

Section I3

STEAM SYSTEMS

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INTRODUCTION

A steam system consists of a steam-supply/generating facility, a steam and condensate return/water piping system, and a steam-use facility (Figure I3-1). In this section, the discussion is focused on the integration of the various equipment within the steam-generating facility. Information is offered which need be considered when designing a steam-supply system. A general guideline is provided which identifies major issues to be addressed, leading to the evaluation of system solutions and ultimately to equipment considerations for selection and design. Finally, an example of an audit and system design are provided for demonstration purposes.

The reader is encouraged to review the specific product sections for additional information. The discussion in this section applies primarily to new systems and new boiler installations. When modifying existing systems, other considerations may apply.

THE STEAM-GENERATING FACILITY

The steam-generating facility, located in the boiler room, consists of boilers, feedwater systems, heat exchangers (e.g., economizers), boiler and system controls, fuel and gas handling equipment (e.g., fuel trains, stacks), and steam/water treatment equipment and piping (Figure I3-2). The purpose of the steam-generating facility is to provide energy (in the form of thermal energy of the steam) to drive other processes in the steam-use facility. In turn, typical steam-use facilities are designed to meet various industrial and commercial needs such as comfort heating, food processing, paper corrugation, etc.

Steam-generating facility design is unique to the specific application and it is dictated by good engineering practice, the ASME code, applicable national, state, provincial and local codes, and utility and insurance requirements. System design and selection depend on job specific operating requirements, boiler room structure and venting, fuel storage, and utility service considerations. There is therefore no simple mathematical expression to correlate steam boiler room design and application. However, there are several characteristics which help define the application and its relevant requirements. For a steam-generating facility, these characteristics include:

1. Type of Application/Load
2. Operating Conditions, Requirements and Constraints
3. Facility Requirements and Limitations
4. Codes and Standards
5. Other Federal, State, Provincial and Local Requirements

Many of these characteristics have been thoroughly discussed in other sections of The Boiler Book. The objective here is to

draw from that information in order to address design of integrated steam systems. Ultimately, the objective is to design a steam-generating facility which is economically optimal for the demands of the steam-use facility.

The following is a step-by-step procedure which assists in the design of steam-generating facilities for industrial and commercial use. These items are typically addressed during an application/energy-use audit of the facility.

Type of Application/Load

1. Categorize the application and load as heating/cooling, process or combination (see Section I1, System Load). There are a number of institutional applications which demand not only heating/cooling, but other steam or hot water requirements for the purpose of cooking, washing, etc. Generally speaking, these institutional loads are classified as heating applications since the requirement typically deals with heating and cooling of air and potable water.

At this juncture, a determination is made whether the boiler should be steam- or hot water-generating (see Section I1). For the remainder of this section, it is assumed that a steam-generating facility is appropriately chosen. (For more information on application considerations for hot water boilers and hot water systems, please refer to Section I2, Hot Water Systems.)

Operating Conditions, Requirements and Constraints

Steam

2. Determine the desired operating pressure. For existing steam-use facilities, the operating pressure has typically been set in the past and now acts as a constraint on the system design at hand. For new facilities, slightly more flexibility exists and yet operating characteristics of equipment in the steam-use facility either set or limit the range of operating pressure of the boiler.
3. Determine the steam load characteristics and ultimately the profile of the steam-use facility in its entirety (see Section I1). It is important to understand both the steady-state load profile as well as the transient and instantaneous demands.
4. Determine the desired or necessary steam quality (dryness) or degree of superheat. Steam quality ranges from 0 to 100% and is defined as the ratio of the amount of saturated steam vapor to the total steam amount (which may consist of both saturated steam vapor and liquid). A 100% steam quality translates to zero amount of saturated steam liquid and, in this condition, the steam is termed to be “dry.”

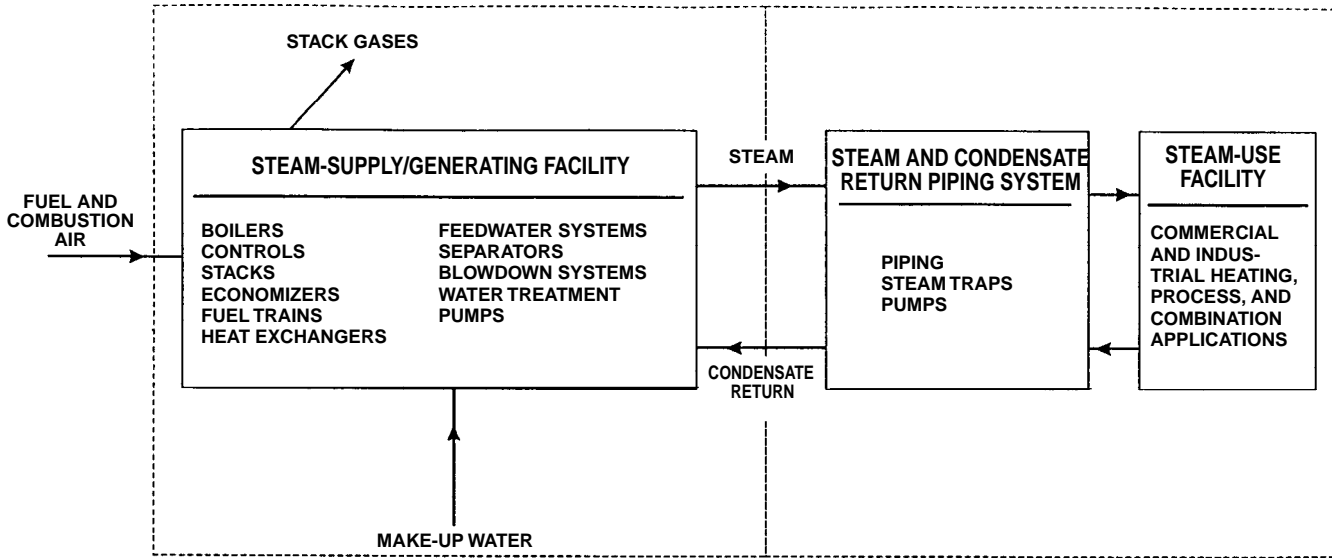


Figure I3-1. Typical Steam System

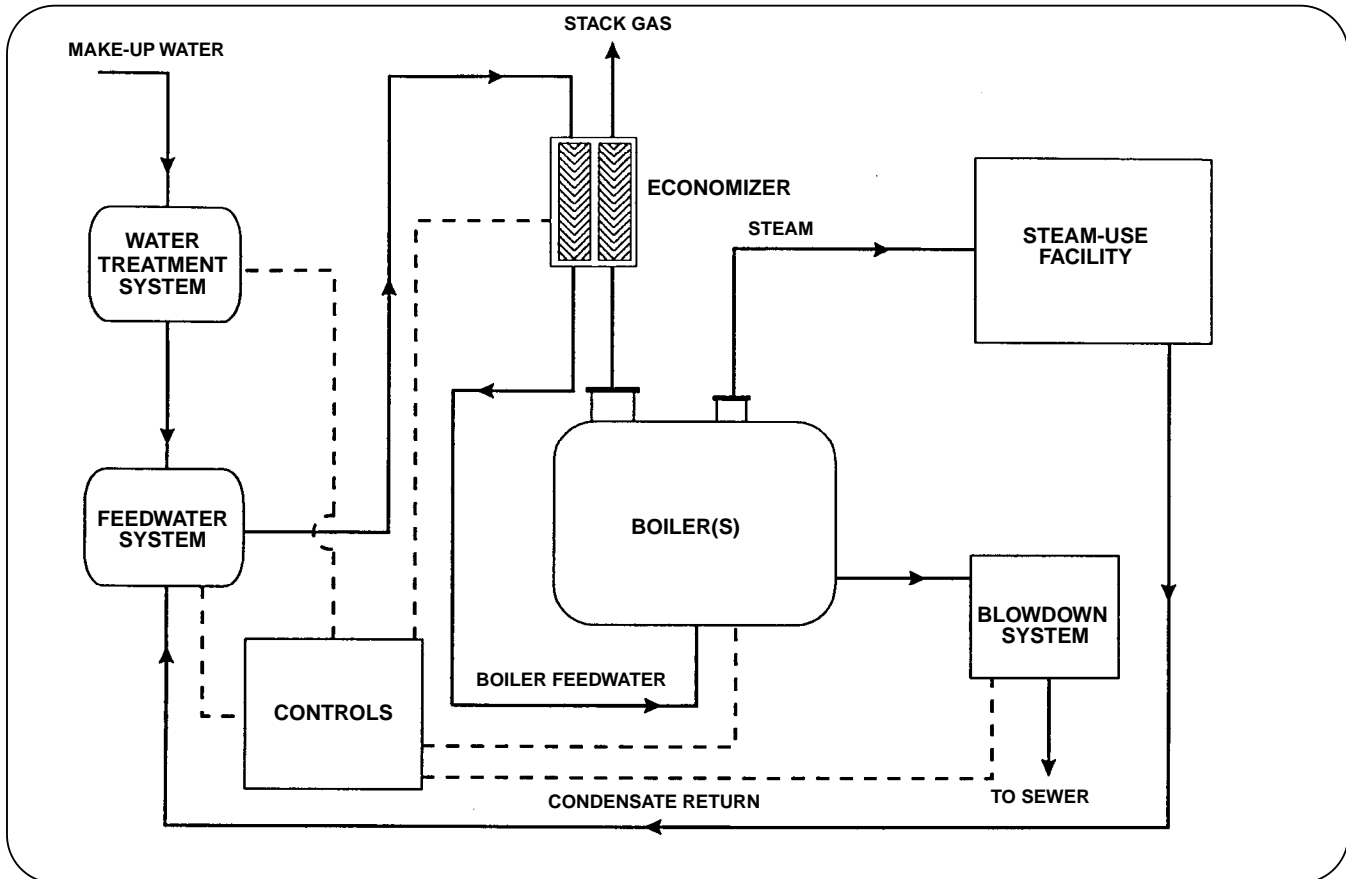


Figure I3-2. Schematic Diagram of a Generic Steam-Generating Facility

The degree of superheat refers to the amount of thermal energy (heat) added to the steam relative to the saturated steam vapor point of reference, typically expressed in units of degrees Fahrenheit. For example, a degree of superheat of 50 °F means that an additional amount of heat has been added to the steam so that the final steam temperature is 50 °F greater than the saturation temperature of the steam at the given operating pressure.

Condensate Return/Make-up Water

5. Determine the condensate return conditions, primarily focusing on temperature, pressure and flow rate (% return).
6. Calculate the make-up water requirement based on the % condensate return.
7. Determine the water charges for the specific facility under analysis.

Water Discharge

8. Determine the maximum temperature for water discharge, which is usually mandated by the local environmental governing authorities.
9. Determine the sewer charges for the specific facility under analysis.

Fuel

10. Determine the type(s) of fuel to be combusted within the boiler. Generally speaking, the fuels are limited to natural gas, propane, and fuel oil (although some other alternate fuels may be used).
11. Obtain a composition analysis for each fuel, which will be necessary for calculating fuel usage for a given load.
12. Determine the fuel costs; this is necessary for the economical optimization of boiler room design. For new boiler(s) installation into an existing system, a two-three year history of fuel billing data would be helpful in the eventual design of the steam-generating facility.

Combustion Air

13. Determine the ambient air conditions in the boiler area and determine current fresh air supply (e.g., louvre area). Primarily, the intention is to understand typical air temperatures and humidity and their variance during the necessary time of boiler operation.

Stack Gas

14. Determine any temperature limitations imposed on the stack gas.
15. Understand the local emission requirements, which will affect the allowable stack gas composition.

16. Determine the physical lengths and flow areas of stack/breeching, most importantly any constraints imposed in this area. These physical attributes will affect the stack gas pressure which can, in turn, have an impact on combustion characteristics and firing rates.

Electrical Power

17. Understand the electrical power overall demand and seasonal profiles.
18. Determine the electrical power costs for the facility. A review of 2-3 year historical data of electric power billing from the local power company will assist in this area. It is important to understand the demand charges separate from the actual electrical energy charges.

Facility Requirements and Limitations

19. In regard to boiler room design, understand the physical limitations of the facility. This understanding should include floor space or footprint for both installation and maintenance considerations as well as height limitations for equipment sizing.
20. Determine noise level requirements.

These twenty audit items are summarized in Figure I3-3.

Codes and Standards

Various Codes and Standards govern the design, fabrication and installation of many of the boiler room components. Of primary importance is the American Society of Mechanical Engineers' (ASME) Boiler and Pressure Vessel Code. The different sections of this Code specify the rules by which steam boilers, pressure vessels and connecting piping are to be designed, constructed and installed.

Section I of the ASME Code contains rules for Power Boilers which, for the case of steam boilers, are boilers designed for a maximum allowable operating pressure (MAWP) greater than 15 psig. Section IV of the ASME Code would provide rules for steam boilers with a MAWP of 15 psig or lower. B31.1 Power Piping Code provides rules for most of the piping systems involved in a typical steam plant, but has special significance relative to Section I in that it contains Certification and Stamping requirements for boiler external piping (BEP). BEP is defined as piping from the first circumferential joint leaving the boiler up to and including the required stop valve or valves. Most, if not all, of the piping included with a packaged boiler is within the scope of BEP. This generally includes steam, feedwater, blowdown, water column and instrument piping. Section VIII of the ASME Code contains rules for unfired pressure vessels, which may apply to deaerators, blowdown separators, etc.

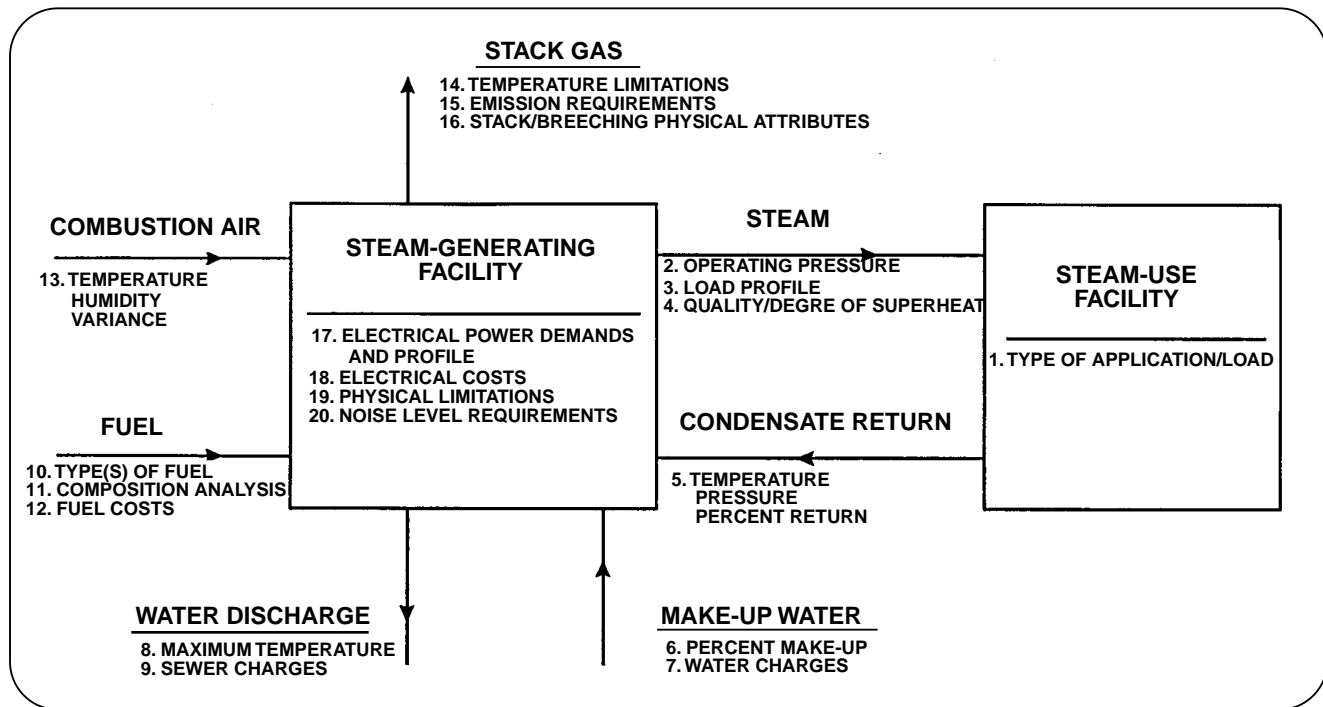


Figure I3-3. Summary of Application/Energy-Use Audit Items

Other Federal, State, Provincial and Local Requirements

There are many other Codes and Standards which apply to other aspects of the design and installation of steam room equipment. For a listing of standards organizations of relevance to the design of steam systems, please refer to Section I4. Local jurisdictions, insurance companies and individual contracts often impose special requirements above and beyond Code requirements, or may require compliance with special Codes and Standards. It is essential that those responsible for the planning of a boiler room installation be familiar with such requirements.

EQUIPMENT CONSIDERATIONS AND HARDWARE DESIGN

Having defined the application and obtained an understanding of the requirements and constraints of the steam system, it is now important to consider basic equipment needs and hardware design. Here the concern deals with potential equipment problems of the steam-generating facility in terms of performance and life. Specifically, the issues to be addressed when designing and integrating equipment into a workable system are: (1) equipment capacity, (2) operating characteristics and constraints of equipment, (3) maintenance issues and the tradeoff with design/initial cost, and (4) the operational effects of each piece of hardware on the overall system operation.

The following is a discussion concerning considerations given

to each subsection of the overall system, categorized as: steam boilers, boiler piping and valves, feedwater systems, water treatment systems, heat exchangers and economizers, and blowdown systems. Stacks and controls are not discussed since the intention here is to concentrate on the steam side of the system. For information concerning controls and stacks, please refer to sections D and F, respectively. Considerations concerning sizing of piping, steam traps, etc. are also not covered in this section; those items are considered as a part of the steam/condensate return handling and piping system design and many references concerning these issues are available.

Steam Boilers

The boiler selection process is based on an evaluation of the system and load requirements as described above, and a comparison with the different boiler types that are available. This section defines a process and the considerations that can be used to select a boiler for a steam system application, based on the requirements discussed in Section I1.

The steam-use facility will have certain operating requirements that are used to establish the boiler design pressure. For example, heating systems often operate at low pressure (a steam pressure of 8 - 10 psig), and would use a boiler that is designed for 15 psig. The boiler design pressure must be higher than the operating pressure, and is usually based on common design pressures. Steam quality, or the moisture content in the steam, may also be a requirement of the facility.

The first step in determining the required boiler size is to deter-

mine the number of boilers. Multiple boilers can be used to divide a seasonal load into more manageable segments, even using different boiler sizes to better match the load. Additional boilers can be used to provide backup and minimize potential down time. Hospitals usually require a substantial amount of backup capability. Increasing the number of boilers also adds to the initial cost, on-going maintenance costs and complexity of the system.

Once the number of boilers have been selected, the capacity of the boilers can be determined. This task should not be limited to matching the peak load and the total capacity of the boilers. For example, the base capacity or number of boilers should be increased if there can be a high instantaneous demand. Some consideration should also be given to how multiple boilers are cycled to minimize the cycling and number of units in use at any one time.

- Increasing the number of boilers will:
 - Minimize down time and maximize reliability.
 - Provide the highest efficiency by matching load to boiler capacity.
 - Increase the total installed cost of the boiler room.
 - Allow the use of smaller boilers and support components.
 - Increase maintenance cost.
 - Increase the size and complexity of the boiler room.
- Minimizing the number of boilers will:
 - Decrease total installed cost.
 - Reduce overall efficiency because of low-load operation.
 - Minimize maintenance costs.
 - Provide a less complex and smaller boiler room.
- Different sized boilers can be used for the large variation in seasonal loads.
- Total boiler capacity should include future expansion considerations.
- Emission regulations may require special controls above a certain total capacity.

At this stage of the selection process, some boiler types can be eliminated based on the operating pressure and capacity requirements. (Table II-1 in Section II can be used as a guide in this process). In addition, the load type may also impact the selection process. For example, watertube boilers are better suited to swing loads while firetube boilers are better for loads with upset conditions. Also, bent tube boilers can be used when quick warm up is required.

- Watertube boilers are the preferred choice for pressures above 350 psig.
- Higher turndown rates improve the boiler load response because the boiler remains on line at low loads.
- Bent tube and electric boilers can provide quick warm-up without thermal shock.
- Steam superheat is generally only available on the IWT boiler.

There are numerous regulatory requirements in the boiler industry. Many boilers are listed by Underwriters Laboratories or a similar agency, which has tested the product to ensure that it meets their minimum standards for safety and performance. Emission regulations have become more common in recent years. Finally, there may be other organizations that will mandate requirements for an installation, such as the city, state or insurance carrier. These requirements may prevent the use of some boiler types.

- Check insurance carrier for requirements.
- A “Package” listing helps insure boiler/burner compatibility.
- Construction and operating permits are usually required by local authorities.
- Federal NSPS regulations, permits and recording applies over 200 hp.

The final stage in the selection process will be the consideration of the operating features and efficiency of the boilers. Initial cost is always a factor, but it should not be the only factor. For example, the boiler efficiency, turndown and maintenance requirements can result in much higher or lower operating costs, and can easily change the cost analysis. Some common considerations that impact overall efficiency and fuel costs are:

- Multiple fuel capabilities, including future conversions.
- More flue gas passes in a firetube boiler will increase heat transfer.
- Heating surface area, usually 5 square feet per boiler hp in a firetube boiler.
- Higher turndown increases boiler efficiency and provides quicker load response.
- Lower excess air operation increases boiler efficiency.
- Economizers can be added to most boilers, which will increase efficiency.

Maintenance and down time can be important considerations in the boiler selection. Using multiple boilers helps reduce the potential for loss of steam generating capability.

- Higher turndown reduces component wear and failure due to on-off cycling.

- Critical operations should include controls to keep the standby boiler hot.
- Always use duplex pumps and filters to allow maintenance without shut down.
- Consider rental boilers as potential backup, and include required piping in the plant.
- Generally boilers with large water volumes and surface areas are more tolerant of feedwater treatment variations and load surges.

The moisture content in steam from a steam generator is normally very small. There are conditions that can upset the normal operation and result in some relatively high amounts of water carry-over. In addition, there are some applications which require extremely dry steam for proper operation. There are some guidelines for maintaining high quality steam, and methods to improve the steam quality.

Feedwater quality is the single most important element in steam quality. General feedwater guidelines are given in this book and others. Special considerations need to be given to the type of boiler. There may be additional requirements based on the boiler type and the conditions of the local water supply. A water specialist should be consulted for specific requirements of an installation.

The steam quality from a boiler can be improved by adding an external separator or an equalizing line similar to a “Hartford Loop.” Such special steam piping arrangements are sometimes used on low pressure steam boilers with small steam chambers.

The industrial watertube boiler offers some additional options for improving the steam quality. One option uses special drum components to further remove solids, resulting in higher steam quality. The other option is to add a superheater to provide superheated steam.

- Water maintenance programs can help insure reliable steam quality.
- Boiler concentrations may need to be adjusted for best steam quality.
- Special steam piping can be used with some boilers (such as the cast iron boiler) to reduce carry-over.
- An external separator will typically remove 90% of the moisture in a steam line.
- Superheated steam and special steam dryers are available on industrial watertube boilers.

Boiler Piping and Valves

This section contains information on boiler piping and valve requirements for low and high pressure boilers.

Relevant highlights of the ASME Code are included. However, for complete details, the reader should review the applicable section of the ASME Code. In addition to the ASME Code, the reader should determine whether there are any special, local insurance or regulatory requirements.

Low Pressure Boilers

The ASME Code contains many recommendations for low pressure steam systems. Here are excerpts that apply to design consideration.

Steam Line Expansion - “Provisions shall be made for the expansion and contraction of steam and hot water mains connected to boilers by providing substantial anchorage at suitable points, and by providing swing joints when boilers are installed in batteries, so there will be no undue strain transmitted to the boilers.” para. HG-703.1

Stop Valves for Single, Multiple, and Steam Boilers

Steam Boilers - “When a stop valve is used in the supply pipe connection of a single steam boiler, there shall be one used in the return pipe connection.” para. HG-710.1

Multiple Boiler Installations - “A stop valve shall be used in each supply and return pipe connection of two or more boilers connected to a common system.” para. HG-710.3

Shutoff Valves - “No shutoff of any description shall be placed between the safety relief valve and the boiler, nor on discharge pipes between such valves and the atmosphere.” para. HG-701.5

Safety and Safety Relief Valves - “Safety and safety relief valves shall not be connected to an internal pipe in the boiler.” para. HG-701.4

Safety Valve Discharge Piping - “A discharge pipe shall be used. Its internal cross-sectional area shall be not less than the full area of the valve outlet or of the total of the valve outlets discharging there into and shall be as short and straight as possible and so arranged as to avoid undue stress on the valve or valves. When an elbow is placed on a safety or safety-relief valve discharge pipe, it shall be located close to the valve outlet. The discharge from safety or safety-relief valves shall be so arranged that there will be no danger of scalding attendants.” Para. HG-701.6 Refer to [Figure I3-4](#).

Bottom Blowoff - “Each boiler shall have a bottom blowoff or drain pipe connection fitted with a valve or cock connected with the lowest water space practicable. The discharge piping shall be full size to the point of discharge.” para. HG-715

High Pressure Boilers

The ASME Code provides many recommendations for high pressure steam boilers. Here are some excerpts that apply to design considerations.

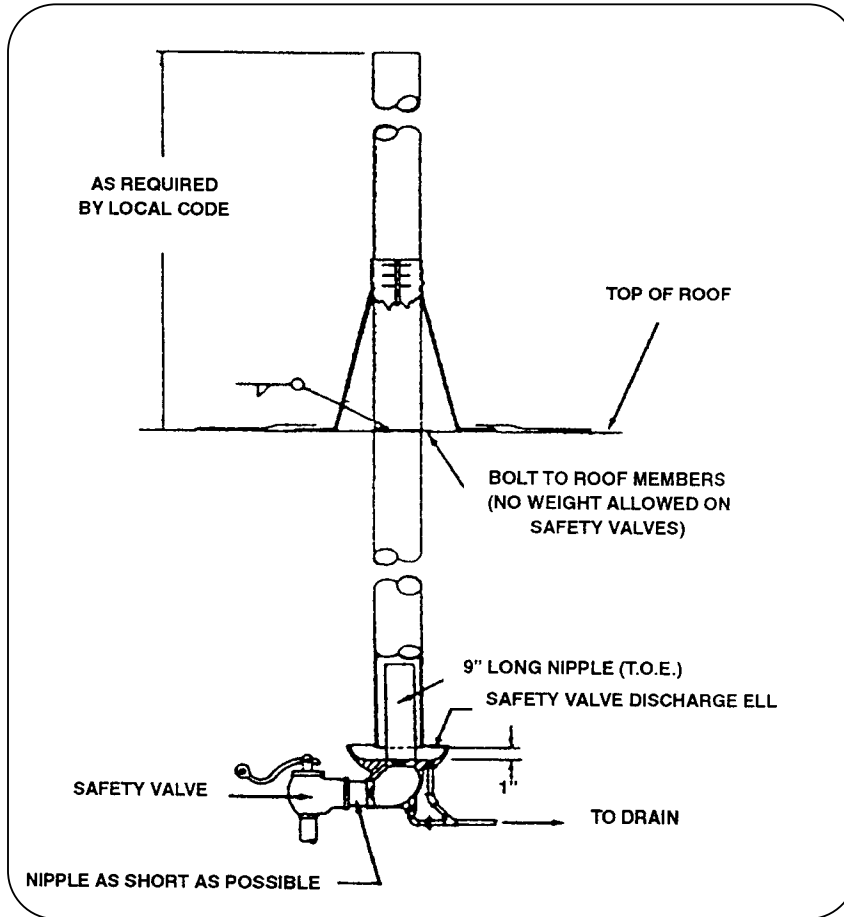


Figure I3-4. Recommended Safety Valve Discharge Piping

Steam Line Expansion - “Provisions shall be made for the expansion and contraction of steam mains connected to boilers, by providing substantial anchorage at suitable points, so that there shall be no undue strain transmitted to the boiler.” para. PG-59.1.2

Steam Stop Valves - “Each boiler discharge outlet, except safety valves or safety relief valves, or preheater inlet and outlet connections, shall be fitted with a stop valve located at an accessible point in the steam-delivery line and as near the boiler nozzle as is convenient and practicable. When such outlets are over NPS2, the valve or valves used on the connection shall be of the outside-screw-and-yoke rising-stem type so as to indicate from a distance, by the position of its stem whether it is closed or open, and the wheel may be carried either on the yoke or attached to the stem.” para. 122.1.7 (A.1) (ASME B31.1)

“When boilers are connected to a common header, the connection from each boiler having a manhole opening, shall be fitted with two stop valves having an ample free-blow drain between them. The discharge of this drain shall be visible to the operator while manipulating the valve. The stop valves shall consist

preferably of one automatic non-return valve (set next to the boiler) and a second valve of the outside-screw-and-yoke type or two valves of the outside-screw-and-yoke type shall be used.” Para. 122.1.7 (A.2) (ASME B31.1)

Stop-Check Valves (Non-Code Recommendations) - A problem confronting the power piping designer is the selection of the best size of stop check valve for his service conditions. This type valve usually has a floating disc member, hence it is important that the valve be sized to provide full disc lift under flow conditions prevailing during the major portion of the service life of the installation. If the valve is too large for flow conditions, the disc will float in a partially open position; this may result in fluttering of the disc and rapid wear of valve parts. Conversely, if the valve is too small for flow conditions encountered, pressure drop will be excessive.

Safety Valves - “No valve of any description shall be placed between the required safety valve or valves and the boiler, nor the discharge pipe between the safety valve and the atmosphere. When a discharge pipe is used, the cross-sectional area shall be not less than the full area of the valve outlet or the total

of the areas of the valve outlets discharging there into and shall be as short and straight as possible and so arranged as to avoid undue stresses on the valve or valves. All safety valve or relief valve discharges shall be so located or piped as to be carried clear from running boards or platforms. Ample provision for gravity drain shall be made in the discharge pipe at or near each safety valve or safety relief valve, and where water of condensation may collect. Each valve shall have an opening gravity drain through the casing below the level of the valve seat. For iron-and-steel bodied valves exceeding 2-1/2 inch size, the drain hole shall be tapped not less than 3/8 inch pipe size." Para PG-71.3 Refer to Figure I3-4, Recommended Safety Valve Discharge Piping.

Safety Valve Mounting - "When a boiler is fitted with two or more safety valves or safety relief valves on one connection, this connection to the boiler shall have a cross-sectional area not less than the combined area of inlet connections of all the safety valves with which it connects and shall also meet the requirements of Paragraph PG-71.3." Para. PG-71.5

Blowoff Valves - The blowoff valve or valves, the pipe between them, and the boiler connection shall be of the same size except that a larger pipe for the return of condensate may be used.

For all boilers . . . with allowable working pressure in excess of 100 psig, each bottom blowoff pipe shall have two slow-opening valves, or one quick-opening valve or cock; at the boiler nozzle followed by a slow-opening valve. A slow-opening valve is a valve which requires at least five 360 degree turns of the operating mechanism from fully closed to fully opened. On a boiler having multiple blowoff pipes, a single master valve may be placed on the common blowoff pipe from the boilers, in which case only one valve on each individual blowoff is required. In such a case, either the master valve or the individual valves or cocks shall be of the slow-opening type. Para. 122.1.7 (ASME B31.1)

Feedwater Valves - "The feedwater piping for all [steam] boilers . . . shall be provided with a check valve . . . between the check valve and the boiler." Para 122.1 (B1) (ASME B31.1)

"When two or more boilers are fed from a common source, there shall also be a globe or regulating valve in the branch to each boiler located between the check valve and the source of supply." Para. 122.1.7 (B.5) (ASME B31.1)

Boiler Feed Systems

The transfer of heat from steam, regardless of process usage, will create condensate. The quantity of collectable condensate varies with the type of application. For instance, with humidification, the steam is released to the environment and the condensate is considered uncollectible. In industrial applications, condensate can typically be collected in large quantity.

An important factor in the condensate return and water make-up system is to ensure that contaminated condensate does not return to the boiler room and its associated equipment. Condensate contaminated with oil, dye, soap, etc. must be disposed of in a safe manner. Contaminated condensate will cause problems such as foaming, priming, unstable water level, and it will increase blowdown requirements.

The collection of clean steam condensate is desirable for several economic reasons. Condensate generally is capable of being collected at temperatures higher than the temperature of raw water make-up. This results in significant fuel cost savings and improved overall system efficiency. Since condensate is formed from steam, it contains little or no dissolved solids. Therefore, using collected condensate reduces chemical usage and associated costs as well.

Additionally, the cost of raw water make-up will be reduced by collecting condensate because the demand for raw water is limited. When considering installation costs, the expected condensate return may allow for down-sizing of the raw water make-up supply system and other components.

Unfortunately, condensate flow from the system may be unpredictable. Unpredictability of returning condensate causes a problem for the boiler, since it should have a continuous and immediately available supply of water. However, there are several ways to collect and store condensate so it is readily available.

A collection or storage tank can be incorporated to act as a reservoir. Products which serve this purpose include boiler feedwater systems, surge tanks, and deaerators.

The function of these products in the overall condensate return and raw water make-up system is as follows. For further information on this equipment, refer to the specific product sections in The Boiler Book.

Boiler Feed System

Boiler feedwater systems help maintain maximum efficiency and prolong the life of the boiler, when investment in a deaerator cannot be justified. Consisting of one or more feed pumps and a corrosion resistant receiver tank, the system automatically supplements condensate with make-up water to replace system losses. When equipped with an automatic preheater, feedwater temperatures can be maintained at temperatures up to 210 °F (maximum). At this temperature, substantial amounts of oxygen and carbon dioxide are released, reducing the amount of chemicals required to protect the boiler and system from corrosion. Preheating is recommended if the return condensate constitutes 50% or less of the required feedwater.

Boiler feed systems typically combine one or more boiler feed pumps with a tank to store condensate and make-up water. These components are typically furnished as a complete package with level, temperature, and pressure controls. Additional

features such as deaeration hardware and more sophisticated controls may be considered.

The purpose of the boiler feed system is to provide a reservoir with sufficient surge capacity to accommodate intermittent condensate flowrates, and to provide stable suction conditions for the boiler feed pump(s). The selection of a boiler feedwater system is primarily driven by surge capacity. For this reason, it is necessary to accurately estimate peak condensate flowrates from the steam-use facility, considering also factors due to transient conditions such as equipment startups, piping hydraulics, and system interactions. Once this information is obtained and understood, a boiler feed tank of sufficient size may be selected.

The operating characteristics of the boiler and steam-generating system have an impact on the type of controls and features included in the boiler feed system. In particular, those factors influencing pump selection will also have an effect on the height of the boiler feedwater system, the level control system, and suction piping design. The characteristics of the returning condensate should also be considered when selecting feedwater system components, corrosion resistant linings, and pressure/temperature controls.

There are many cost/benefit tradeoffs available when configuring a boiler feed system. A partial list includes:

- **Feedwater Preheat** reduces thermal shock.
- **Premium Lining/Galvanizing** reduces corrosion.
- **Premium Level Control** reduces overflow losses.
- **Code Rated Pressure Tank** reduces flash steam losses.
- **Deaeration Hardware** reduces corrosion and thermal shock.

Each of these options has a direct benefit on the long-term operating costs of the system. Their increased initial costs must be balanced against the overall capital cost and the expected life of the system. For more information on boiler feed systems, please refer to Section H5.

Surge Tanks (Condensate Receiver Tanks)

Surge tanks can greatly reduce dependence on cold, untreated raw water to replace boiler system losses by collecting condensate by gravity return for re-use in the boiler feed system. Surge tanks are required when no other storage exists or when intermittent peak loads of condensate can exceed the storage capacity of the deaerator. Integrated control automatically introduces makeup water to supplement condensate only when necessary to meet boiler demand. Refer to [Section H4](#) for more detailed information.

Deaerators

Deaeration is widely recognized as the most acceptable method for removing oxygen and carbon dioxide from makeup

water and condensate. Without deaeration, the dissolved gases can cause serious corrosion in the boiler and other system hardware.

Deaerators are considered essential for:

- All boiler plants operating at 75 psig or more.
- All boiler plants with little or no standby capacity.
- All boiler plants where production depends on continuous operation.
- All boiler plants operating with makeup water of 25% or more.

In addition to removing oxygen and carbon dioxide, deaerators also heat boiler feedwater. The large storage capacity provides an effective means for recovering heat from exhaust steam and hot condensate. With a deaerator, further savings result from the reduced need for oxygen-scavenging chemical treatment. For further information, refer to [Sections H1, H2, and H3](#).

Pumps

There are five design criteria that must be considered before the proper boiler feed pump can be selected.

1. Will the pump run continuously or intermittently?
2. What is the temperature of the water being pumped?
3. What is the pump capacity requirement in gpm?
4. What is the pump discharge pressure requirement?
5. What is the NPSH (net positive suction head) required?

Continuous or Intermittent Operation - Continuous or intermittent operation of a pump is determined by the critical nature of the desired water level control. The water level control requirements are primarily based on the type of boiler, but are also affected by the load, operating pressure, and feed water temperature. Continuous operation provides better water level control, but adds cost and components to the system.

Boiler types with a relatively low water volume, such as watertube boilers, require more precise water level control than boiler types with a large water volume, such as firetubes. This is due to the relationship between drum (vessel) size and gallons of water content. For example, a fifty gallon change in a watertube boiler might represent a one inch change in water level, while the same fifty gallon change in a firetube boiler might only represent a fraction of an inch change in water level.

Frequent load swings will require more accurate water level control to ensure the feedwater flow matches the steam flow requirement. Frequent load swings may require continuous feedwater control to maintain proper water level.

The relationship between operating pressure and feedwater temperature can make water level control more critical if the

temperatures vary or if there is a large differential between saturation temperature and feed water temperature. Large temperature differentials could result in a reduction in boiler water level when feed water is added. The reduction is caused by a quenching effect, which lowers the boiler water temperature slightly, reducing the steam/water volume, thereby lowering the water level. This type of water level reduction is generally more common on smaller, low pressure boilers.

Selection of Pump Type (Centrifugal or Turbine) - Once the criteria for water level control is determined, the type of feed pump can be selected.

Highly accurate water level control can be achieved with a centrifugal type pump, running continuously, in conjunction with a modulating feed water valve on the boiler.

An effective but less precise means of water level control can be provided using a turbine type pump, with intermittent (on-off) operation. With intermittent operation, larger swings in water level control will result.

Although not common, turbine pumps have been used in conjunction with a modulating feedwater valve to provide water level control. In this application, a relief device must be included to discharge water back to the feedwater tank to protect the pump from dead head pressures. Dead head pressures can cause overheating, cavitation, and subsequent pump damage. A concern of this design is the use of a relief device as a control valve, and the inherent performance and reliability factors.

Pump Water Temperature - The temperature of the pumped water must be specified to ensure proper design and construction. Pumps use packing or mechanical seals to seal the area between the pump shaft and the pump casing. These seals have temperature limitations and, if misapplied, the seals will fail. Standard pump seals are adequate up to temperatures of approximately 215 °F. Higher temperature seals are available for temperatures up to 250 °F and, for temperatures above 250 °F, external water cooling is usually employed to protect the seals. For applications above 250 °F, contact your local Cleaver-Brooks authorized representative.

Pump Capacity Requirements - Determining pumping capacity requirements involves slightly different criteria for centrifugal and turbine type pumps. For both pump types, the maximum boiler capacity must be determined. The maximum boiler capacity, or evaporation rate, is usually calculated in pounds of steam per hour, and should be converted to gallons per minute, and have blowdown added to it for pump selection purposes. For assistance in this calculation, contact your local Cleaver-Brooks authorized representative.

The pump capacity for turbine pumps, with intermittent operation, should be equal to 2 times the maximum evaporation rate of the boiler.

The pump capacity for centrifugal pumps, with continuous operation, is equal to: evaporation rate times 1.15 (safety fac-

tor), plus by-pass flow requirement (in gpm) for the pump. The by-pass flow is usually regulated through a fixed orifice, and is of sufficient quantity to prevent cavitation within the pump under dead head conditions. The by-pass orifice must be located between the pump discharge and the modulating feedwater valve to allow water to recirculate back to the storage tank.

Pump Discharge Pressure Requirements - Pump discharge pressure requirements are calculated by determining the boiler operating pressure and calculating the line losses between the pump and the boiler. The pump discharge pressure needs to overcome the piping line losses, and boiler pressure in order to get water into the boiler.

All calculations need to be converted to feet of head for pump selection purposes. Therefore, convert boiler operating pressure to feet of head, and add to that value the equivalent length (in feet of head) of the piping and associated valves between the pump discharge and the boiler.

Net Positive Suction Head (NPSH) - Every pump design has a certain requirement for net positive suction head. This is the amount of liquid in feet that must be above the pump suction centerline in order to prevent cavitation and to provide proper pump operation.

Net positive suction head required (NPSH-R) by the pump must be exceeded by the net positive suction head available (NPSH-A) from the system.

Calculation: $NPSH-A = HP + HZ - HF - HVP$

NPSH-A - Available NPSH expressed in feet of fluid.

HP - Absolute pressure on the surface of the liquid at the pump suction location, expressed in feet. This could be atmospheric pressure or vessel pressure (pressurized tank).

HZ - Static elevation of the liquid above, or below the centerline of the impeller, expressed in feet.

HF - Friction and entrance head loss in the suction piping, expressed in feet.

HVP - Absolute vapor pressure of the fluid at the pumping temperature, expressed in feet.

Cleaver-Brooks makes selections that are based on pumps having the lowest possible NPSH-R. This is done to provide the lowest stand height and the lowest overall height of the tank. There are some sacrifices which must be accepted in order to have low NPSH-R. Usually a selection with a low NPSH-R is a pump that is larger and usually requires a greater horsepower drive. Generally speaking, however, it is more important to keep the overall height to a minimum than to select a pump with a higher NPSH-R.

Pumps (General) - The design criteria for transfer pumps (pumps which pump water to a deaerator) is the same as the criteria just covered for boiler feed pumps.

Cleaver-Brooks and our authorized representatives provide a full line of pumps, and pump selection services for application in both steam and hot water systems. For assistance, contact your local Cleaver-Brooks authorized representative.

Water Treatment Systems

General - Harmful elements are contained in surface and well water. Surface and well water are also called “raw water.” A sample of the raw water should be analyzed early in the equipment planning stage. The analysis provides a clear definition of the particular threats posed by the water source. Your Cleaver-Brooks representative can assist you in defining the harmful elements, and can help in planning a water treatment program and in selecting the proper treatment equipment.

The following is a discussion of the elements commonly found in raw water.

Surface water usually has high suspended solids and dissolved gases and low dissolved solids. Well water normally has high dissolved solids and low suspended solids and dissolved gases.

Suspended solids represent the undissolved matter in water, including dirt, silt, biological growth, vegetation, and insoluble organic matter.

When minerals dissolve in water, ions are formed. The sum of all minerals or ions in the water is the total dissolved solids or TDS.

Iron can be soluble or insoluble. Insoluble iron can clog valves and strainers and can cause excessive sludge build up in low lying areas of a water system. It also leads to boiler deposits that can cause tube failures. Soluble iron can interfere in many processes, such as printing or the dyeing of cloth. In domestic water systems, porcelain fixtures can be stained by as little as 0.25 ppm of iron.

Water hardness is the measure of calcium and magnesium content as calcium carbonate equivalents. Water hardness is the primary source of scale in boiler equipment.

Silica in boiler feedwater can also cause hard dense scale with a high resistance to heat transfer.

Alkalinity is a measure of the capacity of water to neutralize strong acid. In natural waters, the capacity is attributable to bases, such as bicarbonates, carbonates, and hydroxides; as well as silicates, borates, ammonia, phosphates, and organic bases. These bases, especially bicarbonates and carbonates, break down to form carbon dioxide in steam, which is a major factor in the corrosion of condensate lines. Alkalinity also contributes to foaming and carryover in boilers.

pH is a measure of the degree of acid or base of a solution. The pH scale is from 0 to 14, with 0 being the most acidic and 14 being the most basic or alkaline.

Dissolved oxygen is the amount of oxygen gas dissolved in the raw water and is caused by the solubility of atmospheric oxy-

gen. Dissolved oxygen is not related to the combined oxygen contained in the water molecule H₂O. All surface and rain water contain dissolved oxygen, because of their contact with the atmosphere. With enough contact, the dissolved oxygen content will reach saturation for the corresponding temperature. The solubility of oxygen is affected by solid content. Water with a higher solid content will contain less oxygen than distilled water. Surface water usually contains more oxygen than well water. As the raw water temperature rises, dissolved oxygen is released and can cause corrosion of iron and steel. Therefore, the problem caused by dissolved oxygen in boiler systems is corrosion in the boiler feedwater piping, economizer, boiler, and steam and condensate return piping.

Hence, the generation of steam from naturally occurring water sources can be complicated by the presence of various chemical constituents in the water supply. The American Society of Mechanical Engineers has published guidelines on boiler water and boiler feedwater quality for steam boilers. Most boiler installations will require some form of water treatment in order to conform to these guidelines. A few methods of treatment are depicted in [Tables I3-1](#) and [I3-2](#).

The Objectives of Feedwater Treatment

Proper boiler feedwater treatment is an absolute necessity! Unless the boiler receives water of proper quality, the boiler's life will be shortened. The water supply for a steam system may originate from rivers, ponds, underground wells, etc. Each water supply source requires a specific analysis. Depending upon the analysis, various pretreatment methods may be employed to prepare make-up water for the boiler feedwater system.

The objectives of boiler water treatment in general are as follows:

1. Prevent hard scale deposits or soft sludge type deposits which would, if present, impair the rate of heat transfer and possibly result in overheating and damage to the pressure vessel.
2. Prevent general corrosion or pitting to assure maximum life of the boiler at the lowest maintenance cost.
3. Prevent intercrystalline cracking or caustic embrittlement of boiler metal.
4. Prevent carryover to assure high quality steam at an economical rate of continuous and intermittent blowdown.

The accomplishment of these objectives will, in all cases, involve several forms of treatment including:

- Pretreatment of the make-up water before it enters the boiler feedwater system.
- Chemical treatment of the boiler water internally in the boiler.

Table I3-1. Removal of Harmful Elements with Various Types of Equipment

| DISSOLVED CONSTITUENT | SOFTENER | CLORIDE CYCLE DEALKALIZER | FILTERS | DEAERATORS |
|--|-----------------|---------------------------|--------------------|------------------------------------|
| Calcium Ca ^B | 98-100% | Must have soft water | No Change | No Change |
| Magnesium Mg ^B | 98-100% | Must have soft water | No Change | No Change |
| Hardness ^A | 98-100% | Must have soft water | No Change | No Change |
| Sodium Na | Increases | No Change | No Change | No Change |
| Bicarbonate Alkalinity HCO ₃ ^A | No Change | 90% | No Change | No Change |
| Sulfate SO ₄ | No Change | 90-95% | No Change | No Change |
| Chloride Cl | No Change | Increases | No Change | No Change |
| Silica SiO ₂ ^A | No Change | 20% | No Change | No Change |
| Soluble Iron Fe | 100% | Must have soft water | No Change | No Change |
| Total Dissolved Solids ^A | No Change | No Change | No Change | No Change |
| Suspended Solids ^A | Must Be Removed | Must be removed | Down to 10 Micron | No Change |
| Dissolved Gases ^A | No Change | Free CO ₂ Only | See Filter Section | To .005 cc/liter of O ₂ |

NOTE: All of the above packaged water systems can be readily integrated into existing Cleaver-Brooks boiler rooms. All are designed to accommodate boilers of any make.

A. Specifically limited by ASME guidelines on boiler feedwater quality.

B. The sum of calcium and magnesium equal the hardness. Hardness has been listed as a separate item for those analyses showing hardness only.

Table I3-2. Makeup Water Impurities, Limits and Treatment Methods

| MAKE-UP WATER TEST | TYPICAL IMPURITIES | TYPICAL LIMITS | TREATMENT METHOD |
|--------------------|--------------------|----------------------------|----------------------|
| Oxygen | 6 ppm | <.007 ppm ^A | Deaeration/Chemical |
| Hardness | 86 ppm | <1.0 ppm ^A | Softener |
| Suspended Matter | 0.1 ppm | 0.15 ppm ^A | Blowdown |
| pH | 6.87 | 7.0-10.5 ^A | Chemical |
| Silica | 10 ppm | <150 ppm ^B | Blowdown |
| Alkalinity | 100 ppm | <700 ppm ^B | Blowdown/Dealkalizer |
| Dissolved Solids | 500 µ-mho/cm | <7000 µmho/cm ^B | Blowdown |

A. Limits for feedwater.

B. Limits of boiler.

In addition, the selection of pretreatment methods will depend upon the chemistry of the raw water and the plant operating characteristics. In most cases, pretreatment becomes more critical as the percentage of make-up to the system increases.

Raw Water Make-up

Impurities in raw water make-up can be removed and controlled either chemically or mechanically with various equipment. Mechanical means of removing or controlling impurities will result in less chemicals being added to the boiler and system. However, mechanical means will not remove or control all impurities. Chemicals will still be required to provide the desired results.

The following are descriptions of feedwater pretreatment equipment and a discussion of their functions in the overall feedwater pretreatment cycle. For further information on equipment, refer to the specific product sections.

Filters

The need for special filter equipment to remove impurities can be readily determined by a raw water analysis. Filters should be considered in order to remove sand, iron, chlorine, and some dissolved organics and sediments. Refer to [Section H7](#).

Water Softeners

Water softeners should be used whenever raw water hardness exceeds 5 ppm. A softener removes calcium and magnesium and exchanges them with highly soluble sodium ions. Removing hardness prevents scale buildup on heat transfer surfaces and helps maintain peak boiler efficiency. A water softener also is the base for many sophisticated pretreatment processes that require the control of water hardness for proper operation. Refer to [Section H8](#).

Dealkalizers

Dealkalizers use softened water and remove negatively charged ions of bicarbonate, carbonate, sulfate nitrate, and silica. They are replaced with chloride ions. Removal of bicarbonate alkalinity controls formation of carbon dioxide and reduces the corrosion of condensate piping. Dealkalization reduces the need for neutralizing chemicals by as much as 90% and cuts fuel costs by minimizing blowdown. Refer to [Section H9](#).

Chemical Feed Systems

Chemical feed systems treat feedwater, boiler water, and condition blowdown sludge where an additional measure of protection against corrosion and scaling is required. Refer to [Section H6](#).

In summary, the benefits of water treatment equipment include improved boiler efficiency, corrosion reduction and therefore component life, and improved steam purity. The selection and sizing of water treatment equipment is dictated by the capacity of the steam system, the chemical constituents in the make-up water supply, and the operating characteristics of the overall system. Generally speaking, the greater the treatment load (in units of lb/hr removal), the larger the equipment. It is important when designing a water treatment system that a detailed water analysis be available as a guide.

The design of the water treatment system is influenced by cost/benefit tradeoffs in equipment selection. These influences may include:

- **Chemical Feed Systems** which have low initial costs, but significant operating costs.
- **Component Duplexing** which tends to ensure uninterrupted operation.
- **Chloride Cycle Dealkalizers** which reduce blowdown losses.
- **Filters** which also reduce blowdown losses and maintenance.
- **Skid Mounting** which decreases installation costs.
- **Premium Regeneration Controls** which may decrease operating costs.

These equipment selection economic tradeoffs are influenced by size, criticality, and operating environment of the steam system.

Economizers

During boiler operation in typical commercial and industrial applications, approximately 10-20% of the heating value of fuel is expelled with the stack gases to the atmosphere. Stack economizers are designed to recover significant amounts of this stack gas energy loss, thereby vastly improving boiler system efficiency, as shown in [Section G](#), Tables G-5 and G-6.

There are several considerations when selecting an economizer:

- **Gas-side Pressure Drop.** Added back-pressure on the boiler stack affects the combustion air fan throughput capability. The economizer and combustion air fan(s) must be sized properly in order to assure a suitable system operation and capacity.
- **Feedwater Temperature.** The feedwater to the economizer must be deaerated and the temperature setpoint minimally at 220°F to prevent tube corrosion.
- **Water-side Pressure Drop.** Feedwater pumps must be sized to accommodate the economizer pressure drop. Additionally, a continuous modulating feedwater system is required to ensure proper flow rates through the economizer.

A full product line description of Cleaver-Brooks Boilermate Economizers, including sizing and performance information, is offered in [Section G](#).

Blowdown Systems

A number of factors determine the need for boiler blowdown. As mentioned earlier, the amount of total dissolved solids (TDS) is one. The American Boiler Manufacturers Association (ABMA) has developed recommended limits for total and suspended solids for different boiler operating pressures. Refer to [Table I3-3](#) for recommended limits for total and suspended solids.

Other controlling factors for determining blowdown requirements are alkalinity, suspended solids, and other chemical factors. In boilers operating over 600 psig, silica content could be the limiting factor.

Solids are brought into the boiler by the feedwater. Even though the water is treated, either mechanically or chemically, neither means of treatment is capable of removing all substances. A small amount of crystallized solids will be present in the boiler water, which can tend to encrust surfaces.

That is, solids become less soluble in the high temperature of the boiler water and tend to crystallize and concentrate on heat-

Table I3-3. Recommended Limits for Total Suspended Solids

| OPERATING PRESSURE PSIG | TOTAL SOLIDS PPM | SUSPENDED SOLIDS PPM |
|-------------------------|------------------|----------------------|
| 0-300 | 3500 | 300 |
| 301-450 | 3000 | 250 |
| 451-600 | 2500 | 150 |
| 601-750 | 2000 | 100 |
| 751-900 | 1500 | 60 |
| 901-1000 | 1250 | 40 |

ing surfaces. Internal chemical treatment is therefore required in order to keep harmful scale and sludge from forming.

Scale has a low heat transfer value and acts as an insulating barrier. Insulation retards heat transfer, which not only results in lower operating efficiency but, more importantly, can cause overheating of boiler metal. Overheating of boiler metal results in tube failure or other pressure vessel metal damage.

Scale is caused primarily by calcium and magnesium salts, silica, and oil. Any calcium and magnesium salts, along with organic materials in the boiler water, are generally precipitated by the use of sodium phosphate in order to maintain these precipitates or “sludge” in a fluid form.

Solids, such as sodium salts and suspended dirt, do not readily form scale. However, as boiler water boils, forming relatively pure steam, the remaining water becomes increasingly thicker with solids. If the concentration is permitted to accumulate, foaming and priming will occur and the sludge can cause harmful deposits that potentially result in overheating of the metal. Therefore, lowering or removing concentrated solids requires the use of boiler water blowdown.

Types of Blowdown

There are two principal types of blowdown: manual (intermittent) bottom blowdown and surface (continuous) blowdown.

Manual (Intermittent) Bottom Blowdown - Bottom blowdown is necessary for the proper operation of the boiler. Bottom blowdown removes sludge and controls the level of TDS. On a manual system, the blowdown tapplings are located at the bottom or lowest part of the boiler, so that the dissolved solids in the boiler water are lowered, and a portion of the sludge that accumulates in the lower portion of the boiler is removed.

Surface (Continuous) Blowdown - Surface blowdown involves a continuous, low flow of boiler water extracted from the surface of the water level in order to skim off sediment, oil and other impurities. The blowdown is regulated by a flow control valve, which is adjusted as needed to control the TDS level. The surface blowdown opening is on the top center line of the pressure vessel and is provided with an internal collecting pipe terminating slightly below the working water level.

A controlled orifice valve is used to allow a continual, yet controlled, flow of concentrated water. Periodic adjustments are made to the valve in order to increase or decrease the amount of blowdown in accordance with test analysis.

There are a few considerations when designing a blowdown system:

- **Local Code Requirements:** If necessary, a blowdown aftercooler should be incorporated to bring the blowdown water temperature to a level acceptable to the sewer system and local code requirements.
- **Blowdown Heat Recovery:** Since the blowdown water is discharged at the saturated steam temperature, a significant amount of energy may be expelled during blowdown. A well-designed blowdown heat recovery system can control blowdown rates and dissolved solids concentration while recovering heat for make-up water preheating.

When selecting a blowdown heat recovery system, two factors should be considered: (1) tube materials and construction, and (2) blowdown flowrate control. The high velocities and abrasive nature of blowdown water necessitates quality construction materials such as stainless steel, as well as design for vibration damping. Secondly, it is important to control blowdown rate so as to match makeup water flow rates for optimal heat recovery.

In most cases, the intermittent nature of bottom blowdown will preclude recovery of the blowdown energy losses. Moreover, the bottom blowdown can contain suspended matter or sludge that will tend to clog a heat exchanger. With a continuous blowdown system, heat may certainly be recovered, transferred to make-up water, before the blowdown is cooled and sent to sewer.

- **Flash Tank Heat Exchangers:** Flash tank heat exchangers are also designed to recover heat from blowdown water, but provide an added feature of producing low-pressure steam for deaeration. The portion of blowdown water which is not flashed either enters a blowdown heat recovery system for make-up water preheating or is discharged to sewer.

SYSTEM INTEGRATION AND OPTIMIZATION

The discussion in this section attempts to provide to the reader assistance to approach in designing and integrating various equipment into a workable system. A workable system is one that meets the requirements and purposes of the system, has satisfactory life and maintenance costs, and abides by all constraints such as pressures, temperatures, footprint, noise, emissions, etc. In summary, a workable system performs the assigned duty, given the imposed constraints and requirements.

System optimization, on the other hand, is the process of determining system configuration and state point conditions which provide maximization of some objective such as the

present value of overall life costs. Optimized design may offer the steam-user significant savings over the life of the steam-generating facility. It is the design which maximizes profitability for the owner over time.

For a given application, there are many workable designs, but only one optimal design. The discussion in this section entails a “search” method to approaching the optimal design. Components/equipment are added arbitrarily and evaluated for effect on system performance and ultimately cost/benefit to the steam system owner. Obtaining the optimum design is more involved than that presented in this section and is beyond the scope of this discussion.

EXAMPLE - STEAM SYSTEMS

The following is an example of a relatively simple low pressure steam heating system. The entire steam-generating facility of an existing heating system is evaluated for replacement. An application/energy-use audit results in the following information.

1. **Type of Application/Load:** Heating

2. **Nominal Steam Pressure:** 10 psig

3. **Steam Load Characteristics/Profile:**

The steam system operates 5 months/year.

During 3 months (2160 hours)

Minimum load: 0

Maximum load: 5,600 kBtu/hr

Average load: 650 kBtu/hr

During 2 months (1440 hours)

Minimum load: 0

Maximum load: 8,100 kBtu/hr

Average load: 2,500 kBtu/hr

Transient loads, instantaneous demand, and sudden load swings do not exist.

4. **Steam Quality Requirements:** 98% steam quality at boiler pressure vessel exit

5. **Condensate Return Conditions:**

Temperature: 200 °F

Pressure: 2 psig

% Return: 90%

6. **Make-up Water Requirement:** 10%

7. **Water Charges:**

\$68.04/month service charge

\$0.833/ccf consumption charge

8. **Water Discharge Max. Temp:** 120 °F

9. **Sewer Charges:**

\$13.72/month service charge

\$0.573/ccf use charge

10. **Types of Fuel:**

Natural Gas

Light Oil considered as a back-up

11. **Fuel Analysis:**

Natural Gas

Methane: 86.0% (vol.)

Ethane: 7.2% (vol.)

Nitrogen: 6.8% (vol.)

SG: 0.619

HHV: 21,100 Btu/lb (1000 Btu/scf)

No. 2 Oil

Carbon: 85.8% (wt.)

Hydrogen: 12.7% (wt.)

Sulfur: 0.2% (wt.)

HHV: 19,420 Btu/lb

12. **Fuel Costs:**

Natural Gas: \$4.50/MMBtu (\$3.50 MMBtu interruptible)

No. 2 Oil: \$4.20/MMBtu

13. **Combustion Air Conditions:**

Avg Temp¹: 80 °F

Rel Hum: 60%

14. **Stack Gas Temperature Limits:** N/A

15. **Emission Regulations:**

There are none currently, but requirements are in the expected future. Site is located in a non-attainment zone.

16. **Stack/Breeching Physical Attributes:**

A new single stack is to be designed by the boiler supplier.

17. **Electrical Power Demand:** Not applicable in this case

¹ Boiler room combustion air temperature ranges from 60 °F to 100 °F.

18. Electrical Power Costs:

\$0.0345/kWhr on-peak

\$0.0245/kWhr off-peak

19. Physical Limitations of Facility: None

20. Noise Level Requirements: <90 dBA

When designing a steam generating facility, necessary system capacity and approximate fuel costs need to be considered. This will allow both qualitative and quantitative economic analyses of different installation alternatives.

First, required system capacity should be calculated. This is the maximum load.

A total capacity of 241 horsepower is required for this applica-

$$8100 \frac{\text{kBtu}}{\text{hour}} \left(\frac{\text{hp hour}}{33.475 \text{ kBtu}} \right) = 241 \text{ hp}$$

tion. Next, approximate fuel costs are calculated using the following:²

$$\text{total load} = \sum (\text{load}_i) (\text{hours}_i)$$

$$\begin{aligned} \text{total load} &= 2160 \text{ hrs} \cdot 650 \text{ kBtu/hr} + 1440 \cdot 2500 \text{ kBtu/hr} \\ &= 5,004,000 \text{ kBtu} \end{aligned}$$

$$\text{total fuel cost} = \frac{(\text{total load}) (\$/\text{MMBtu})}{\eta}$$

where η = system efficiency (decimal)

$$\frac{\$4.50}{\text{MMBtu}} (5,004,000 \text{ MBtu}) \left(\frac{1}{0.76} \right) = \$37,530$$

² Efficiency should be set to 80% for process loads and 60% for heating loads. In a heating application such as this one, the operating efficiency of the system may be much lower than the stack efficiency of the boiler. The reason for this is that the boiler may fire for only a few minutes in the morning. During the long off-cycle, heat is transferred from the boiler to its surroundings, allowing the steam contained within the boiler to cool and condense. When steam is again required, this lost heat must be replaced through several minutes of operation before steam may be supplied. Typical efficiencies for this type of operation range from 50 to 75%.

Boiler Selection

As this steam generating facility is replacing an existing one, pressure is already set at 10 psig. This system operating constraint allows the use of a 15 psi boiler which falls under Section IV of the ASME code. In addition to pressure requirements, steam quality requirements need to be met. The customer's system/application requirement is 98%. Most boilers offer 98.5% steam quality at low pressure; therefore this is not a limitation.

The large amount of idle time and low-load firing apparently suggest a two boiler installation (boilers operate most efficiently near their rated capacity), with a large boiler for winter and a smaller model for spring and fall. Reviewing the fuel bill, however, indicates that an improvement in efficiency would not justify increased installation, maintenance and capital costs that the customer wishes to minimize. Furthermore, there is no need for back-up in this application. Therefore, the recommendation is to install a single boiler. However, high-turndown would be desirable to prevent excessive cycling.

With the necessary capacity calculated, and the number of boilers to be installed decided, several boiler types can be ruled out immediately. Neither the Vertical Firetube nor the Model 4 Watertube Boilers are available in sufficient size for this system. At the opposite extreme, the load is far too small for an industrial watertube boiler. Remaining boilers include the firebox, firetube, flextube, electric and cast iron boilers. The cast iron boiler may be ruled out because of its higher initial cost; the electric may be ruled out because of higher operating costs. The remaining boilers, the firebox, firetube and flextube all are good choices for heating loads requiring low pressure steam.

Instantaneous load is not an issue with a heating load. Likewise, there are no large load swings to consider.

An application under federal emission regulations (NSPS) needs to be submitted because this installation is capable of using over 10 MMBTU/hr. There are no federal emissions requirements for this boiler because of the fuels selected. Local permits for construction and operation will also be required. Furthermore, it is desirable that the boiler be UL listed. There are no current local emission requirements, although they are expected to occur in the near future as the site is located in an ozone nonattainment area.

To minimize maintenance, a boiler with 5 square feet of heating area per horsepower should be selected. The large water chamber and surface area reduce the need for cleaning, and minimize upsets caused in water treatment. A turndown capability increased from the standard 4-1 would further reduce maintenance and prolong boiler life. A 10-1 turndown, standard on the CB and CB (LE) [low emission] Firetube Boilers (250-800 hp), would result in significant fuel savings in this

application. In a heating system such as this, eight to twelve cycles per hour are common. The 10-1 turndown drastically reduces such excessive cycling and decreases purge energy losses and cycling wear on components.

Both the CB and CB (LE) Firetube Boilers guarantee steam quality above the system requirements.

The certainty of a future tightening of emission regulations leads to a decision in favor of the 60 ppm CB (LE) Firetube Boiler³. Although both the firebox and flextube boilers may be retrofitted with low NOx burners, it is done at considerable cost. The CB (LE) Firetube Boiler's ability to meet all future emission regulations, along with its fuel savings, 10-1 turndown, and low cost for emissions reduction, make it the best choice.

The customer currently carries uninterruptable gas service, paying \$4.50/MMBtu. The customer has the opportunity for savings by switching to a dual fuel burner, which would allow for interruptible service. With the gas cost reduced to \$3.50/MMBtu, and assuming that light oil at \$4.20/MMBtu would be used 20% of the time, the resultant fuel bill is \$30,490, or a \$7,040 savings.

The final choice in this example will be a 250 horsepower 60 ppm CB (LE) Firetube Boiler with a dual fuel burner. As this is a heating load, and no expansion is foreseen, the 20% over-sizing used in boiler selection for some systems is not necessary here. In this application, the CB (LE) Firetube Boiler was selected due to high turndown capability and the ability to meet future emissions regulations. These features compensate for the higher capital costs of other boiler choices which could meet demand.

Condensate Return And Feedwater System

This system has 90% condensate return. This yields a make-up water requirement of 10%. If we assume a constant specific heat, and a make-up water temperature of 40 °F, a direct mixing would result in a feedwater temperature of 184 °F.

It must first be decided whether to use a boiler feed system or a deaerating system. In either case, this system must consist of a water reservoir, a stand (to provide sufficient net positive suction head for the pump) and a pump. In this system, the percentage of make-up water is low, and the feedwater mix temperature is relatively high. Oxygen in the system may be controlled by chemicals. These conditions, coupled with an already low annual fuel cost, decide against additional spending for a deaerating system.

3. The 60 ppm CB (LE) Boiler may be converted to 30 or 20 ppm at low cost. The 60 ppm model has lower electric demands and is predicted to meet all future requirements.

A rule of thumb for tanks is to have a fifteen minute water supply for boiler feed systems and a ten minute supply for deaerating systems. A larger tank may be used for systems with high condensate return, and a smaller tank for systems with a high percentage of make-up. In this system, a fifteen minute water supply corresponds to 2100 lb, or 253 gallons. A 270 gallon tank will be specified, allowing for the high percentage condensate return.

In a heating system with a firetube boiler there is neither a large load swing nor a necessity for precise boiler water level control. Therefore, an intermittent operation turbine style pump will be selected to minimize system cost. As the feedwater temperature is well below 215 °F, there is no need for high temperature pump seals. Duplex pumps will be specified to minimize maintenance downtime.

Water Treatment

Water treatment options include chemical, deaeration, softening and filtering. A test result yielded the results in [Table I3-4](#)

The limits for silica, alkalinity and dissolved solids are all limits for the boiler water itself. These can be controlled through blowdown (described below). The decision to control oxygen through chemicals has already been made. It will be necessary to include a water softener in the water treatment system to remove hardness.

Blowdown

Manual bottom blowdown should be specified. The low fuel bills preclude the option of continuous blowdown with heat recovery. Additional equipment necessary includes a bottom blowdown separator and aftercooler. These are necessary to reduce the blowdown water temperature to the maximum 120°F.

Table I3-4. Water Test Results and Limits

| SUBSTANCE | TEST RESULT | LIMITS |
|------------------|-------------|---------------|
| Oxygen | 6 ppm | <0.007 ppm |
| Hardness | 86 ppm | <5.0 ppm |
| Suspended Matter | 0.1 ppm | <0.15 ppm |
| pH | 6.8 | 7.0-10.5 |
| Silica | 10 ppm | <150 ppm |
| Total Alkalinity | 100 ppm | <700 ppm |
| Dissolved Solids | 500 µmho/cm | <7000 µmho/cm |

Efficiency Enhancement

The small annual fuel bills rule out a reasonable return on investment for efficiency enhancing equipment such as an economizer, oxygen trim or blowdown heat recovery. On large systems selecting such options may be the wise economic decision.

System Schematic

A schematic of the resulting system is shown in [Figure I3-5](#).

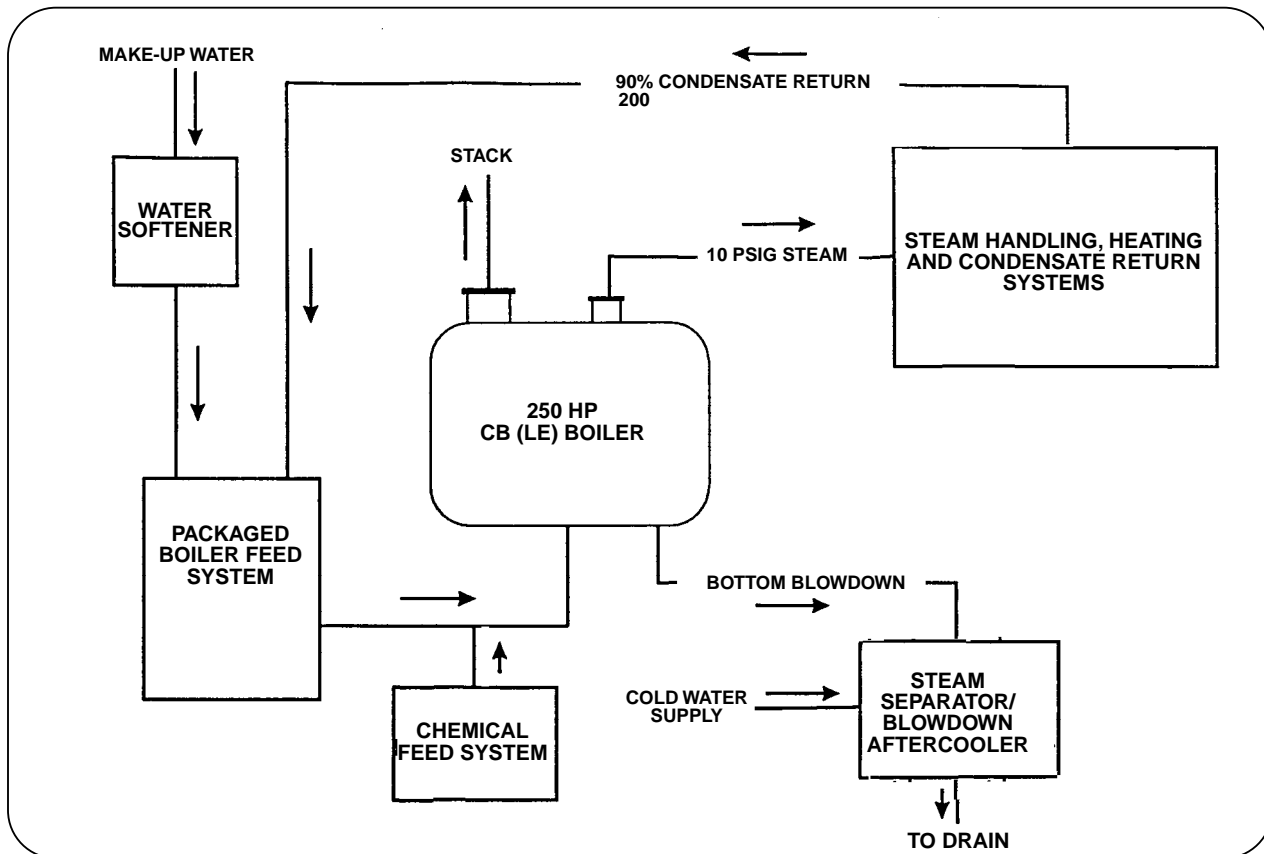


Figure I3-5. Example of System Configuration