

CHEMICAL PROCESSING

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Steam eHandbook

**Take the
Heat Off Your
Steam System**

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Control Steam System Energy Costs

Steam system losses can silently drain profits

By Ven V. Venkatesan

OPERATING AND maintaining a reliable steam system is vital to chemical processing plants and can have significant cost impact on a plant's annual budget. Typical profit drainers in operating and maintaining a steam system include excessive fuel cost, inefficient steam generation, less-than-optimal steam utilization and poor condensate recovery. Ensuring adequate supply of steam often results in excessive capacity usage, expensive fuel choices or condensate draining to grade, leading to compromised efficiency levels and higher steam cost. Because steam system dependency is unavoidable, addressing those three issues is crucial to minimizing steam costs.

Optimize steam generation capacity. A chemical processing plant in upstate New York operated all six of its boilers to meet its frequently surging steam demand. After analyzing the normal and peak steam demands of its several processing buildings, engineers concluded that one boiler could be stopped during the day with the help of a steam demand controller and another during the night shift. Successful results from multiple trials stopping one boiler during the night shift paved the way for operating personnel to stop the second boiler during the day.

The necessity to review steam demand may arise when a plant expands its capacity or adds

another steam-dependent processing unit. In such cases, a new steam demand analysis combining the existing and additional steam demands may help optimize new boiler capacity to meet the increased demand. It even may be possible to avoid a new boiler addition.

Optimize fuel choice. Steam costs highly depend upon the cost of fuel fired in the boiler. Typically, fuel prices increase from low-grade fuels such as biomass, to medium-grade fuels like coal, to higher-grade petroleum fuels such as oil and LPG. Natural gas prices usually fall between medium- and higher-grade fuel costs. Most chemical processing plants in the United States use natural gas to fuel their boilers. A few plants use coal-fired boilers to meet steam demand, while very few use biomass as their fuel and those that do must modify their boilers accordingly.

The project cost of installing boilers also increases as the fuel choice moves from gaseous fuels to liquids, solids and biomass fuels. In addition, steam generation cost significantly depends upon the plant's location and the availability, and market prices, of fuels. Predicting fuel supply price changes long term is very difficult, so, one way to optimize steam cost is to retrofit or modify the boilers' burners or combustion systems to fire multiple fuels.

Some plants generate rejects or unusable and unmarketable byproduct streams. Retrofitting boiler burners to fire those waste streams as fuel could help reduce steam costs. Hence, it's worth investing in multiple fuel-fired boiler systems in all medium- and large-sized chemical processing plants.

Improve condensate return systems. Processes critically dependent on steam heating must have reliable condensate removal. Condensate backing up inside the heat transfer equipment (due to stalling, excessive back-pressure in the return piping or water hammer problems) should be drained to grade to avoid interruptions in steam heating. Properly sizing the condensate return piping and providing appropriate flash separation from steam condensate is an essential requirement of a condensate return system. However, properly sized return piping could become under-sized when more condensate sources are connected to it, or excessive flash steam generation occurs in the return piping due to operational changes of the steam-heated equipment.

Because the immediate option to maintain steam heating is to waste the condensate by draining it to grade, personnel should alert management to the monetary losses associated with condensate drain. If not addressed, steam cost will remain high and profits will drain silently.

Utilize waste heat for steam generation. Most plants have waste gas incinerators operating continuously to burn off toxic and other waste gases from the process. Because these waste gas stream flows occur occasionally and mostly in small quantities, fuel always is firing the incinerator beds to maintain the incineration temperature. In some plants, this fuel firing almost equals the consumption of a small- or medium-sized boiler. Hence, it's

worth exploring waste-heat steam generation from incinerators or heaters that exhaust the flue gases to stacks at temperatures above 400°F.

Next month's column will highlight more on controlling steam system energy costs.

LOOK AT YOUR PIPING SYSTEM

More opportunities exist in other parts of the system, in particular, the large network of pipelines, valves and other fittings that are possible sources of heat energy loss. In addition, the steam distribution system requires devices to collect condensate, keep steam dry and control its flow and required pressure level. If these devices aren't designed and maintained properly, the energy loss could be substantial.

A steam distribution system collects steam from boilers, waste heat boilers and steam turbine exhausts. In multiple-pressure-header steam systems, the lower-pressure-level headers automatically collect steam from the higher-pressure headers through letdown valves. As steam travels through various pressure-level pipelines to the point of use, it loses some of its heat and energy content, resulting in condensate formation.

For plants with sections of steam distribution piping outdoors, energy and process engineers can monitor steam demand change when it rains to quickly assess losses due to poor pipe insulation. One chemical processing complex in West Virginia with widely distributed steam distribution piping reported a 5,000-lb/hr steam surge whenever it rained. Losses likely occur even when it doesn't rain and go up during the winter months. Hence, it's worth conducting an insulation survey at least once every three years and fixing any damaged or exposed hot surfaces. Providing insulation blankets

is preferable for pipe sections and fittings, especially those located outdoors, that require periodic removal for maintenance.

Steam's thermodynamic properties offer some design challenges in transporting heat to multiple locations. Because heat loss can quickly transform steam into a bi-phase fluid, it's important to take extra care when designing the steam distribution piping. To ensure dry steam supply and steam flow free from water hammer, the condensate formed in steam lines should be removed at appropriate sections of the steam distribution piping. Piping should slope downward in the flow direction and include drip legs at sufficient distances and before each rising section of pipe. Each drip leg should include a steam trap to drain out the collected condensate, ensuring dry steam delivery. Typically, these requirements should be addressed during the design stage. However, I find missing drip legs, inadequately sized drip legs and drip legs without steam traps in more than 90% of the plants I visit. Both wet steam supply and water hammer — resulting from an absence of steam traps or cold-plugged steam traps — lead to condensate accumulation that can slow down the heating of the process and cause plant stoppages. Hence, plant engineers shouldn't think only leaking steam traps cause energy losses. An annual steam trap survey and fixing failed steam traps is an essential requirement that shouldn't be compromised when management trims budgets.

Steam leaks and condensate drains are visible profit drainers in a steam distribution system. Instead of accepting them as low-priority house-keeping issues, fix them as soon as they are noticed. High-pressure superheated steam leaks generally

aren't visible and pose a safety risk to personnel. They might be worth fixing, even if "on -line" leak repair is the only option. If plant engineers have the option to review the design of new or extended steam distribution systems, they should consider providing enough isolation valves, by identifying and classifying critical maintenance-prone sections.

Periodic steam system audits should be a routine part of the plant engineer's cost optimization plan. Audits typically focus on finding any steam, condensate or heat losses and verifying the correct operation of the steam-heated equipment. Because of the higher temperature of steam and condensate, steam distribution systems are ideal subjects for inspection with infrared (IR) test instruments. Thermal imaging IR cameras are now available at affordable prices and provide temperature information across a wide field of view. Even if a steam leak occurs inside an enclosed object, such as a steam trap, it can be detected easily by an IR camera. Thermal imagers also can be used to identify hot spots on steam handling equipment with broken or damaged insulation. (For more on thermal imagers, see: "Use Thermal Imagery for Process Problems," <http://goo.gl/2W0G8D>.)

According to a U.S. Department of Energy survey, steam accounts for one-third of all the energy used in process plants. Monitoring and optimizing the cost of your steam system can yield big rewards. Ignoring inefficient operation easily could drain profits. ●

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Optimize your Steam System

A simple four-step approach can improve steam efficiency

By Ven V. Venkatesan

FOR MOST process plants, steam systems are so vital they could be compared with the human body's blood circulating system. Hence, consider steam system losses just as life-threatening as a severe blood loss in our own bodies.

Maintaining an efficient and reliable steam system is very critical for the plant's process integrity and financial health. Recently, I came across a plant that survived market recessions successfully simply because it optimized its steam system costs when market conditions were good. In this two-part series, we will review four steps for steam system optimization.

Step 1: Review your steam generation systems. First, we have to ask ourselves, "Did we convert our purchased fuels into steam at the best possible efficiency?" Reviewing parameters for stack temperature and stack oxygen content could help identify deviations and the best possible efficiency levels. The parameters relevant to cost optimization include fuel costs and unutilized waste, such as heat steam generation.

At many sites I visit, one of the most common areas in need of steam system efficiency improvements is the steam generator or boiler. The two combustion optimization efforts — excess air control and additional heat recovery that we discussed in our first two columns, "Take a Fresh Look at Your Process Heaters" — Part I and II (<http://goo.gl/8oTeBV> and <http://goo.gl/dumkqb>), are also applicable to the fired boilers.

Boilers offer additional opportunities for efficiency improvements. One is the blowdown control. Though well-established, automatic blowdown systems are still not available in many operating boilers. Depending upon the boiler's feed water quality, blowdown losses could change from insignificant to significant levels. Adding an automatic blowdown controller could easily reduce and maintain the blowdown losses, instead of depending on manual control only. Even with an automatic blowdown system in service, it is necessary to regularly monitor the feed water and drum water qualities to maintain the desired blowdown levels.

Another common efficiency improvement opportunity is the blowdown heat recovery. If there is no blowdown heat recovery system in place at your plant, consider adding one that would recover flash steam and sensible heat separately to conserve feed water and reduce waste water.

Step 2: Perform a critical evaluation of the steam distribution system. Steam distribution systems commonly suffer from both visible and invisible losses. Continuous flow of high-pressure steam to a lower pressure header through a pressure reducing valve (PRV) is one of the invisible losses. Supplying steam from higher-than-required pressure to a user is another kind of invisible loss.

[For details about the use of models to provide insights, including for dealing with upsets and transient conditions, see “Consider Dynamic Simulation for Steam System Design,” <http://goo.gl/RsPv1S>.]

The concept of cogeneration is to recover the mechanical energy in reducing the high-pressure steam into low-pressure steam and then utilize the latent heat for process heating. It may be worth running some pumps or blowers with steam, if there is a constant flow of high pressure steam through a PRV.

Space heating during winter months and most tank farm heating require only low-pressure steam. If you notice a high-pressure steam supply to such users at your site, reconsider supplying low-pressure steam to them.

Failed steam traps in closed condensate collection systems are another kind of invisible distribution system loss. Whenever there’s excessive backpressure in the condensate return system or

excessive venting at the collection tank, the most probable cause is typically failed steam traps. A systematic steam trap survey could identify the problem.

Leaks and missing insulation are some of the visible losses in a steam distribution system. Standardized methods already exist to fix these visible losses and so do not delay in taking these obvious actions.

Step 3: Review steam utilization by various steam users. The most useful part of steam’s heat content is its latent heat, rather than its sensible heat. (Superheated steam is preferred only to supply steam turbines.) To fully utilize the latent heat in steam, two critical factors apply:

1. continuous removal of condensate from the heat exchanger and
2. maintenance of the lowest possible backpressure.

If the condensate removal is reduced, condensate could flood heat exchanger surface, limiting the area available for heat transfer. If the backpressure at the outlet of an exchanger increases, the latent heat available from steam would be reduced gradually.

When the backpressure equals the supply steam pressure, the heat exchanger potentially could stall. Hence, it is better to check the existing heating control systems to ensure the steam-heated exchanger is neither flooded nor stalled. [For more on such issues, see “Make the Most of Condensate,” <http://goo.gl/QNV4Qc>.]

For optimized steam use consider other options to do the same job. Switching to motor drives, instead of steam turbines, is a common alternative when excessive low-pressure steam is vented.

However, when high-pressure steam is continuously dropped through a valve to lower pressure level, installing a steam turbine is a better option.

Another option is to use mechanical vacuum pumps in place of steam jet ejectors. At low ranges of vacuum creation, steam jet ejectors need at least ten times more input energy than mechanical vacuum pumps. Also, whenever steam jet ejectors are used the condensate must be drained to the sewer, adding to the wastewater treatment plant load.

Many process plants use steam strippers, where steam directly contacts the process streams to raise the temperature of the incoming stream and then strip out the intended component. It would be more efficient to indirectly heat the incoming stream in a separate (external) exchanger, then supply steam only for the purpose of stripping. This would recover part of the supplied steam as condensate and reduce the amount of wastewater generation.

It is very common to see many air-cooled and cooling-water exchangers. Thus, one option to optimize steam use is to preheat the incoming stream with a process stream that goes to cooling. It may be possible to identify a suitable heat source nearby. In some plants, the wasted heat from boiler or furnace exhausts also could be utilized to preheat the incoming stream. Keep in mind the concept of “pinch” technology — matching suitable heat sinks and heat sources.

Step 4: Recover and reuse the condensate to the maximum possible extent. Steam systems are designed to work on 100% make-up boiler feed water. In the most efficient steam systems, the make-up

water addition is only about 20%.

At present, most process plants must treat and dispose wastewater they generate. The steam condensate, if not collected and reused, would end up in the wastewater stream. So first, have your energy or utility engineer calculate the value of the steam condensate. It could be surprisingly high, justifying many condensate recovery actions.

Reasons for not recovering and reusing the condensate include:

1. collection pipes and pumps weren't provided in the initial design,
2. fear of contamination in the condensate, or
3. concerns about backpressure/water hammer in the return system.

Modern online analytical instruments can obviate fear of contamination, eliminating that excuse for draining the condensate. Specialists can easily address backpressure and water hammer in the return system. In addition, reengineering the existing system with necessary piping changes and additions could eliminate the water hammer problem. Cases exist where prolonged water hammer caused catastrophic damages to the integrity of steam systems — with a few ending in fatal accidents. Eliminating water hammer not only optimizes the steam system, but improves the system's integrity. ●

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Head Off Exchanger Errors

Selecting the most-appropriate heads for a shell-and-tube unit is crucial

MOST PROCESS shell-and-tube heat exchangers are manufactured to Tubular Exchanger Manufacturers Association (TEMA) standards. These standards include a three-letter designation of the exchanger type that specifies overall mechanical layout in the form: front-end head, shell type and rear-end head.

Figure 1 shows the most common front-head-end and rear-head-end designations. It illustrates a two-pass exchanger configuration on the tube side. The front-end head gets the tube-side fluid into the exchanger. Multiple tube-pass exchangers include a channel to separate the flow in each pass. Table 1 provides rough guidelines for application of the common front-end heads.

A-type heads allow for easy access directly to the

tube sheet without having to disconnect the head from the piping. This makes tube cleaning relatively straightforward. B-type heads also allow access to the tube sheet for cleaning but require removing the head from the piping. B-type heads eliminate one body flange ring and, so, are less expensive.

C-type heads have the tube sheet integral with the head, which usually is welded to the tube sheet. However, in lower-pressure and smaller-diameter applications, the tube sheet may be welded inside a flanged pipe section. C-type heads most often are used with hazardous tube-side services that still require cleaning. The welding eliminates one area where leaks might occur.

N-type heads have the head, tube sheet and shell

FRONT-END-HEAD GUIDELINES

TYPE	DESCRIPTION	FAVORED APPLICATIONS
A	Removable cover, channel integral with head	Fouling tube-side fluids
B	Bonnet	Clean tube-side fluids
C	Removable cover, channel and tube-sheet integral with head	Hazardous service on tube side
N	Removable cover, channel, tube-sheet and shell integral	Hazardous service or very clean fluid on shell side

Table 1. Each type of head suits a different specific service.

FLOATING-REAR-END-HEAD GUIDELINES

TYPE	DESCRIPTION	FAVORED APPLICATIONS
S	Backing ring	Moderately fouling shell-side fluids
T	Pull-through head	Fouling shell-side fluids
U	U tubes, no internal head	Maximum area needed in shell

Table 2. The head variants best handle certain kinds of applications.



all welded together. They typically are selected when both the tube and shell sides contain hazardous materials. They also may be used in very clean shell-side services to save money. The design must allow for thermal expansion. Most exchangers will require expansion joints in the shell to accommodate thermal stresses due to different temperatures on each side. Without thermal expansion joints, the exchangers tend to leak at the tube sheet.

The rear head can be either fixed or floating. The fixed-head types have similar configurations to front-end heads: the L-type resembles the A-type front-end head, the M-type the B-type front-end head, and the N-type the front-end N-type. They all have the same benefits and constraints as the corresponding front-end heads.

Floating heads have completely different configurations. The floating head disconnects the rear end of the tubes from the shell. This allows for differential thermal expansion between the shell and tubes without need for expansion joints. Table 2 highlights particularly suitable uses for the most common rear-end-head types: the S, T and U. The S-type and T-type use an internal head; both allow for the simplest tube replacement.

The S-type has a two-piece backing ring that flanges to the internal head to keep the shell fluid and the tube fluid separated. The backing ring normally is larger than the inside diameter of the shell. This configuration enables tubes to be relatively close to the shell wall. It does require taking the rear head off the exchanger to pull the tube bundle out.

The T-type doesn't use a backing ring. The internal flange for the rear head is smaller than the shell diameter. The tube bundle can be removed for cleaning the shell side without needing to open the rear end of the exchanger. T-type rear heads routinely are used when the shell-side fluid is fouling. Due to the clearance required for the rear head, T-type exchange-

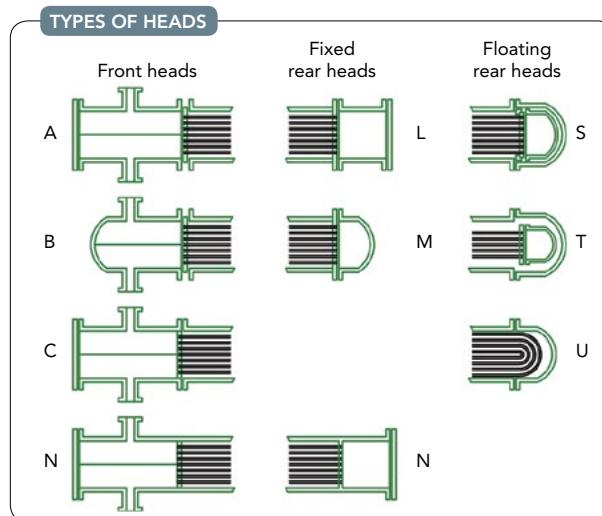


Figure 1. The Tubular Exchanger Manufacturers Association provides specific designations for heads.

ers are larger for the same area or have less area for the same shell than S-type ones.

U-type exchangers completely dispense with the internal tube sheet — enabling the tubes to be placed closer to the shell wall. This minimizes shell size for new exchangers or provides the maximum area for an existing shell. The U-tube configuration allows each tube to expand or contract independently. For multiple-pass exchangers, this may be important because tube passes may significantly differ in temperature. Except for the outside tubes, tubes can't be replaced easily. Tube leaks normally are dealt with by plugging a tube.

Each of these configurations fills specific niches. Choosing the right configuration is the starting point to a cost-effective and usable shell-and-tube exchanger. For tips about allocating fluids in tubular exchangers, see: "Pick the Right Side," <http://goo.gl/aijRl4>. ●

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