Maximising gas plant capacity

Water entrapment and foaming must be avoided to maximise LPG recovery and minimise downstream unit contaminants. Fundamental process and equipment design principles that cause water entrapment and foaming are reviewed

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FCC and coker gas plant absorber/deethaniser (stripper) revamps need to fully utilise column capacity to maximise propylene recovery and capacity. Yet two phenomena – formation of a free-water phase and foaming – continue to limit capacity, reduce propylene recovery and increase LPG product C_2 and hydrogen sulphide (H_2S) content. Reliance on process models that do not predict where free-water forms or the increase in vapour/liquid loading that accompany it, and failure to account for foaming systems, are largely to blame.

FCC and coker gas plants recover C_3 and C_4 hydrocarbons from main column overhead wet gas, reject the bulk of the C_2 and H_2S to fuel gas and separate the C_3 and C_4 from the gasoline or coker naphtha. In the primary absorber, main column overhead liquid and debutaniser bottoms absorb C_3 and C_4 from the feed gas leaving the HP receiver. To meet downstream unit specifications, C_2 and H_2S must be stripped from the C_3 and heavier hydrocarbons feeding the deethaniser (Figure 1).

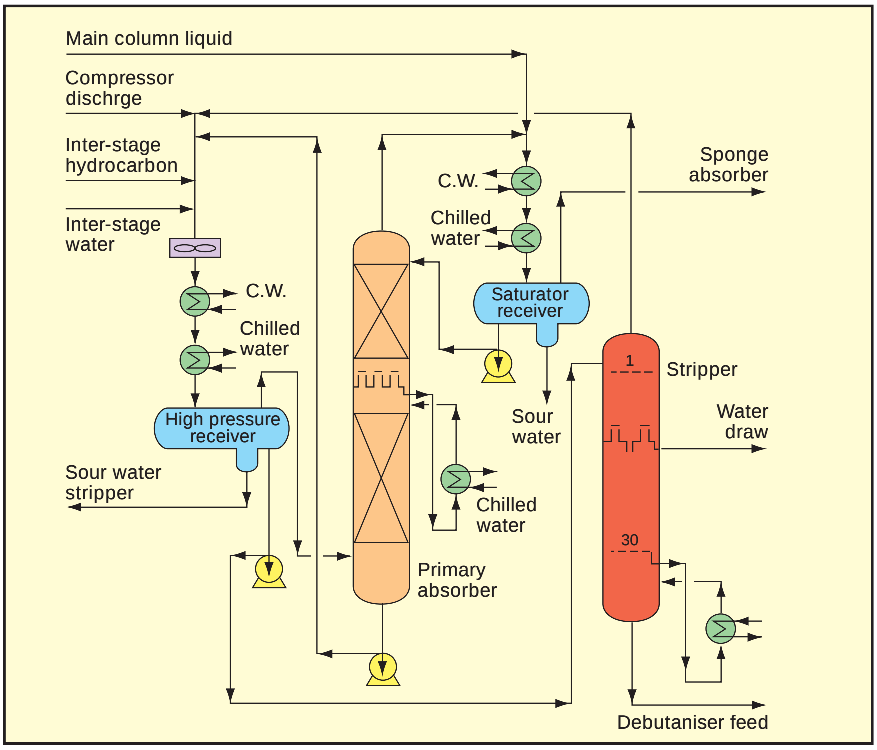

Figure 1 *Typical gas plant deethaniser configuration*

In most gas plant designs the deethaniser bottom stream feeds the debutaniser where the C_3 and C_4 are fractionated from FCC gasoline or coker naphtha. In a small percentage of gas plants the deethaniser bottoms stream feeds a depropaniser operating at higher pressure (Figure 2). In this case, most of the water and C_2 need to be removed upstream in the deethaniser. Otherwise, severe foaming occurs directly above, in the feed zone and directly below the feed in the depropaniser.

If the depropaniser diameter is too small or the trays are designed without using a system factor, flooding occurs well below design feed rates. System factors between 0.7 and 0.8 have been observed. Fortunately, only a few refiners have the depropaniser immediately downstream of the deethaniser, so this problem is not common.

Gas plant absorbers recover C_3 and heavier hydrocarbons at operating pressures and temperatures between 100 and 260 psig and 50–140°F while C_2 and H_2S are stripped in the deethaniser. The goals are to maximise C_3 recovery while removing only enough C_2 and H_2S to meet downstream unit specifications. Low temperature and high pressure in the absorber and HP receiver favour C_3 recovery, but also increase the tendency to form free-water.

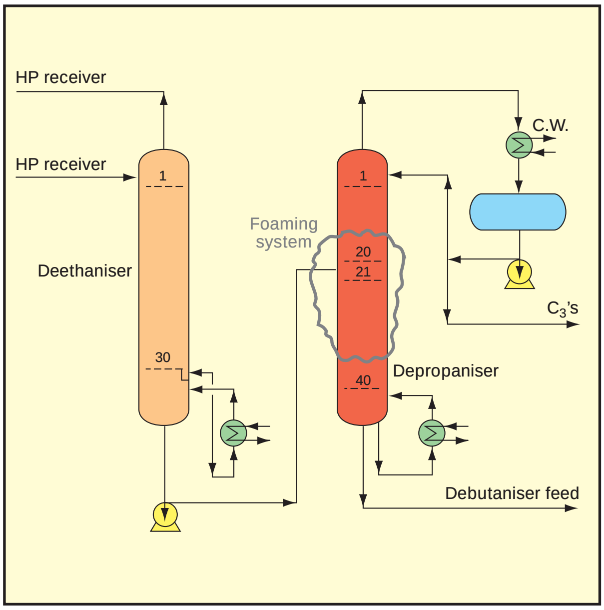

Figure 2 *Deethaniser bottoms stream feeding depropaniser*

Water may be formed in the absorber as cold liquid streams contact hotter vapour at feed and inter-cooler return locations, but this causes few problems. Conversely, when a water phase is present in the top of the deethaniser, it can significantly reduce capacity. Moreover, low temperature and high pressure also increase this system's tendency to foam.

Figures 3 and 4 show two common absorber/deethaniser system process flow schemes.

Figure 3 has two columns, external high-pressure (HP) condensers and receiver, and an inter-cooler. The HP receiver condenser cools compressor discharge, deethaniser overhead vapour and absorber bottoms liquid streams. Ideally, the HP receiver is designed to effectively separate condensed hydrocarbon liquid and water phases. Vapour containing C_3 and C_4 and lighter components feed the bottom of the absorber while the hydrocarbon stream saturated with water is pumped to the deethaniser.

Because the absorber bottoms stream is routed to the HP receiver condensers, water can be separated before feeding the deethaniser. Yet, in several instances poor HP receiver oil/water phase separation have caused free-water in the feed to the deethaniser.

An alternative flow scheme uses a single column for absorbing and deethanising (Figure 4). Discharge from the wet gas compressor is cooled and the three phases are separated in the HP receiver. The vapour stream feeds the absorber section while HP receiver liquid is pumped to the top tray of the deethanising section. Liquid leaving the absorber flows directly to the top of the deethanising section and deethanising section overhead vapour flows directly into the absorber.

Because stripper vapour and absorber bottoms liquid streams flow internally, they are not cooled. Thus, the single column design is more energy efficient and lower capital than a two-column flow scheme. But the single column design is more difficult to operate without high C_3 losses to fuel gas. Furthermore, operating conditions are very favourable to formation of free-water phase in the top of the deethanising section, whereas the water phase is not always present with the two-column design.

Main column overhead liquid and debutaniser bottoms recycle streams recover C_3 and C_4 from the wet gas compressor discharge stream. Pre-saturators and inter-coolers are sometimes used to minimise temperature rise. Occasionally, chillers or refrigeration are used to lower operating temperature below cooling water temperatures (Figure 1). The deethaniser then strips C_2 and H_2S by adding heat with reboilers, side reboilers, and/or feed pre-heaters.

Absorber C_3 and C_4 recovery is largely a function of liquid/vapour molar (L/V) ratio inside the column, and operating temperature and pressure. Lean oil absorbs C_3 and C_4 and the temperature rises due to latent heats of the components being absorbed. Inter-coolers and pre-saturators reduce temperature rise and improve C_3 recovery by 4–6% when designed properly. Some FCC gas plants use chillers to increase propylene recovery to over 99%. As absorber L/V increases and temperature decreases, propylene recovery improves. Yet as recovery goes up, the amount of heat

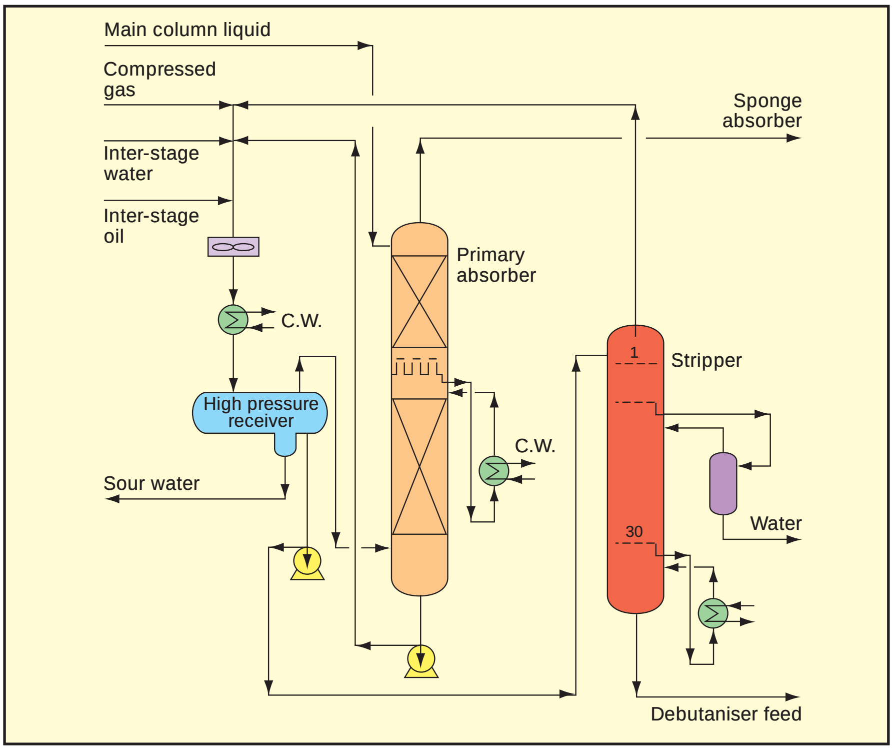

Figure 3 *Common absorber/deethaniser system process flow schemes with two columns, an external high-pressure condenser and receiver, and an inter-cooler*

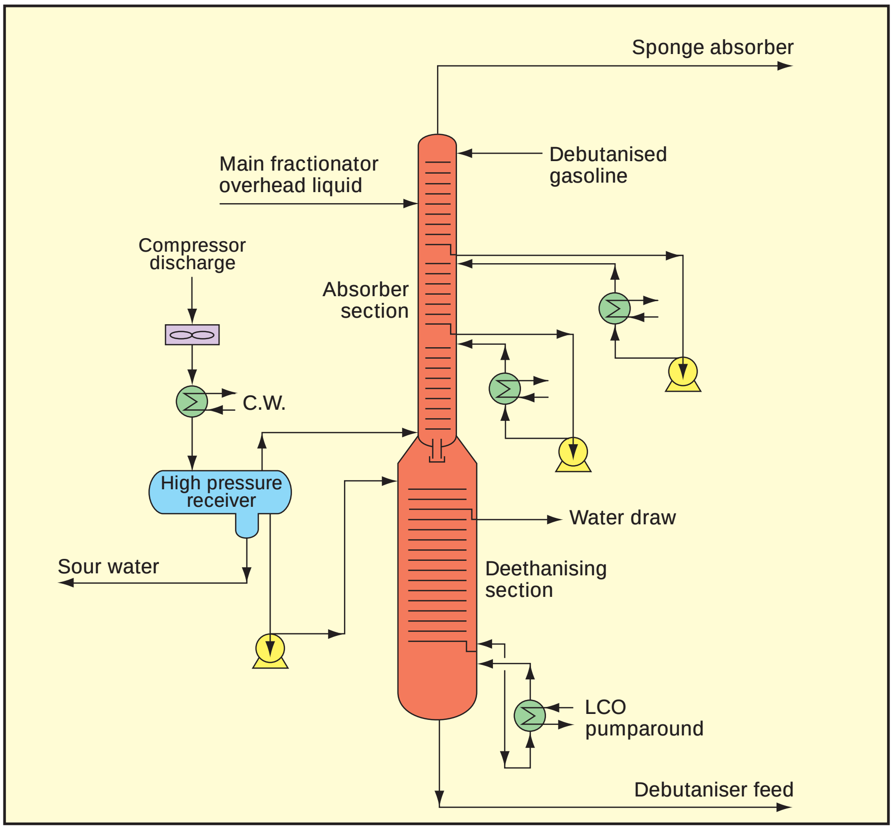

Figure 4 *Alternative absorber/deethaniser flow scheme uses a single column for absorbing and deethanising*

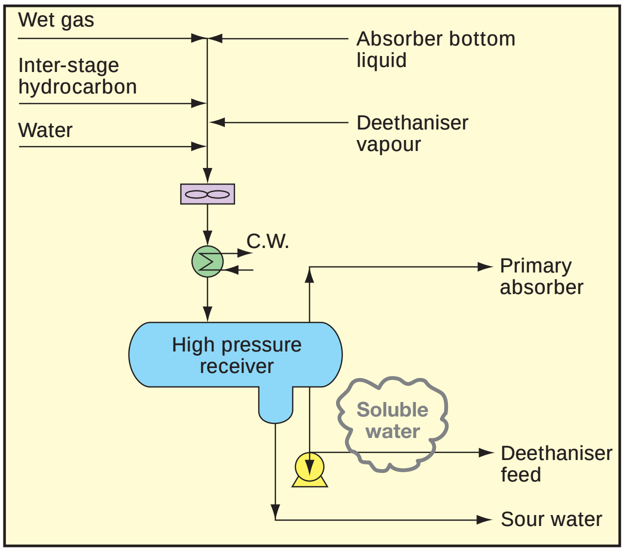

Figure 5 *Deethaniser with HP receiver designed so that all free-water is removed and only soluble water enters the deethaniser*

that must be added in the deethaniser to strip C_2 and H_2S also increases.

Minimising heat input to meet downstream unit C_2 or H_2S specifications maximises absorber C_3 recovery because L/V in the absorber goes up. But in practice, controlling deethaniser bottoms product C_2 or H_2S content is difficult because the quantities are very low, thereby making inferential control using temperature ineffective and unresponsive. Yet it remains the most common control methodology. For example, decreasing deethaniser bottoms temperature by only 4ºF increases C_2 and H_2S leaving the column by 300% or more. Thus, most deethanisers are operated with excess heat input resulting in lower absorber L/V and higher C_3 losses to fuel gas than necessary.

With the two-column flow scheme, deethaniser overhead vapour is routed to the HP receiver condensers. These condensers remove heat and reduce vapour flow to the absorber, thereby increasing L/V. With the single column design, excess deethanising heat input must be removed by the inter-coolers, which generally have little spare capacity. Therefore, excess deethaniser heat input rapidly decreases C_3 recovery and increases fuel gas production. Hence, trade-offs are inherent with single and two-column flow schemes.

Water phase

Water enters the gas plant with the wet gas and the overhead liquid (that is saturated with water) as well as with wash-water streams. The presence of free-water has little influence on operating performance of the absorber. Water can form where main column overhead liquid, debutanised gasoline or inter-cooler streams enter the column. But when water becomes trapped in the deethaniser, it creates higher vapour and liquid loads than expected. Because process models do not predict a water phase and the higher vapour and liquid loads accompanying it, column internals are often designed with insufficient capacity.

Water entrapment is caused by both process flow scheme and equipment design. With two-column designs (Figure 3), if the HP receiver is designed correctly, all free-water is removed and only soluble water enters the deethaniser (Figure 5). In some instances, deethaniser feed contains free-water resulting from poor water-oil separation. Even though the quantity of soluble water may be small, when low feed and overhead temperatures trap it, the column can flood.

Since only small amounts can leave with the bottom product because temperature is too high, most must go out with the overhead vapour. In some instances, deethaniser feed is preheated with an exchanger from HP receiver temperatures of 50–110ºF to 135–150ºF (Figure 1). When a single absorber/stripper column is used without feed preheat, temperature in the top of the deethanising section almost always causes a free-water phase.

While a pre-heater generally eliminates free-water by raising feed and overhead temperature high enough to allow all the water to leave with the overhead vapour, reducing deethaniser feed and overhead temperature improves C_3 recovery. Deethaniser C_2 and H_2S removal are improved when feed temperature is minimised because column vapour/liquid loads are higher throughout the column when the reboiler adds all the heat. Furthermore, adding heat to the feed raises HP receiver condenser duty.

Water entrapment, foaming

Water formation can flood the deethaniser or deethanising section in a single column. Because water entrapment reduces column capacity, often reboiler heat input must be reduced increasing the amount of C_2 or H_2S in the bottom product. Foaming also reduces column capacity because vapour and liquid phases do not separate effectively above the tray deck or in the downcomers. Water entrapment and foaming occur because the process temperature is low and pressure is high. In some cases, process flow scheme changes, such as adding a feed preheater, can eliminate the problem; in others, equipment changes are needed.

Foaming is not common in refinery columns, therefore its influence on tray design is often overlooked. When foaming occurs, the tray active area and downcomers have less capacity. Foaming occurs because low HP receiver temperature and high deethaniser pressure increase feed C_2 composition. The C_2 composition profile changes very rapidly in the top few trays of the deethaniser. When the deethaniser column floods, reboiler heat input is typically reduced, which sends more C_2 and H_2S to the downstream columns.

Case history 1

Low deethaniser overhead temperature

A deethaniser experienced periodic flooding. During upsets, HP receiver level rapidly increased causing the level controller to raise deethaniser feed rate in an attempt to maintain level. Since column flooding caused massive carry-over of feed with the overhead vapour, HP receiver level continued to increase. Cutting deethaniser reboiler duty was the only way to quickly gain control of level and prevent the HP receiver from overflowing into the absorber.

When columns flood, large volumes of liquid accumulate on the trays. Cutting reboiler duty reduced vapour rate, which caused the accumulated liquid held on the trays to quickly drop to the bottom of the column. Light components in the debutaniser feed increased column pressure because they could not be condensed. Non-condensables were vented to the wet gas compressor inter-stage system.

During the upsets, gamma scans showed flooding initiated in the middle of the column. Moreover, operating data showed each time the HP receiver temperature dropped below 100ºF, column pressure drop increased dramatically followed by liquid carry-over. Additionally, as HP receiver temperature decreased, deethaniser reboiler duty increased to supply additional heat. Because column vapour and liquid loading increased when feed temperature decreased, the problem was blamed on tray capacity limitations.

Thus existing conventional trays were replaced with high capacity trays even though calculations could not support the modifications. A single high capacity tray design was used throughout the column. Following the revamp, the column continued to flood at nearly the

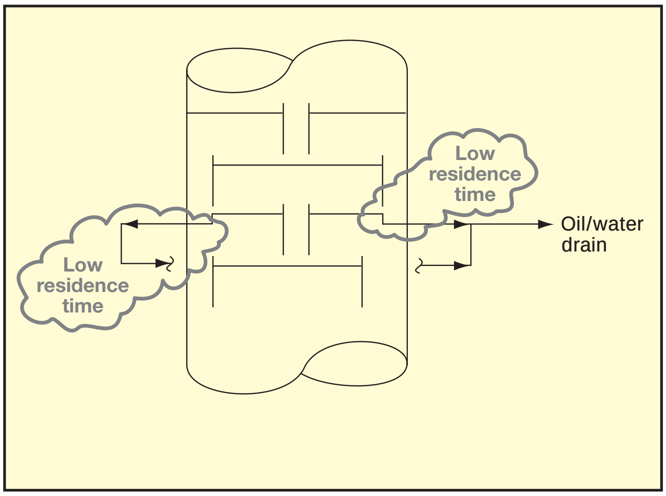

Figure 6 Deethaniser with water-draw sump installed in one of the active trays, and an external oil/water separator system

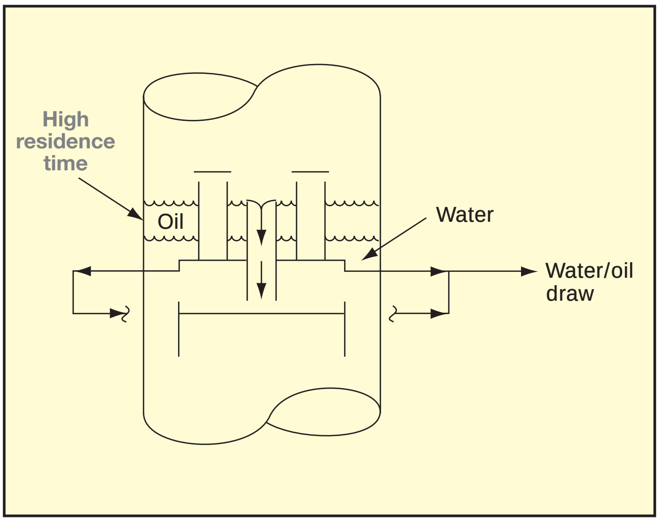

Figure 7 Deethaniser with optimised water-draw system

same feed rate even though it now had high capacity trays. As feed temperature and column overhead temperature dropped to 100ºF and 115ºF respectively, column pressure drop again began to increase. Eventually HP receiver temperature increased and reboiler duty had to be reduced. Further gamma scanning showed flooding occurred in the middle of the column, not the bottom where the vapour and liquid loadings are highest.

Without water entrapment, vapour and liquid loadings are highest in the bottom of the column. Thus, the column should have flooded from the bottom of the column, not in the middle, if tray hydraulic capacity was a problem.

But why did the column flood in the middle section and not the bottom?

Minimising HP receiver temperature increased propylene recovery by reducing vapour flow rate to the absorber. But lower temperature also increased the C_2 and C_3 in the deethaniser feed and lowered deethaniser overhead temperature. At the same time, reboiler duty was increased to provide additional heat needed to meet bottom product C_2 and H_2S specifications. However, when the top temperature decreased to 110°F, all the water entering could not go overhead with the vapour product, thus a water phase formed. At the same time feed C_2 content rose, increasing the system's tendency to foam. Short-term operational changes set minimum HP receiver temperature at 120°F, which allowed the column to operate without flooding. But this reduced propylene recovery by more than 3%.

Deethanisers are often designed with water draws to remove free-water before it can accumulate. Figure 6 shows the water draw sump installed on one of the active trays and an external oil/water separation drum. In theory, oil and water were withdrawn from the active tray and separated in the external drum. Hydrocarbon from the drum flowed back to the column, while water should have been periodically drained from the external drum. But the tray draw sump did not provide sufficient residence time to separate water and oil inside the column. Hence, mainly hydrocarbon flowed to the external drum. Since no water appeared in the external drum, everyone assumed that free-water did not exist inside the column.

While process models are essential tools, they do not always give the insight needed to design equipment. Because deethaniser columns have liquid loadings of 40–55gpm/ft^2 of column diameter, effectively separating small amounts of water from the oil requires considerable residence time. During the next outage, a properly designed water draw system was installed. Three trays were removed and a completely seal-welded collector tray was installed (Figure 7). Water is now continuously withdrawn from the column, eliminating water entrapment.

Case history 2

Single column absorber/stripper

A single column absorber/deethaniser designed with two inter-coolers, water draws on each inter-cooler exchanger

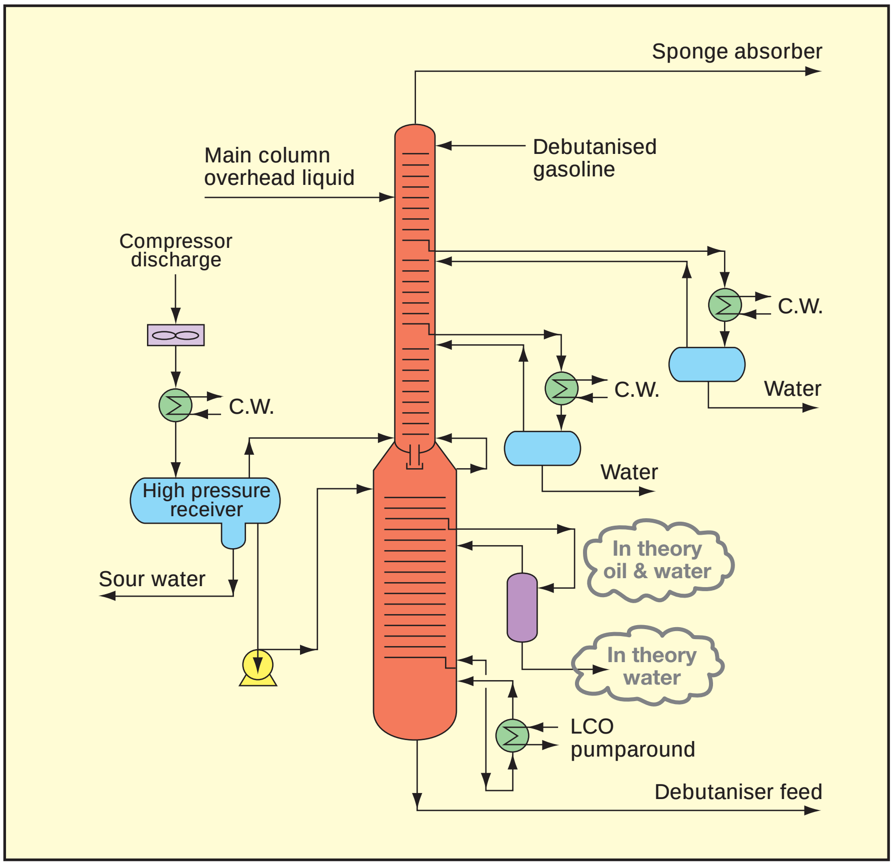

Figure 8 Single column absorber/deethaniser

and a water draw and an external draw pot (Figure 8) experienced periodic flooding. During upsets, pressure drop across the deethanising section increased rapidly while bottom product flow rate to the debutaniser decreased. As in Case 1, flooding caused carry-over, however, the consequences were more severe.

When the deethanising section flooded, tray spacing filled with liquid from the location where flooding initiated and pressure drop increased. Because the feed rate exceeded the column internals capacity, liquid could not flow down the column. Once the deethanising section filled, then the absorber section began to flood. When the absorber section was full, massive liquid carry-over with the overhead vapour sent large amounts of gasoline into the sponge absorber. Since sponge absorber bottom returns to the main column, when it vaporised at the high temperature in the LCO PA section, the main column flooded.

Again, reboiler duty had to be reduced to allow the accumulated liquid inside the column to flow to the bottom. But reboiler temperature had to be drastically reduced to allow free-water to leave with the bottom product because deethanising section vapour flows directly to the absorber section. Absorber section low temperatures prevent water from leaving the top of the column. In the two-column design, the HP receiver allows water and oil to be separated, thus it is more forgiving. Additionally, the HP receiver has a large liquid capacity that keeps deethaniser flooding from reaching the absorber.

Because both the deethanising and absorber sections were full of liquid and reboiler temperature had to be dramatically reduced allowing free-water to leave with the bottom product, liquid in the bottom column contained high concentrations of C_2 and H_2S. Processing this light material through the debutaniser took several hours and required venting (non-condensables) from the overhead receiver to maintain pressure control.

Moreover, debutaniser overhead LPG product C_2 and H_2S content increased to over 5% and several thousand parts per million, respectively. Consequently the LPG amine contactor became overloaded raising caustic consumption to meet the product H_2S specification and the alky unit had problems handling the C_2s. Because the vent stream was routed to the wet gas compressor inter-cooler, this material recycled back to the absorber/deethanising section increasing feed rate.

Operating data showed the upsets occurred during periods when the ambient temperature was low. Cold weather allowed the main column overhead receiver temperature to drop to 90°F and inter-cooler return temperatures were as low as 75°F. Because FCC charge rate was limited by wet gas compressor capacity, low receiver temperature reduced wet gas rate allowing higher FCC charge rate. Furthermore, propylene recovery increased to 96%.

Because FCC charge rate was more important than propylene recovery, short-term operating changes were made to control flooding. HP receiver fin-fans were shut down to raise receiver temperature. Vapour temperature to the absorber and deethanising section liquid feed temperatures also increased. In some instances it was necessary to block in one of the absorber inter-coolers to further increase temperature. These changes raised the vapour temperature leaving the absorber section to 140°F, decreasing propylene recovery by 3–5%.

The column was eventually revamped. A properly designed water draw tray was installed to eliminate water entrapment. Because the absorber bottoms liquid and deethanising section vapour are not routed to the HP receiver in the single column design, if a free-water phase is formed in the absorber or deethanising sections, it must be withdrawn. Thus a properly designed water draw tray is critical, otherwise water entrapment occurs and periodic column flooding cannot be avoided.

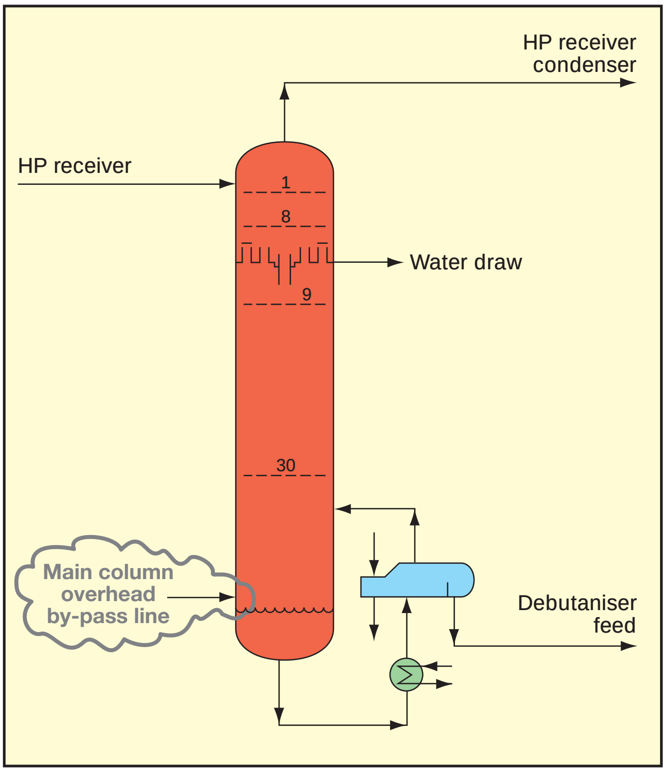

Figure 9 *Existing two-column absorber and deethaniser system with a new line was installed to bypass some of the main column overhead liquid directly to the deethaniser reboiler inlet*

Case history 3

Installing a feed pre-heater

A two-column absorber and deethaniser system used chilled water to reduce absorber lean oil and HP receiver temperatures to improve LPG recovery (Figure 1). Again, water was being trapped in the top section of the deethaniser causing it to flood, thereby reducing FCC charge rate and conversion. Gamma scans showed flooding started in the top third of the column rather than the bottom , where vapour and liquid loads are highest.

Since flooding was chronic and severe, a line was installed to bypass some of the main column overhead liquid directly to the deethaniser reboiler inlet (Figure 9). By reducing deethaniser column loadings, design FCC charge rate and reactor conversion were met. But propylene recovery dropped because lean oil flow through the absorber decreased and HP receiver vapour flow increased, reducing absorber L/V significantly.

Because propylene recovery dropped, FCC feed rate and conversion were adjusted to maximise LPG yield without incurring large losses to fuel gas. Since main column overhead liquid was routed to the deethaniser reboiler inlet, only one theoretical stage was available to strip C_2 and H_2S. Hence, the bypass rate was limited.

Some refiners maximise reactor C_3s because they produce chemical or polymer grade propylene, thus maintaining high recovery requires chilled water exchangers to reduce operating temperatures below cooling water temperatures, especially during summer months. Chillers produce 50–60°F water with refrigeration or lithium bromide systems.

While colder absorber lean oil and HP receiver temperatures increase C_3 recovery, they also raise the amount of C_2 and C_3 condensation in the HP receiver. In this case, the HP receiver operated at 70–80°F. Therefore, the deethaniser feed contained large concentrations of C_2. Because composition changes rapidly across the top few

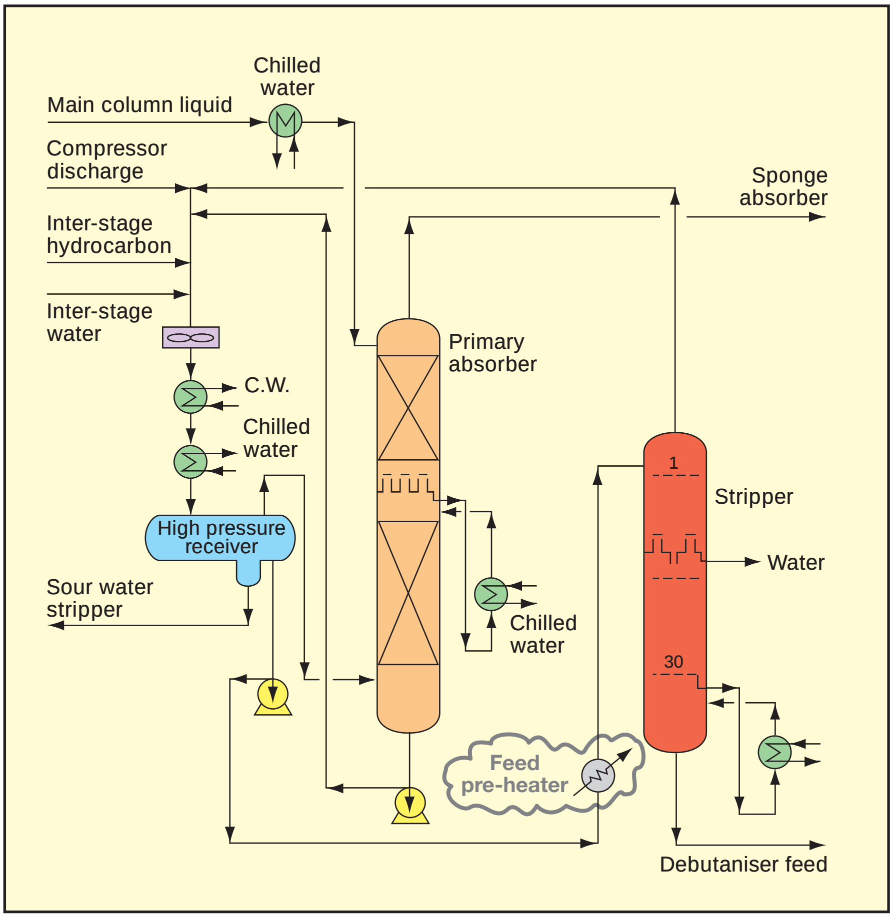

Figure 10 *Installing a pre-heater eliminated deethaniser flooding*

trays in the deethaniser, this system foams. Furthermore because deethaniser feed temperature is very low, water cannot escape with the overhead vapour stream.

Since the deethaniser had a properly designed water draw tray located eight trays below the top of the column, water entrapment was not a problem.

During upsets, the deethaniser column had the same symptoms as Case 1 and Case 2. Gamma scans showed flooding began above the water draw tray, not below where the vapour and liquid loads are highest. Because deethaniser liquid loadings are always very high, downcomer top area must be large and downcomer clearances high to prevent downcomer choke and high downcomer back-up. Low temperature deethanisers are foaming systems because the composition profile changes rapidly across the top few trays. Thus, tray designs need to account for foaming. In this case, downcomer top area was marginal and downcomer clearances were too low to handle foaming. But fixing the trays required a shutdown.

Finding a solution that did not require a shutdown and allowed FCC charge and conversion to be increased was essential. Since installing a feed pre-heater lowers feed liquid C_2 content, reduces liquid rate throughout the column, allows the bypass line to be closed, and could be installed without a shutdown, it was the best short-term solution.

Before installing a pre-heater, the complete system design was evaluated because HP receiver condenser duty increased, feed rate to the deethaniser increased and the HP receiver had to separate more hydrocarbon liquid from water. Furthermore, because total heat input to the deethaniser increased, propylene recovery marginally decreased. But installing a pre-heater eliminated flooding (Figure 10), which raised FCC charge rate and conversion without taking a shutdown.

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