

Optimising steam systems: part I

Simple techniques to reduce the cost of ownership of a refinery's steam distribution system and condensate return using steam traps and separators

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So far 2010 is proving to be another challenging year for the refining industry. Not only is it currently experiencing spare oil production capacity of over 6 million barrels/day, leading to a fall in refining margins, but the US Environmental Protection Agency (EPA) has confirmed its stance, that greenhouse gases (GHGs) are a threat to health and welfare. This has led to the Mandatory Reporting of Greenhouse Gases Rule, requiring all US oil and petrochemical companies, as with all sectors of the economy, to monitor and report their GHG emissions. In Europe, the EU has committed to cutting its CO₂ emissions by 20% by 2020 from 1990 levels.

This article, and part II to be published at a later date, looks at ways of optimising the steam system, to reduce energy costs (lowering GHG emissions), water consumption and boiler chemicals. In addition, ensuring the steam is of the correct quality, quantity and pressure when it arrives at its point of use can improve process performance.

It is estimated that steam generation accounts for approximately 50% of the total energy consumption in a typical refinery, with energy costs accounting for more than 50% of the total operating expenditure.

The US Department of Energy estimates that steam generation, distribution and cogeneration offer the most cost-effective energy efficiencies in the short term, with potential energy savings of more than 12%. Table 1 estimates the typical savings that can be achieved

Potential savings in a refinery's steam distribution system and condensate return				
Measure	Fuel saved, %	Payback period, yr	Other benefits	
Steam distribution	Improved insulation	3–13	1.1	
	Steam trap maintenance	10–15	0.5	
	Automatic steam trap monitoring	5	1	
	Leak repair	3–5	0.4	Reduced requirement for major repairs
	Flash steam recovery/condensate return	Dependent on existing use for flash steam	Variable dependent on application	Reduced water consumption and water treatment costs
Condensate return alone	10	1.1	Reduced water consumption and water treatment costs	

Table 1

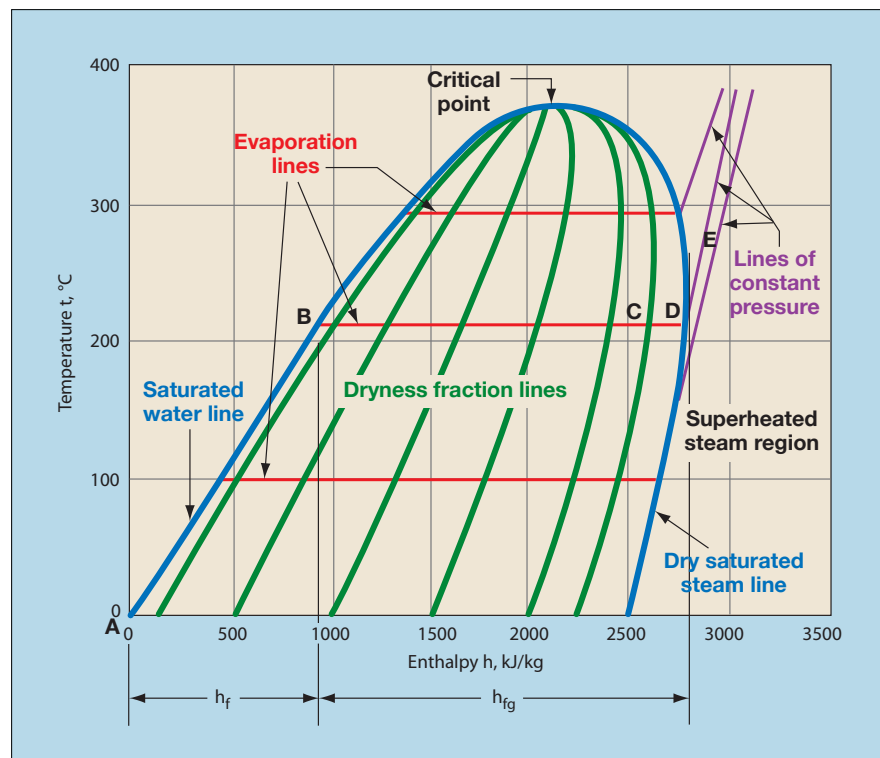


Figure 1 Temperature enthalpy diagram

for the steam distribution system and condensate return of a US refinery.

Further savings can be achieved in the powerhouse where steam is generated. However, this article

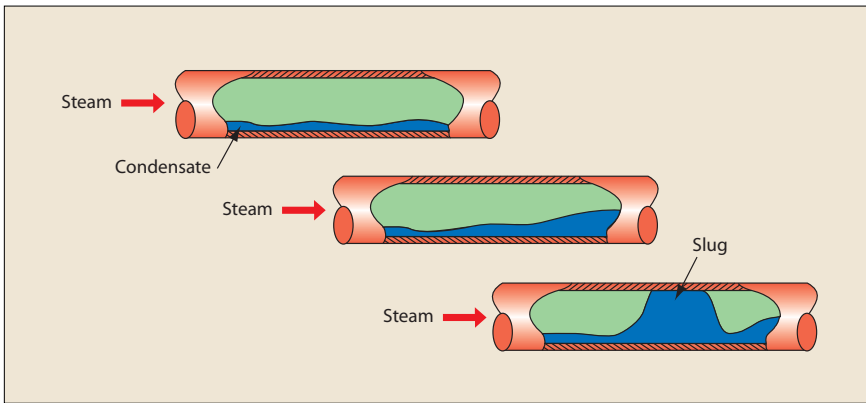


Figure 2 Development of conditions for water hammer

will examine only steam distribution and condensate return.

Before looking at potential improvements and ways of optimising the steam system, it is worth understanding the basic properties and characteristics of steam. These can be outlined in a temperature enthalpy diagram (see Figure 1).

When energy is added to water, the temperature rises until it reaches the point of evaporation (point B in Figure 1), which varies with pressure. The energy required to reach point B is sensible heat (h_p). Any additional energy will convert the water to steam at a constant temperature. At point D, all water has been completely converted to steam, which is known as dry saturated steam with a steam quality (dryness fraction) of 100%.

The energy added between points B and D is the enthalpy of evaporation (h_{fg}) and is the energy steam gives out as it condenses back to water. It is the enthalpy of evaporation that is used in refining.

If further energy is added, the steam's temperature will increase, creating superheated steam (E). Superheated steam is used in a typical powerhouse (at approximately 100 barg and 450°C) as part

of the cogeneration or combined heat and power (CHP) system.

For heating purposes, superheated steam offers very little extra energy and, in fact, the steam has to cool to saturated temperature before the enthalpy of evaporation can be released. Therefore, using superheated steam instead of saturated steam at the point of use actually slows down the heating process.

For the process to achieve maximum efficiency, steam needs to arrive at the correct:

- Quality: target dryness fraction of 100%
- Quantity to allow the process to meet demand
- Pressure, which determines saturated steam temperature and specific volume, so affecting thermal transfer.

Steam quality is a measure of dryness fraction. If the dryness fraction is lower than 100% (say, point C in Figure 1), the available energy/kg of steam is less. Steam quality can be improved by ensuring the mains are well insulated and condensate is removed effectively using steam traps and separators.

The quantity of steam required will depend on the process energy

requirements. Effective delivery relies on correct sizing of the steam distribution lines and control valves serving the application. This can become an issue when processes are upgraded or additional assets are added, as it increases the steam load beyond the steam mains original specification. This results in increasing velocities within the steam system, causing higher pressure losses through the distribution system. If the steam pressure is lower than the acceptable design pressure, the process is de-rated, as the steam is at a lower saturation temperature, reducing the energy transfer rate.

Several key areas have the greatest effect on reducing energy costs and improving efficiency: steam system insulation, water hammer and steam trapping.

Steam system insulation

Steam mains and ancillary equipment must be effectively insulated, in particular valves, strainers and separators, which have large surface areas. After any maintenance work on the steam system, the insulation must be replaced properly; good insulation reduces heat losses by up to 90%.

To put this into context, 1m of an uninsulated 100mm steam main operating at 10 barg emits approximately 1.0 kW, which is equivalent to wasting nearly 16 tonnes of steam a year. This assumes that the pipe is dry and there is no wind chill. Good insulation reduces these losses to approximately 1.6 tonnes of steam a year.

But even when insulation standards are good, a certain amount of steam condenses out during distribution. This needs to be removed to maintain steam quality and prevent the possibility of water hammer.

Water hammer

As steam begins to condense, condensate forms droplets on the inside of the walls. These are swept along in the steam flow, merging into a film. The condensate then gravitates towards the bottom of the pipe, where the film begins to increase in thickness.

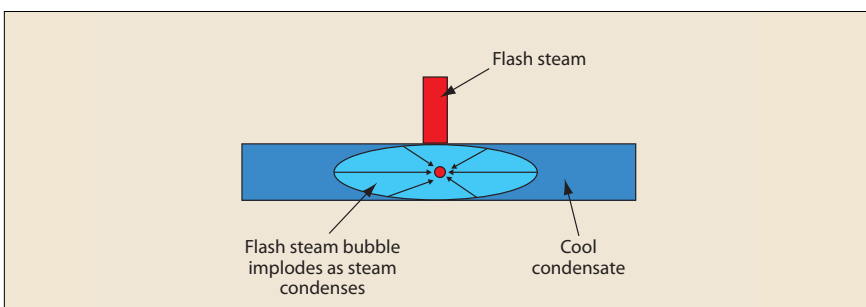


Figure 3 Development of conditions for thermal shock

Three main types of steam trap

Mechanical	Thermodynamic	Thermostatic
<i>Principle of operation:</i> Distinguishes between steam and condensate using difference in density between steam and condensate	<i>Principle of operation:</i> Distinguishes between steam and condensate through variation of flow dynamics between the two fluids	<i>Principle of operation:</i> Uses difference in temperature between steam and condensate
Removes condensate as it forms	Removes condensate as it forms	Condensate has to cool below the steam saturation temperature before the trap will open, which leads to backing up of condensate

Table 2

The build-up of droplets of condensate along a length of steam pipework can eventually form a slug of water, which will be carried at steam velocity (25–30 m/s) along the pipework (see Figure 2). This slug of water will eventually slam into bends in the pipework, valves or separators in its path.

There is a second cause of water hammer known as thermal shock. This occurs in two-phase systems, where water occurs in two states (water and steam) in the same pipe. It can also occur in steam mains, condensate return lines and heat exchange equipment. Steam bubbles become trapped within pools of condensate, which have cooled sufficiently below saturated temperature and immediately collapse.

Since a kilogram of steam occupies several hundred times the volume of one kilogram of water,

when the steam collapses condensate is accelerated into the resulting vacuum. As the void is filled, water impacts the centre, sending shock waves in all directions.

Thermal shock can, therefore, occur where higher temperature return systems containing flash steam are discharged into sub-cooled condensate return lines. The forces resulting from water hammer can be immense, causing steam mains to physically move or, in worst-case scenarios, rupture.

At best, water hammer increases maintenance costs and at worst a ruptured steam main will bring the plant to a halt, possibly causing injury to personnel. Water hammer can be prevented easily through good engineering practice and by using steam traps at regular intervals to prevent the build-up of condensate.

Steam trapping

Some of the most common problems found in a steam system can be traced back to either the steam trap application or poor condensate removal. These issues can normally be resolved through good engineering practice, selection of the correct steam trap and a steam trap management programme.

Types of steam trap

When selecting steam traps, it is worth remembering that most use three principles of operation, summarised in Table 2. Each principle has its strengths and weaknesses, dependent on the application being served. Table 3 gives examples of applications and the preferred type of trap for the application.

There are some general rules and guidelines on where to position steam traps:

Preferred type of trap for various applications

Application	Trap types	Comments
Process applications eg, heat exchangers: Reboilers Preheaters Water heaters	Mechanical	Mechanical steam traps will remove the condensate as it forms, regardless of fluctuating loads, ensuring maximum steam space and heating surface area within the heat exchanger Mechanical steam traps also have the greatest capacity, making them ideal for process applications
Distribution lines eg, steam mains	Thermodynamic	Thermodynamic traps are robust and relatively low cost. TDs remove the condensate as it forms, so eliminating the risk of condensate backing up into the steam line
	Thermostatic	Thermostatic traps, by their nature, will back up with condensate, but they are robust and relatively low cost. Thermostatic traps can be used on distribution mains, providing there is a “cooling leg” between the trap and the steam mains
Critical tracing eg, sulphur lines	Thermodynamic	Thermodynamic traps are the first choice, as they are compact, robust and low cost. They remove condensate as it forms, ensuring the traced product does not solidify
	Mechanical	Mechanical traps are also used, but tend to be less compact
Non-critical tracing eg, instrumentation	Thermostatic	Thermostatic traps allow the condensate to sub-cool within the tracer before being discharged. This makes use of the sensible heat in the condensate and reduces the release of flash steam, particularly important if the trap is discharging to grade

Table 3

- Along the steam main at approximately every 30–50m intervals, using a pocket that is the same diameter as the steam main up to 100mm. This will ensure all condensate running along the bottom of the pipe is captured and removed (see Figure 4)

- At all low points on the steam main and wherever the steam main rises; at a gantry, for example

- Before control valves, in particular valves serving a process. A separator ensures steam entering the process is dry, saturated steam, improving the efficiency of heat exchange. It also minimises the risk of erosion of the control valve, reducing maintenance costs, and ensures condensate is drained when the control valve is in the closed position, preventing the risk of water hammer. A typical separator and trap installation protecting a pressure control valve station is shown in Figure 5

- Before steam isolation valves, to remove the potential build-up of condensate when the valve is closed

- At the end of each steam main; this should be fitted with either a steam trap with good air venting properties or a separate air vent.

Modern steam trap stations normally consist of quick-fit connectors, which allow traps to be isolated and changed in minutes. This has significantly reduced maintenance costs and the total cost of ownership of steam traps.

Testing and maintaining steam traps

Modern steam traps are generally reliable and robust, assuming they have been correctly sized and selected for the given application. However, they can fail. A steam trap has two modes of failure: it can fail either open or closed/blocked.

If a steam trap fails open, there are two major consequences:

- Steam wastage, resulting in higher energy costs/greater emissions, increased consumption of water and boiler feed chemicals

- If the condensate is being returned, the condensate line becomes pressurised, which can have the effect of de-rating the capacity of any other steam trap discharging into the same conden-

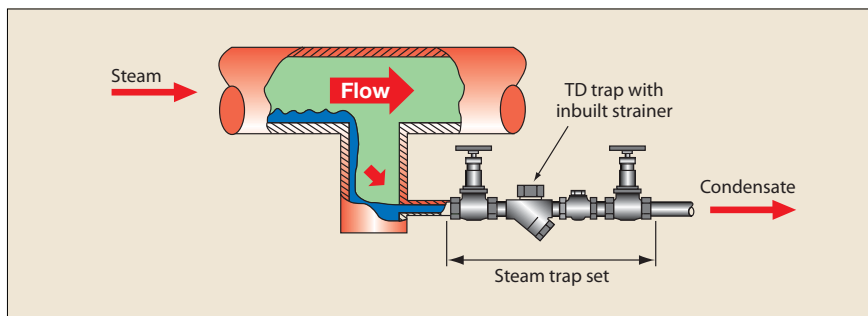


Figure 4 Steam trap arrangement

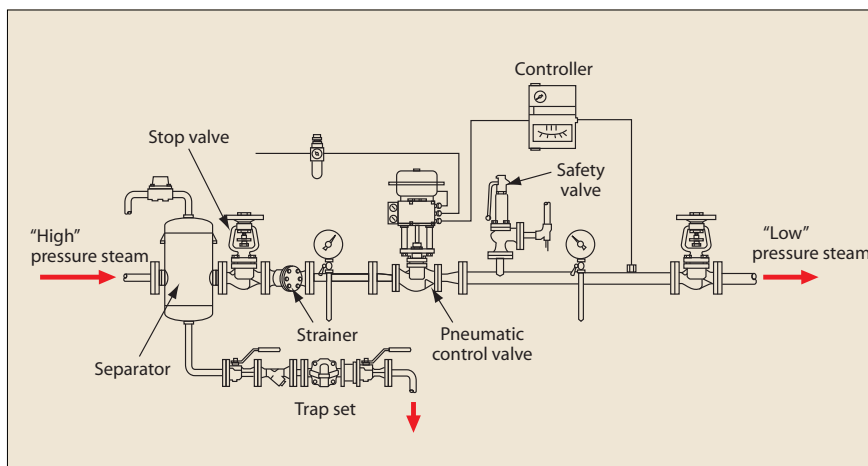


Figure 5 Typical separator and trap installation

During a steam trap audit, it is not unusual to find more than 10% of the steam trap population failed open

(HP), medium-pressure (MP) and low-pressure (LP) steam mains when failed open. Although the figures are conservative, this clearly shows the need to ensure steam traps are checked regularly and failed traps replaced as soon as possible. HP traps should be checked at least every six months, while MP and LP traps annually.

During a steam trap audit, it is not unusual to find more than 10% of the steam trap population failed open, where a customer has not implemented a steam trap management scheme. In value terms, this normally shows potential annual savings of \$100 000s, with a payback of less than six months. Figure 5 shows examples taken from actual steam trap audits.

sate line. This is because the differential pressure across the steam trap has been reduced, so less condensate will pass through a given sized orifice.

Table 4 shows typical steam losses from a single 1/2 inch TD steam trap used on high-pressure

Steam losses from a 1/2 inch TD steam trap		
Line pressure	Approx steam loss, t/yr* (discharging into condensate line)	Approx steam loss, t/yr* (discharging to grade)
100 barg	460	920
20 barg	95	190
5 barg	25	50

* Based on 8700 hours/year

Table 4

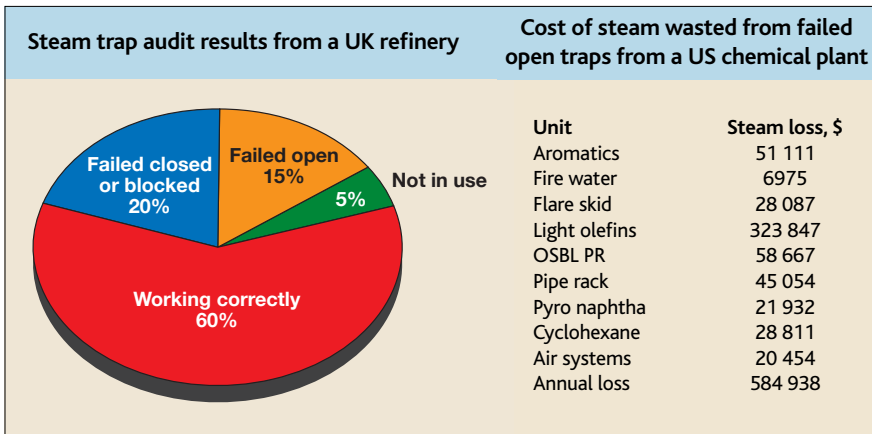


Table 5 Steam trap audits of UK and US refineries

Cold steam traps

Cold steam traps are either failed closed, blocked or have been isolated (having failed open). Although it is harder to achieve a return on investment by repairing these traps, the consequences of ignoring this situation can be much more costly. Failing to replace or maintain cold traps can result in:

- Corrosion leading to system degradation and increased maintenance costs

- Water hammer, with the potential for catastrophic failure of the steam system — a major safety issue
- Freezing, leading to pipe ruptures
- Valve erosion, wire drawing, vibration and failed valve packing, where traps have failed upstream of control valves
- Corrosion and loss of heat transfer on tracing lines, leading to higher pumping costs or

solidification of the product being traced

- Blade erosion, vibration and drive shaft wear on turbines.

Separators on a steam system

Separators are used to remove entrained water in the steam system, to bring the steam quality to nearly 100%. They consist of baffle plates, which separate the water droplets from the steam flow (see Figure 6).

Separators should be installed in the following applications:

- Upstream of control valves, particularly just before a process where they: protect steam equipment from erosion caused by wet steam; ensure the process receives dry saturated steam, so improving performance; and drain the build-up of condensate upstream of the control valve when in the closed position
- At boiler off-take, to knock out any carry-over prior to distribution
- Downstream of desuperheater stations, to remove any remaining

water that was not absorbed by the superheated steam

- Upstream of steam turbines, preventing the risk of damage through water droplets or water hammer.

Desuperheater stations

Superheated steam is generated in most plant powerhouses as part of the cogeneration or CHP process. The pressures and temperatures generated are far too high to be used in most refining and petrochemical processes. Therefore, this HP superheated steam is let down to the MP and LP distribution lines, using turbines or pressure-reducing stations.

All steam desuperheaters work on the same principle: injecting water into the superheated steam, where it evaporates, absorbing excess energy and resulting in steam with approximately 5°C of superheat. This remaining superheat is soon lost as the steam is distributed to the point of use. Figure 7 shows a typical desuperheater application on a letdown station.

The quantity of water required to desuperheat the steam is controlled by maintaining the steam temperature downstream of the desuperheater to between 5°C and 10°C above the steam saturation temperature.

If the temperature is too close to

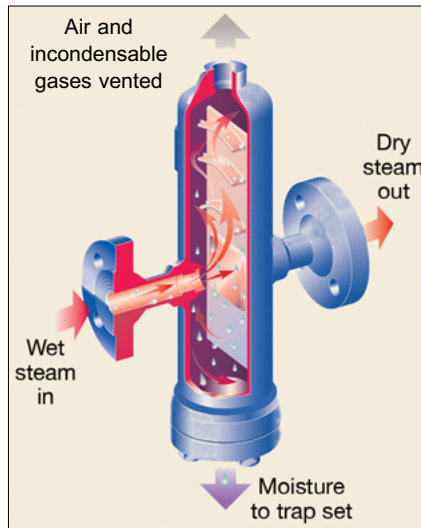


Figure 6 Steam system separator

the saturation curve, there is a risk that too much water will be injected into the system, leading to poor steam quality and all the problems associated with this. If the temperature is too high, excessive superheat will remain, affecting the performance of the downstream process.

Although not much can go wrong with the average desuperheater, it is worth checking the required set points for temperature and pressure, and whether the desuperheater is still correctly sized, particularly if operating conditions or parameters have changed.

Conclusion

This article has discussed the importance of ensuring steam

reaches its point of use at the correct quality, quantity and pressure, and has looked at some of the key areas to consider in reducing maintenance costs and energy losses; namely the impact poor steam quality can have on the steam system and how this can be improved through:

- Ensuring the steam system is properly insulated
- That condensate is promptly removed from the distribution system
- Using the correct steam trap for a given application
- Putting in place a steam trap management programme
- The use of separators
- Checking the installation and performance of desuperheater stations.

The second part of this review of steam system optimisation will consider steam at the point of use and the importance of returning condensate back to the powerhouse. It will also look at examples of why heat exchangers stall and how this has been overcome, together with ways of utilising flash steam within the plant.

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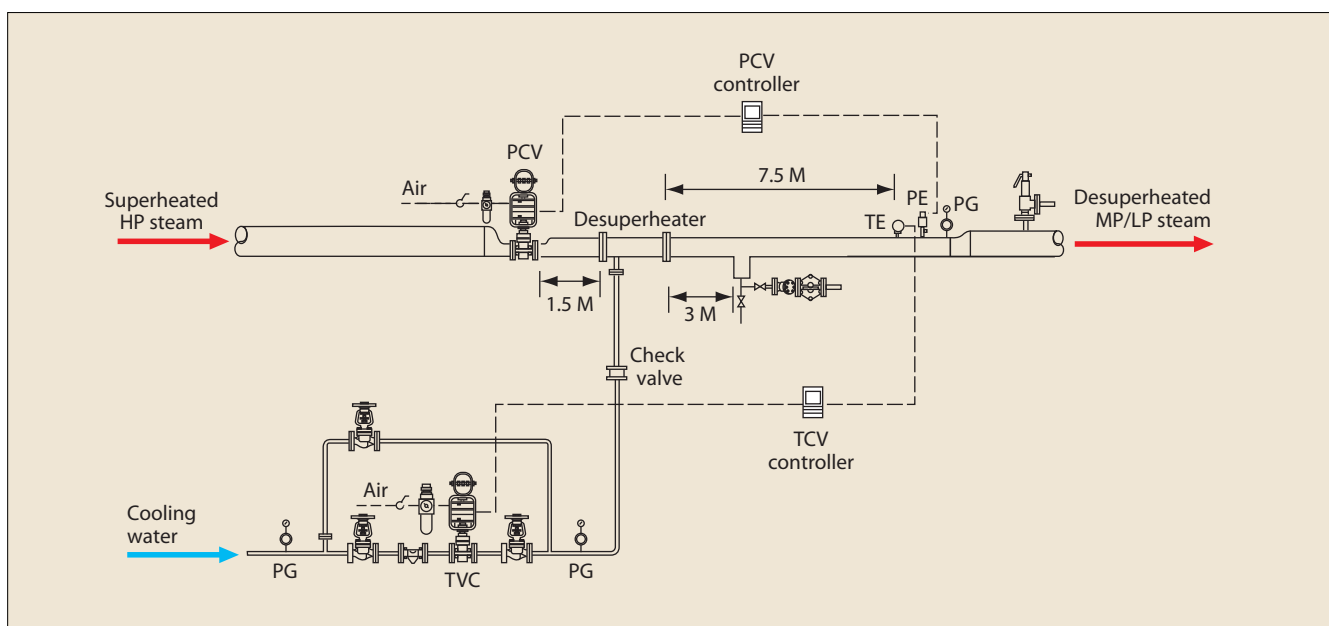


Figure 7 Desuperheater application on a letdown station

Optimising steam systems: part II

A second article on steam system optimisation addresses steam at point of use and good engineering practice to remove and return condensate

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Use of steam in the oil and petrochemical sector can be classified under:

- Primary process requirements; for instance, a reboiler on a distillation column
- Secondary process requirements such as steam tracing
- Emergency requirements, including snuffing in the case of fire or turbine rupture
- Utility requirements such as turbogenerators.

Steam in process heating

Steam is used to vapourise, preheat and heat a process. Regardless of the heat exchanger used, whether it is a kettle-type reboiler (shell and tube), plate-type heat exchanger or heating coils in a tank, the principles of operation and the end result on the steam side are very similar.

When using steam, the rate of heat transfer in a heat exchanger can be defined (in its simplest form) by a basic equation:

$$Q = U \cdot A \cdot (T_s - T_p)$$

Where:

Q = Heat transfer rate, W

U = Heat transfer coefficient, W/m² °C

A = Heat transfer surface area, m²

T_s = Steam saturation temperature, °C

T_p = Mean process temperature, °C

The heat transfer coefficient, U, decreases during operation due to fouling, so heat exchange manufacturers add in a fouling factor to ensure that the reboiler, for example, meets the process load for the required service period. The fouling factor is the additional heat transfer surface area (A) of the heat

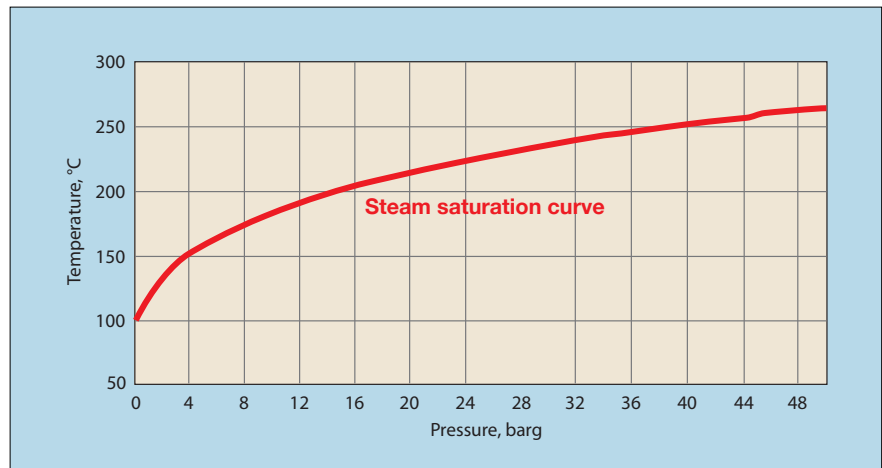


Figure 1 Steam saturation curve

exchanger, which can be anything from 10–50% greater than the area required for a clean surface (depending on the process). The importance of the fouling factor on steam loads and condensate removal will become apparent later in this article.

The steam saturation temperature (T_s) is determined by the steam pressure within the heat exchanger and is defined by the steam saturation curve (see Figure 1). The control valve therefore achieves the correct process temperature by limiting the steam flow (and consequently the steam's pressure/temperature) entering the heat exchanger, replacing the steam that has condensed as it gives up its enthalpy of evaporation to the process fluid. As demand increases, the control valve opens, increasing the steam pressure and temperature, leading to a greater heat transfer rate.

If demand reduces, the control valve throttles and the opposite occurs, lowering the steam pressure

and temperature on the primary side. In addition, if the heat exchanger is new or has just been cleaned, the additional fouling factor may lead to a significantly greater heat transfer surface area (A) than is required for the actual duty, resulting in a lower steam temperature requirement. It is not unusual to find heat exchangers operating with steam pressures just above atmospheric conditions or even at sub-atmospheric pressures, regardless of the steam pressure upstream of the control valve. Understanding this helps to explain the root cause of many of the problems arising with heat exchangers and how they can be overcome.

Heat exchanger stall

Stall occurs when the steam pressure in the heat exchanger drops below the back pressure (condensate line pressure) acting on the steam trap. This prevents the flow of condensate through the steam trap, which in turn causes the condensate to back up. Although

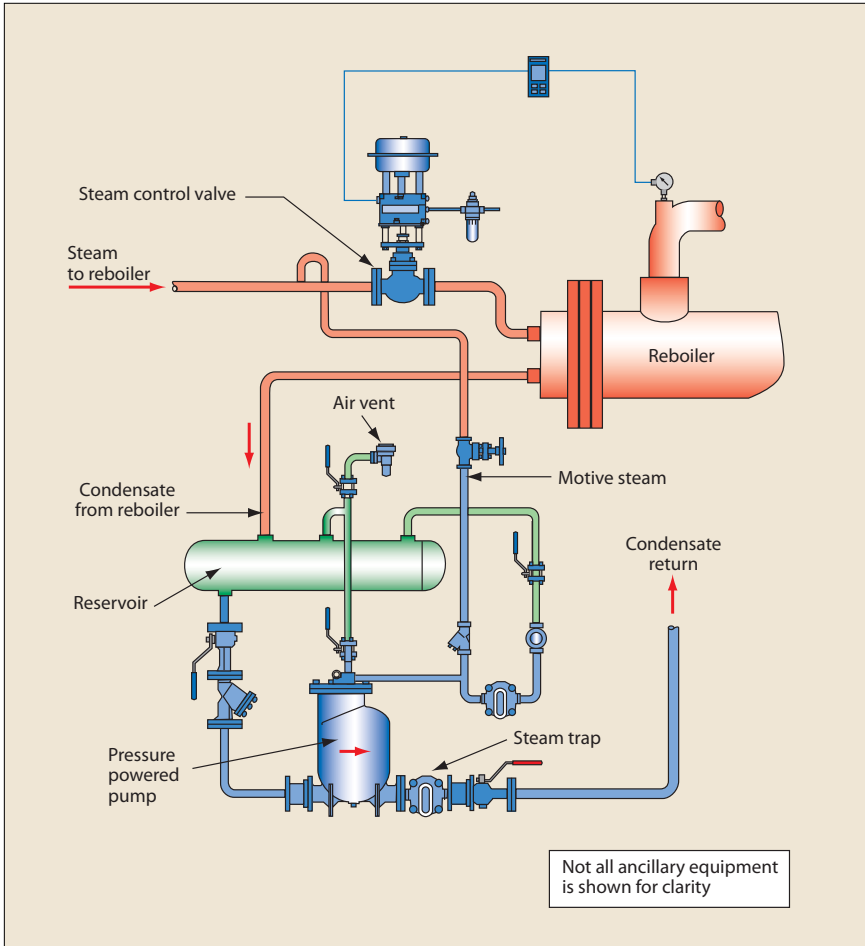


Figure 2 Condensate pump arrangement to overcome stall

this sounds unusual, it is a fairly common situation, particularly on temperature-controlled equipment.

Typical symptoms indicating that a heat exchanger is suffering from stall include:

- Cold or cool steam traps draining the heat exchanger, due to a back up of condensate in the heat exchanger
- Corrosion within the heat exchanger, due to waterlogged condensate standing in the steam space. Many operators believe this is normal and accept it as a fact of life. (It is worth mentioning that corrosion is also a sign of poor water treatment, which should also be investigated)
- Unstable control or cyclic temperatures of the process fluid: as the heat exchanger stalls, it begins to flood, reducing the heat transfer surface area and heat transfer rate. The control valve opens to meet the demand and, in so doing, the steam pressure rises, which in turn overcomes the stall conditions and the condensate is rapidly removed from the heat exchanger. With this

sudden increase in available effective heat transfer surface area, the process starts to go over-temperature. The control valve closes and the cycle repeats itself

- Mechanical stress and cracking in the heat exchanger can be caused by the difference in temperature between steam at the top of the heat exchanger and cool condensate at the bottom
- Water hammer can lead to premature failure of the heat exchanger or surrounding pipe-work. The heat exchanger makes cracking, banging or thumping noises as hot steam bubbles, implode as they condense. Since steam has a considerably higher specific volume compared to water, when the steam collapses condensate is accelerated into the resulting vacuum. As the void is filled, water impacts the centre, sending shock-waves out in all directions
- Water and energy losses are caused by the steam trap bypass valves being left open and conden-

sate being dumped in an attempt to achieve the required process conditions.

Stall can occur when:

- The process temperature is less than 100°C (implying steam temperature on the primary side could be lower than 100°C and therefore below atmospheric pressure)
- The heat exchanger is oversized (which may be necessary to allow for fouling)
- Heat exchanger loads vary, resulting in the control valve having to throttle on low load conditions
- Back pressure is present on the condensate line due to lift, failed open steam traps pressurising the line or if the line is undersized for the condensate loads and flash steam generated.

Stall is easily overcome by using a condensate pump, which allows condensate from the heat exchanger in question to drain freely. A typical arrangement is shown in Figure 2.

When steam pressure on the primary side exceeds the condensate back pressure, condensate passes through the pump body, check valves and steam trap, discharging into the condensate line. Under stall conditions, the condensate backs up in the pump body, lifting a ball float, which closes the exhaust valve and opens the motive steam valve. This pressurises the pump body, forcing condensate into the condensate line. The check valves ensure condensate can only flow in one direction. Figure 3 shows a typical mechanical pump operation.

Stall

To illustrate the effect stall can have on a process, a refinery wished to increase the capacity of one of its columns. Instead of replacing the existing reboiler, it made more commercial sense for the refinery to install an additional shell and tube heat exchanger to preheat the feed column. Once installed, however, the preheater, which had to deal with varying loads, did not meet the required capacity. The inverted bucket trap seemed undersized, but bypassing the steam trap only helped occasionally. Stable control

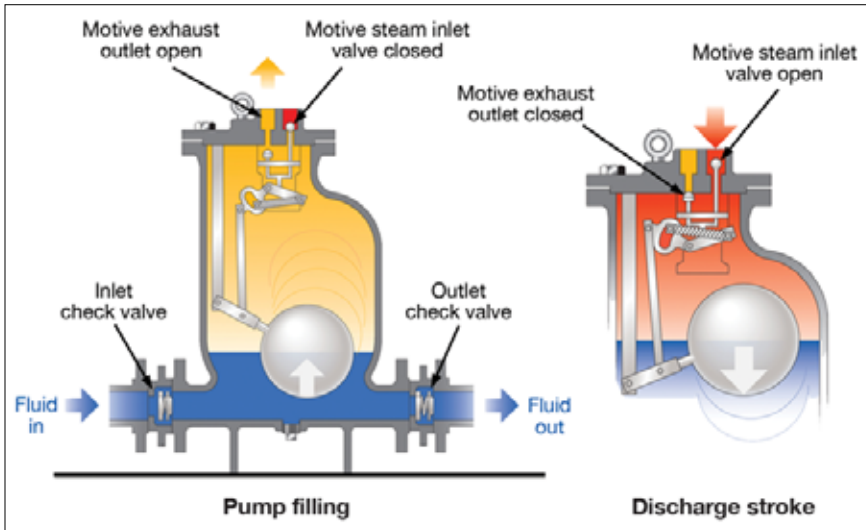


Figure 3 Operation of a mechanical pump

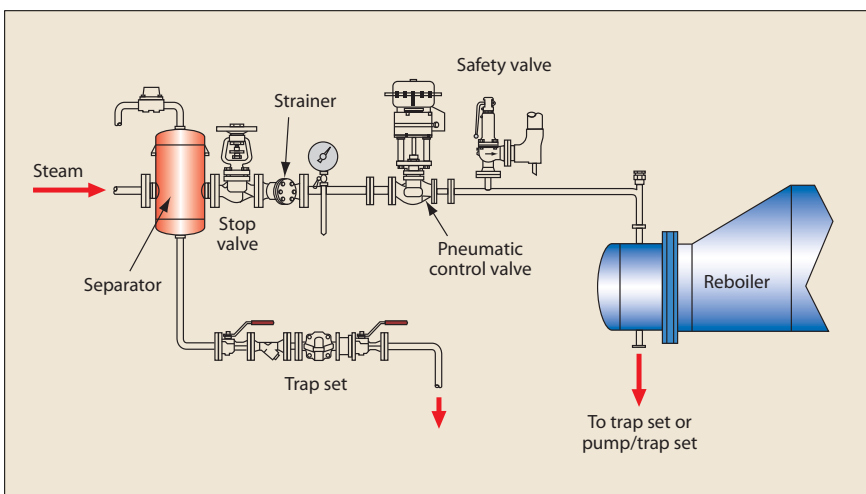


Figure 4 Controlling steam supply to a reboiler

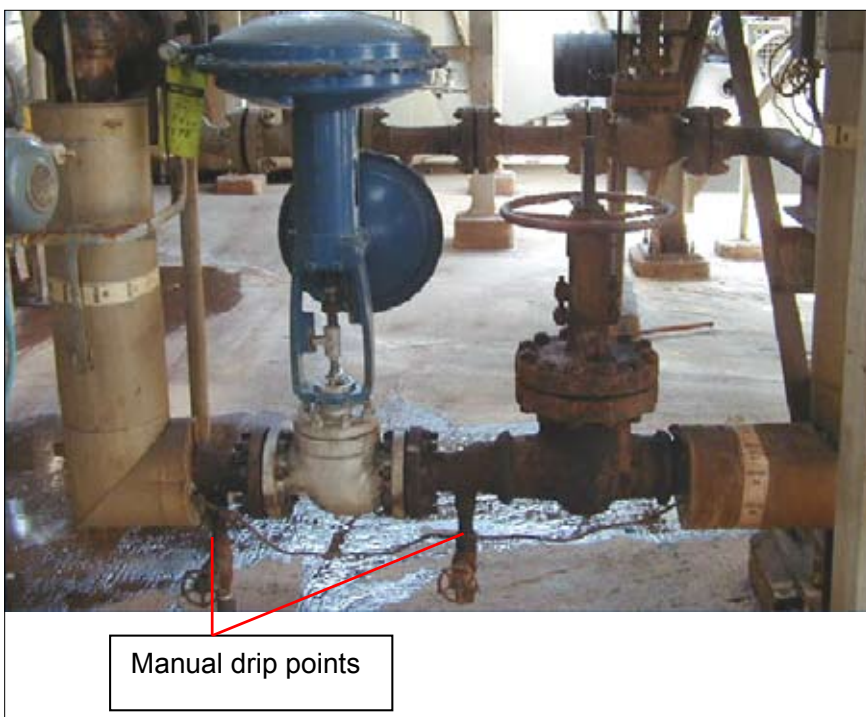


Figure 5 Incorrect control valve installation

could not be achieved and condensate was being dumped at an average rate of 4000 kg/h.

It was discovered that the preheater was operating under clean conditions (maximum fouling factor) and on low loads the control valve was only 25% open. The condensate temperature upstream of the trap was measured at 105°C, which equates to a saturated steam pressure of 0.2 barg. The total back pressure acting on the downstream side of the trap was 1 barg, preventing the condensate from draining from the preheater under these conditions. In other words, the preheater had stalled. By installing a pump and trap with sufficient capacity to drain the preheater, under all operating conditions, the operators achieved the increased capacity.

In this case, the payback period was less than four months, based purely on returning the condensate, which was being dumped, back to the boiler house. The pump was sized to overcome the back pressure caused by the lift and frictional losses generated in the pumped condensate line on its return to the boiler house.

For a process to operate at maximum efficiency, the steam needs to arrive at the correct quality (100% dryness fraction), quantity and pressure. Just before entering the heat exchanger (say, a reboiler), the steam should pass through a separator to remove any entrained water in the steam to maximise quality, a strainer to remove debris and then normally through a control valve (see Figure 4).

Figure 5 shows a poor, but typical, control valve installation below a process heat exchanger. The control valve is at a low point where condensate will collect when the valve is closed. This particular installation caused serious problems for the instrument engineers, leading to:

- Standing corrosion to the isolation valve and associated piping
- Heat exchanger temperature fluctuations
- Water hammer in the coils
- Product losses through poor repeatability.

The control valve had recently been replaced, as it was believed to be the cause of unstable control. In fact, the control system was no more stable after the change-out. In addition to the problems identified earlier, it is common to find control valves suffering from erosion or wire drawing as a result of the two-phase flow (steam and condensate) it is exposed to. The problem can be easily rectified by installing dirt pockets and steam traps to the bottom of each riser, allowing condensate to be removed as it forms. The return on investment is usually very short and in one case was within a matter of weeks.

Figure 6 shows how a steam line should be drained at a low point, whether this is either side of a control valve or on a steam main between gantries.

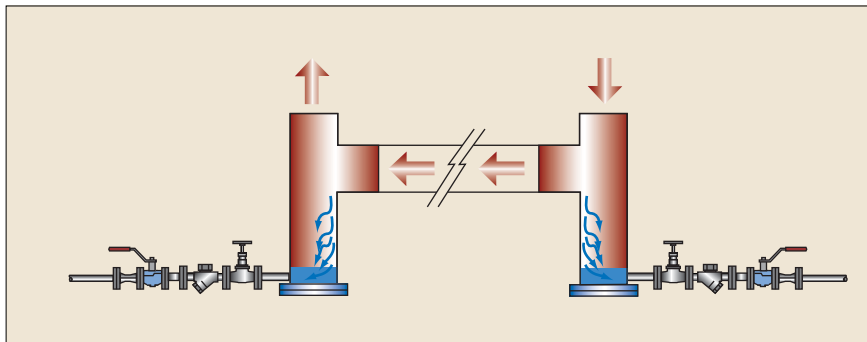


Figure 6 Draining a steam line at a low point

Condensate and flash steam recovery

Once the steam has given out its heat (enthalpy of evaporation), the condensate formed should, wherever possible, be returned back to the boiler house/power plant. Recovering condensate and utilising flash steam results in energy savings, water savings, reduced effluent (as returning condensate means less water dumped) and fewer water treatment chemicals (condensate is pure distilled water, which has already been treated).

Energy savings

Returning condensate alone in a typical refinery, even without utilising the flash steam, will save

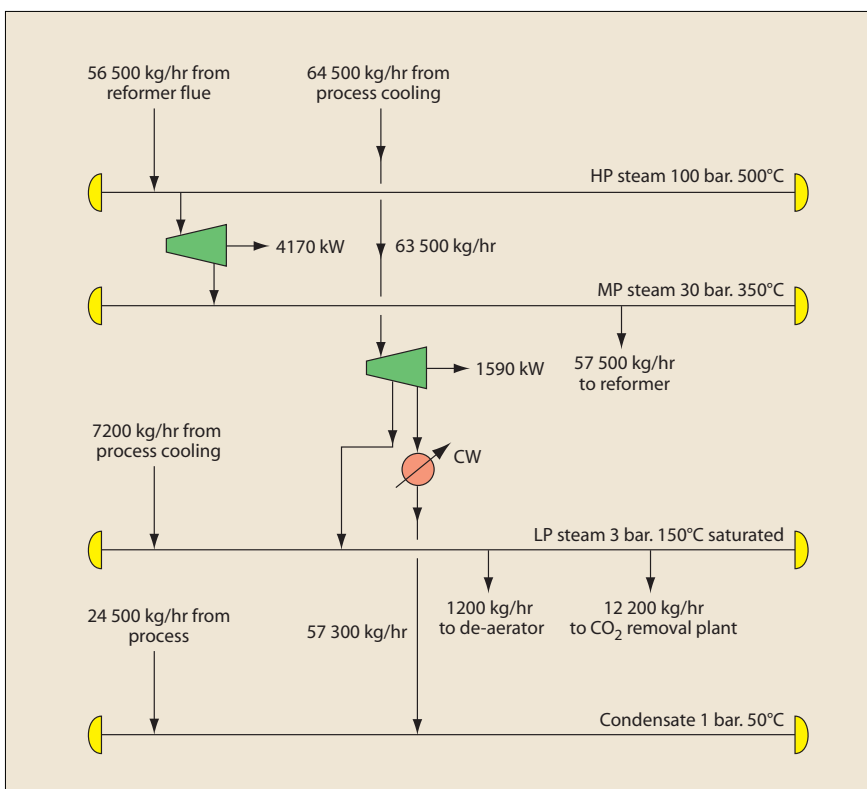


Figure 7 Three-header steam system

approximately 10% of fuel costs.

The steam tables (see Table 1) show that, as pressure rises, the amount of energy remaining in the condensate (sensible heat) increases. In fact, at 30 barg, the energy in the

condensate accounts for 36% of the total steam energy (total heat). Once the condensate has passed through a steam trap to a lower pressure (and hence has a lower saturation temperature), some of the

Steam tables (extract)						
Gauge pressure, barg	Absolute pressure, bara	Temp., °C	Water (h _f) (sensible heat), kj/kg	Specific enthalpy Evapouration (h _{fg}) (latent heat), kj/kg	Steam (h _g) (total heat), kj/kg	Specific volume, m ³ /kg
0	1	100	419	2257	2676	1.673
1	2	120	506	2201	2707	0.881
4	5	159	671	2086	2757	0.315
10	11	184	782	2000	2782	0.177
30	31	236	1017	1787	2804	0.065
80	81	269	1322	1435	2757	0.023
100	101	312	1412	1311	2723	0.018

Table 1

condensate will flash off. This flash steam can be utilised for lower pressure systems.

The schematic in Figure 7 shows a typical three-header steam system. The high-pressure (HP) steam distribution main from the powerhouse is also receiving additional HP steam from the process heat recovery steam generators (HRSG) in the reformer. The HP steam is then let down from HP to medium pressure (MP) using a steam turbine generator. The turbine exhaust steam is fed into the powerhouse MP distribution line for use elsewhere. The low-pressure (LP) steam main from the powerhouse is receiving additional steam from a process cooling HRSG, plus steam from a MP steam turbine generator. The LP steam from the final stage of this turbine goes through a condenser and the condensate is returned to the powerhouse treatment plant.

The greatest amount of condensate is returned through the LP condensate return, which includes the condensate from processes to minimise the risk of stall. However, a typical oil and petrochemical plant will also have separate common condensate lines for draining the HP and MP steam lines.

HP condensate return

Due to the pressures and energy involved, any condensate formed in the HP distribution system is normally passed into a MP steam header (see Figure 8).

The letdown station acts as a throttle, maintaining pressure in the HP condensate line, reducing the amount of flash steam generated and, hence, keeping the condensate line at minimum size. In addition, it protects the MP header from HP steam, should any of the steam traps fail open. The letdown station then reduces the pressure to MP steam levels. The flash steam generated is used as MP steam, while the remaining condensate is cascaded into the MP condensate line.

MP condensate return

MP condensate is normally returned to a LP receiver (see Figure 9).

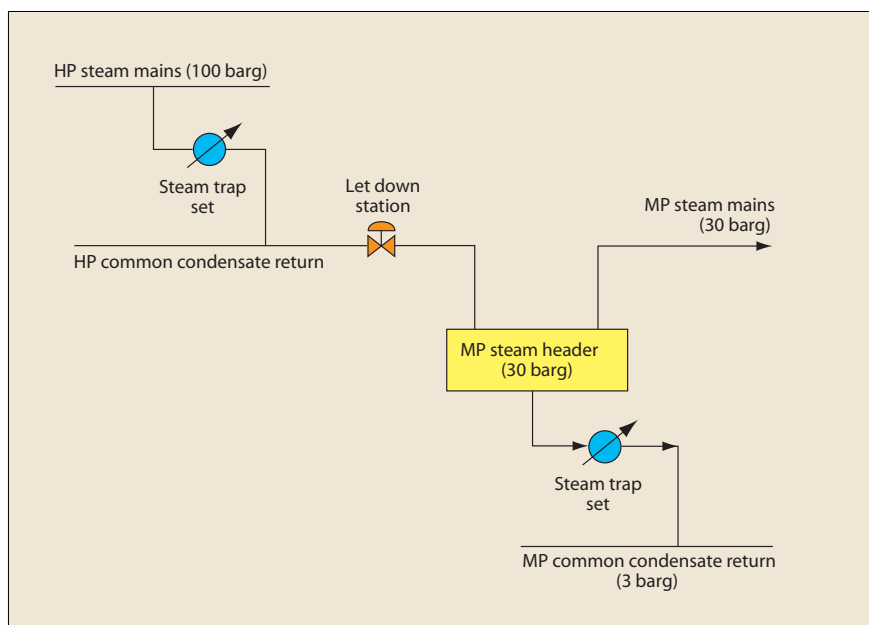


Figure 8 Condensate return for HP steam

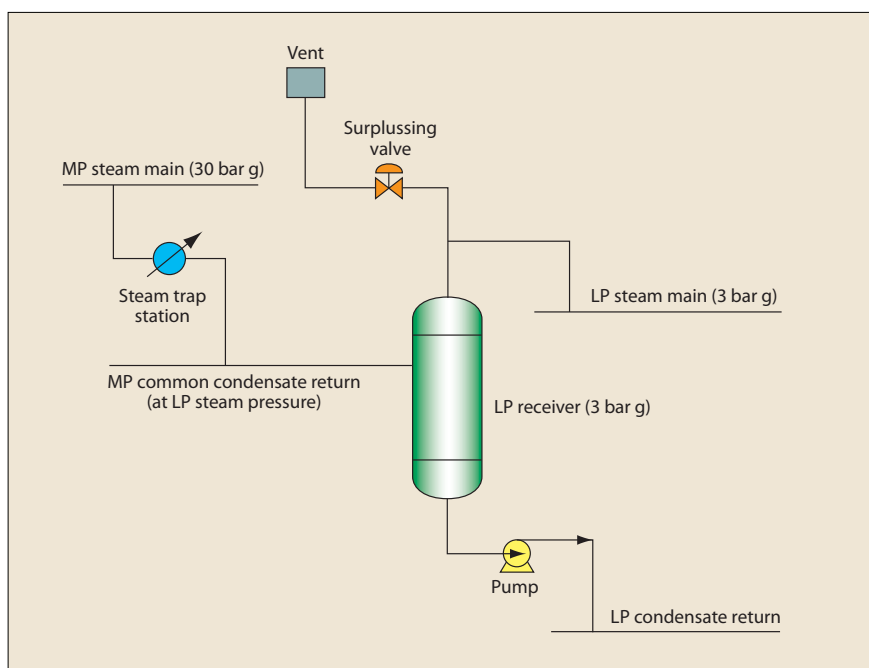


Figure 9 Condensate return for MP steam

Basic types of condensate line

Type of condensate line	Condensate line is sized to carry the following
1 Drain line from process outlet to steam trap	Condensate (still at steam pressure)
2 Discharge line from steam trap	Flash steam
3 Common return line	Flash steam (sum of flash steam from all traps discharging into the line)
4 Pumped return line	Condensate (flash steam will be vented at the pump receiver)

Table 2

Flash steam generated from the condensate can be used as LP steam. A surplussing valve vents excess steam, which will be discussed later.

LP condensate return

Finally, the LP common condensate line can be returned to a vented condensate receiver, before being

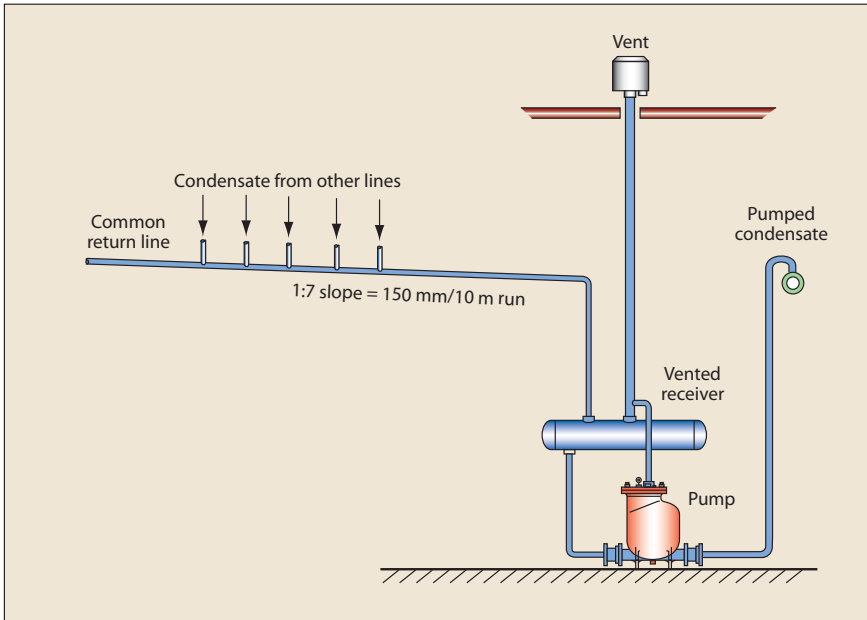


Figure 10 LP condensate return

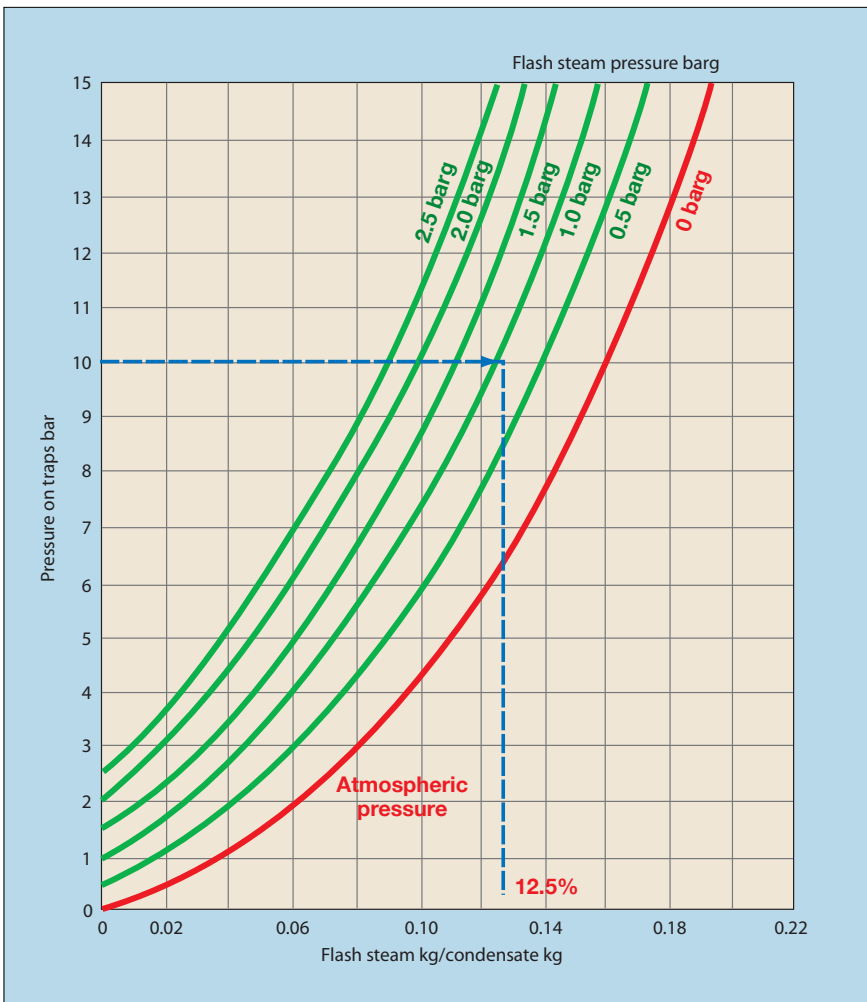


Figure 11 Flash steam generation

pumped back to the boiler/powerhouse (see Figure 10). Even though most of the energy has been utilised, the condensate still has sensible heat

and is treated boiler feed water.

Undersized condensate lines

Sizing condensate lines is a subject in its own right. However, it is

worth mentioning that there are four basic types of condensate line (see Table 2).

Types of condensate lines

In the case of the discharge line from the trap and the common return line, any flash steam generated must be taken into account. Taking the example of a heat exchanger operating at 10 barg steam pressure where condensate is discharged into a common condensate line at 1 barg, and applying the steam tables (see Table 1), the percentage of flash steam generated is:

$$\begin{aligned} \text{Flash steam evaporated} &= ((782 - 506) / \\ & 2201) * 100 \\ &= 12.5\% \text{ of} \\ & \text{condensate flashed} \\ & \text{off} \end{aligned}$$

This is also shown graphically in Figure 11. Although 12.5% of condensate flashing off does not sound significant, the relative volume it occupies compared to the condensate is huge. Taking the example above, 1kg of condensate at 10 barg discharging into a condensate line at atmospheric pressure generates 0.125kg of flash steam. However, in terms of the volume occupied:

0.875kg (1-0.125) of condensate occupies:
0.000875 m³ (based on density of water at approximately 1000 kg/m³)

0.125kg of flash steam occupies:
0.110 m³ (0.125 kg * 0.881 m³/kg using specific volume of steam at 1 barg from steam tables above)

Total volume occupied: 0.000875 + 0.110
= 0.111 m³

% volume occupied by condensate:
1% (0.000875/0.111)

% volume occupied by flash steam:
99% (0.11/0.111)

By not taking into account the flash steam generated downstream of the steam trap, the condensate line will be undersized, increasing the pressure in the line and resulting in higher flash steam velocities. This, in turn, leads to water hammer

and possibly de-rates any steam trap also discharging into the same condensate line.

Common condensate return lines

Condensate from trap discharge lines is normally connected to a common return line, which should gravitate to a receiver or header, where it should eventually be pumped back to the boiler house. In reality, there may be occasions where the condensate line will be at a low point before, say, a riser. In this case, the condensate line will be flooded and will rely on pressure to lift the condensate. There is a real risk of water hammer caused by the flash steam generated travelling along the condensate line at high velocity, picking up slugs of water in its path. In addition, steam traps discharging into the common return line at this point generate the risk of causing water hammer, as the flash steam surrounded by cool condensate can condense rapidly, causing thermal shocks (see Figure 12).

Where possible, low points in the common condensate line should be avoided. However, where this situation arises, it is advisable to use either a float trap, with its continuous discharge, which allows the energy from the relatively small continuous flow to be absorbed and dissipated in the condensate line. Alternatively, a thermostatic trap can be used, depending on the application, which allows the condensate to sub-cool before discharging it into the common line. A thermodynamic trap, with its blast discharge option, should be avoided where possible in this case.

It is important that the separate condensate lines for HP, MP and LP steam are reserved for the specified purpose. For example, a steam trap draining an MP steam main should never be linked to an LP condensate line because of the amount of flash steam generated and the impact such a trap would have on pressurising the system if it failed open.

Pumped return lines

Although it is tempting to add trap discharge lines directly into the

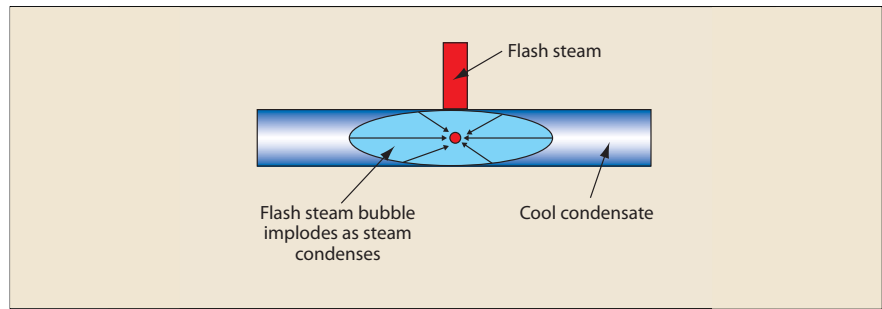


Figure 12 Water hammer caused by flash steam in a condensate line

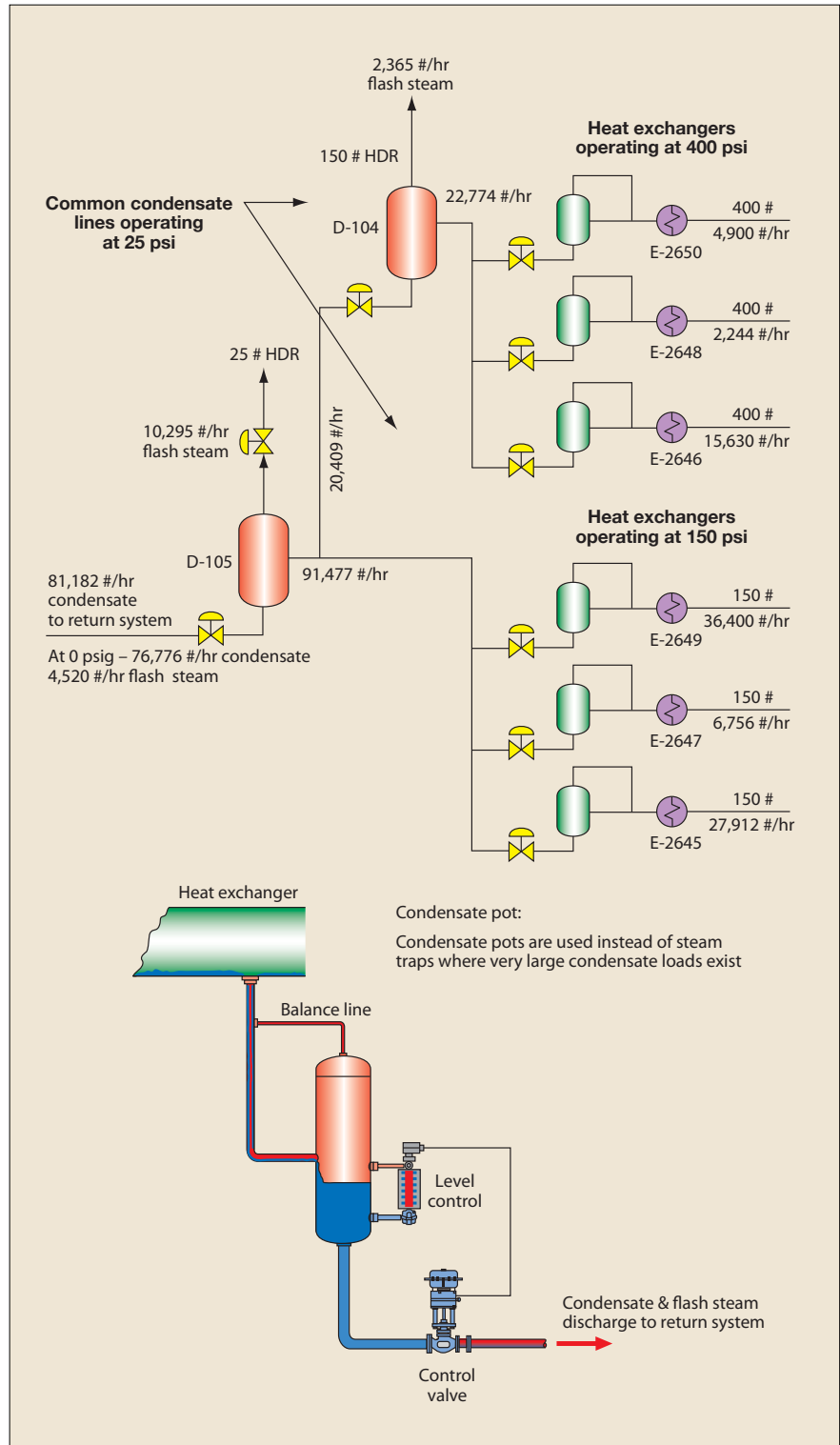


Figure 13 Flash steam recovery

Availability of flash steam from a single asset

Flash steam pressure	Quantity	Application
150 psi (10.3 barg)	2365 lb/hr (1070 kg/hr)	150 psi steam header
25 psi (1.7 barg)	10 295 lb/hr (4680 kg/hr)	25 psi steam header
Sub-total	12 660 lb/hr (5755 kg/hr)	
Atmospheric pressure	4520 lb/hr (2055 kg/hr)	
Total	17 180 lb/hr (7810 kg/hr)	

Table 3

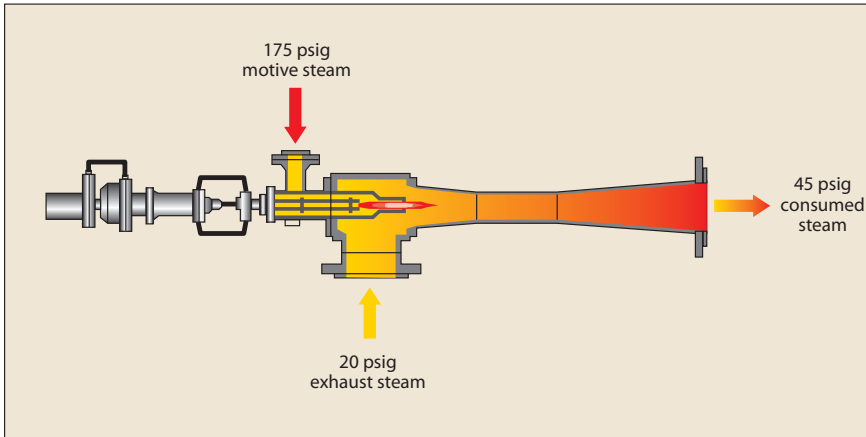


Figure 14 Use of a thermocompressor to upgrade exhaust steam pressure

pumped return line because it happens to be the nearest, it should be remembered that the line will be:

- Sized for condensate only
- Flooded, resulting in the risk of water hammer caused by thermal shock and high velocities caused by flash steam expanding in the condensate main
- Pressurised, which will be acting as a back pressure on the traps discharging into this line, so possibly de-rating the traps performance.

Flash steam recovery

Depending on pressure, the energy used to flash off condensate can account for a large percentage of the total energy in the condensate at pressure. This flash steam can be used on lower pressure applications, saving significant amounts of energy and water. Figure 13 illustrates an example taken from an audit carried out for a refinery in the US.

This example demonstrates the scale of flash steam available, which can be utilised from just one asset (see Table 3).

Unfortunately, in this case, the 4520 lb/h of flash steam generated

at atmospheric pressure was causing significant problems for the refiner, as the condensate line was seriously undersized. This led to extremely high velocities in the atmospheric condensate return and severe water hammer, which in turn resulted in leaks developing in the line. This could be overcome by adding a vented receiver and pump downstream of the 25 psi flash vessel, allowing the condensate to be pumped back to the condensate tank. Where possible, this flash steam should also be utilised, possibly preheating the boiler feed water, or condensed, where at least the water could be returned to the boiler.

One option, depending on energy balances, could be to use a thermocompressor or mechanical vapour recompression to re-energise the flash steam to a useable pressure. The following example shows how a thermocompressor could be used to induce 20 psig steam to an intermediate pressure (45 psig) by using a 175 psig motive supply (see Figure 14).

In this example, an alkylation unit consumes over 24 000 lb/h of 45 psig steam that is currently imported from another asset.

Therefore, there is the potential to utilise steam from a thermocompressor for this service, assuming:

- The 45 psig steam from the other asset could be used elsewhere in the refinery, even if it needs to be generated at a higher pressure
- The cost of 175 psig and 45 psig steam are the same
- A two-to-one ratio of 175 psig and 45 psig steam from the thermocompressor
- Production of 24 000 lb/h of 45 psig steam for use in the alkylation unit.

Under these conditions, the alkylation unit would now consume 16 000 lb/h of 175 psig steam and 8000 lb/h of the currently exhausted 20 psig steam in lieu of the 24 000 lb/h of 45 psig steam from the other asset. This results in annual savings of 8000 lb/hr of exhausted steam. The return on investment in this case would be a matter of months.

Conclusion

Steam generation accounts for approximately 50% of total energy consumption in a typical refinery. This article has focused on:

- The impact stall can have on a heat exchanger and how it can be easily overcome, normally resulting in rapid returns on investment
- The importance of returning condensate to the powerhouse and the good engineering practices involved
- The benefits of utilising flash steam, giving examples of the savings that can be made.

Through good engineering practice and management of the steam and condensate system, significant savings can be realised through lower energy costs, emissions and effluent costs. This, in turn, has a positive impact on process efficiency by increasing output and improving control.

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