the packing material. The pollutants in the air stream either dissolve or chemically react with the liquid.
PAD	See Boss. A pad is larger than a boss and is attached to a pressure vessel.
PARALLEL FLOW BURNER	A type or class of burners which includes the venturi burner. The burner is characterized by the lack of register spin louvres and normally has a venturi section to straighten, balance, and in some cases, meter air flow. The flame is stabilized by either a diffuser, spinner, or bluff body.
PARALLEL POSITIONING	Fuel and sir 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.
PARTICULATES	Fine liquid or solid particles such as dust, smoke, mist, fumes, or smog found in the air or emissions.
PASS	A confined passageway through which a fluid, gas, or products of combination flows in essentially one direction.
PEA	Anthracite or bituminous coal size. In anthracite through 13/16" over 9l6" round hole screen; in bituminous ¾" x ⅜".
PEAK LOAD	The maximum load carried for a stated period of time.
PEEP HOLE	A small hole in a door covered by a movable cover.
PETEROLEUM	Naturally occurring mineral oil consisting predominately of hydrocarbons.
pH	A measure of the acidity of alkalinity of a material, liquid, or solid. pH is represente 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 elements 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 ration.
PARTS PER MILLION (Cont'd)	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.
PULSATION	Rapid fluctuations in furnace pressure.
PULVERIZER	A machine which reduces a solid fuel to a fineness suitable for burning in suspension.
PUMPS AND HEATER SETE	Assembled unit consisting of oil heater, fuel pump, strainer, valve, and piping and temperature controls. May be either simplex or duplex arrangements.
PUMP, AUTOMATIC OIL	A pump which automatically pumps oil from the supply tank and delivers the oil under a constant head to an oil-burning appliance.
PUMP, OIL-TRANSFER	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.
PURGE	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 contined therein.
PURGE METER INTERLOCK	A flow meter so arranged that an air flow 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.
PURGE, POST	A method of scavenging the furnace and boiler passes to remove all combustible gases after flame failure controls have sensed pilot and main burner shutdown and safety shut-off valves are closed.
PURGE, PRE—IGNITION	A method of scavenging the furnace and boiler passes to remove all combustible gases before the ignition system can be energized.
PURITY	The degree to which a substancel is free of foreign materials.
PUSHER	A device for giving motion to fuel bed by reciprocating motion, such as moving block in the bottom of a retort.
PYRITES	A compound of iron and sulfur naturally occurring in coal.
RADIATION LOSS	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.
RAM	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 500F without distortion or deterioration.
REGISTER BURNER	A type or class of burner. Air is admitted through one or multiple zones of adjustable louvres which impart a rotary motion to the air. The flame is stabilized by the swirling air from the register louvres 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" over 3/16" round mesh screen.
RINGLEMANN CHART	AA 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.
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 all 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 it's 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 minus ¾" 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 force draft 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. Non-combustible 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% or more and less than 92% and dry volatile matter 14% or less and more than 8%, 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 electeromagnetic 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 milliamps (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 air tight envelope.
SLACK	Screening, or fine coal; maximum top size seldom above 2½".

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 non-black 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 c 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.
SOx	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 lb. of a substance 1 degree fahrenheit.
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.

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° F and 14.696 pounds per square inch pressure. A dry cubic foot of air at these conditions weighs .0763 lbs 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° F, standard pressure is 14.7 psia. 2. Air Pollution Control (U.S.) — Standard temperature is 70° F, standard pressure is 14.7 psia. 3. Other — Standard temperature is 32° 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 all 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 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. A slight weep in a boiler joint, not in sufficient amount to form drops.
SWELL	The sudden increase in the volume of the steam in the water-steam mixture below the water level.
SWINGING LOAD	A load that changes at relatively short intervals.
TEMPERING MOISTURE	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 suplied 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 all 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 the setting.
WASTE HEAT	Sensible heat in non-combustible 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.
WATER AND SEDIMENT	Moisture and foreign matter in liquid fuel. Appreciable amounts of water and sediment tend to cause fouling of handling equipment.)
WATER BACK	One or more horizontal watertubes located over and laterally across the ash discharge end of a stoker to prevent ash adhesion to the wall and to reduce air leakage form the ash pit into the furnace.
WATER COLUMN	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.
WATER COOLED BAFFLE	A baffle composed essentially of closely spaced boiler tubes.
WATER COOLED BURNER THROAT	Burner throat water cooled by waterwall tubes bent to conform to the throat and covered by refractory.
WATER-COOLED STOKER	A stoker having tubes in or near the grate surface through which water is passed for cooling the grates.
WATER-COOLED WALL	A furnace wall containing watertubes.
WATER GAGE	The gage glass and its fittings for attachment.
WATER HAMMER	A sudden increase in pressure of water due to an instantaneous conversion of momentum to pressure.
WATER LEG	A vertical or nearly vertical box header, sectional header, or water-cooled sides of an internal firebox composed of flat or circular surfaces.
WATER LEVEL	The elevation of the surface of the water in a boiler.
WATER SEAL	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.
WATER TUBE	A tube in a boiler having the water and steam on the inside and heatl applied to the outside.
WATER VAPOR	A synonym for steam, usually used to denote steam of low absolute pressure.
WEATHERING	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 air tight 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 air flow into individual zones of a stoker.
ZONES	Divisions of the stoker windbox in which air can be maintained at different and controllable pressures.

INDEX

	Paragraphs
Air	
In Combustion	1-5b
Compressors	
Dryers	2-45d
Excess, Calculation of	1-5c
Excess, control of	1-15g
Pollution, Regulations	2-30
Theoretical	1-5b
Air Heaters	2-8, 3-27
Maintenance of	5-13
Alkalinity	4-2e
Test for	App. B-1b
Annunciators	2-27e
Ash Handling Equipment	2-20
Maintenance of	5-21
Atomizers, Oil	2-21a
Baghouses (see Fabric Filters)	
Blowdown	3-16c, 404c, 4-8
Calculations	App. D-1
Heat Recovery	4-8a
Boilers	
Blowdown	3-16c, App. D
Circulation	1-15e
Classifications of	2-1
Cleaning of	2-17, 4-12, 4-13
Components	2-3, 2-5, 2-10, 2-11, 2-12, 2-13, 2-14, 2-15, 2-16, 2-17
Controls	2-25, 2-26
Design Codes	2-2, 2-9, 3-5
Draft Loss	1-15d
Feedwater Pumps	2-37f
Fire Tube	2-4
Heat Transfer in	1-15
Hot Water	2-6
Idle	4-19
Maintenance	5-11
Meter	2-28a
Operation	3-12
Operation of Accessories	3-13
Package	2-5f
Placing in Service	3-9, 3-10, 3-11
Water Calculation	App. D
Water Tube	2-5
Borax-Nitrite	4-7f

Burners
Gas 2-23
Oil 2.21b
Calcium Carbonate ..... 4-2a(1)
Calcium Sulfate ..... 4-2a(2)
Carbon Dioxide
In Water 4-2d, 4-7e
Carbon Monoxide
Analyzers ..... 2-28g(2)
Carryover 4-3d
Causticity 4-2e
Test for ..... App. B-2b, App. B-2c
Caustic Soda ..... 4-7a(1), 4-10s(a)
Central Boiler Plants
Efficiency 1-13, 3-36
Equipment in 1-3
Operation ..... Chapter 3
Types 1-1
Chemical Feed (see Internal Treatment)
Chemicals, Mixing 4-11, 4-17a, 4-17b
Chloride Anion Exchangers 4-6e
Coal 1-4a, 1-6
Characteristics for Stokers 2-18h
Combustion Equipment for 2-18
Firing of 3-8a, 3-8b, 3-8c, 3-17
Handling Equipment 2-19, 2-19b, 5-20
Pollutants from 2-31f
Sizing of 2-18b, 2-18c
Storage 2-19a
Sulfur Content 2-7
Combustion
Chemical Reactions 1-5a
of Coal 1-6
Controls 2-26, 3-20
Efficiency 1-11
Fluidized Bed 2-18g
of Natural Gas 1-8
of Oil 1-7
Principles 1-5
Compressors
Air 2-45, 5-39
Condensate
Line Grooving 4-3c
Pumps 2-37
Conductivity ..... 4-8b, App. B
Controls
Combustion 2-26, 3-20
Concepts 2-26a
Feedwater 2-25
Maintenance 5-25, 5-26, 5-27, 5-28

Pneumatic 2-26b
Pollution 2-31, 2-32
Safety 2-27, 3-21
Corrosion 4-3c
Boiler 4-1
Distribution System 4-1
Economizers 2-7
Cyclohexylamine ..... 4-7e(2), 4-10h
Deaerators 4-6h
Maintenance of 5-33
Operation of 4-16c
Dealkalizers 4-6e
Demineralizers 4-6f
Dispersants 4-7d
Dissolved Solids 4-3a
Control of 4-3a
Test for ..... Ap. B-2f
Distribution System
Effects on Plant Efficienty 3-35f
Losses ..... 1-13, 1-2b(9)
Draft Gages 2-28f
Economizer 2-7, 3-27
Maintenance 5-12
Efficiency
Boiler 1-12, 3-34
Central Boiler Plants 1-13, 3-35
Combustion 1-11, 3-34
Mechanical Collectors 2-32d
Electrical Equipment 2-43, 3-31
Electrodialysis 4-6g
Electrostatic Precipitators 2-34
Energy
Electrostatic Precipitator Requirments 2-34d
Fabric Filter Requirements 2-33d
Losses from Steam System 1-26
Mechanical Collector Requirements 2-33d
External Treatment 4-4a, 4-6
Chemical Analysis Procedures ..... App. B
Operation of 4-16
Fabric Filters 2-33
Applications 2-33e
Cleaning Methods 2-33c
Energy Requirements 2-33d
Fans
Combustion Air ..... 2-18b(4), 2-18c(5)
Forced Draft 2-38
Induced Draft 2-39
Maintenance of 5-42
Operation of 3-25, 3-30
Overfire Air ..... 2-18c(2)
Feedwater, Boiler
Calculations ..... App. D-2
Control of 2-25, 3-15

Pumps 2-37f
Treatment ..... Chapter 4
Flame Failure 3-32
Flue Gas
Analysis 1-10
Monitoring Equipment 1-10, 2-28g
Temperature 3-34a
Flues and Ducts 2-40b
Fluidized Bed Combustion 2-18g
Fuels (see specific type)
Furnace
Purge 3-7i
Types 2-5a, 2-5b
Fusible Plugs 2-16, 5-16
Gage Cock 2-10
Gage Glass 2-10, 3-16a
Hardness 4-2
Test for ..... App. B-1a
Heat Balance
Calculations ..... Aplp. C
High Temperature Water System ..... 1-2b(3)
Steam System ..... 1-2b)1)
Heaters
Deaerating 4-6h
Feedwater 2-36, 3-26
Heat Transfer
In Air Heaters 2-8
In Boilers 1-15d
Conduction 1-15b
Convection 1-15c, 1-15f
In Economizers 2-7
Optimization of 1-15g
Radiation 1-15a
Higher Heating Value (sec also specific fuel) 1-5d
Hot Lime Hot Sodium Zeolite Softeners 4-6c
Hot Process Lime Soda Softeners 4-6b, 5-32
Hot Water
Comparison with Steam 1-2b
Generation of 1-14
Hydrogen Zeolite Softeners 4-6d
Injectors 2-37e, 3-24, 5-37
Insulation 2-47g
Internal Treatment 4-4b, 4-7
Calculations ..... App D-4
Operation of 4-17
Iron 4-2c
LPG 2-24
Low Temperature Water 1-2c, 4-7f
Lubricants 5-9a
Magnesium Bicarbonate ..... 4-2a(3)
Magnesium Chloride ..... 4-2a(4)
Maintenance ..... Chapter 5
Forced 5-2a

Lubrication 5-9a
Preventive 5-2b, 5-10, 5-11
Record Card System 5-6
Spare Parts 5-8
Tools 5-7
Mechanical Collectors 2-32
Cyclones 2-32a
Efficiency of 2-32d
Energy Requirements 2-32e
Maintenance 5-29
Multicyclones 2-32b
Pressure Drop 2-32e
Meters
Air Flow-Steam Flow 2-28a
Flow 2-28d
Morpholine ..... 4-7e(2), 4-10g
Motors 2-42, 5-41
Natural Gas 1-4c, 1-8
Combustion Equipment 2-23, 5-24
Firing of 3-8e, 3-19
Pollutants from ..... 3-3l d
Oil 1-4b, 1-7, 1-9a
Combustion Equipment 2-21, 5-22
Firing of 3-8d, 13-18
Pollutants from ..... 2-3l e
Pumping 2-22a
Storage and Handling k2-22, 5-23
Opacity 1-9c
Indicators ..... 2-28g(3)
Operation ..... Chapter 3
Emergency Procedures 3-28, 3-29, 3-30, 3-3l, 3-32
Plant Logs 3-3, 4-9
Standing Procedures 3-2
Startup 3-7, 3-8
Water Treatment System 4-9
Oxides of Nitrogen
Analyzers ..... 2-28g(4)
Control ..... 2-3l a
Oxides of Sulfur
Analyzers ..... 2-28g(4)
Control ..... 2-18g, 2-3l b
Oxygen (see also Air)
Analyzers ..... 2-28g(1)
In Water 4-2d, 4-7c
Particulate ..... 2-3l c
Control of 2-32, 2-33, 2-34, 2-35
pH 4-2f, 4-7a
Test for ..... App B-3a
Phosphates 4-7b, 4-10b
Test for ..... App B-2d
Piping 2-47

Pressure
Controls 2-28c, 3-13
Gages 2-12, 2-28e
Switches 2-27c
Pumps 2-37
Boiler Feedwater 2-37f
Centrifugal 2-37b, 3-22
Condensate k2-37g
Direct Acting 3-23
Installation of 2-37a
Jet Pumps k2-37e
Maintenance 5-34, 5-35, 5-36
Positive Displacemen t 2-37d
Reciprocating 2-37c
Vacuum 2-37h
Quebracho Tannin ..... 4-10c, 4-7d(1)
Test for ..... App. B-2e
Recorders 2-28i
Reverse Osmosis 4-6g
Safety Valve 2-13, 3-16b, 5-15
Scale 4-3a
Scanners 2-27d, 3-32
Scrubbers 2-35
Silica 4-2b
Sludge 4-3b
Soda Ash ..... 4-7a(2)
Sodium Sulfite 4-10d
Test for ..... App. B-2a
Stacks 2-40a, 5-30
Steam
Generation 1-14
Quality ..... 1-2b(9)
Traps 2-46, 5-40
Smoke 1-9b
Indicators ..... 2-28g(3)
Sodium Zeolite Softeners 4-6a, 4-16a, 5-31
Soot 1-9a
Sootblowers 2-17, 3-16d, 3-34a, 5-17
Stokers 2-18a
Chain Grate 2-18d
Controls for 2-26e
Maintenance 5-18
Spreader 2-18c
Traveling Grate 2-18d
Underfeed 2-18b
Vibrating Grate 2-18e
Superheater 2-5e
Suspended Solids 4-2c
Temperature
In Combustion 1-5
Controls 2-28b, 3-13
Flue Gas 3-34a

Gages 2-12, 2-28h
Switches 2-27e
Turbines 2-41, 5-38
Valves
Blowoff 2-15
Butterfly ..... 2-47f(5)
Check ..... 2-47f(6)
Gate ..... 2-47f(2)
Globe ..... 2-47f(3)
Non-Return 2-14
Outside Screw and Yoke 2-14
Plug ..... 2-47f(4)
Pressure Control 2-28c
Safety 2-13, 5-15
Vent Condenser ..... 1-2b(2), 4-6b(3)(b)
Water (see also Chapter 4)
Analysis of ..... 4-15, App. B
Boiler Feedwater, Controls 2-25, 3-10a
Boiler Feedwater, Pumps 2-37f
Circulation in Boilers 1-15e
Hardness ..... 4-2a, App. B-1
Heaters 2-36
Impurities in 4-2, 4-3
Sampling 4-14
Temperature in Economizers 2-7
Water Column 2-11, 3-16a, 5-14
Water Treatment ..... Chapter 4
External 4-4a
Internal 4-4b
Requirements 4-5

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