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# Power Plant Evaluation and Design Reference Guide

Tyler G. Hicks

# *Power Plant Evaluation* and *Design Reference Guide*

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# Foreword

Power plant design is both a demanding and a rewarding task that attracts mechanical, electrical, civil, chemical, petroleum, and nuclear engineers. These engineers are helped by a score of other specialists—drafters, stress analysts, metallurgical engineers, welding contractors, economists, financial experts, etc. The results of their joint efforts are seen throughout the world in a variety of power plants—large, small, and in-between.

Despite the huge need for power plants in both developed and developing nations, there are few books to which the designer can refer for assistance and ideas. This book is aimed at meeting the need for an up-to-date work covering the entire field of power-plant design.

But instead of being written by one person—or a few—this book has a different genesis, drawing from a number of recently published works and magazine articles, blending their content into a unified treatment of modern power plant design. Using this approach, the editor was able to use the best materials from a number of works to produce a valuable design reference guide for the working power plant designer—no matter what engineering or technical background the designer might bring to the task. Thus, the book will be valuable to mechanical, electrical, chemical, petroleum, civil, textile, nuclear, and consulting engineers throughout the world, whether they design industrial or utility plants, or any combination thereof.

To meet the need for published material in the field, the content of this reference guide has been carefully chosen to embrace the entire field of power plant design. Thus, the user of this guide will find detailed coverage of steam, hydro, nuclear, and internal-combustion engine plants. Additional coverage serves the needs of designers working in solar, wind, tidal, and a variety of other alternative power-source fields. So the guide serves to meet a long-felt need for a modern reference for power plant designers throughout the world.

The guide starts with a comprehensive analysis of industrial power plants and steam systems. Such plants and systems probably demand more design creativity and skill than almost any other type, since there is little standardization amongst industrial power plants. Some are nearly utilities in their design and operation. Others are simply "reducing valves" which reduce the pressure of steam between a boiler plant and an industrial steam system, generating electricity as a byproduct of the process. Such plants were truly the cogeneration leaders. They squeezed the last Btu of energy out of a pound of steam long before the word cogeneration was coined. And with today's greater emphasis on energy conservation, the industrial power plant makes greater demands than ever on the designer's skill and vision. This section provides valuable tips to any designer who does work for industrial firms of all types.

Next, the guide covers steam power plants for central-station utility installations. Since the steam plant is the most widely used central-station facility, the coverage is in great depth. A variety of plants are described and their design approach analyzed. Data in this chapter are useful to the industrial plant designer as well.

Power plant costs—their estimation and use—is the third major topic discussed in this guide. Since "it always comes down to money" in every design situation, power plant costs are of primary concern to every designer. Both specific costs and trends of these costs are considered in this section.

Cogeneration—a new buzzword in power-plant design—is the subject of Section 4. As noted earlier, the concept of cogeneration has been with power-plant designers for many years. But the new emphasis on byproduct power has produced other views of this important subject. They are covered in detail in this section of the guide.

Hydroelectric power systems, next in popularity to steam systems, are covered in Section 5. Since the rise in uncertainty of supply and price of fossil fuels, hydro has made a comeback. Long neglected low-head sites once thought uneconomic now sport brand new generating facilities. The design and cost aspects of this new trend are covered in great detail in this section of the guide. Much useful design information is provided.

A variety of alternative energy sources—geothermal, solar, wind, wave, and ocean thermal difference—are covered in the sixth section of this guide. Specific design information which can be used in the engineering office is presented for each type of energy source considered.

Municipal wastes from residential and industrial sources continue to grow every year. Coupled with the need to deal with shrinking landfill availability and the relatively high energy content of each pound of waste, there is a persistent desire to utilize such waste to conserve natural resources. Section 7 gives the latest thinking on how waste can be used to generate power while reducing the problem of where to discard waste.

Energy storage is becoming more important as the cost of both plants and fuel rises. To evaluate any proposed storage method, a designer must know what methods are available, their relative efficiency, and the cost of each method. These topics are covered in detail in Section 8 of the guide.

Growing concern for the environment, and the effects of power generation on the surrounding area, are of critical importance to designers today. Acid rain, snow, and fog get enormous attention from various environmental groups. Every power-plant designer must be equipped with a knowledge of how to reduce pollution of the environment. Section 9 covers the environmental aspects of power generation in great detail.

Economic operation of power systems is discussed in the next section of the guide. Since fuel costs are such a critical factor in every plant today, the economic operation of every plant must be considered by the designer when planning a new installation. Typical design factors critical to economic operation are discussed in this section.

Finally, Section 11 covers power system reliability factors. With so much attention being paid to the elimination of power failures of all kinds, this section provides every designer with key ideas useful during the design process.

The works used in compiling this guide are acknowledged in each section. The editor thanks the various authors, manufacturers, and agencies for allowing access to their material. It is truly hoped that the guide proves useful to every power plant designer during every stage of the planning, design, and operation of modern power plants of all types.

Tyler G. Hicks

# Contents

Section **1**

# *Industrial Power Plants and Steam Systems*

Steam power plants comprise the major generating and process steam sources throughout the world today. Internal-combustion engine and hydro plants generate less electricity and steam than steam power plants. For this reason we will give our initial attention in this book to steam power plants and their design and application.

In the steam power field two major types of plants serve the energy needs of customers—industrial plants for factories and other production facilities—and central-station utility plants for residential, commercial, and industrial demands. Of these two types of plants, the industrial power plant probably has more design variations than the utility plant. The reason for this is that the demands of industry tend to be more varied than the demands of the typical utility customer.

To assist the power-plant designer in understanding better the many variations in plant design, industrial power plants are considered first in this book. And to provide the widest design variables, a power plant serving several process operations and all utilities is considered.

In the usual industrial plant, a steam generation and distribution system must be capable of responding to a wide range of operating conditions, and often must be more reliable than the plant's electrical system. The system design is often the last to be settled but the first needed for equipment procurement and plant startup. Because of these complications the power plant design evolves slowly, changing over the life of a project.

From "Steam-System Design: How it Evolves," by John F. Peterson and William L. Mann, *Chemical Engineering*, vol. 92, no. 21, October 14, 1985, 

A steam generation and distribution system must be capable of responding to a wide range of operating conditions, and often must also be more reliable than the plant's electrical system. Its design is the last to be settled but the first needed for procurement and startup. Because of these complications, the design evolves slowly, changing constantly over the life of a project.

The plant for which a steam system is being designed is assumed here to consist of several process operations, a unit that supplies all the utilities (including boiler feedwater and steam), and offsite facilities, such as a wharf, a relief system, a tankcar and truck loading station, pipe-racks, and administration buildings. Fig. 1-1 shows the site plan, which is assumed to cover an area of 3,000 feet by 3,000 feet.

A typical steam and condensate system diagram for a major process plant is illustrated in Fig. 1-2. Its elements, which are normally found in a large chemical complex or oil refinery, include: (1) three pressure levels of steam—high, medium and low—which are distributed throughout the facility, (2) a boiler plant, (3) process consumers of steam, (4) steam turbines, (5) waste-heat recovery systems, (6) pressure-letdown stations, (7) boiler feedwater deaerator, and (8) condensate-recovery system. The integration of all these into a reliably functioning system is the objective of the steam-system designer.

## Process steam loads

Steam is a source of power and heating, and may be involved in process reactions. Its applications include serving as a stripping, fluidizing, agitating, atomizing, ejector-motive and direct-heating stream. Its quantities, pressure levels and degrees of superheat are set by such process needs.

As reaction steam, it becomes a part of the process kinetics, as in $H_2$, ammonia and coal-gasification plants. Although such plants may generate all the steam needed, steam from another source must be provided for startup and backup.

The second major process consumption of steam is for indirect heating, such as in distillation-tower reboilers, amine-system reboilers, process heaters, piping tracing and building heating. Because the fluids in these applications generally do not need to be above 350°F, steam is a convenient heat source.

Again, the quantities of steam required for these services are set by the process design of the facility. There are many options available to the process designer in supplying some of these low-level heat requirements, including heat-exchange systems, and circulating heat-transfer-fluid systems, as well as steam and electricity. The selection of an option is made early in the design stage and is based predominantly on economic trade-off studies.

Generating steam from process heat affords a means of increasing the overall thermal efficiency of a plant. After providing for the recovery of all the heat possible via exchanges, the process designer may be able to reduce cooling requirements by making provisions for the generation of low-pressure (50-150 psig) steam. Although generation at this level may be feasible from a process-design standpoint, the impact of this on the overall steam balance must be considered, because low-pressure steam is excessive in most steam balances, and the generation of additional quantities may worsen the design. Decisions of this type call for close coordination between the process and utility engineers.

Steam is often generated in the convection section of fired process heaters in order to improve a plant's thermal efficiency. High-pressure steam can be generated in the furnace convection section of process heaters, which have radiant heat duty only (e.g., $H_2$-plant reformers, catalytic reformer/heaters).

Adding a selective-catalytic-reduction unit for the purpose of lowering $NO_x$ emissions may require the generation of waste-heat steam to maintain the correct operating temperatures to the catalytic-reduction unit.

Heat from the incineration of waste gases represents still another source of process steam. Waste-heat flues from the CO boilers of fluid-catalytic crackers and from fluid-coking units, for example, are hot enough to provide the highest pressure level in a steam system.

## Selecting pressure and temperature levels

The selection of pressure and temperature levels for a process steam system is based on: (1) moisture content in condensing-steam turbines, (2) metallurgy of the system, (3) turbine water rates, (4) process requirements, (5) water treatment costs, and (6) type of distribution system.

*Moisture content in condensing-steam turbines* — The selection of pressure and temperature levels normally starts with the premise that somewhere in the system there will be a condensing turbine. Consequently, the pressure and temperature of the steam must be selected so that its moisture content in the last row of turbine blades will be less than 10-13%. In high-speed turbines (greater than 9,000 rpm), a moisture content of 10% or less is desirable. This restriction is imposed in order to minimize erosion of the blades by water particles. This, in turn, means that there will be a minimum superheat temperature for a given pressure level, turbine efficiency and condenser pressure for which the system can be designed.

To quantify the selection, let it be assumed that a superheat temperature is to be determined on the basis of a turbine condensing at 0.7 psia (1½ in. Hg) and having an efficiency of 80% (reasonable for large turbines). The *minimum* superheat temperature can be calculated from a Mollier diagram. The results for various pressure levels are listed in Table 1-1. Based on these data, the following minimum supply-side superheat temperatures for the indicated pressures are required in order to attain no less than 11.5% moisture in the exhaust: 1,500 psig—930°F; 900 psig—825°F; 600 psig—750°F; and 150 psig—490°F.

*System metallurgy* — A second pressure-temperature concern in selecting the appropriate steam levels is the limitation imposed by metallurgy. Carbon steel flanges, for example, are limited to a maximum temperature of 750°F because of the threat of graphite (carbides) precipitating at grain boundaries. Hence, at 600 psig and less, carbon-steel piping is acceptable in steam distribution systems. Above 600 psig, alloy piping is required. In a 900- to 1,500-psig steam system, the piping must be either a ½ carbon-½ molybdenum or a ½ chromium-½ molybdenum alloy.

*Turbine water rates* — Steam requirements for a turbine are expressed as water rate, i.e., lb of steam/bhp, or lb of steam/kWh. Actual water rate is a function of two factors: theoretical water rate and turbine efficiency.

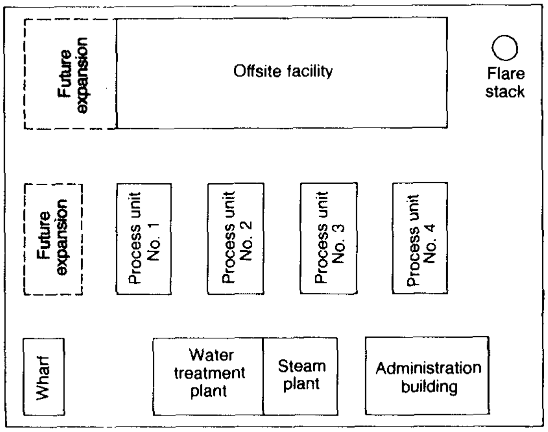


**Figure 1-1** — Site plan of the hypothetical plant for which steam system is being designed

The first is directly related to the energy difference between the inlet and outlet of a turbine, based on the isentropic expansion of the steam. It is, therefore, a function of the turbine inlet and outlet pressures and temperatures.

The second is a function of size of the turbine and the steam pressure at the inlet, and of turbine operation (i.e., whether the turbine condenses steam, or exhausts some of it to an intermediate pressure level). From an energy standpoint, the higher the pressure and temperature, the higher the overall cycle efficiency.

*Process requirements* — When steam levels are being established, consideration must be given to process requirements other than for turbine drivers. For example, steam for process heating will have to be at a high-enough pressure to prevent process fluids from leaking into the steam. Steam for pipe tracing must be at a certain minimum pressure so that low-pressure condensate can be recovered.

*Water treatment costs* — The higher the steam pressure, the costlier the boiler feedwater treatment. Above 600 psig, the feedwater almost always must be demineralized; below 600 psig, softening may be adequate. It may have to be of high quality if the steam is used in the process, such as in reactions over a catalyst bed (e.g., in hydrogen production).

*Type of distribution system* — There are two types of systems: local, as exemplified by powerhouse distribution; and complex, by which steam is distributed to many units in a process plant. For a small local system, it is not impractical from a cost standpoint for steam pressures to be in the 600-1,500-psig range. For a large system, maintaining pressures within the 150-600-psig range is desirable because of the cost of meeting the alloy requirements for higher-pressure steam distribution system.

Because of all these foregoing factors, the steam system in a chemical process complex or oil refinery frequently ends up as a three-level arrangement. The highest level, 600 psig, serves primarily as a source of power. The intermediate level, 150 psig, is ideally suitable for small emergency turbines, tracing off the plot, and process heating. The low level, normally 50 psig, can be used for heating services, tracing within the plot, and process requirements. A higher fourth level is normally not justified, except in special cases as when a large amount of electric power must be generated.

Whether or not an extraction turbine will be included in the process will have a bearing on the intermediate-pressure level selected, because the extraction pressure should be less than 50% of the high-pressure level, to take into account the pressure drop through the throttle valve and the nozzles of the high-pressure section of the turbine.

## Drivers for pumps and compressors

The choice between a steam and an electric driver for a particular pump or compressor depends on a number of things, including the operational philosophy. In the event of a power failure, it must be possible to shut down a plant orderly and safely if normal operation cannot be continued. For an orderly and safe shutdown, certain services must be available during a power failure: (1) instrument air, (2) cooling water, (3) relief and blowdown pumpout systems, (4) boiler feedwater pumps, (5) boiler fans, (6) emergency power generators, and (7) fire water pumps.

These services are normally supplied by steam or diesel drivers because a plant's steam or diesel emergency system is considered more reliable than an electrical tie-line.

The procedure for shutting down process units must be analyzed for each type of process plant and specific design. In general, the following represent the minimum services for which spare pumps driven by steam must be provided: column reflux, bottoms and purge-oil circulation, and heater charging. Most important is to maintain cooling; next, to be able to safely pump the plant's inventory into tanks.

Driver selection cannot be generalized; a plan and procedure must be developed for each process unit.

The control required for a process is at times another consideration in the selection of a driver. For example, a compressor may be controlled via flow or suction pressure. The ability to vary driver speed, easily obtained with a steam turbine, may be basis for selecting a steam driver instead of a constant-speed induction electric motor. This is especially important when the molecular weight of the gas being compressed may vary, as in catalytic-cracking and catalytic-reforming processes.

In certain types of plants, gas flow must be maintained to prevent uncontrollable high-temperature excursions during shutdown. For example, hydrocrackers are purged of heavy hydrocarbon with recycle gas to prevent the exothermic reactions from producing high bed temperatures. Steam-driven compressors can do this during a power failure.

Each process operation must be analyzed from such a safety viewpoint when selecting drivers for critical equipment. The size of a relief and blowdown system can be reduced by installing steam drivers. In most cases, the size of such a system is based on a total power failure. If heat-removal is powered by steam drivers, the relief system can be smaller. For example, a steam driver will maintain flow in the pump-around circuit for removing heat from a column during a power failure, reducing the relief load imposed on the flare system.

**Table 1-1** — Superheat-temperature minimums and moisture-content maximums for an 80%-efficient turbine condensing at 1½-in. Hg

| Inlet-steam pressure, psig | Inlet-steam temperature, °F | Moisture content, % |
|---|---|---|
| 1,500 | 1,000 | 9.5 |
| | 900 | 12.5 |
| | 800 | 16.5 |
| 900 | 900 | 9.3 |
| | 800 | 12.1 |
| | 700 | 15.1 |
| 600 | 800 | 10.1 |
| | 700 | 13.0 |
| | 600 | 16.5 |
| 150 | 600 | 8.1 |
| | 500 | 11.2 |
| | 400 | 14.8 |

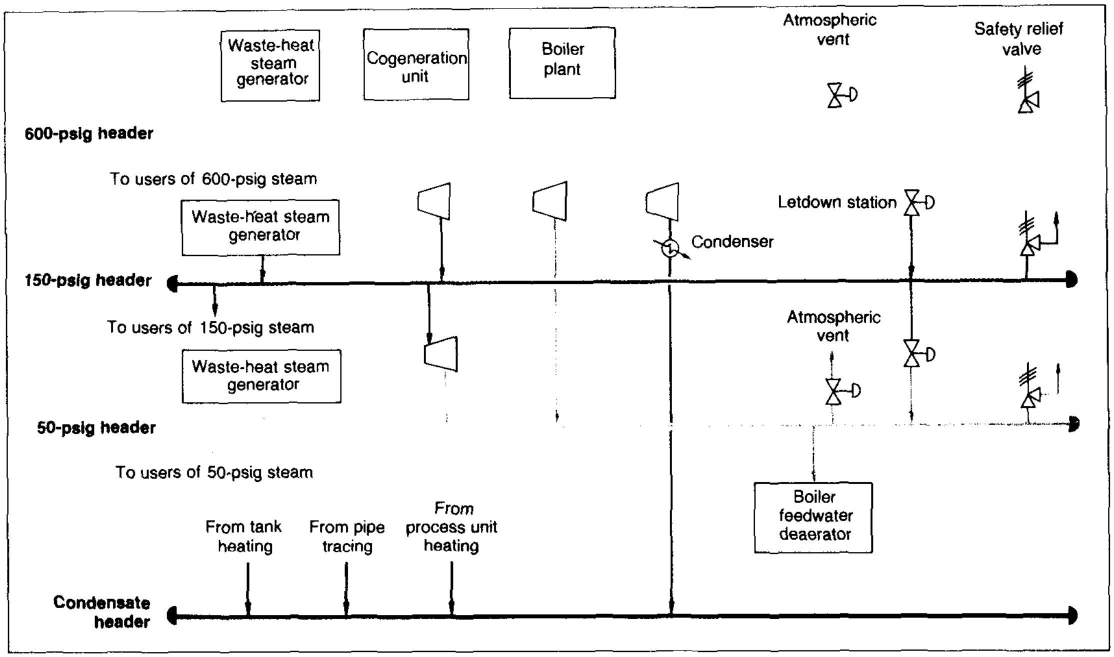



**Figure 1-2** — This steam and condensate system is typical of that found in a large chemical complex or oil refinery

Equipment support services (such as lubrication and seal-oil systems for compressors) that could be damaged during a loss of power should also be powered by steam drivers.

Driver size can also be a factor. An induction electric motor requires large starting currents — typically six times the normal load. The drop in voltage caused by the startup of such a motor imposes a heavy transient demand on the electrical distribution system. For this reason, drivers larger than 10,000 hp are normally steam turbines, although synchronous motors as large as 25,000 hp are used.

The reliability of life-support facilities — e.g., building heat, potable water, pipe tracing, emergency lighting — during power failures is of particular concern in cold climates. In such a case, at least one boiler should be equipped with steam-driven auxiliaries to provide these services.

Lastly, steam drivers are also selected for the purpose of balancing steam systems and avoiding large amounts of letdown between steam levels. Such decisions regarding drivers are made after the steam balances have been refined and the distribution system has been fully defined. There must be sufficient flexibility to allow balancing the steam system under all operating conditions.

## Selecting steam drivers

After the number of steam drivers and their services have been established, the utility or process engineer will estimate the steam consumption for making the steam balance. The standard method of doing this is to use the isentropic

Table 1-2 — Typical theoretical steam rates, in lb/kWh, for determining turbine actual steam consumption

| Exhaust pressure | Steam inlet conditions, psig/°F 1,500/925 | 900/825 | 600/750 | 150/500 | 50/400 |
|---|---|---|---|---|---|
| 600 psig | 29.99 | 68.2 | | | |
| 150 psig | 13.97 | 18.18 | 23.83 | | |
| 50 psig | 10.7 | 12.90 | 15.36 | 39.9 | |
| 1 atm | 8.09 | 9.25 | 10.40 | 17.51 | 29.10 |
| 4.0 in. Hg abs. | 6.368 | 7.03 | 7.65 | 10.78 | 14.00 |
| 1.5 in. Hg abs. | 5.845 | 6.388 | 6.888 | 9.30 | 11.52 |

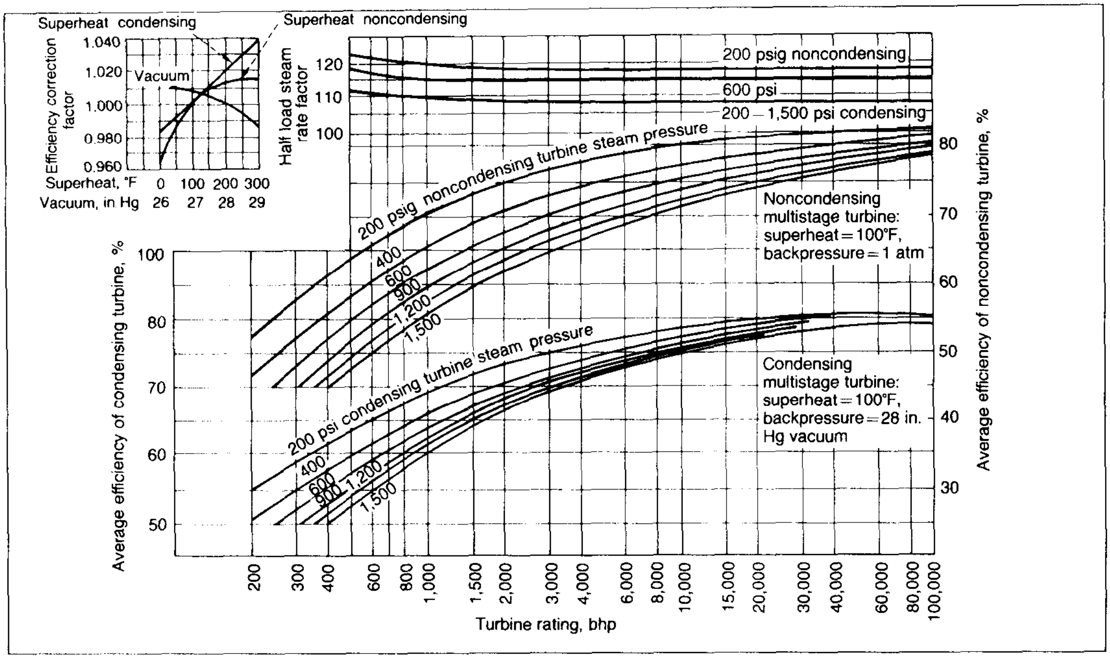



Figure 1-3 — Average efficiencies of multistage backpressure and condensing turbines

expansion of steam corrected for turbine efficiency. The isentropic expansion rates, called theoretical steam rates, are tabulated in the Keenan and Keyes "Theoretical Steam Rate Tables" [*1*].

Actual steam consumption by a turbine is determined via:

$$SR = (TSR)(bhp)/E$$

Here, $SR$ = actual steam rate, lb/h; $TSR$ = theoretical steam rate, lb/hr/bhp; $bhp$ = turbine brake horsepower; and $E$ = turbine efficiency.

Typical theoretical steam rates are presented in Table 1-2. To convert the usually tabulated lb/kWh value to lb/hr/bhp, multiply it by 0.746 (the factor for converting bhp to kW).

Turbine efficiency foremostly depends on size: that of small turbines (10-50 bhp) range from 30% to 40%, and that of large turbines (10,000-50,000 bhp) from 70% to 80%. Efficiency is also a function of steam superheat, turbine speed and (in the case of noncondensing turbines) pressure ratio. These corrections are normally minor. Examples of efficiency for backpressure and condensing turbines are shown in Fig. 1-3 [*9*].

When exhaust steam can be used for process heating, the highest thermodynamic efficiency can be achieved by means of backpressure turbines. Large drivers, which are of high efficiency and require low theoretical steam rates, are normally supplied by the high-pressure header, thus minimizing steam consumption.

Small turbines that operate only in emergencies can be allowed to exhaust to atmosphere. Although their water rates are poor, the water lost in short-duration operations may not represent a significant cost. Such turbines obviously play a small role in steam-balance planning.

## Constructing steam balances

After the process and steam-turbine demands have been established, the next step is to construct a steam balance for the chemical complex or oil refinery. A sample balance is shown in Fig. 1-4. It shows steam production and consumption, the header systems, letdown stations, and boiler plant. It illustrates a normal (winter) case.

It should be emphasized that there is not one balance but a series, representing a variety of operating modes. The object of the balances is to determine the design basis for establishing boiler size, letdown station and deaerator capacities, boiler feedwater requirements, and steam flows in various parts of the system.

The steam balance should cover the following operating modes: normal, all units operating; winter and summer conditions; shutdown of major units; startup of major units;

loss of largest condensate source; power failure with flare in service; loss of large process steam generators; and variations in consumption by large steam users.

From 50 to 100 steam balances could be required to adequately cover all the major impacts on the steam system of a large complex.

At this point, the general basis of the steam system design should have been developed by the completion of the following work:

1. All significant loads have been examined, with particular attention focused on those for which there is relatively little design freedom — i.e., reboilers, sparging steam for process units, large turbines required because of electric power limitation and for shutdown safety.

2. Loads have been listed for which the designer has some liberty in selecting drivers. These selections are based on analyses of cost competitiveness.

3. Steam pressure and temperature levels have been established.

4. The site plan has been reviewed to ascertain where it is not feasible to deliver steam or recover condensate, because piping costs would be excessive.

5. Data on the process units are collected according to the pressure level and use of steam — i.e., for the process, condensing drivers and backpressure drivers. A summary of such information is shown in Fig. 1-5.

6. After Step 5, the system is balanced by trial-and-error calculations or computerized techniques to determine boiler, letdown, deaerator and boiler feedwater requirements.

7. Because the possibility of an electric power failure normally imposes one of the major steam requirements, normal operation and the eventuality of such a failure must both be investigated, as a minimum.

## Checking the design basis

After the foregoing steps have been completed, the following should be checked:

*Boiler capacity* — Installed boiler capacity would be the maximum calculated (with an allowance of 10-20% for uncertainties in the balance), corrected for the number of boilers operating (and on standby).

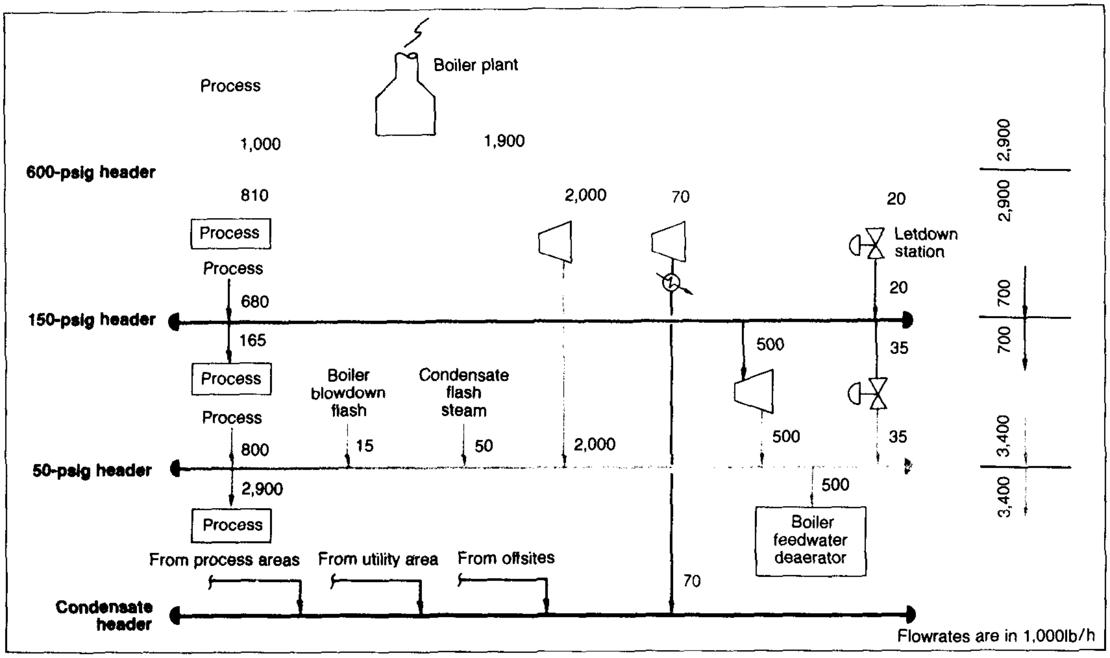



**Figure 1-4** — A normal (winter) case steam balance is constructed after process and turbine demands have been established

The balance plays a major role in establishing normal-case boiler specifications, both number and size. Maximum firing typically is based on the emergency case. Normal firing typically establishes the number of boilers required, because each boiler will have to be shut down once a year for the code-required drum inspection. Full-firing levels of the remaining boilers will be set by the normal steam demand. The number of units required (e.g., three 50% units, four 33% units, etc.) in establishing installed boiler capacity is determined from cost studies. It is generally considered double-jeopardy design to assume that a boiler will be out of service during a power failure.

*Minimum boiler turndown* — Most fuel-fired boilers can be operated down to approximately 20% of the maximum continuous rate. The minimum load should not be expected to be below this level.

*Differences between normal and maximum loads* — If the maximum load results from an emergency (such as power failure), consideration should be given to shedding process steam loads under this condition in order to minimize installed boiler capacity. However, the consequences of shedding should be investigated by the process designer and the operating engineers to ensure the safe operation of the entire process.

*Low-level steam consumption* — The key to any steam balance is the disposition of low-level steam. Surplus low-level steam can be reduced only by including more condensing steam turbines in the system, or devising more process applications for it, such as absorption refrigeration for cooling process streams and Rankine-cycle systems for generating power. In general, balancing the supply and consumption of low-level steam is a critical factor in the design of the steam system.

*Quantity of steam at pressure-reducing stations* — Because useful work is not recovered from the steam passing through a pressure-reducing station, such flow should be kept at a minimum. In the Fig. 1-5 150/50-psig station, a flow of only 35,000 lb/h was established as normal for this steam-balance case (normal, winter). The loss of steam users on the 50-psig systems should be considered, particularly of the large users, because a shutdown of one may demand that the 150/50-psig station close off beyond its controllable limit. If this happened, the 50-psig header would be out of control, and an immediate-pressure buildup in the header would begin, setting off the safety relief valves.

The station's full-open capacity should also be checked to ensure that it can make up any 50-psig steam that may be lost through the shutdown of a single large 50-psig source (a turbine sparing a large electric motor, for example). It would be undesirable for the station to be sized so that it opens more than 80%. In some cases, rangeability requirements may dictate two valves (one small and one large).

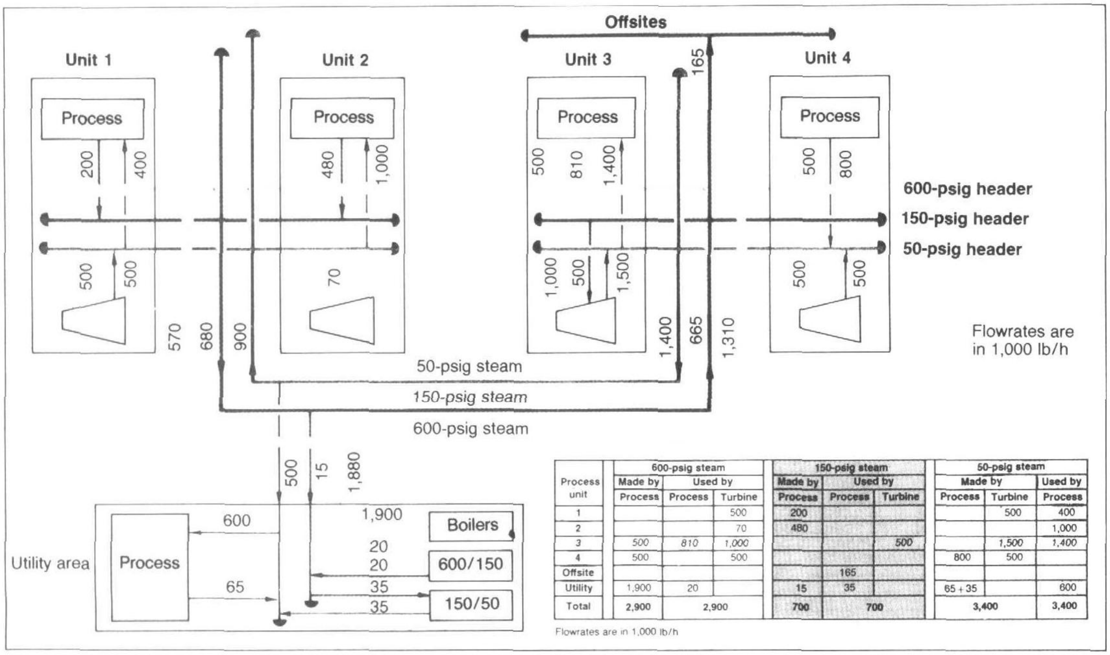
*Intermediate pressure level* — If large steam users or suppliers may come onstream or go offstream, the normal (day-to-day) operation should be checked. No such change in normal operation should result in a significant upset (e.g., relief valves set off, or the system pressure control lost).

If a large load is lost, the steam supply should be reduced by the letdown-station. If the load suddenly increases, the 600/150-psig station must be capable of supplying the additional steam. If steam generated via the process disappears, the station must be capable of making up the load. If 150-psig steam is generated unexpectedly, the 600/150-psig station must be able to handle the cutback.

The important point here is that where the steam flow could rise to 700,000 lb/h, this flow should be reduced by a cutback at the 600/150-psig station, not by an increase in the flow to the lower-pressure level, because this steam would have nowhere to go. The normal (600/150-psig) letdown station must be capable of handling some of the negative load swings, even though, overall, this letdown needs to be kept to a minimum.

On the other hand, shortages of steam at the 150-psig level can be made up relatively easily via the 600/150-psig station. Such shortages are routinely small in quantity or duration, or both (startup, purging, electric drive maintenance, process unit shutdown, etc.)

*High-pressure level* — Checking the high-pressure level is generally more straightforward because rate control takes




| Process unit | 600-psig steam Made by Process | 600-psig steam Used by Process | 600-psig steam Used by Turbine | 150-psig steam Made by Process | 150-psig steam Used by Process | 150-psig steam Used by Turbine | 50-psig steam Made by Process | 50-psig steam Made by Turbine | 50-psig steam Used by Process |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | | 500 | 200 | | | | 500 | 400 |
| 2 | | | 70 | 480 | | | | | 1,000 |
| 3 | 500 | 810 | 1,000 | | | 500 | | 1,500 | 1,400 |
| 4 | 500 | | 500 | | | | 800 | 500 | |
| Offsite | | | | | 165 | | | | |
| Utility | 1,900 | 20 | | 15 | 35 | | 65 + 35 | | 600 |
| Total | 2,900 | 2,900 | | 700 | 700 | | 3,400 | | 3,400 |

Flowrates are in 1,000 lb/h

**Figure 1-5** — Data on the steam generated and consumed by each process can be summarized in a table or diagram place directly at the boilers. Firing can be increased or lowered to accommodate a shortage or surplus.

## Typical steam-balance cases

The Fig. 1-4 steam balance represents steady-state condition, winter operation, all process units operating, and no significant unusual demands for steam.

An analysis similar to the foregoing might also be required for the normal summertime case, in which a single upset must not jeopardize control but the load may be less (no tank heating, pipe tracing, etc.)

The balance representing an emergency (e.g., loss of electric power) is significant. In this case, the pertinent test point is the system's ability to simply weather the upset, not to maintain normal, stable operation. The maximum relief pressure that would develop in any of the headers represents the basis for sizing relief valves. The loss of boiler feed water or condensate return, or both, could result in a major upset, or even a shutdown.

## Header pressure control during upsets

At the steady-state conditions associated with the multiplicity of balances, boiler capacity can be adjusted to meet user demands. However, boiler load cannot be changed quickly to accommodate a sharp upset. Response rate is typically limited to 20% of capacity per minute. Therefore, other elements must be relied on to control header pressures during transient conditions.

The roles of several such elements in controlling pressures in the three main headers during transient conditions are listed in Table 1-3. A control system having these elements will result in a steam system capable of dealing with the transient conditions experienced in moving from one balance point to another.

## Tracking steam balances

Because of schedule constraints, steam balances and boiler size are normally established early in the design stage. These determinations are based on assumptions regarding turbine efficiencies, process steam generated in waste-heat furnaces, and other quantities of steam that depend on purchased equipment. Therefore, a sufficient number of steam balances should be tracked through the design period to ensure that the equipment purchased will satisfy the original design concept of the steam system.

This tracking represents an excellent application for a utility data-base system and a system linear programming model. During the course of the mechanical design of a large "grass roots" complex, 40 steam balances were continuously updated for changes in steam loads via such an application.

## Cost tradeoffs

To design an efficient but least-expensive system, the designer ideally develops a total minimum-cost curve — which incorporates all the pertinent costs related to capital expenditures, installation, fuel, utilities, operations and maintenance — and performs a cost study of the final system. However, because the designer is under the constraint of keeping to a project schedule, major, highly expensive equipment must be ordered early in the project, when many key parts of the design puzzle are not available (e.g., a complete load summary, turbine water rates, equipment efficiencies and utility costs).

A practical alternative is to rely on comparative-cost estimates, as are conventionally used in assisting with engineering decision points. This approach is particularly useful in making early equipment selections when fine-tuning is not likely to alter decisions, such as regarding the number of boilers required, whether boilers should be shop-fabricated or field-erected, and the practicality of generating steam from waste heat or via cogeneration.

**Table 1-3**—Roles played by the various control elements in regulating header pressures

| | Headers | | | | | |
|---|---|---|---|---|---|---|
| | High pressure | | Medium pressure | | Low pressure | |
| Control element | + | – | + | – | + | – |
| 600/150-psig pressure-reducing station | ↑ 1 | ↓ | ↓ 1 | ↑ 1 | | |
| 150/50-psig pressure-reducing station | | | ↑ 2 | ↓ 2 | ↓ 1 | ↑ |
| 600-psig atmospheric vent valve | ↑ 2 | | | | | |
| 50-psig atmospheric vent valve | | | | | ↑ 2 | |
| 600-psig safety relief valve | ↑ 3 | | | | | |
| 50-psig safety relief valve | | | | | ↑ 3 | |

Legend: + = pressure is rising
– = pressure is falling
O = step sequence 1, 2, 3, etc.
↑ = control element opens
↓ = control element closes

The significant elements of a steam-system cost-comparative study are costs for: equipment and installation; ancillaries (i.e., miscellaneous items required to support the equipment, such as additional stacks, upgraded combustion control, more extensive blowdown facilities, etc.); operation (annual); maintenance (annual); and utilities.

The first two costs may be obtained from in-house data or from vendors. Operational and maintenance costs can be factored from the capital cost for equipment based on an assessment of the reliability of the purchased equipment.

Utility costs are generally the most difficult to establish at an early stage because sources frequently depend on the site of the plant. Some examples of such costs are: purchased fuel gas — \$5.35/million Btu, raw water — \$0.60/1,000 gal, electricity — \$0.07/kWh, and demineralized boiler feedwater — \$1.50/1,000 gal. The value of steam at the various pressure levels can be developed [5].

The comparative-cost estimate technique is highly effective in determining the power-boiler design basis. A normal power-boiler demand of 1,900,000 lb/h is indicated in Fig. 1-2. The choice of boiler number and size will depend on their ability to provide 1,900,000 lb/h of 600-psig steam when one boiler is shutdown for inspection or maintenance.

Let it be further assumed that the emergency balance requires 2,200,000 lb/h of steam (all boilers available). Listed in Table 1-4 are some combinations of boiler installations that meet the design conditions previously stipulated.

Table 1-4 indicates that any of the several combinations of power-boiler number and size could meet both normal and emergency demand. Therefore, a comparative-cost analysis would be made to assist in making an early decision regarding the number and size of the power boilers.

(Table 1-4 is based on field-erected, industrial-type boilers. Conventional sizing of this type of boiler might range from 100,000 lb/h through 2,000,000 lb/h for each.)

An alternative would be the packaged-boiler option (although it does not seem practical at this load level). Because it is shop-fabricated, this type of boiler affords a significant saving in terms of field installation cost. Such boilers are available up to a nominal capacity of 100,000 lb/h, with some versions up to 250,000 lb/h.

**Table 1-4** — Boiler sizing basis for some combinations of installations

| To meet normal demand (1,900,000 lb/h) | | To meet upset demand (2,200,000 lb/h) | |
|---|---|---|---|
| **No. of boilers normally operating** | **Rated capacity of each boiler, 1,000 lb/h** | **No. of boilers installed** | **Installed capacity, 1,000 lb/h** |
| 3 | 650 | 4 | 2,600 |
| 4 | 500 | 5 | 2,500 |
| 5 | 400 | 6 | 2,400 |
| 6 | 350 | 7 | 2,450 |

**Table 1-5** — Typical pressure setpoints in a three-header system

| | Steam-system setpoints, psig | | |
|---|---|---|---|
| | **50-psig system** | **150-psig system** | **600-psig system** |
| Turbine-casing pressure safety valve | 100 | 185 | None |
| Header pressure safety valve | 80 | 175 | 715 |
| Atmospheric vent valve | 60 | None | 660 |
| Pressure-reducing station | 53 | 155 | 615 |
| Line-loss allowance | 5 | 8 | 30 |
| Distant subheader operating point | 48 | 147 | 585 |

Selecting turbine water rate (i.e., efficiency) represents another major cost concern. Beyond the recognized payout period (e.g., 3 years), the cost of drive steam can be significant in comparison with the equipment capital cost. The typical 30% efficiency of the medium-pressure backpressure turbine can be boosted significantly.

Driver selections are frequently made with the help of cost-tradeoff studies, unless overriding considerations preclude a drive medium. Electric pump drives are typically recommended on the basis of such studies. Turbine spares may be specified to help operations get through an upset. Offsite pump drives are usually electric, because of the high cost of installing steam and condensate-recovery piping.

Steam tracing has long been the standard way of winterizing piping, not only because of its history of successful performance but also because it is an efficient way to use low-pressure steam.

## Design considerations

As the steam system evolves, the designer identifies steam loads and pressure levels, locates steam loads, checks safety aspects, and prepares cost-tradeoff studies, in order to provide low-cost energy safely, always remaining aware of the physical entity that will arise from the design.

How are design concepts translated into a design document? And what basic guidelines will ensure that the physical plant will represent what was intended conceptually?

Basic to achieving these ends is the *piping and instrument diagram* (familiar as the P&ID). Although it is drawn up primarily for the piping designer's benefit, it also plays a major role in communicating to the instrumentation designer the process-control strategy, as well as in conveying specialty information to electrical, civil, structural, mechanical and architectural engineers. It is the most important document for representing the specification of the steam system.

On it are shown all the major equipment items, identified by number. Also included in it are such significant mechanical features as pump design capacities and pressure outputs, motor horsepowers, exchanger duties, vessel diameters and tangent-to-tangent dimensions, and insulation thicknesses.

Instruments are numbered, located, and identified as to function. Flows, pressures, temperatures and abnormal operating conditions are taken from line designation tables (described later), which form an important adjunct to the piping and instrument diagram.

Piping is identified by line number, the line size and pipe specification identification reference being included. This information, together with the data in the line designation table, allows the piping designer, the pipe-support designer, and the stress analyst to complete the detail design of all the steam and condensate piping systems.

The piping-specification document represents a source of American National Standards Institute (ANSI) code references and standards, and procurement descriptions and specifications, as well as of piping and valve material, temperature range, maximum pressure range, corrosion allowance, gasket material and pipefitting connections for each service (class).

The line designation table carries design information that cannot be easily portrayed in the piping and instrument diagram. Every numbered process, utility and blowdown line is tabulated in it, along with pertinent normal and upset characteristics. Mass or volumetric flows, or both, are entered in it for line sizing and instrument selection purposes. The identification of each line's source and destination make it possible to determine absolute line loss and commodity flow velocity. Upset pressures and temperatures form the bases for sizing relief valves, and provide data for making stress analyses, for choosing the type of pipe support (guides, slide-shoes, anchor points, hangers and spring supports), and for designing and locating expansion loops. Insulation requirements and thickness, whether for saving energy or protecting personnel, also are indicated.

The applicable piping code for chemical plants and petroleum refineries is ANSI B31.3.

### Establishing steam pressure profiles

In setting up the program for implementing the design of the overall steam system, early consideration should be given to the multiplicity of pressure settings that must be established. Such things as safety-valve settings for each header, setpoints for pressure-reducing stations, atmospheric-vent and turbine-casing safety valves, and actual operating pressures are all important in promulgating the procurement of the proper equipment and instrumentation, which inevitably must be completed early in the development of the design.

A typical pattern of pressure points for each system is presented in Table 1-5. Although many of the settings are arbitrarily designated, some general guidelines can be applied in their selection.

### Profile of the 50-psig header

The 53-psig operating point at the reducing station provides a minimum operating point of 48 psig at distant subheader takeoffs. Thus, a maximum of 5 psig has been allowed for sizing the header line (using the normal, winter steam balance as the design basis; of course, other balance cases may override this basis for line sizing).

The atmospheric-vent setpoint at 60 psig was selected with these thoughts in mind: (1) the pressure-reducing station will accommodate normal hour-by-hour pressure swings in the 50-psig header, including any fluctuations caused by a significant change in the supply or consumption of 50-psig steam; (2) the system furnishes deaeration steam to the water-treatment facility, and a backup supply to the pressure-reducing station will prevent pressure surges in the deaeration steam; and (3) the atmospheric-vent system is not to be the first line of control.

The header safety relief valve is set at 80 psig because this is well within the pressure-temperature profile for 150-psig carbon-steel flanges (even with a superheat temperature as high as 750°F), and it affords a reasonable range between the setpoints of the turbine safety valve and the atmospheric vent (consideration being given to the fact that the pressure-reducing station's accumulation pressure is +10%, i.e., 88 psig, and its reseating pressure is –7%, i.e., 74 psig). Note that, because of the quantity of steam passing through the 50-psig header, it may be desirable to install more than one pressure-relief valve, with settings slightly staggered to smooth out the popping and reseating of relief valves.

By code, one pressure-relief valve for each turbine is required to protect the casing at (or below) the maximum allowable working-pressure rating, in case the discharge valve were closed. This rating, which varies with manufacturer, is related to the casing material (cast iron, carbon steel, alloy and stainless steel, etc.). It is mandatory that the turbine safety valve be set to relieve at a pressure higher than that of the 50-psig steam system relief, to avoid having the turbine's relief valve act as the system's relief valve.

### Profile of the 150-psig header

The same general considerations apply to the pressure profile of the 150-psig header. However, in the interest of economy, this system has not been provided with an atmospheric vent. A pressure buildup in the 150-psig header is, instead, relieved by reducing the letdown at the 600/150 psig station, which will initiate a boiler cutback, or by increasing the letdown through the station. With either action, atmospheric venting will probably occur until boiler steam generation has been cut back to a manageable level.

Noted that, when the 150-psig flange pressure/temperature curve is addressed at a 490°F superheat, the continuous pressure rating of the 150-psig header flange network is approximately 175 psig. Although the code does permit temporary excursions above the curve, the 175-psig rating was selected because it still provides ample margin above the header setpoint of 155 psig.

**Table 1-6**—Steam generation for three levels of electric-power generation

| Pressure/temperature, psig/°F | Steam generation, 1,000 lb/h | | |
|---|---|---|---|
| | 9,000 kW | 25,000 kW | 80,000 kW |
| Unfired boilers: | | | |
| 160/371 | 69.9 | 155.8 | 393.0 |
| 630/755 | 53.5 | 107.6 | 301.0 |
| 895/830 | 50.4 | 100.0 | 283.0 |
| 1,525/955 | — | — | — |
| Supplementary fired to 1,400°F exhaust gas: | | | |
| 630/755 | 97.1 | 226 | 539 |
| 895/830 | 94.0 | 219 | 522 |
| 1,525/955 | 88.9 | 207 | 494 |
| Excess air and 300°F stack temperature, fully fired to 10%: | | | |
| 630/775 | 327 | 755 | 1,739 |
| 895/830 | 318 | 736 | 1,694 |
| 1,525/955 | 306 | 706 | 1,626 |

The turbine safety valve's setpoint, which again is based on the manufacturer's recommendation, must protect against the turbine being blocked-in, and cannot be set so low as to relieve before the header safety valve (175 psig).

### Profile of the 600-psig header

Establishing the pressure profile of the 600-psig header follows the same pattern. An atmospheric vent has been included to relieve modest pressure rises until boiler output has been adjusted. A setpoint of 615 psig has been set for the letdown station, with a line pressure loss of 5% (30 psig) allowed for distant points of steam consumption.

It is likely that the boiler safety relief valves will provide header relief. Design up to the boiler's first block valve is governed by the ASME Pressure Vessel Code, rather than by ANSI 16.3, the first typically being more conservative.

### Overview of steam-system control

Because an upset at one point in the steam system has an impact throughout the entire system, the controls designer must establish the sequence of control remedies that will restore normalcy. This will ensure that the highest priority areas will be protected first, and that two control-system elements will not oppose each other.