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	CO₃—	Carbonate
Fe++	Ferrous Iron	HCO₃-	Bicarbonate
Fe+++	Ferrous Iron	HCO₃-	Bicarbonate
H+	Hydrogen	PO₄—	Phosphate
K+	Potassium	SO₄—	Sulfate
Mg++	Magnesium	SO₃—	Sulfite
Na+	Sodium	SiO₃—	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

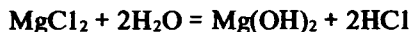FIGURE 4-3. SUPERHEATER TUBE SHOWING
CARRYOVER DEPOSITS

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:
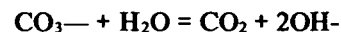$$MgCl_2 + 2H_2O = Mg(OH)_2 + 2HCl$$
The hydrochloric acid is a gas which can leave the liquid water and corrode the boiler just above the water line.

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.
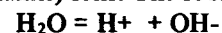
d. **Dissolved Gases/Oxygen and Carbon Dioxide.** Water that comes in contact with air will absorb oxygen and carbon dioxide. Raw water typically contains about nine parts per million of dissolved oxygen. While many impurities would be acceptable at this level, oxygen is not and treatment must be applied 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:

$$4\ Fe(OH)_2 + 2H_2O + O_2 = 4\ Fe(OH)_3$$
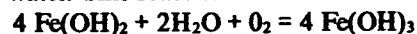
This reaction occurs in both cold and hot water and allows more iron ions to enter the water. At higher temperatures, ferrous hydroxide reacts in water to form magnetic iron oxide or magnetite. Heating surfaces of boilers are usually black because of this insoluble black oxide which precipitates out 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 O_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 heatinᵧ 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 ʾ 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.
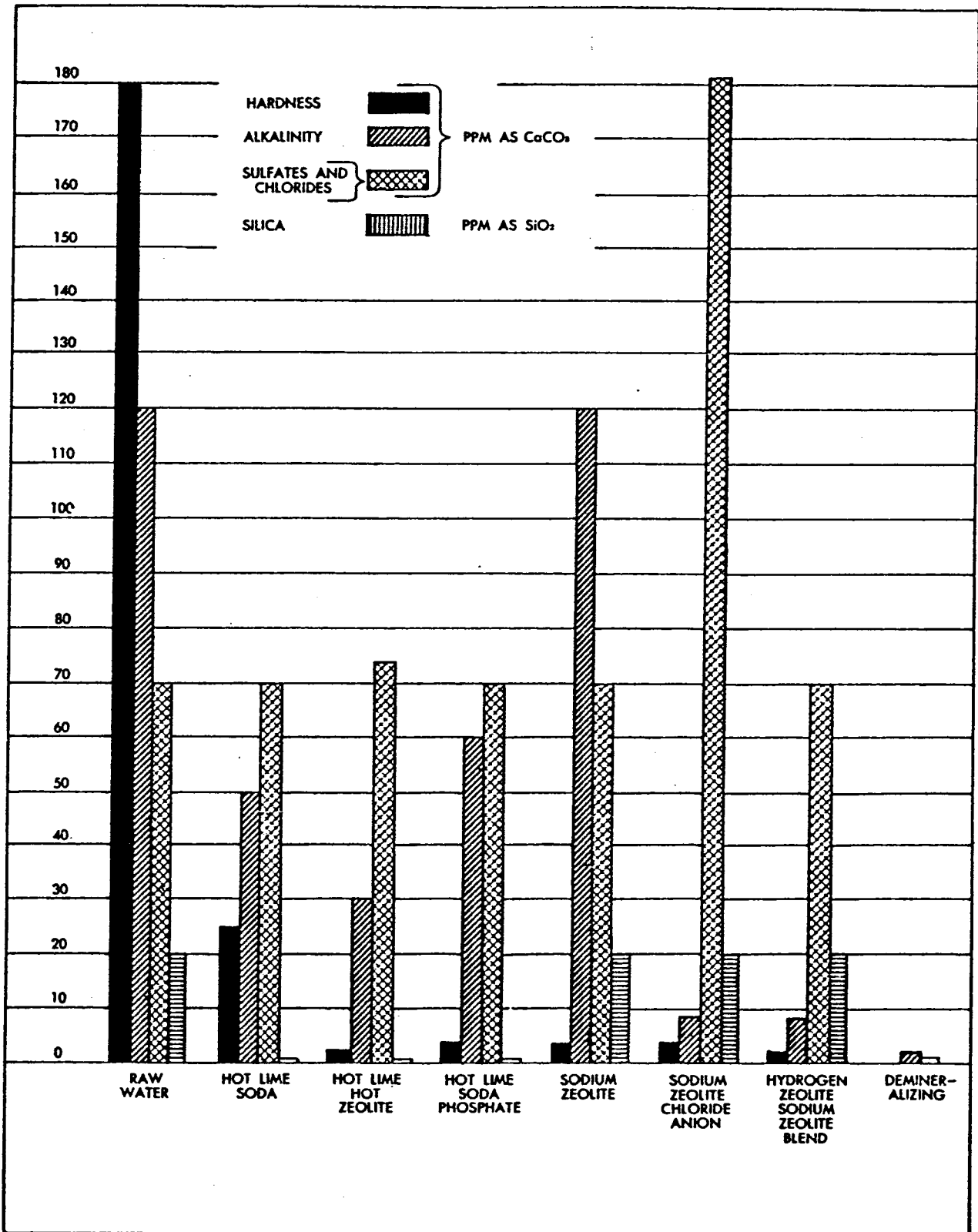
FIGURE 4-4.   EFFECTS OF TREATMENT
ON RAW WATER
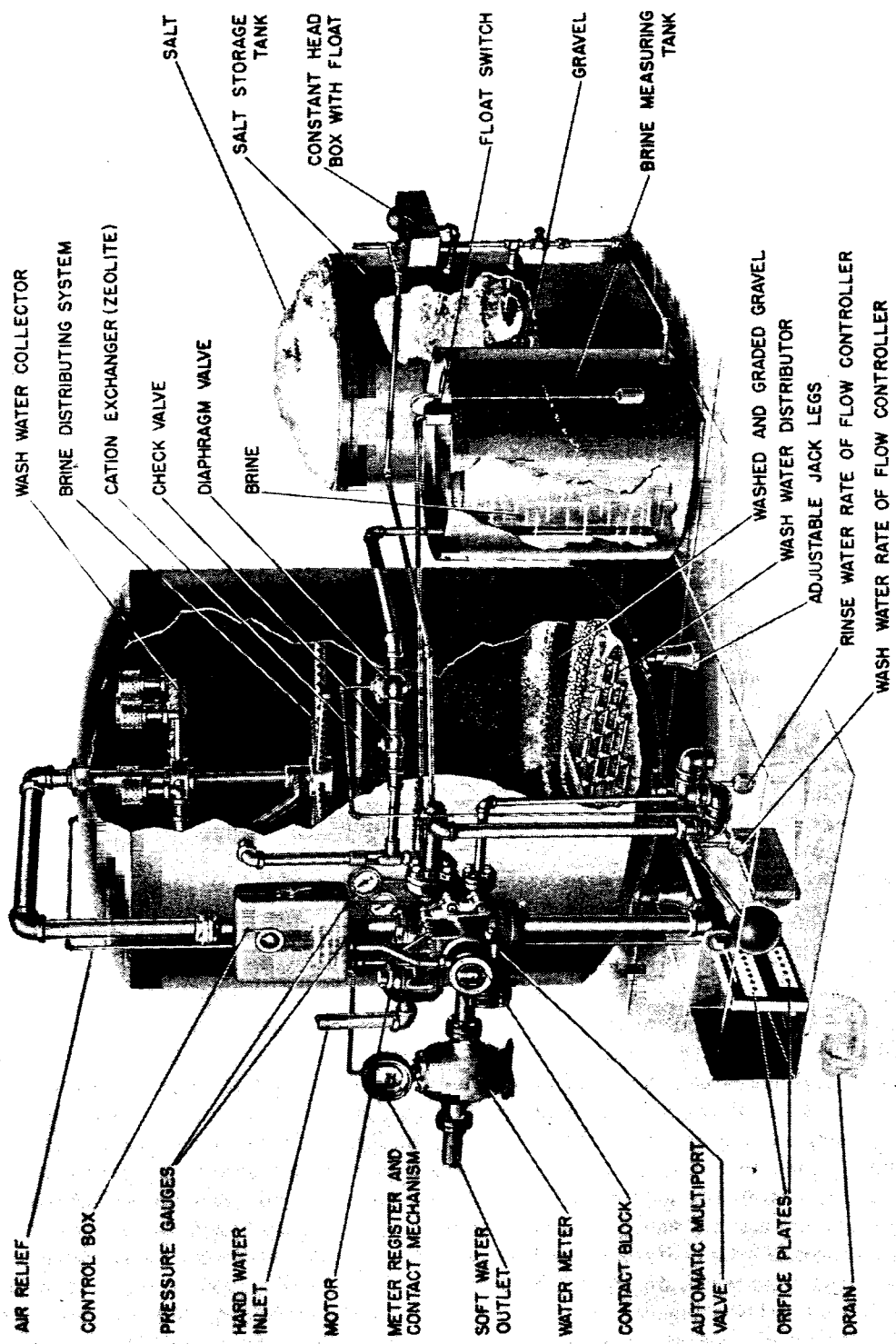
FIGURE 4-5. SODIUM ZEOLITE SOFTENER

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
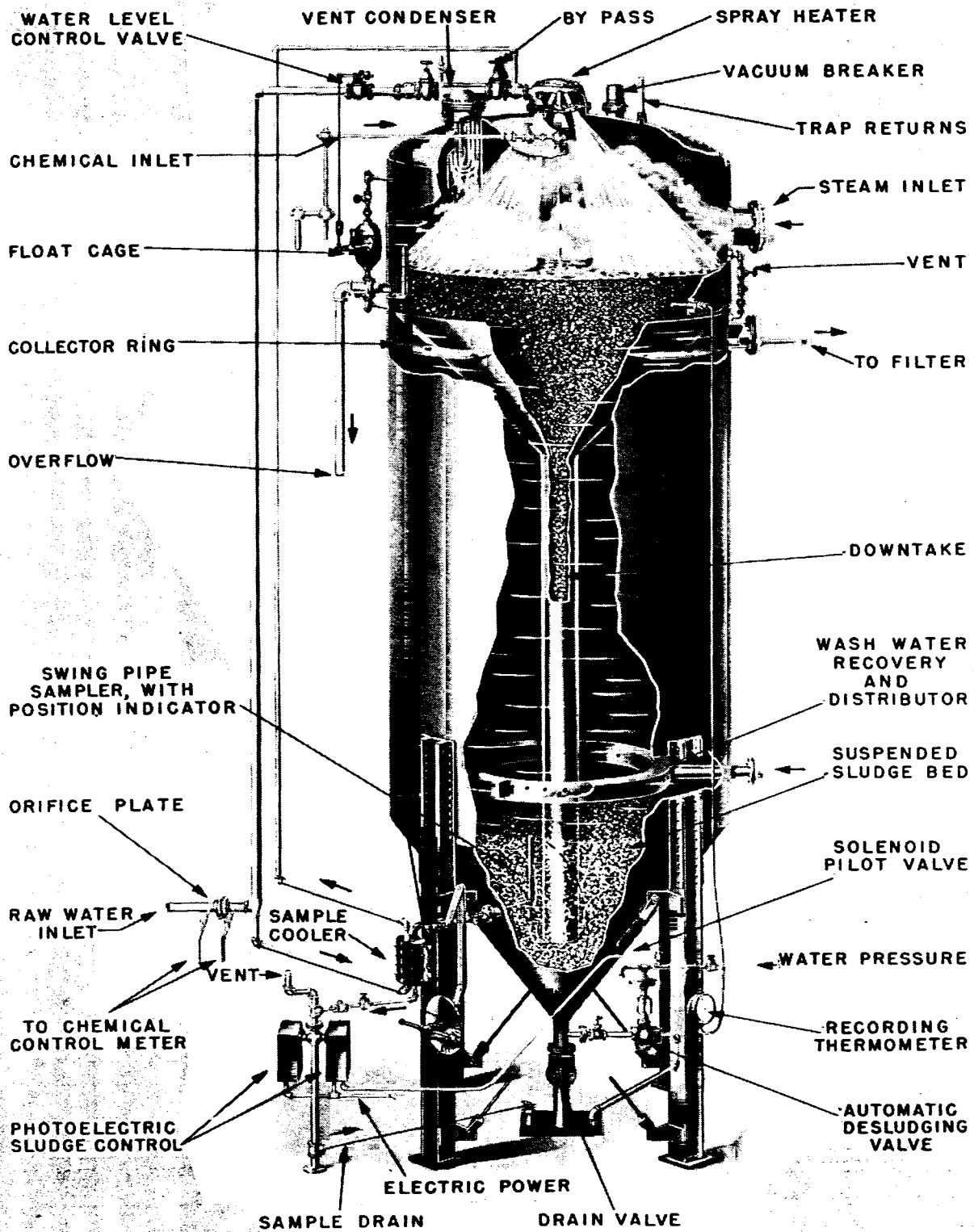
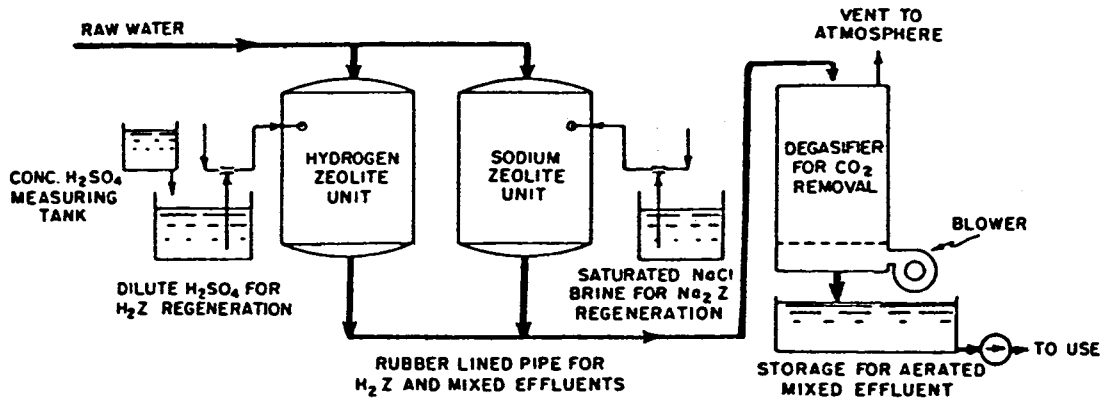FIGURE 4-6. HOT PROCESS LIME SODA SOFTENER

LEGEND

⫢ GATE VALVE

⫢ SWING CHECK VALVE

◦ RATE-OF-FLOW INDICATOR
SIGHT GLASS

◦ METER

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

RAW WATER

VENT TO
ATMOSPHERE

CONC. H₂SO₄
MEASURING
TANK

HYDROGEN
ZEOLITE
UNIT

SODIUM
ZEOLITE
UNIT

DEGASIFIER
FOR CO₂
REMOVAL

BLOWER

DILUTE H₂SO₄ FOR
H₂Z REGENERATION

SATURATED NaCl
BRINE FOR Na₂Z
REGENERATION

RUBBER LINED PIPE FOR
H₂Z AND MIXED EFFLUENTS

STORAGE FOR AERATED
MIXED EFFLUENT

TO USE

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

RAW WATER

VENT TO
ATMOSPHERE

ALKALINE
NEUTRALIZER

HYDROGEN
ZEOLITE
UNIT

DEGASIFIER
FOR CO₂
REMOVAL

CONC. ACID
MEASURING
TANK

DILUTE ACID FOR
H₂Z REGENERATION

BLOWER

RUBBER LINED PIPE FOR
H₂Z EFFLUENT

STORAGE FOR AERATED
NEUTRALIZED H₂Z EFFLUENT

TO USE
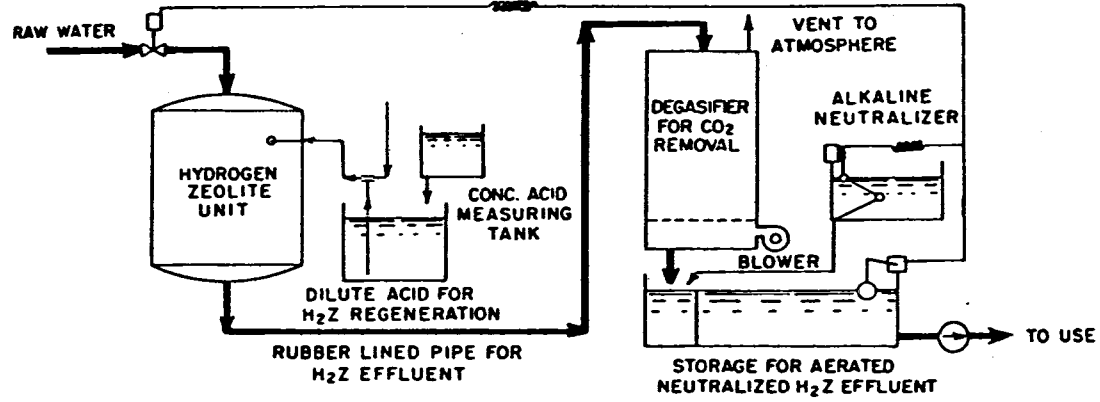
FIGURE 4-9. HYDROGEN ZEOLITE WITH
ALKALINE NEUTRALIZATION
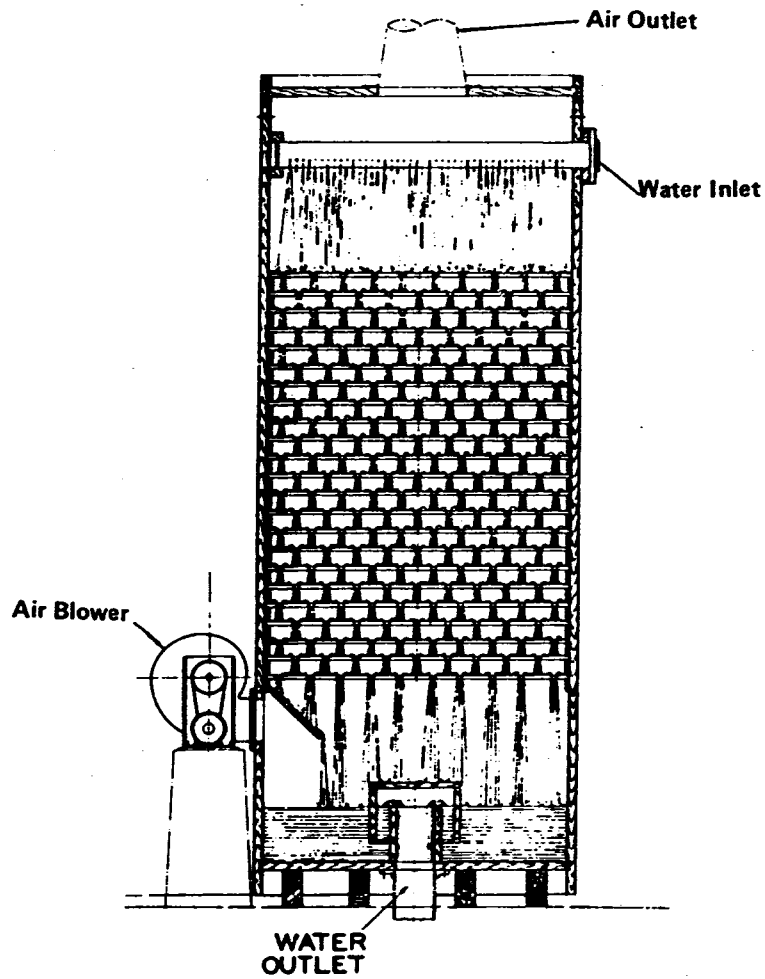
FIGURE 4-10. DEGASIFIER/DECARBONATING TOWER

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 makeup 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
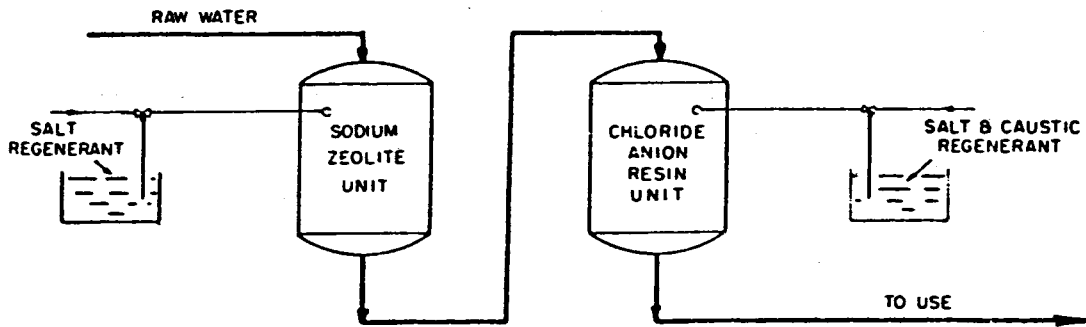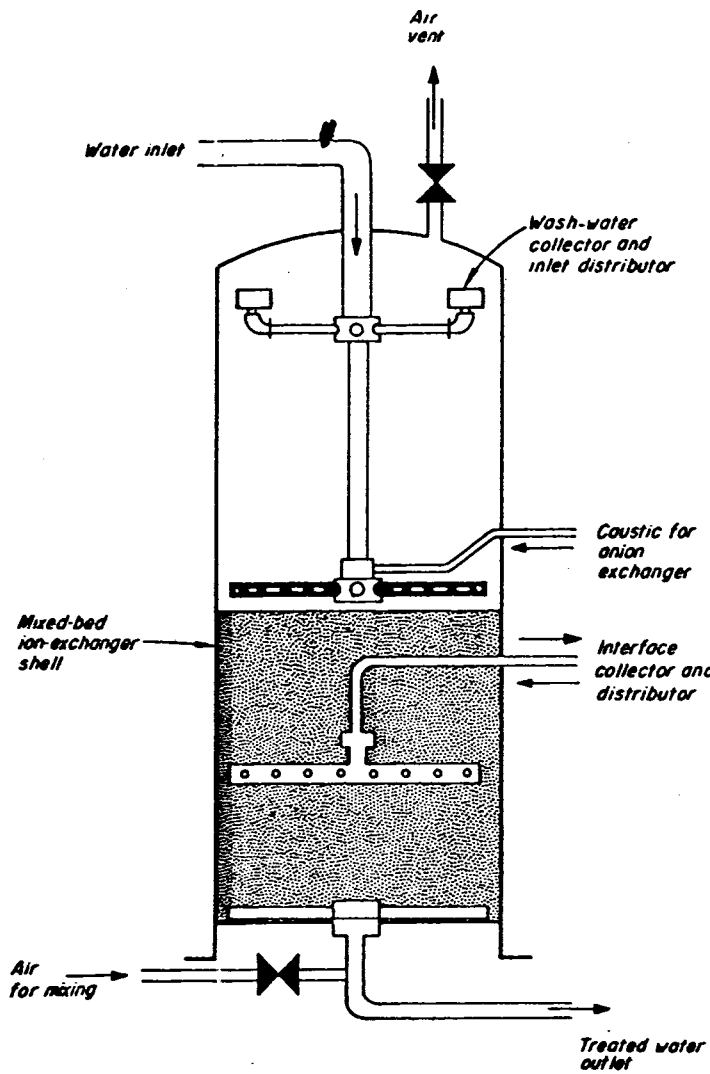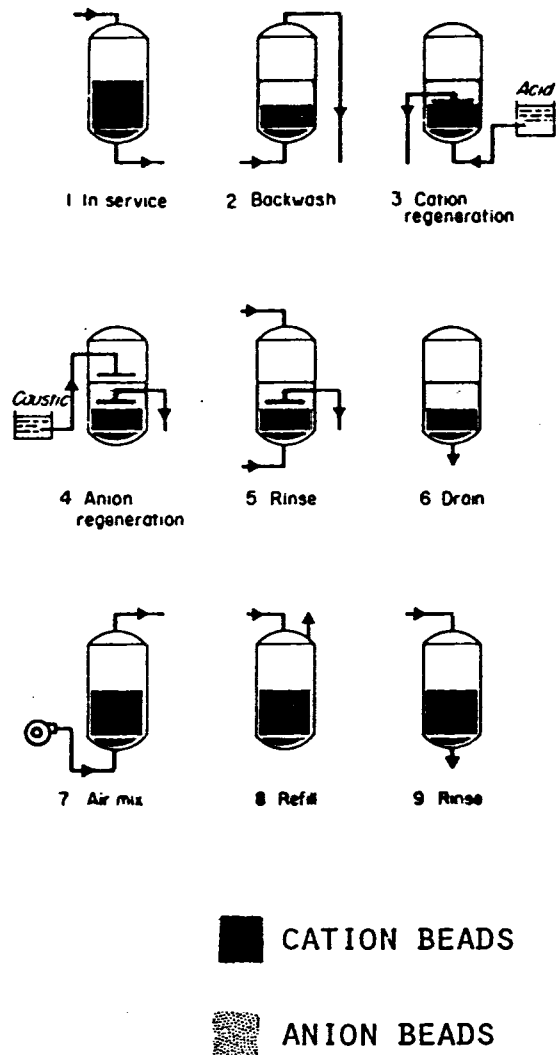
RAW WATER

SALT
REGENERANT

SODIUM
ZEOLITE
UNIT

CHLORIDE
ANION
RESIN
UNIT

SALT & CAUSTIC
REGENERANT

TO USE

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

Air vent

Water inlet

Wash-water collector and inlet distributor

Caustic for anion exchanger

Mixed-bed ion-exchanger shell

Interface collector and distributor

Air for mixing

Treated water outlet

1 In service   2 Backwash   3 Cation regeneration

4 Anion regeneration   5 Rinse   6 Drain

7 Air mix   8 Refill   9 Rinse

■ CATION BEADS

▨ ANION BEADS

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 greater 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
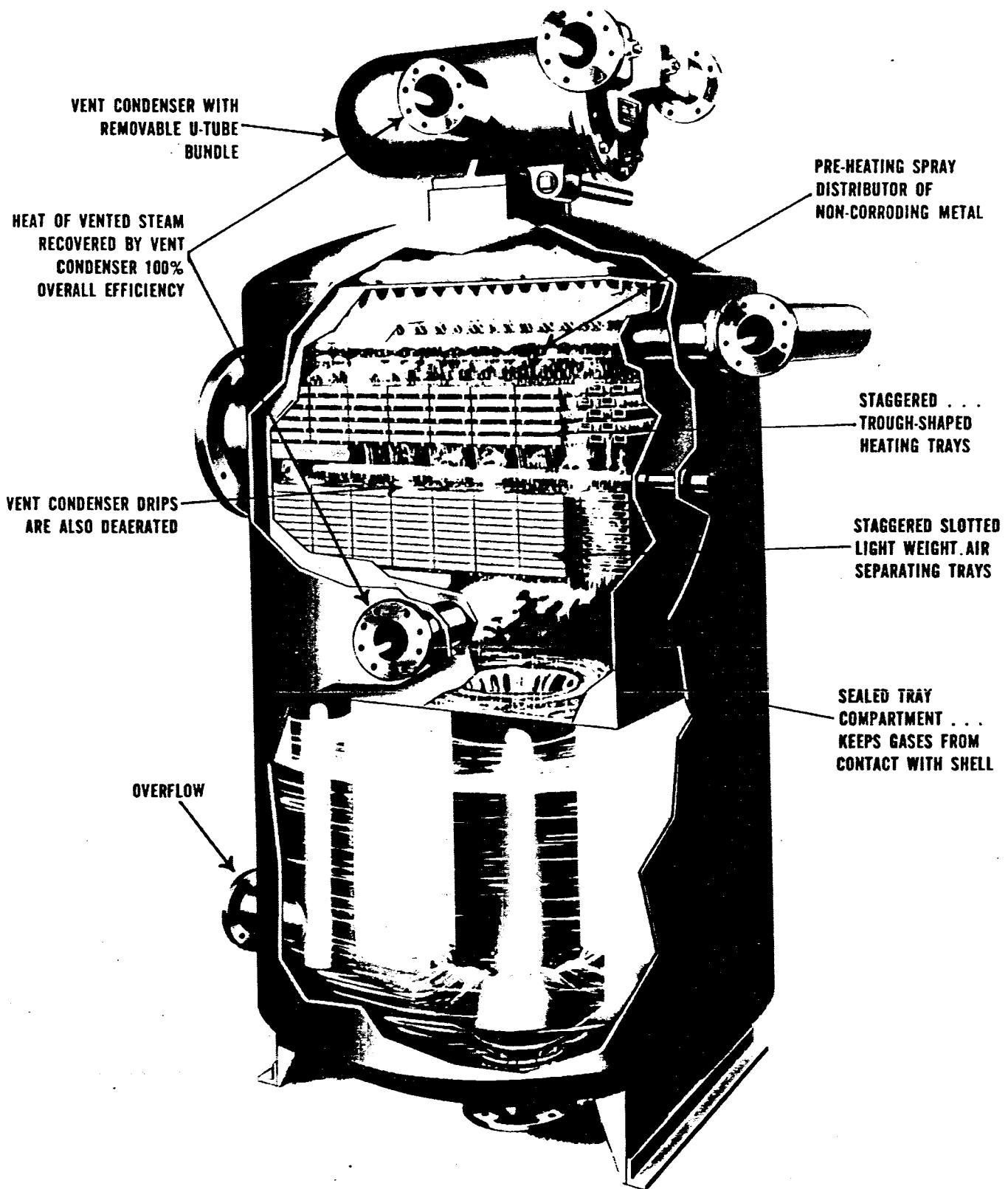
VENT CONDENSER WITH
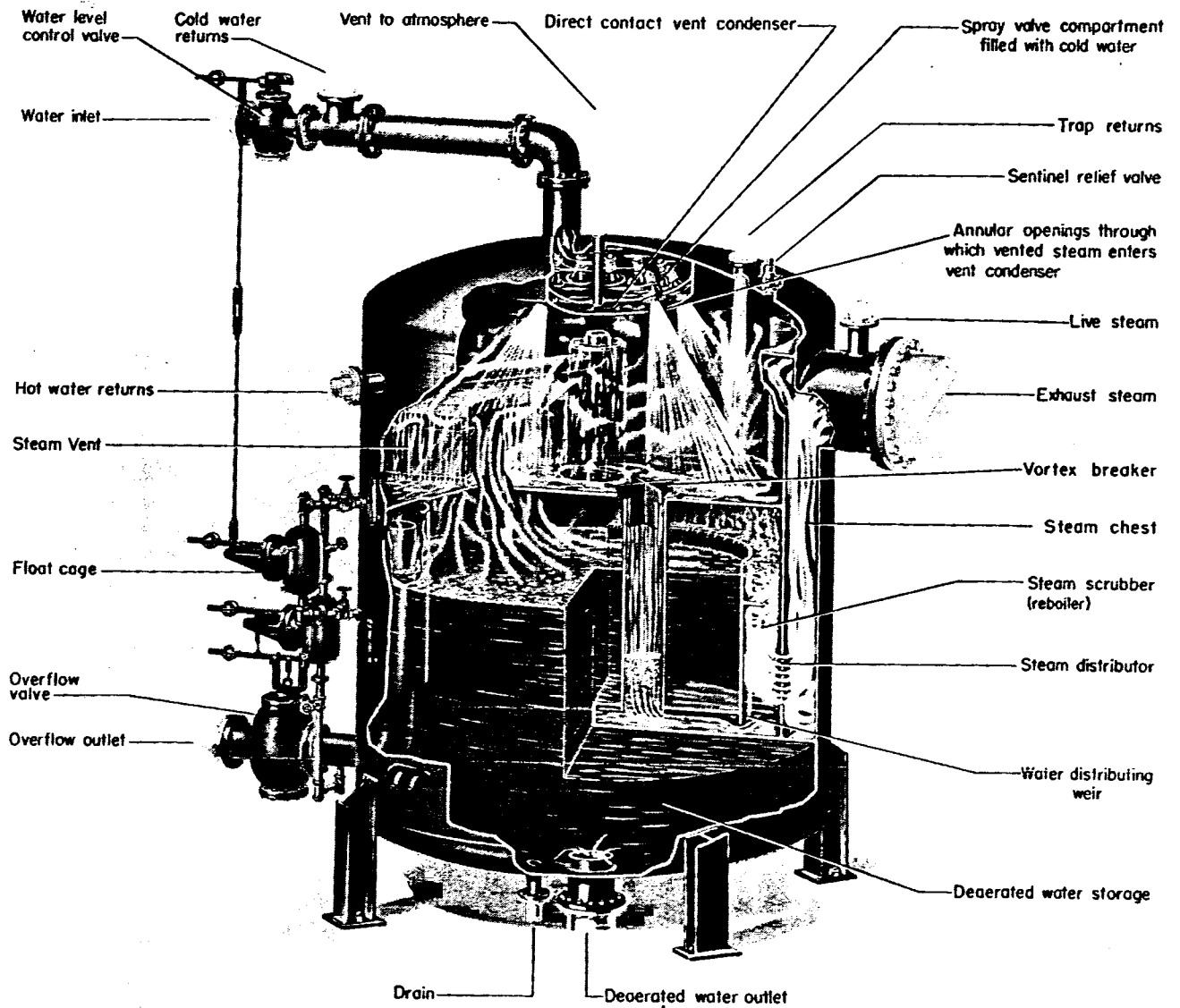REMOVABLE U-TUBE
BUNDLE

PRE-HEATING SPRAY
DISTRIBUTOR OF
NON-CORRODING METAL

HEAT OF VENTED STEAM
RECOVERED BY VENT
CONDENSER 100%
OVERALL EFFICIENCY

STAGGERED . . .
TROUGH-SHAPED
HEATING TRAYS

VENT CONDENSER DRIPS
ARE ALSO DEAERATED

STAGGERED SLOTTED
LIGHT WEIGHT.AIR
SEPARATING TRAYS

SEALED TRAY
COMPARTMENT . . .
KEEPS GASES FROM
CONTACT WITH SHELL

OVERFLOW

FIGURE 4-13. TRAY DEAERATOR

Water level
control valve

Cold water
returns

Vent to atmosphere

Direct contact vent condenser

Spray valve compartment
filled with cold water

Water inlet

Trap returns

Sentinel relief valve

Annular openings through
which vented steam enters
vent condenser

Live steam

Hot water returns

Exhaust steam

Steam Vent

Vortex breaker

Steam chest

Float cage

Steam scrubber
(reboiler)

Steam distributor

Overflow
valve

Overflow outlet

Water distributing
weir

Deaerated water storage

Drain

Deaerated water outlet

FIGURE 4-14. SPRAY DEAERATOR

Cond. Return

Relief Valves
Press.   Voc.

Back Pressure Relief

Raw Water

Surge Tank

Control
Lever

Vent

Live
Steam

Heater

Oil
Separator

Control
Lever

Bypass

Exhaust
Steam

Feed Pump

To Boilers

Fans Stokers etc.
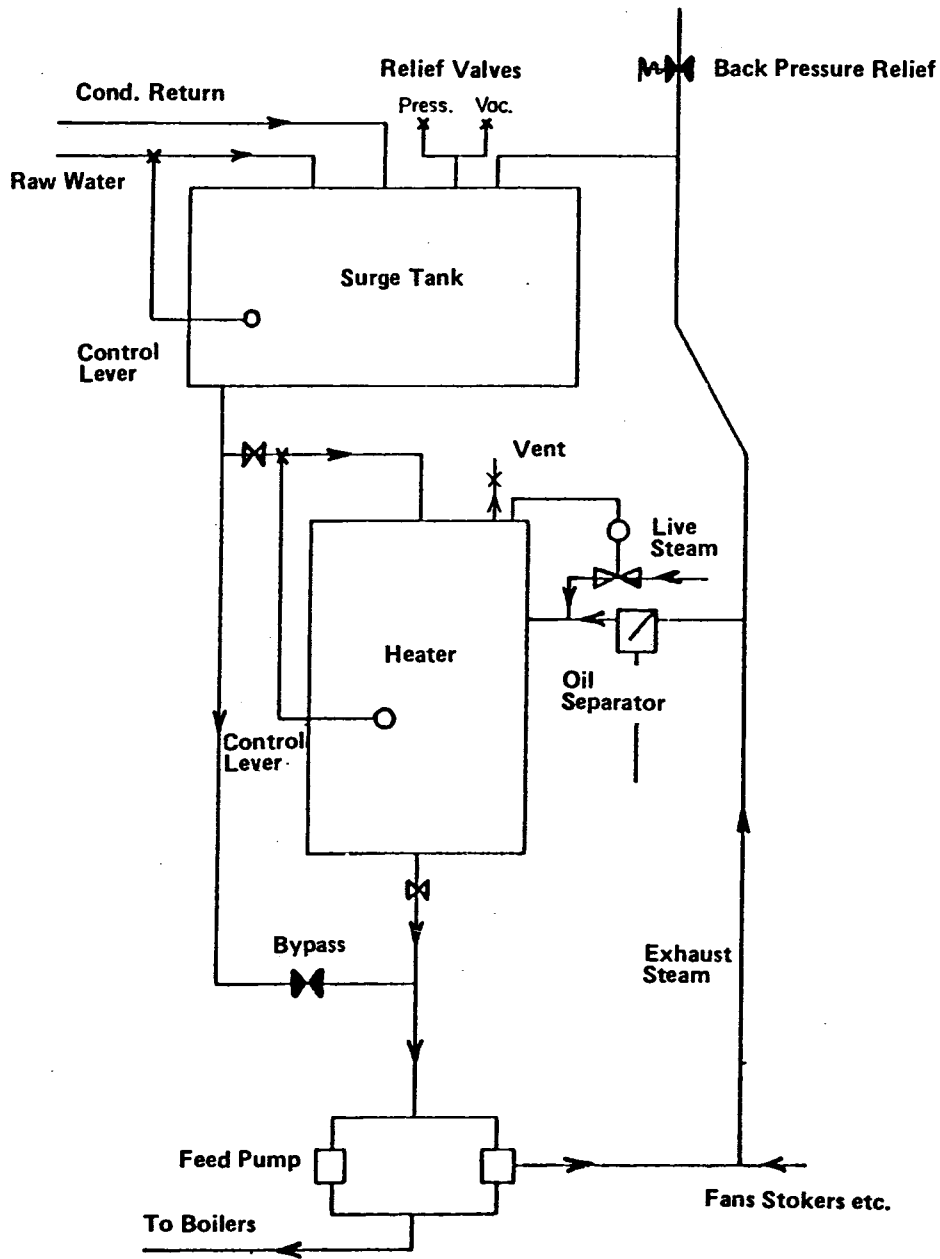
FIGURE 4-15. TYPE I DEAERATOR INSTALLATION
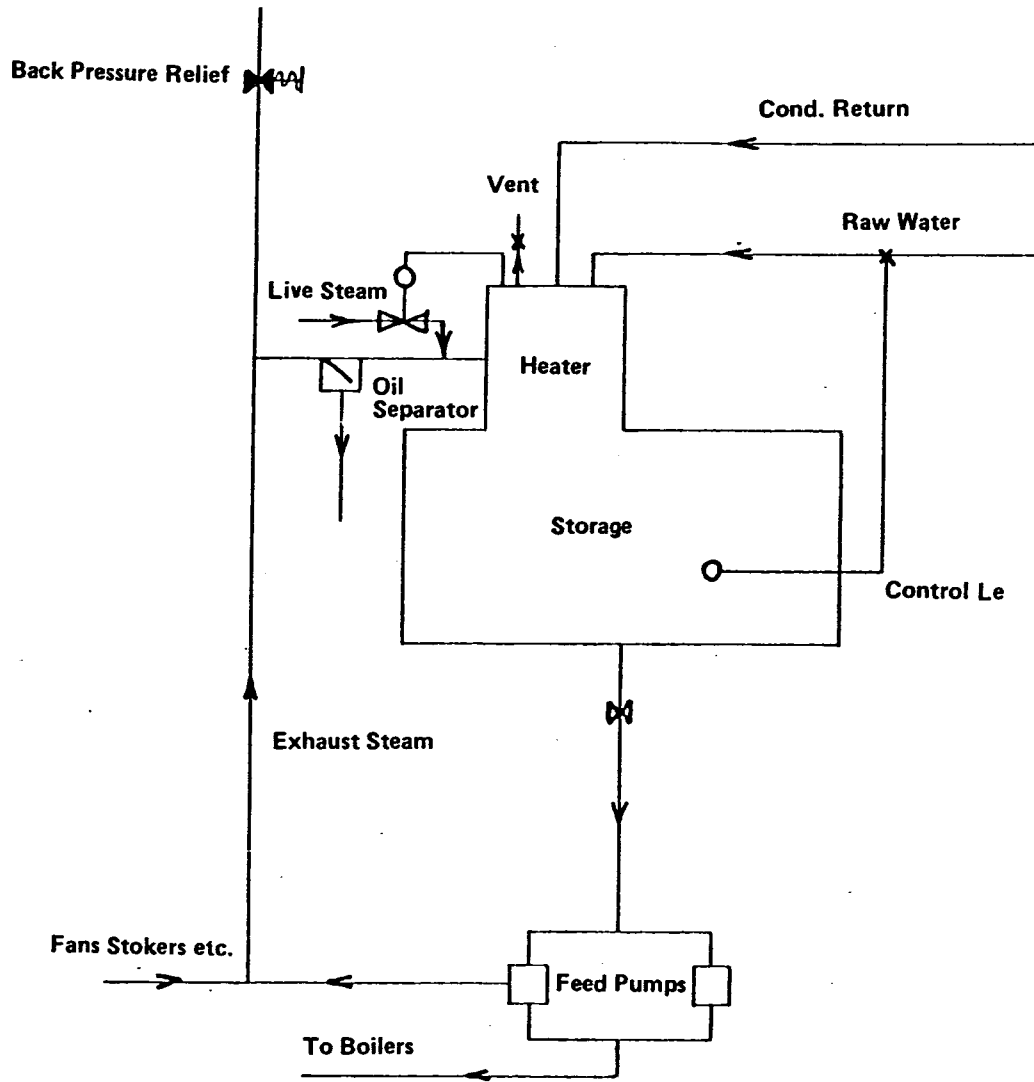
FIGURE 4-16. TYPE II DEAERATOR INSTALLATION
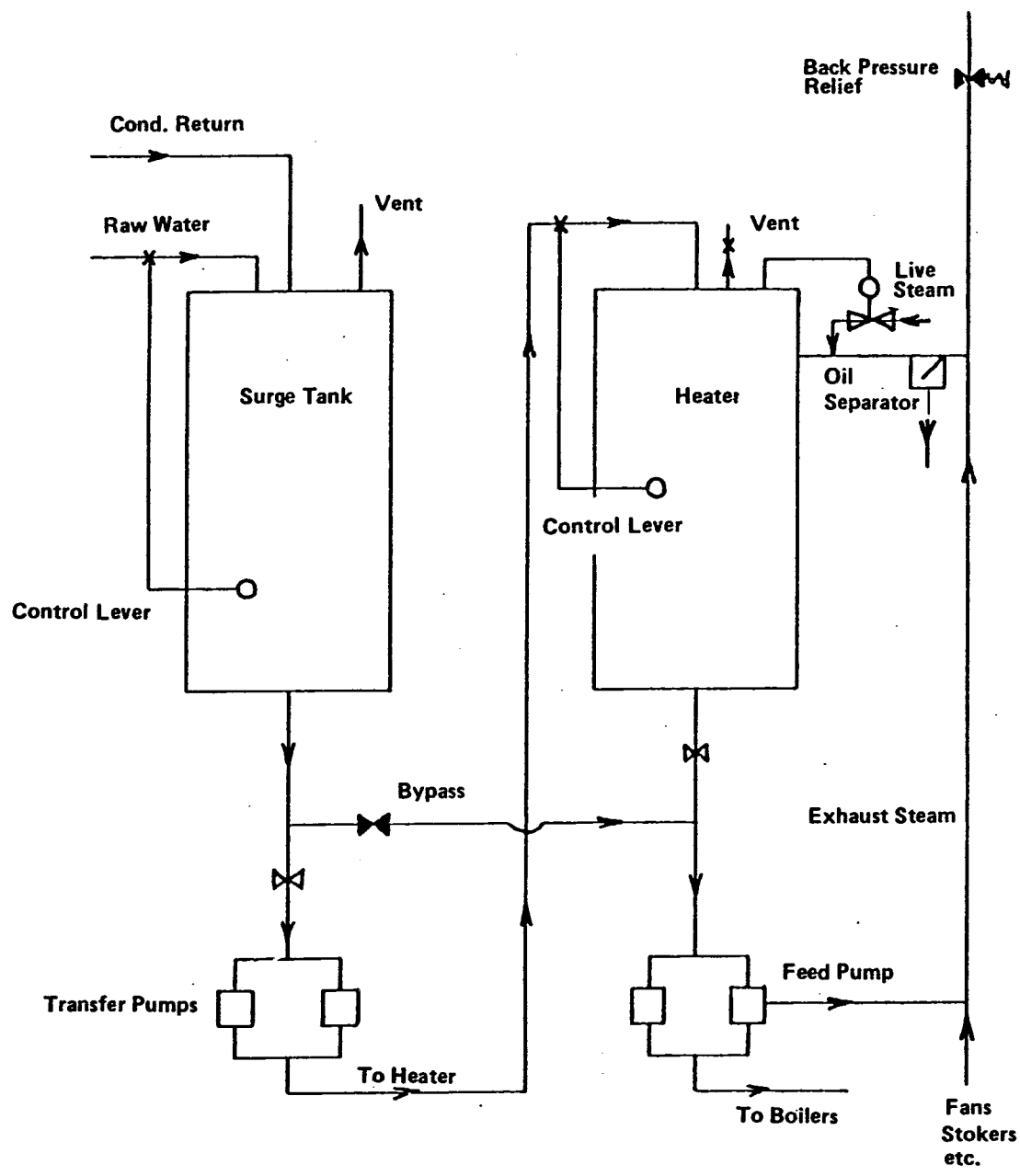
FIGURE 4-17. TYPE III DEAERATOR INSTALLATION

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 provided with 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:

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

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:

$$Na_2SO_3 + \tfrac{1}{2}O_2 = Na_2SO_4$$
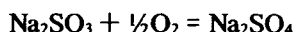
The reaction is slow at moderate temperatures. Catalysts such as copper and cobalt are sometimes added to the sulfite to enhance reaction in room temperature water. Catalyst feed is not necessary during normal unit operation because the trace metal content of makeup water is sufficient to catalyze the 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
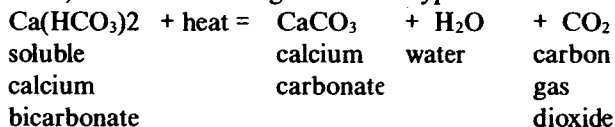
The carbon dioxide is discharged from the boiler with the steam. It then redissolves, either in pockets of condensate in the steam line or in the return condensate and forms carbonic acid. Carbon dioxide and oxygen become more corrosive when combined than they are individually. Both external treatment 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
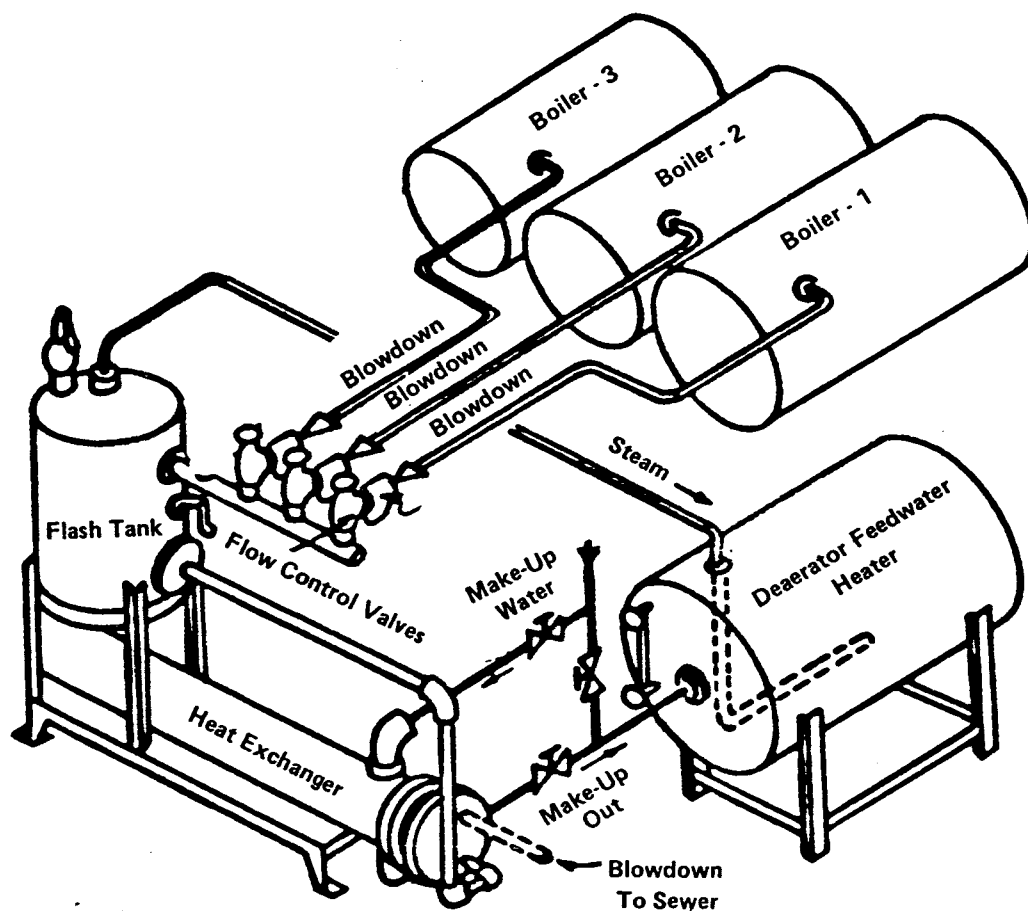
FIGURE 4-18. BLOWDOWN SYSTEM WITH FLASH
TANK AND HEAT EXCHANGER

...ince 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 f 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

CONTINUOUS
BLOWDOWN LINE

SAMPLE
COOLER

COOLING
WATER

MODULATING
CONTROL VALVE

MANUAL
OR MINIMUM
BYPASS VALVE

CONDUCTIVITY
SENSOR

CONDUCTIVITY
CONTROLLER

TO

FLASH TANK/
HEAT EXCHANGER

TO

DRAIN/SAMPLE
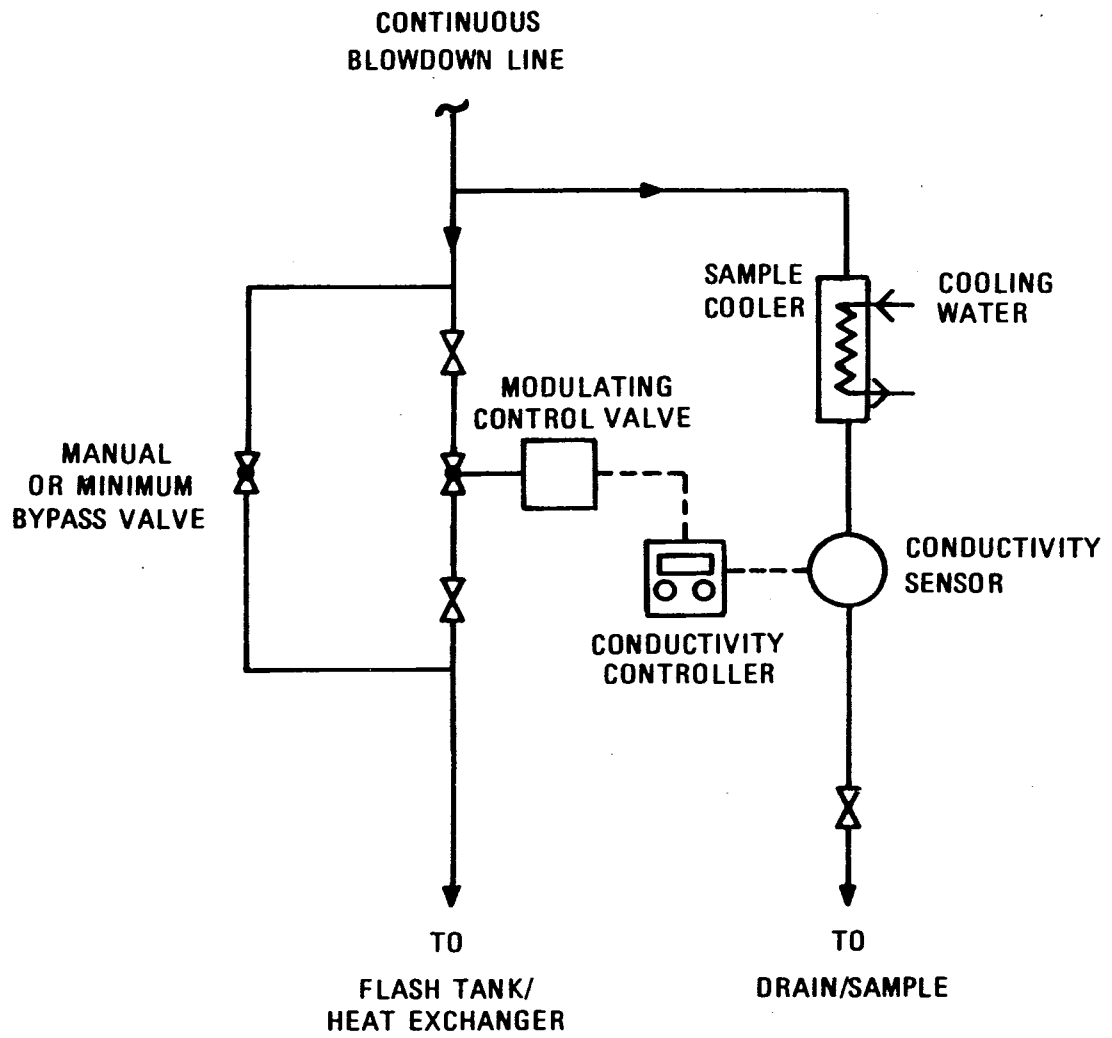
FIGURE 4—19. AUTOMATIC CONTINUOUS BLOWDOWN CONTROLS

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.	PHOSPHATE (30-60)	CAUSTICITY (20-200)	TANNIN (M)	SODIUM SULFITE (20-40)	TOTAL DISSOLVED SOLIDS	BLOW DOWN (Inches/Seconds)	CAUSTIC SODA	PHOSPHATE	TANNIN	SODIUM SULFITE	STEAM HEADER pH	RETURN SYSTEM pH	PINTS	1,000 GAL.	SALT ADDED
F	1	50	140	M	35	3200	30	4	4	6	2	11.0	8.0	4	6760	160
Su	1	60	180	M	40	3000	30	4	4	6	2	11.1	8.2	4	5900	
S	1	70	220	Dk	45	2700	30	3	3	4	2	11.1	8.3	4	5760	
M	1	70	200	Dk	40	3100	30	3	3	4	8	11.0	8.0	4	6500	
T	1	60	180	H	35	3500	30	3	3	6	2	11.1	8.2	4	6590	
W	1	50	140	M	40	3800	30	4	3	6	2	11.0	8.0	4	6600	
Th	1	40	140	M	35	3700	30	4	3	6	2	11.0	7.8	4	6700	
F	1	40	140	M	30	3100	30	4	4	6	2	10.7	7.8	4	6640	160
Su	1	50	160	M	35	3000	30	4	4	6	2	11.3	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	2	10.9	7.8	4	6600	
T	1	40	120	LT	35	3300	30	4	4	6	2	10.9	7.6	4	6570	
W	1	30	100	M	35	3300	30	4	4	6	2	11.0	8.2	3	6400	
Th	1	30	120	M	30	3200	30	4	4	6	8	11.1	8.0	3	6450	
F	1	40	120	M	35	3400	30	3	4	6	6	11.1	8.2	3	6370	
Su	1	40	140	M	45	3300	30	3	3	4	6	11.2	8.2	3	5200	160
S	1	30	120	M	35	3200	30	3	3	4	6	11.2	8.4	3	5010	
M	1	40	100	M	30	3500	30	3	3	4	6	11.0	8.0	3	5300	
T	1	40	100	M	30	3600	35	3	3	4	6	11.0	8.0	3	5150	
W	1	40	120	H	35	3100	30	3	3	4	6	11.0	7.8	3	4300	
Th	1	40	100	M	35	3100	30	3	3	4	6	11.0	7.8	3	4200	
F	1	40	100	M	30	3300	30	3	3	4	6	11.1	8.0	3	4150	
Su	1	50	120	M	35	3100	30	3	3	4	6	11.1	8.2	3	4010	
M	1	60	120	Dk	40	3000	30	3	3	2	6	11.1	7.8	3	4050	160
T	1	60	100	Dk	35	3000	30	3	3	2	6	11.1	7.8	3	4100	
W	1	50	80	H	30	3100	30	4	3	4	8	11.0	7.8	3	4070	
Th	1	40	100	M	25	3700	30	3	2	4	8	10.9	7.6	3	4050	
F	1	40	120	M	25	3500	30	3	4	4	6	11.0	7.2	3	3830	
Su	1	30	140	M	30	3200	30	3	4	4	6	11.0	8.0	3	3770	

NAME OF CHEMICAL: CYCLO HEXAMINE

WEST TO SUMMER OPERATING MODE 4/16   CLOSED SOUTH MEMBER 4/19

PREPARED BY: Gary Clark   DATE: 5/2/88
APPROVED BY: Robert L. Green   DATE: 5/3/88
POST ENGINEER: James P. —   DATE: 5/6/88

DA FORM 4367, 1 APR 73   REPLACES DA FORM 8-97, 1 JUN 60, 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 foreign 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
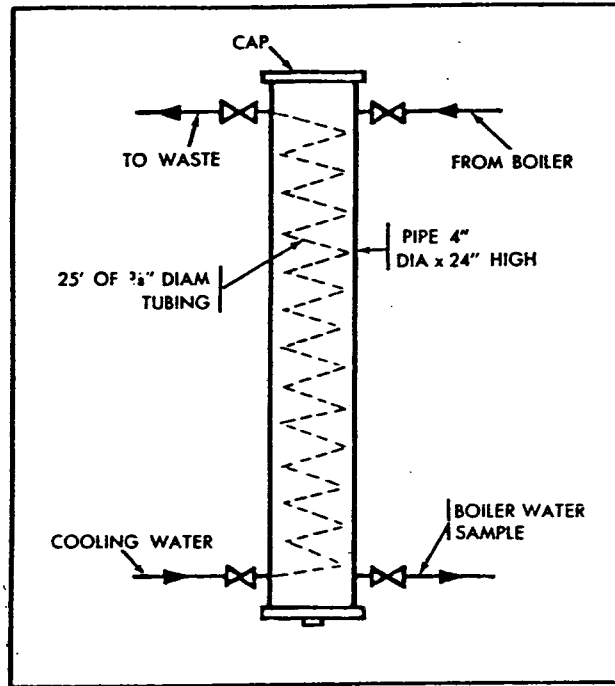
FIGURE 4-22. WATER COOLED SAMPLE COOLER

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 conspicuosly near the softening units. Follow these instructions in the egeneration, 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:
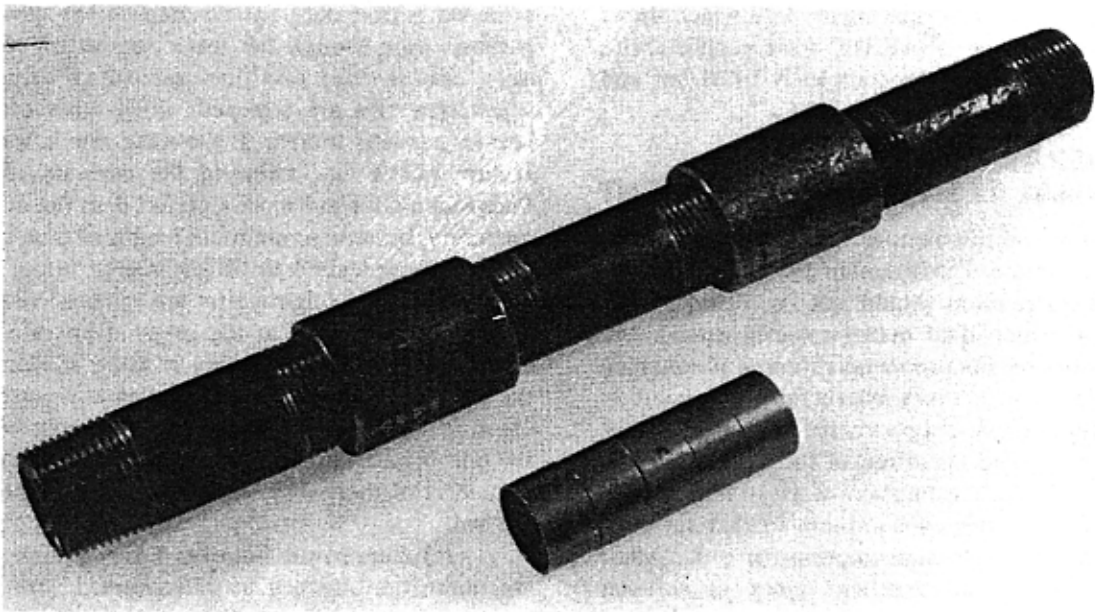
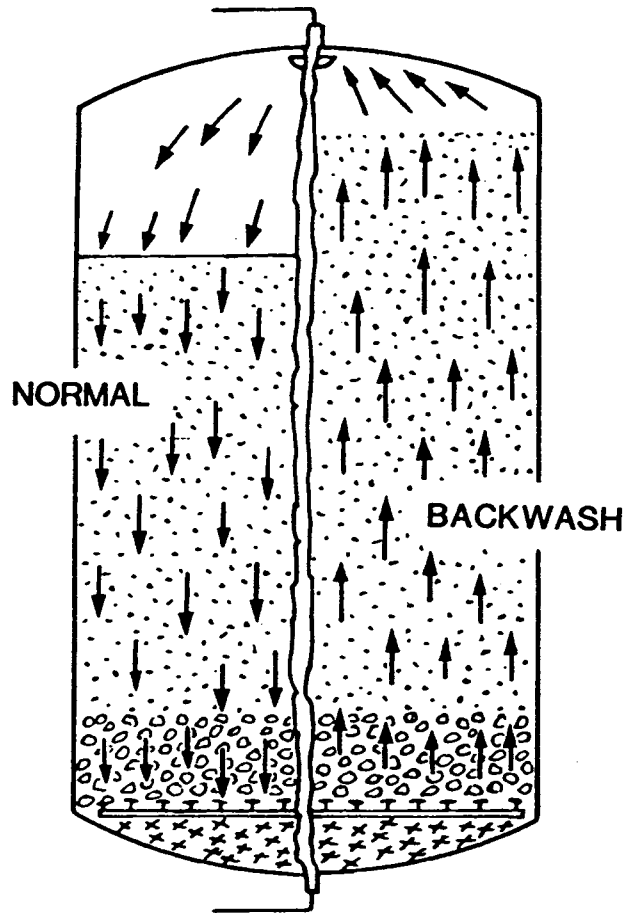FIGURE 4-23. CONDENSATE CORROSION TESTER
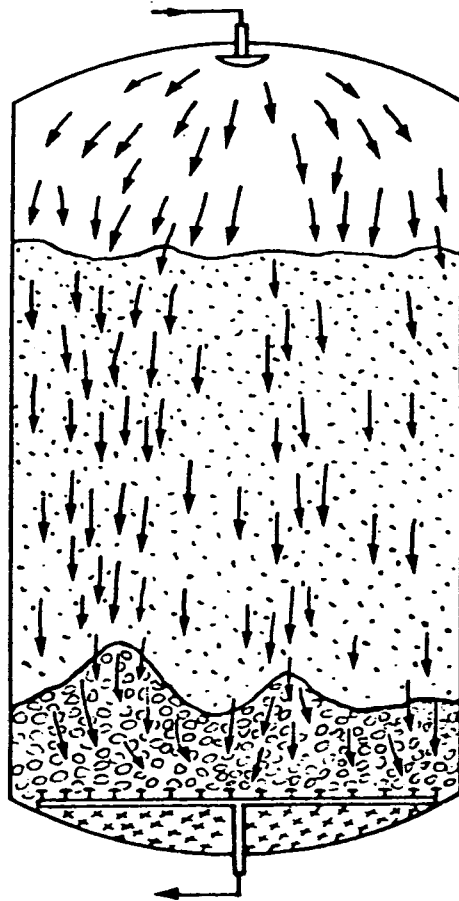
FIGURE 4-24. ZEOLITE SOFTENER WATER FLOWS

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

e 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:

$$\text{Salt (NaCl) required (lbs)} = \frac{\text{Gallons of Water Softened x Hardness of Water as CaCO}_3 \text{ in Grains per Gallon}}{2,000}$$

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.

BACK

LEFT

RIGHT

MEASUREMENTS
ARE ENTERED
IN CIRCLES

FRONT

SMALL CIRCLES
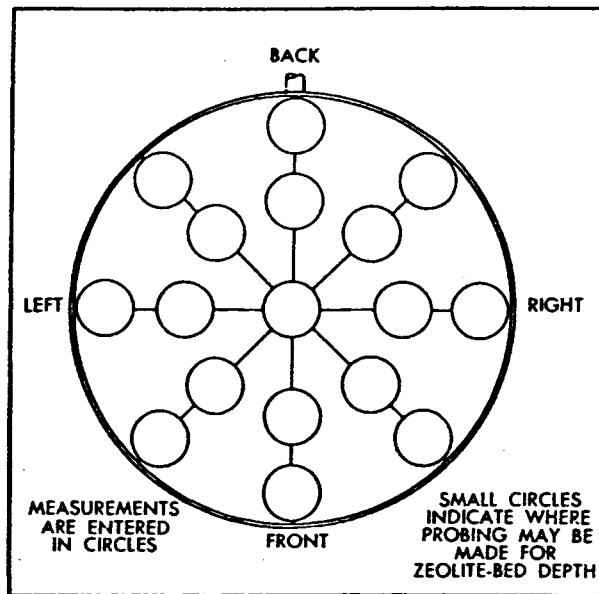INDICATE WHERE
PROBING MAY BE
MADE FOR
ZEOLITE-BED DEPTH

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

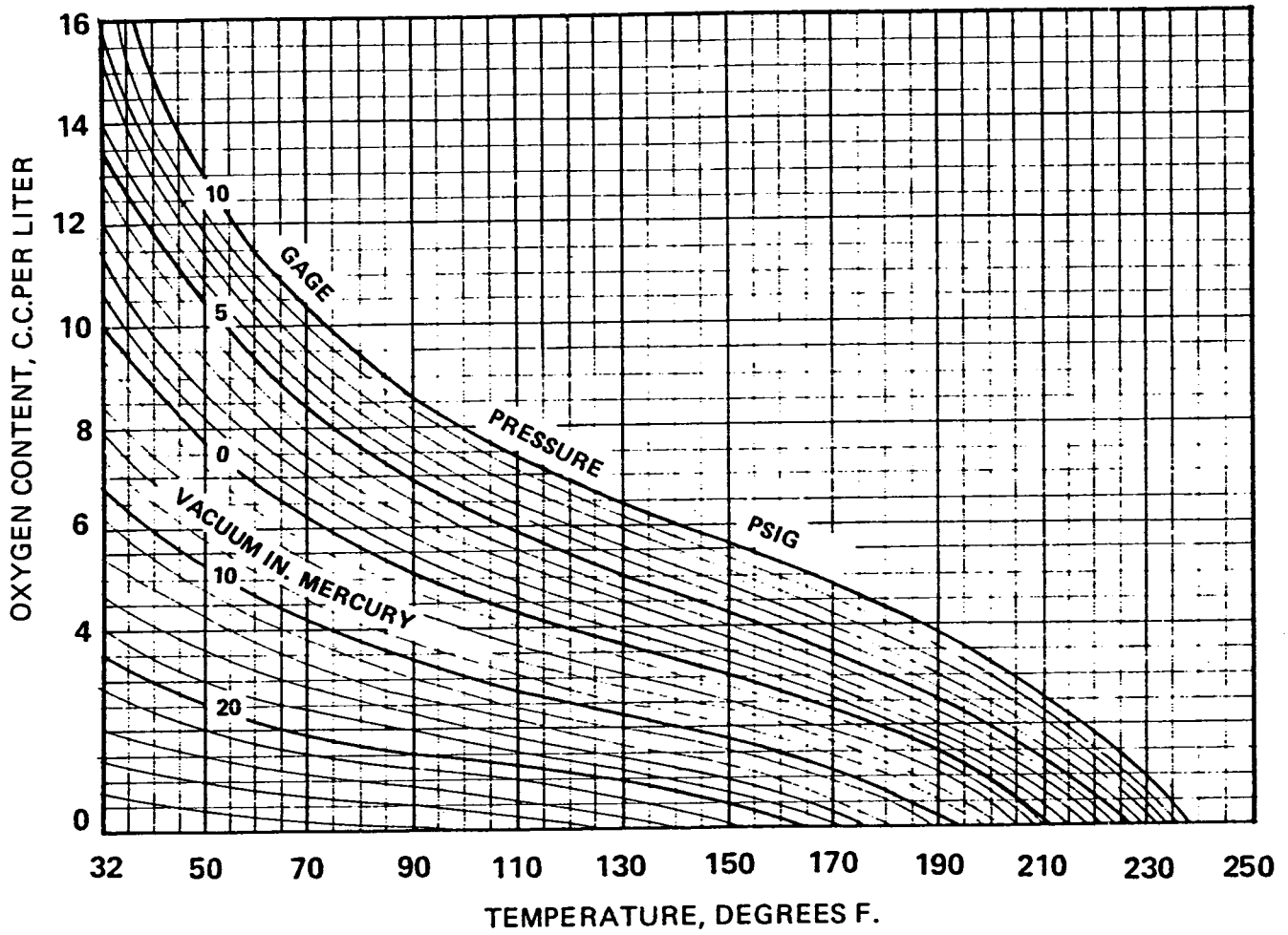*Exact   Temperatures are shown to the nearest whole degree

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.

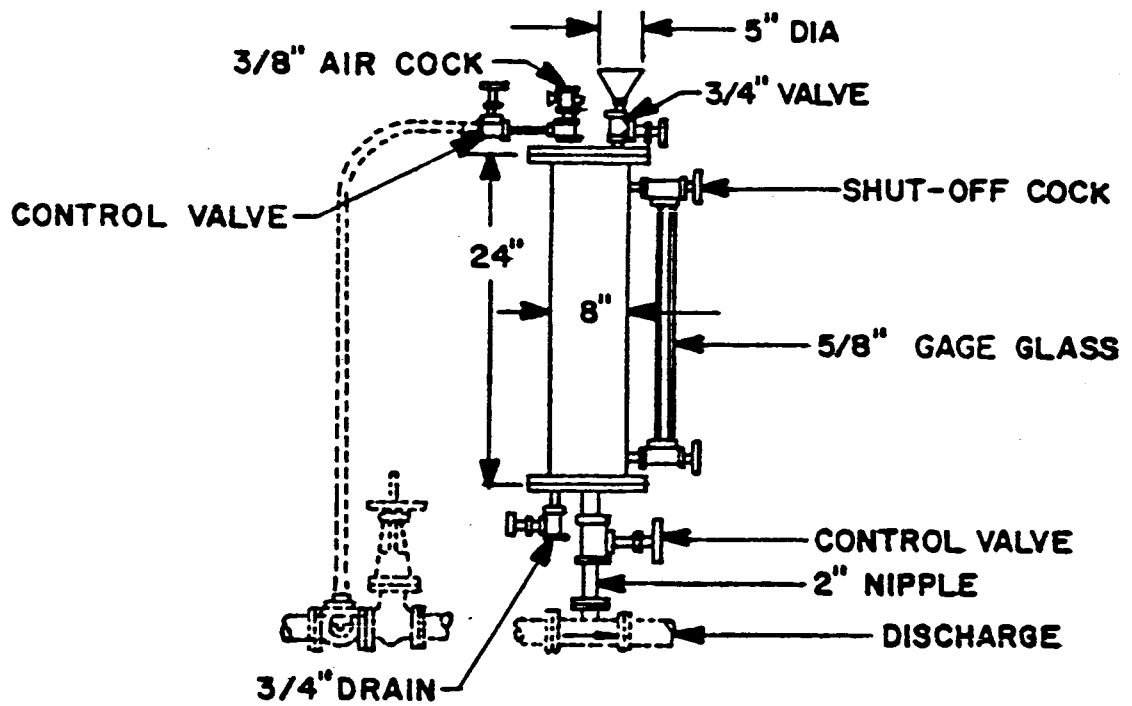(1) Do not feed any chemical ahead of the feedwater heater or deaerator.
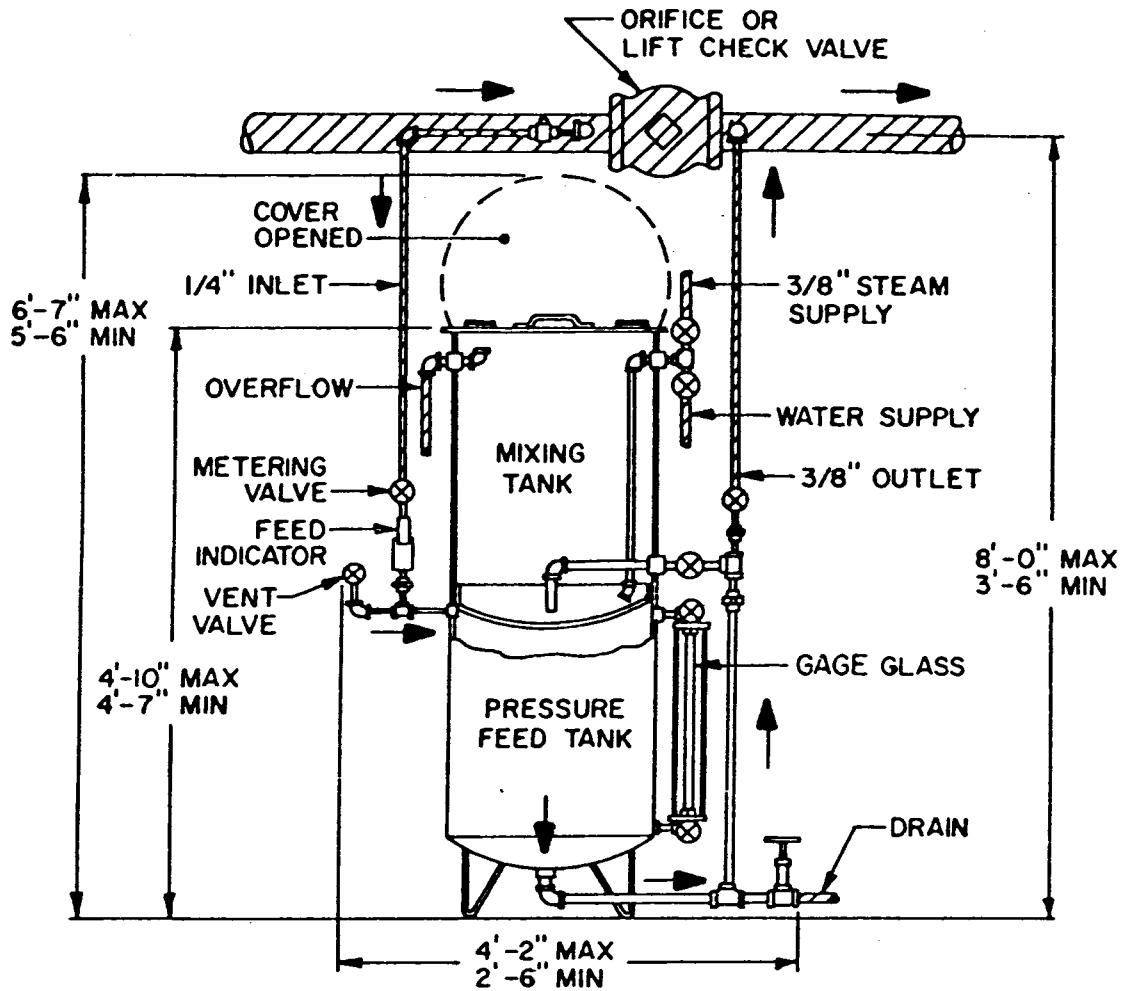
FIGURE 4-28. PRESSURE POT FEEDER

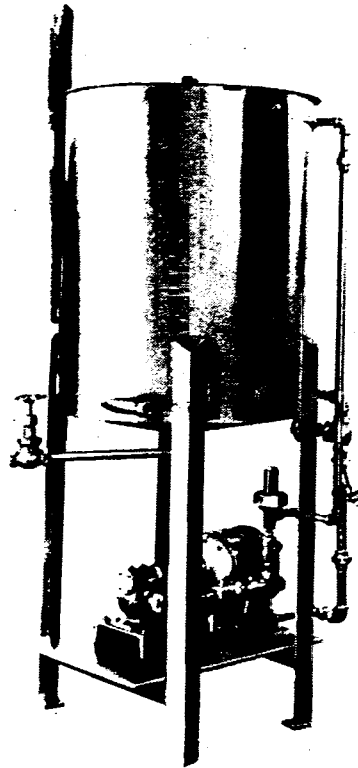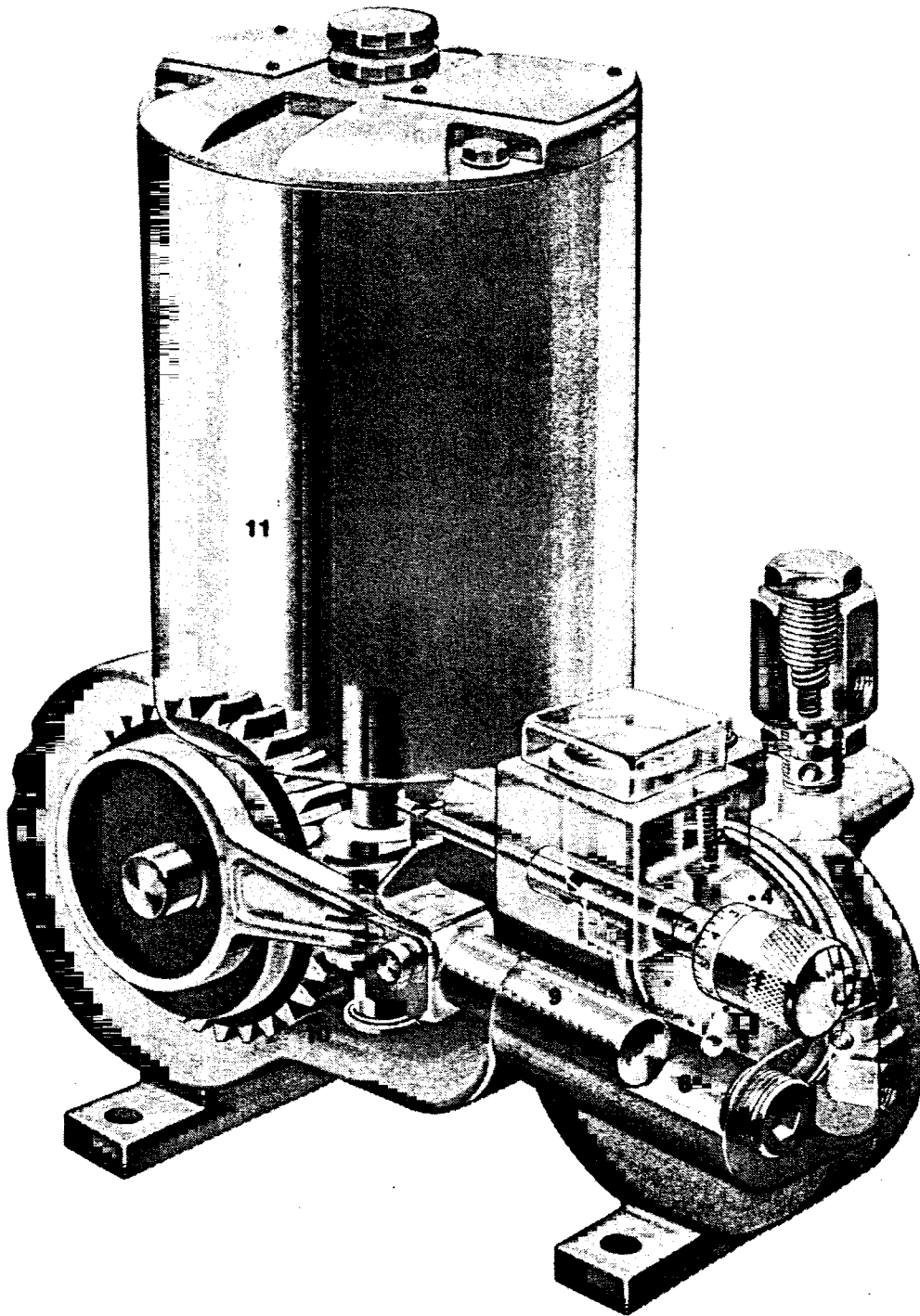FIGURE 4-29. AUTOMATIC PROPORTIONING FEEDER

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' 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 motor² 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
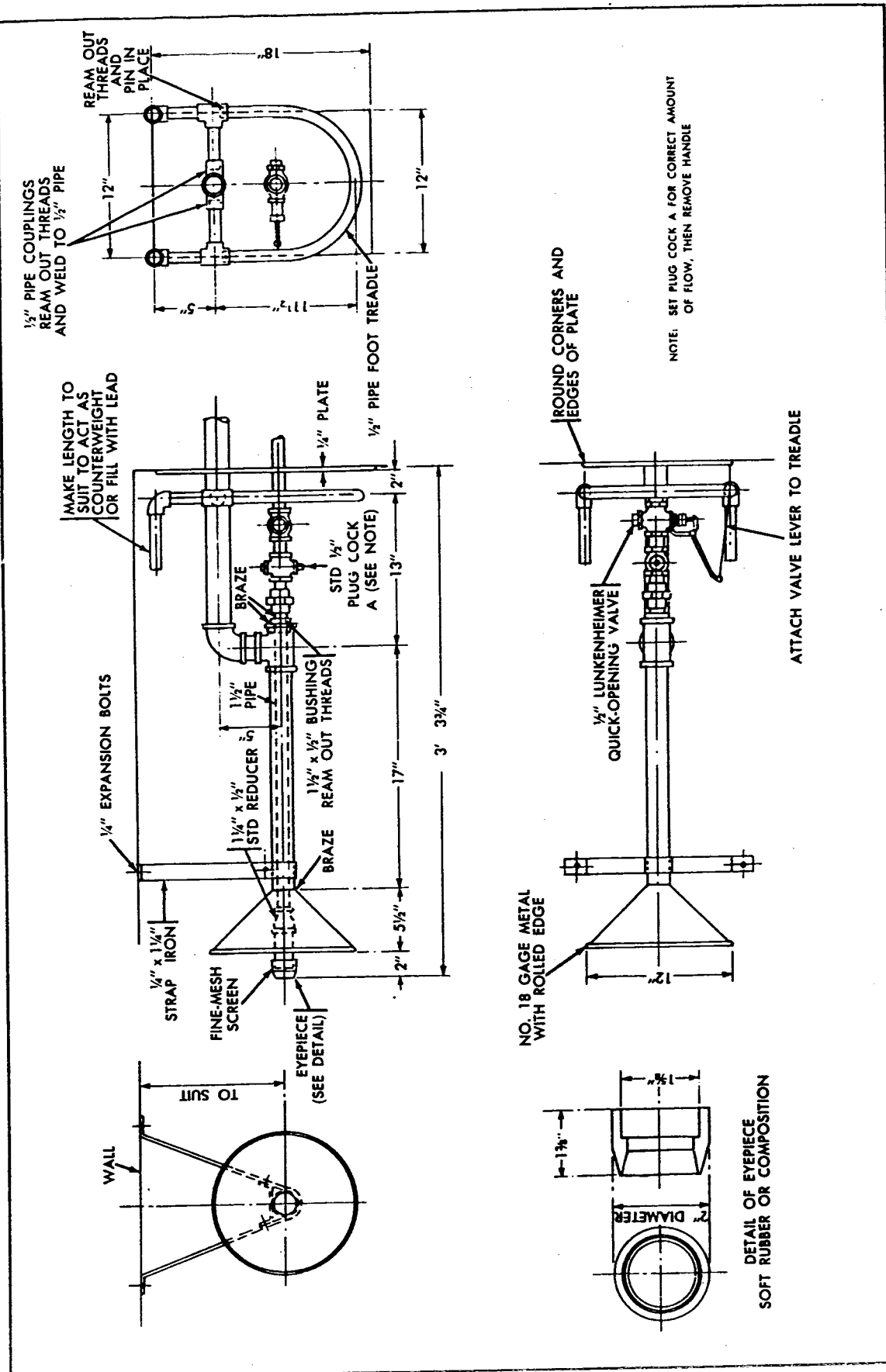
FIGURE 4-32. EYEWASH STATION

IF WATER PRESSURE IS NOT AVAILABLE, INSTALL A
SUPPLY TANK OF 100- TO 200-GALLON CAPACITY

PRESSURE WATER LINE

SHOWER SPRAY HEAD

QUICK-OPENING LEVER
VALVE HELD IN CLOSED
POSITION BY HEAVY
SPRING OR
COUNTERWEIGHT

7'6" APPROX

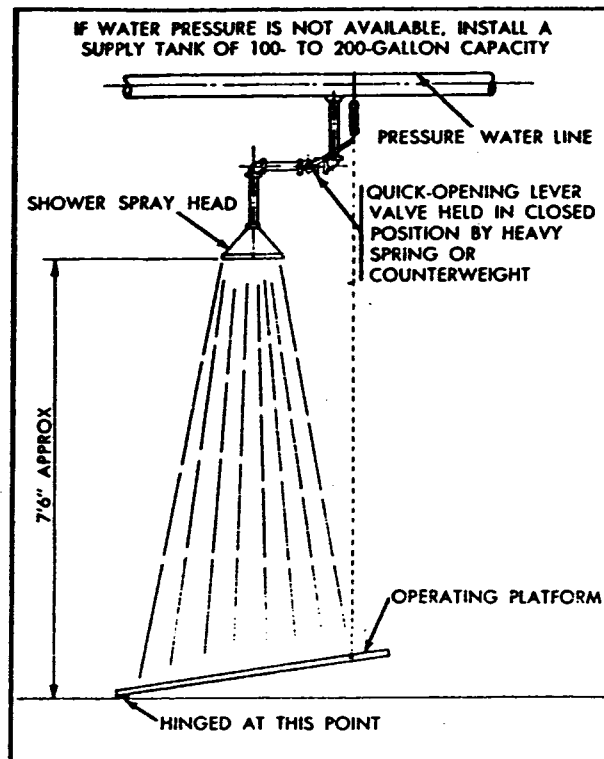OPERATING PLATFORM

HINGED AT THIS POINT

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.

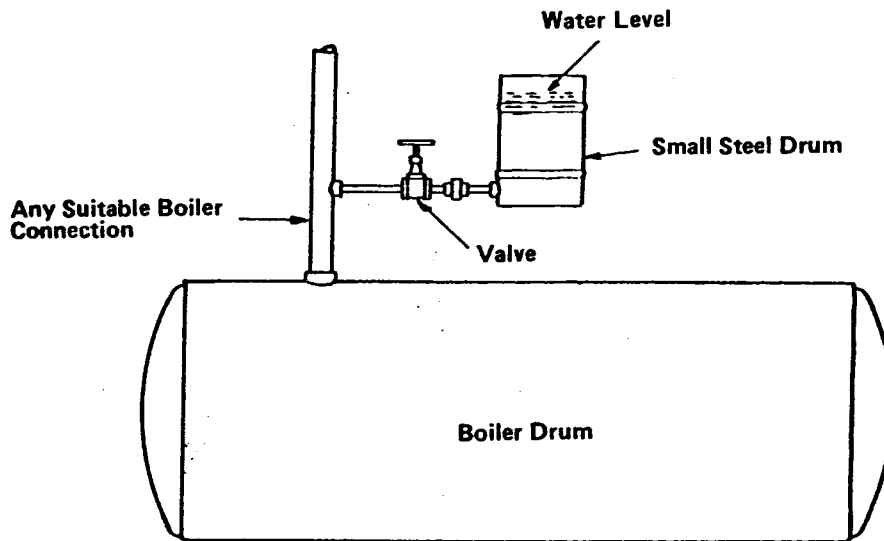(6) To resume operation, reopen the boiler, remove the trays of quicklime or silica-gel, reseal all drumheads and manholes, and replace all piping removed and blanked.

FIGURE 4-34. WET STORAGE METHOD