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Allocate new plant focus to steam system design—Part 1

New plant construction includes expectations for optimized production performance to achieve targeted profitability. After a capital investment decision is made to build a new plant, it can take years to secure critical items, including property, permits, technology licensors, front-end engineering and design (FEED), staffing, training, engineering and procurement for final design and construction.

Significant focus is placed on the production process itself, analyzing multiple variables that include marketing demand/flexibility, the availability of base materials and decisions of how to sustain or increase high yields. Due to the significant daily production dollars involved, having an operational plant that begins earning profits quickly is a high priority. Once in operation, plant production is actively managed; however, its heat source, steam, is often not given proactive focus. While analyzing operating plant issues, a common causal thread is that the steam system has been taken for granted, not only during operation, but also beginning with original design. Further examination often reveals an expectation that the design firm or licensor utilizes current best practices for steam system design. In each of the cases presented here, the original design led to many of the issues encountered.

Within the past 18 mos, several process instances were attributed to less than-optimal system design, and included:

- **Steam utility wetness issues** causing difficulty in the fluid catalytic cracking unit (FCCU), missing traps on the steam header and expansion loops trapped incorrectly
- **Steam utility water slugs** creating a swamp and fog zone at a key turbine pump driver

- **Condensate return hammer** so severe that it was destroying piping on both the 6-in. header and the nearly 16-ft-tall flash drum
- **Flash drum supply piping hammer** from steam backfill
- **Stripper reboiler backup** due to poor drainage.

STEAM UTILITY WETNESS ISSUES IN AN FCCU

A refinery reported significant wetness issues that were affecting reliability in the FCCU. An analysis of the steam utility headers over several days revealed that the site's own best practices were not utilized in the installation of those new headers when installed by the EPC. While it seems reasonable to assume a best practice design by an EPC or licensor, inquiries should be made about the mechanism employed by the end user to control the plant deliverable of high-quality steam. The actual identified items and the recommended paths forward are reviewed here.

Supply optimized steam. Some relatively simple, basic requirements can help supply high-quality steam to plant production, and one of the most important is the removal of condensate that has dis-entrained from the steam supply and runs along the bottom of the steam line (**FIG. 1**).

The steam can be flowing faster than 90 mph under normal circumstances, so the effects of kinetic and thermodynamic energy must be considered. A key requirement is to minimize the level of that condensate by draining it from the pipeline at regular intervals using collecting legs (**FIG. 2**). These collection points must have adequate volume to

hold water and include a mud leg to discharge debris that may collect over time. A non-subcooling steam trap that enables automatic condensate discharge

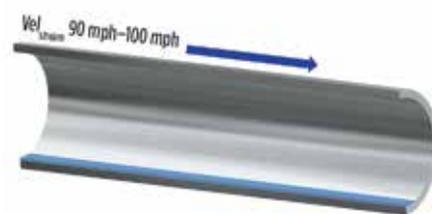


FIG. 1. Condensate accumulates in steam pipes and must be collected for removal by steam traps.



FIG. 2. Collecting legs are wide to catch condensate, deep with a low take-off to hold condensate, and use a mud leg for blowdown.

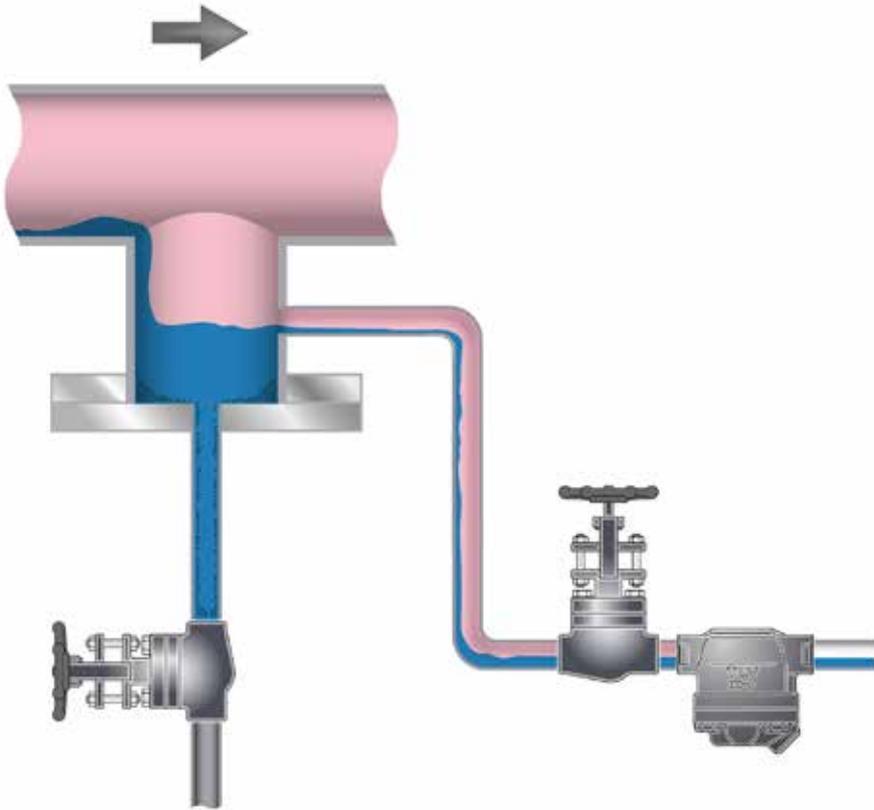


FIG. 3. Steam traps should be installed lower than the take-off from the collecting leg to help increase trap reliability.

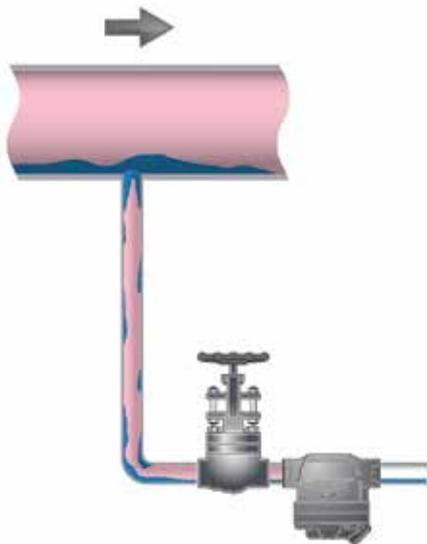


FIG. 4. Condensate flows over a small-diameter collecting leg, effectively rendering the collection point useless.

should be installed below the vertical take-off from the drainage pocket. The trap's horizontal distance from the vertical line should be minimized. Traps seek to recognize the difference between steam and condensate, so having a drop-

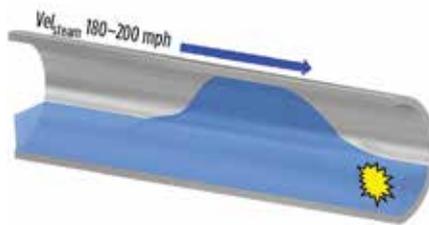


FIG. 5. Warning: Condensate level can build up in a steam line when it is not removed, creating a dangerous condition.

down entrance immediately before the trap can provide a distinct separation of the fluids (**FIG. 3**).

A common pitfall occurs when a collecting leg's diameter is too small to catch the condensate that flows above it (**FIG. 4**). Rapidly moving condensate, with a cross-sectional width greater than an undersized pocket diameter, will simply pass over the drain point. For example, consider a 20-in. header with a 2-in. collecting leg diameter rather than the recommended minimum 10-in. diameter. It is time-consuming to check overhead on new construction to determine if an adequate pocket diameter is installed, but this type of audit is a key rec-

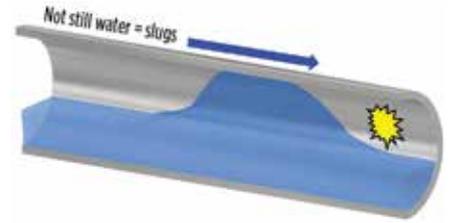


FIG. 6. Condensate waves can form, closing off the cross-sectional area and creating a high-velocity water slug.

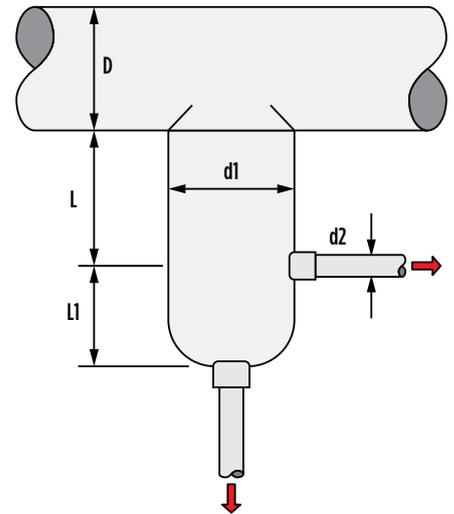


FIG. 7. An effective CDL design begins with an adequately-sized collecting leg and low take-off for discharge through "d2."

ommendation to control the quality of steam reaching production. The FCCU experienced this similar circumstance in at least one utility location, contributing to its severe wetness issue.

What can happen? This site did not disclose the exact issues it was experiencing in the unit, but the expectation was that water hammer or turbine events must have motivated a root cause assessment.

Although explained in literature,¹⁻⁴ it is useful to review what can happen when condensate is not effectively discharged from a steam system. Left undrained, condensate level rises while the steam velocity above it increases considerably (**FIG. 5**).

The high velocity can form waves that block the pipe's cross-sectional area. At the point where condensate closes off the pipe, the steam velocity may have increased dramatically, compressing momentarily due to condensate inertia and then propelling condensate and causing a water hammer event (**FIG. 6**).³



FIG. 8. An effective collecting leg/CDL includes a variety of piping components.

These incidents are avoidable with well-designed, well-placed, well-installed and well-maintained collecting legs. Several important dimensions exist for the design of the pocket itself (FIG. 7). Diameter “d1” helps collect condensate; the combination of “L” (determined by the take-off “d2”) and “d1” provide a reservoir in case the trap does not discharge continuously; and “L1” provides a mud leg capability to keep much of the system debris from blocking the trap or its strainer.

Maintaining a correct “L” is essential so that the reservoir pocket is not undersized, and condensate intended to be drained does not remain in the steam supply. TABLE 1 provides specific size recommendations for optimized collecting leg design. With a proper leg design, an effective condensate discharge location (CDL) containing piping and components can be finalized. The final compilation depends on site requirements and whether the condensate is discharged to an atmospheric gravity return or to a pressurized return header (FIG. 8).

Correct CDL placement along the steam utility line must provide reasonable drainage points. Generally, CDLs should be placed 100 ft–150 ft apart, at risers and at drops to equipment supply (FIG. 9). One refinery’s FCCU supply had site standards requiring CDL placement for the header line size at every 100 ft. However, an assessment revealed at least one section with no CDL for more than 1,300 ft, and that first CDL had an undersized, 2-in. pocket diameter rather than 10 in. Another refinery had a steam supply of more than 2,000 ft without a CDL. The user must have expected that the systems design engineer followed best practice standards for CDL placement. For whatever reason, that did not occur, and it is no surprise that the site experienced wetness issues.

TABLE 1. Collecting leg sizing (minimum requirements)

North/South America

D	D	d1	L				L1		d2
			Supervised, manual		Automatic				
mm	in.	in.	in.	mm	in.	mm	in.	mm	in.
20	0.75	0.75	12	300	28	700	4	100	0.75
25	1	1	12	300	28	700	4	100	0.75
32	1.25	1.25	12	300	28	700	4	100	0.75
40	1.5	1.5	12	300	28	700	4	100	0.75
50	2	2	12	300	28	700	4	100	0.75
65	2.5	2.5	12	300	28	700	4	100	0.75
80	3	3	12	300	28	700	4	100	0.75
100	4	4	12	300	28	700	4	100	1
150	6	4	12	300	28	700	4	100	1
200	8	4	12	300	28	700	4	100	1
250	10	6	15	380	28	700	6.5	165	1
300	12	6	18	450	28	700	6.5	165	1
350	14	8	21	530	28	700	6.5	165	1
400	16	8	24	600	28	700	6.5	165	1
500	20	10	30	760	30	760	6.5	165	1

Notes:

1. Distance between steam traps is 100 ft–150 ft
2. For steam traps with non-continuous operation, dimension “L” might be increased to prevent condensation accumulation
3. The above dimensions are recommendations and may need to be adjusted depending on system and operating conditions
4. Dimensions are based on ASHRAE steam system practice
5. “Supervised” refers to manual blowdown at startup, whereas no startup personnel may be involved with “Automatic”

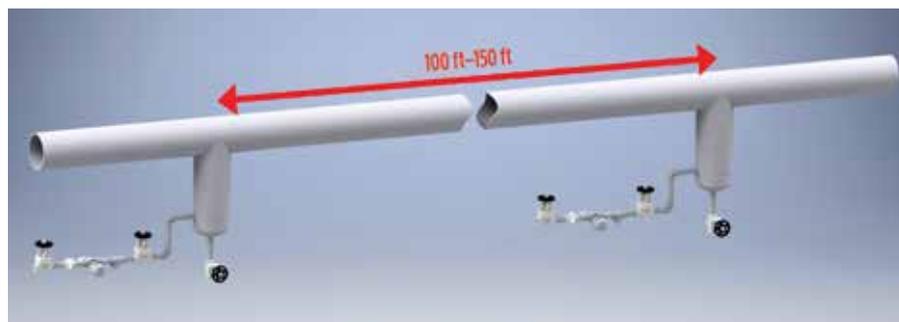


FIG. 9. Collecting legs and CDLs are normally located every 100 ft–150 ft, as well as at risers, drops and before expansion loops.

Drain expansion loops. Multiple instances have occurred where a site’s installed steam expansion loops have only included line size piping and no condensate drainage point (FIG. 10). One possible reasoning for this drainage oversight, however incorrect, is that the system designer believed that only steam would be flowing in a “steam supply” line (FIG. 11). What the original piping designer may not have realized is that steam lines have condensate flowing within them. Condensate develops naturally in the steam system from convection and radiation



FIG. 10. Danger: Expansion loops on steam lines without a collecting leg to remove condensate can expect water hammer.



FIG. 11. Danger: Piping designers sometimes believe steam lines have steam flow only within, especially on superheat.

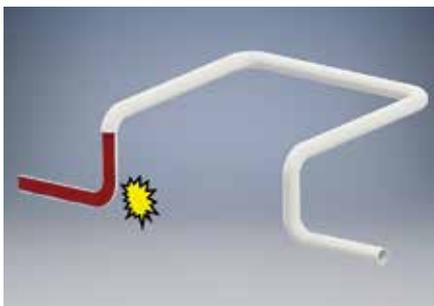


FIG. 12. Warning: Even superheat lines can accumulate condensate that must be removed through a collecting leg/CDL.



FIG. 13. Uni-directional steam flow requires a condensate collecting leg/CDL on the upstream side of an expansion loop.



FIG. 14. Bi-directional steam flow requires condensate collecting legs/CDLs on both sides of an expansion loop.

losses and can even be present in lines designated to carry superheat. If condensate is not removed, water hammer can be expected, particularly at any vertical riser (FIGS. 1 and 12).

Flow direction. If steam supply is flowing in only one direction, then the CDL often can be installed on the inlet side of the expansion loop, where condensate naturally pools (FIG. 13). However, some process considerations may not be evident to the designer. For example, steam may change its path, sometimes reversing its direction due to generation/demand considerations elsewhere (such as waste heat). In one refinery FCCU supply, a change in steam flow direction was caused by rerouting from a new boiler.



FIG. 15. An oversized collecting leg, a CCB, can help remove larger condensate accumulations.



FIG. 16. CCBs may be helpful on a variety of installations experiencing condensate difficulties.

Since the original header design only included CDL on the inlet side of the expansion loop, no CDL was in place to remove condensate (on the new inlet side) when the flow reversed, and hammer damage was experienced. Whenever bi-directional flow might occur, CDL drainage on both sides of the expansion loop is recommended (FIG. 14).

Solutions. In at least one instance, it was not possible for the plant to shut down to install more than 10 CDLs in a main 24-in. supply header. Some mitigation was needed, and the combination of a condensate collection bottle (CCB) and engineered separator drain was an intermediate consideration until a best practice improvement could be installed. As a potential stop-gap measure, the CCB's purpose is to collect as much disentrained condensate as possible before using slug-tolerant separation to improve utility steam quality (FIG. 15).

Before implementation, a CCB installation concept and other piping measures must be completely analyzed by a registered professional engineer for load, stress and support calculations to ensure appropriate final piping design.

Condensate slugs at turbine. Another refinery was experiencing undisclosed turbine issues, but trips and plating were suspected after an onsite assessment. The utility supply pulled from the main header, approximately 250 ft away, and it was taken from the

bottom of the piping rather than the top (as is the recommended best practice). The utility main was designed for superheat, and the designers most likely felt that condensate would not be at its bottom, so it was incorrectly used for the branch steam take-off.

Along the branch distance, several CDLs had the steam traps lined out, and the vertical feed to the turbine was also taken from the bottom at the end of the branch supply pipe rather than the top. Although the refinery upkeep was generally exceptional in every visible way, this installation resulted in a small swamp and fog zone surrounding the turbine. It was not possible to physically access within 25 ft of the driver.

A previous retrofit showed other issues relative to incorrect strainer location, separator steam trap sizing (too small) and inlet/case/outlet steam trap selection and installation. It was infeasible to shut off the branch supply to improve steam quality by pulling steam from the top of the headers, so a possible consideration by the site's reliability team was to install a new 8-in., 250-ft supply branch.

Instead, an alternative recommendation was to improve drainage by installing correct, non-subcooling steam traps on the branch supply and implementing an oversized diameter CCB ahead of the separator to collect condensate that flowed down to the turbine supply. With proper trapping along the long branch run, a large CCB (if approved by a registered professional engineer) with high-capacity steam trap at the turbine entrance, improved steam supply piping design, and appropriate steam traps for the turbine itself, some mitigation of the issues is expected (FIG. 16).

Part 2, which will appear in the February issue, will continue the discussion on improving production reliability by managing the design of condensate systems to deal with potential issues prior to installation. **HP**

ACKNOWLEDGMENT

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