

Sweetening Process Foaming and Abatement

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Abstract

Solvent foaming has been described as the number one operational problem encountered in natural gas processing plants and refinery sweetening processes today. Millions of dollars are reported lost every year in capacity reduction, lost solvent, downstream process damage, and environmental discharges that can be directly attributed to solvent foaming. The causes of foaming are well known, documented and communicated throughout the gas processing and refining community, yet the problems persists. One reason is that the separation devices commonly installed in sweetening plants target individual families of contaminant. Foaming tendency and break time are the only data in a typical analysis that even attempt to preempt these costly problems. The contaminants that are actually causing the individual plant problems are seldom, if never, quantitatively identified.

This article describes foaming causes, and how foams form in different areas of a typical sweetening plant. It presents data that demonstrate relationships between foam and carryover volume that help explain why different levels of foaming cause varying degrees of carryover. New correlations between foaming and lost solvent transport activity are also presented. Lastly, it describes a new and practical development for the separation of foaming contaminants from hydrocarbon treating solvents that focuses on the foam itself rather than individual contaminant families. The device concentrates the contaminants that are actually causing the problem and allows mitigation at the source.

Surfactants Cause Foaming

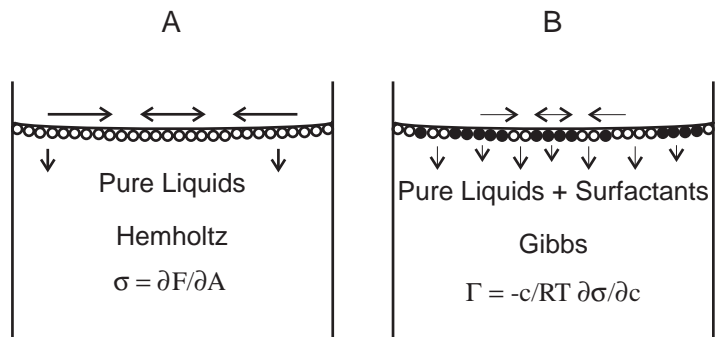
Foam is made up of thousands of gas filled bubbles, and classified as a “gas in liquid” dispersion or emulsion. Bubbles form when a liquid film encapsulates gas. The primary component in the film structure that makes up the bubble wall is surface active agent, or *surfactant*. There is also a significant volume of continuous liquid associated with the bubble wall, or *Plateau border*. Most of the continuous liquid is pooled at the junction, or *vertex* of the Plateau borders. Surfactant films separate from the continuous liquid because the interactive forces between the surfactant molecules are stronger than those between the surfactant and the continuous liquid molecules. Further, the dissimilar end of the surfactant is repelled by the continuous liquid, which enhances its tendency to encapsulate the gas.

Surfactants may be soluble or insoluble in the continuous liquid. They spontaneously concentrate at gas - liquid and liquid - liquid interfaces because they have an ionic hydrophilic polar end and a saturated hydrophobic nonpolar end.¹ If the continuous solution is aqueous, the polar end tends to orient itself toward the continuous solution, and the nonpolar group toward the interface. These molecules also adsorb to anything with similar surface chemistry suspended in the

solvent. By concentrating at interfaces, even extremely low concentrations of surfactant cause dramatic changes in surface tension because they interrupt the molecular continuity of the interface. When a surfactant is added to a pure solvent, the surface tension will decrease quickly. As the concentration of surfactant increases, the surface tension decreases to that of the pure surfactant. Therefore, surface tension is proportional to the surfactant concentration at the interface.

In a pure liquid, molecules in the continuous solution are surrounded by “like” molecules (see figure 1A). The interactive forces between the molecules are equal in all directions. Molecules at an interface, either gas - liquid or liquid - liquid, interact with “like” molecules below and to their sides, and with un-like molecules above. Normally, the interaction between similar molecules is stronger than the force between dissimilar molecules. This difference in

Figure 1. Homogeneous and Heterogeneous Surface Tension



interactive force makes the surface contract. The contractive force is known as surface tension. The Hemholtz free energy equation describes the dependence of the surface tension on the change of interactive force with the change in area.

When a surfactant is added to the pure liquid, it's surface composition changes. The interactive forces between the surface molecules also change. There is a reduction in surface tension with increased interfacial surfactant concentration. This surface excess concentration is described by the Gibbs Equation (fig. 1B). Heterogeneous surfaces, i.e., those containing surfactants, generally have lower surface tensions. The interaction between the surfactant molecules concentrated at the interface is of lower energy than that of the pure solvent.

Changes in temperature and pressure at the gas - liquid interface affect surface tension. The changes vary with the type of surfactant, concentration, and the chemistry of the continuous fluid. Increases in temperature and pressure tend to reduce surface tension of aqueous fluids. Generally variations in temperature have a greater affect on surface tension than pressure. However, this is not always the case. Changes in gas solubility with pressure can have a pronounced effect on surface tension in some cases.

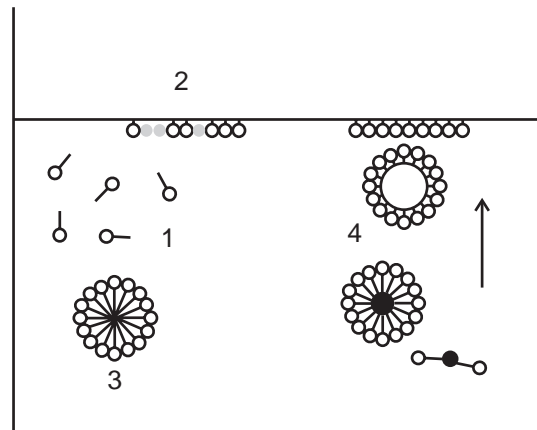
Surfactants are classified by the ionic charges on their polar ends. Anionic surfactants like carboxylate sulfates, sulfonates, and phosphates are negatively charged at their polar ends. Cationic surfactants like quaternary amine salts and long chain amines have positive charges as their polar groups. Nonionic surfactants such as polyoxyethylenated

alkylphenols are only weakly charged at their polar ends. Amphoteric or zwitterionic surfactants exhibit either positive or negative charges depending on the continuous solution's pH. In acid environments they are protonated and exhibit a positive charge. Being hydroxylated in basic solutions, they exhibit negative charges.

Surfactants tend to disperse in the continuous fluid at low concentrations (fig. 2, #1). However, when exposed to an interface they orient to produce the lowest surface energy or equilibrium (fig. 2, #2). Molecular movement caused by diffusion and turbulence causes the ends of the molecules to come close together. The probability of ends with similar chemistry coming close together increases with concentration. The ends of the molecules with similar chemistry orient together creating small dispersed surfactant aggregates called micelles (fig. 2, #3). The concentration at which micelles form is called the *critical micelle concentration*. If there are droplets of immiscible liquid, gas bubbles, or solid surfaces with similar chemistry, the surfactants will adsorb to these surfaces

(fig. 2, #4). The surface of the solid particles or bubbles then exhibits the surfactant's surface chemistry. This is how they act as dispersants and emulsifiers. Oil droplets suspended in an aqueous fluid are hydrophobic until coated by the nonpolar ends of a surfactant. The polar ends of the surfactant molecules face the aqueous phase increasing the polar characteristics of the oil droplet's surface. In effect, the surfactant reverses the hydrophobic nature of the droplet surface to hydrophilic. If the specific gravity of the contaminant is

Figure 2. Surfactant Orientation



less than the continuous solution, the particle or bubble will settle to the surface carrying the adsorbed surfactant. In the case of a gas bubble, it may leave the surface and form foam (fig. 3). As the gas bubbles settle to the surface they adsorb the surfactant dispersed in the continuous liquid. Anything in the liquid that has an affinity for the surfactant will adhere to the gas bubble, be carried to the gas - liquid interface, and incorporated into the foam structure, i.e., solid particles, dissolved ionic compounds and immiscible liquids.

Gas bubbles form extremely high gas - liquid interface areas when bubbled through continuous liquids. Smaller bubbles create larger combined areas. As the gas bubbles rise to the gas - liquid interface they accumulate surfactant dispersed in the liquid, and their surfaces become more heterogeneous. The surface tension of the liquid surrounding the gas bubble is therefore reduced making it more sensitive to shear forces in the liquid. The settling gas bubbles scrub the surfactant from the bulk liquid, and increase the concentration at the liquid's surface. Reaching the gas - liquid interface,

the surfactant film surrounds the gas bubble as it is displaced out of the liquid and forms a foam bubble. The next gas bubble to reach the surface forms a similar bubble. As the bubbles accumulate, foam is formed on the surface of the liquid.

Newly formed wet foam is elastic and insensitive to shear stresses. As soon as the bubble protrudes through the gas - liquid interface the solvent incorporated in the Plateau borders and vertex begins to drain due to gravity. Drainage continues until an equilibrium with Plateau border capillary action is reached. High density foams tend to drain more slowly due to the number of vertex between the smaller bubbles. Anything incorporated in the film that increases its drainage resistance also increases its stability. Bubbles at the surface of the foam drain into

the foam structure below. This liquid drainage acts like reflux, sustaining the bubble elasticity below.² As the drainage reaches the continuous liquid interface any excess surfactant not incorporated into the film increases the concentration at the liquid surface. This increase in surfactant concentration further accentuates foam bubble formation. As the free liquid drains, the film's surface becomes more rigid and sensitive to shear stress. The film may become rigid enough to break apart if enough shear is encountered. At this point, the bubble may burst and coalesce with a neighboring bubble. Foam bubble coalescence is known as *coarsening* because the appearance of the foam becomes less uniform and more coarse.

Gas diffusion between cells or bubbles also plays a large role in foam stability. The difference in pressure between the bubbles drives the gas diffusion. Fick's law defines the transport relationship³:

$$\text{volume rate of gas transfer} = k \times \text{film area} \times \text{differential pressure}$$

The diffusion coefficient, k , is dependent on gas partial pressures and the film permeability characteristics. The Young-Laplace equation describes the pressure inside a bubble as being higher than its surrounding pressure. The differential pressure across the film is proportional to the surface tension and area on which the pressure acts (fig. 4). The film's surface tension and capillary action between Plateau borders dictate the minimum thickness of the stable film in its environment.

Figure 3. Foam Development and Drainage.

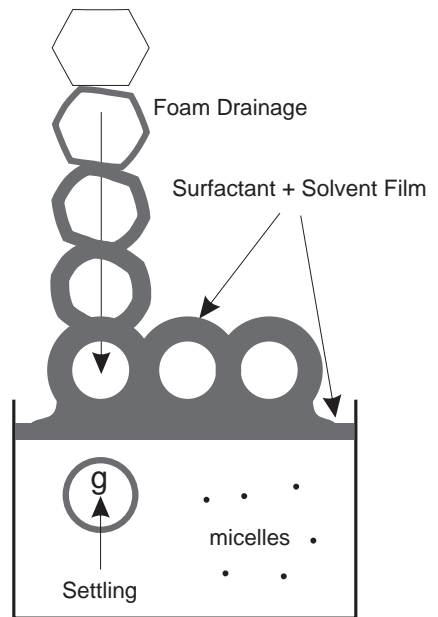


Figure 4. Bubble dP

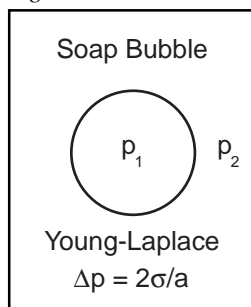
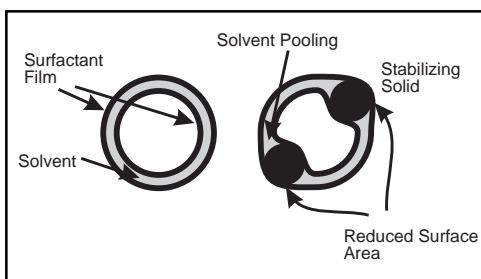


Figure 5. Foam Stability



Hydrophilic solid particles are known to stabilize aqueous foam. Hydrophobic solids have been used as an antifoam or destabilizing additive in aqueous systems. The hydrophilic solids improve foam elasticity by reducing the relative surface area on which shear and pressure act, and liquid pooling. (fig. 5). Pools of liquid form in the meniscus when the solvent wets the surface of a solid particle. The solid particles incorporated in the film increase its stable liquid volume, thereby maintaining its elasticity.

Foaming Upsets are Expensive

Several articles have been published giving case histories of foaming upsets and plant foaming abatement strategies. Few of these articles actually report having solved foaming problems on a long-term basis. Even fewer offer solution testimonies that are applicable to other plants. According to a recent article, "... foaming in treating units can be caused by an endless number of different factors...".⁴ Foaming is the most frequent reason for upsets in natural gas plants and petroleum refinery sweetening processes.^{5,6} Millions of dollars are spent on capital equipment, operations, and maintenance addressing foaming problems every year.

Two of the most recognized areas of revenue loss due to foaming are product throughput and lost solvent.⁷ Lost production was reported to be over two million dollars per year in one gas processing plant.⁸ Further, they were adding \$100,000/year in antifoam, and changing their particle filters every hour. Spending to control the amine foaming in the plant amounted to almost \$500,000.00. Mobil's Mary Ann gas plant reported a greater than 20% loss of capacity, significant amine losses, Claus and MODOP catalyst damage, and SCOT unit corrosion due to Sulfinol foaming in the plant.⁹

A survey of over 50 refineries stated that, on the average, they replaced their amine inventories three times per year.¹⁰ If each refinery had an inventory of only 65,000 gallons, this would equal over 9.8 million gallons of amine lost

per year. One plant spent over \$400,000.00 in amine particle filters alone trying to curtail solvent problems.¹¹ These few examples represent losses of well over 10 million dollars in a single year directly attributed to solvent foaming.

Indirect costs associated with amine foaming are more difficult to quantify but are probably higher than lost capacity and fluid. Examples of indirect costs would include inhibited mass transfer efficiency of the solvent, downstream process damage like fouled mole sieve or Claus catalyst, and environmental discharge violations.

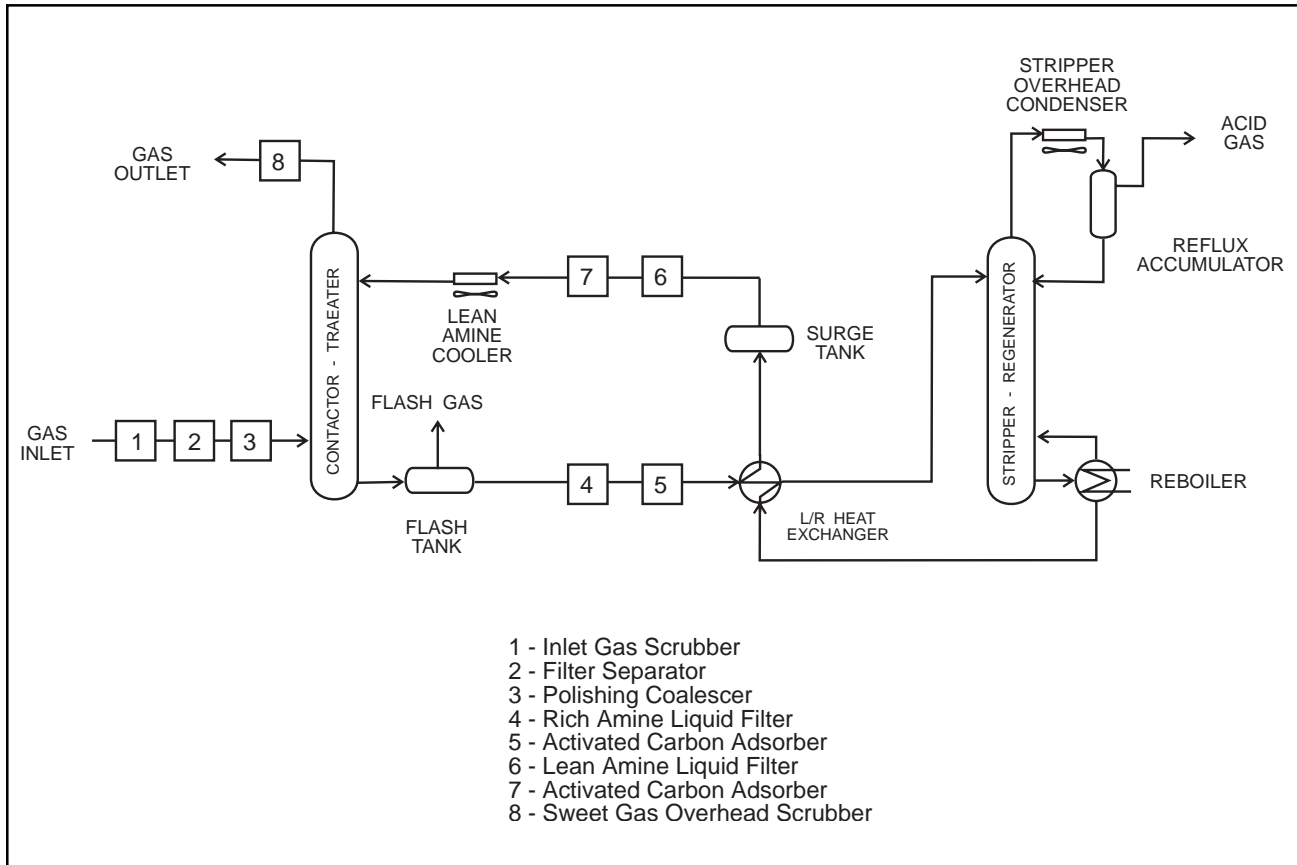
In 1991, the Petroleum Refinery Workgroup formed by Region 5 of the Environmental Protection Agency began studying refinery processes that had air emissions.¹² Part of that effort concentrated on fuel gas combustion devices. In 1992, seven Region 5 refineries were reporting high levels of excess emissions related to fuel gas. Amine foaming was identified by the refiners as the most frequent cause. Corrective actions included; installing more contactors, repairing corrosion related system damage, implementing new maintenance and operations programs, increasing amine flow, and reducing production rates in the problem units. Once again, the costs to implement these changes had to run in the millions of dollars.

Lastly, and probably most costly would be the reduction of the solvent's gas transport opportunity.¹³ The ability of the solvent to remove acid gases is directly affected by surfactant contamination. The mass transfer efficiency of the surfactant film at the gas - liquid interface replaces that of the solvent. In one bioreactor study oxygen mass transfer was reduced over 70% due to surfactant contamination.¹⁴ The average of several studies showed a reduction in mass transfer of over 60% with various solvents and gases. Any reduction in solvent activity by surfactant contamination would significantly increase processing costs.

Maintaining Clean Solvents

Clean solvents don't foam. Likewise, the most severe solvent contaminants aren't visible. Sweetening systems are designed with similar contaminant control devices. These devices are common, and have been used in amine systems for many years. Plants have been trying to maintain clean solvents and prevent foaming problems by installing separation devices that target individual families of contaminants, i.e., solids, liquids, and soluble compounds. Figure 6 shows a typical sweetening system flow diagram including separation devices. This individual contaminant family removal strategy can cause considerable confusion when an upset takes place. Plant personnel have to figure out which device failed while trying to clean the solvent and restore treating capacity to the plant.¹⁵ Unlike a failed motor, pump, blower, etc., a failed separation device isn't usually obvious. Difficulties identifying problems have resulted in the wide spread practice

Figure 6. Typical Sweetening Process Flow Diagram



of temporarily masking the event by adding antifoam while investigating the causes. Today, adding antifoam has become a primary reaction to foaming upsets while the upset causes are investigated. Some plants even add antifoam automatically with slight increases in tower differential pressure.

The contaminant removal devices normally installed in the plant include inlet gas separators, flash drums, liquid filters, and activated carbon adsorbers. Inlet gas separators can be any one or a combination of scrubbers (fig 6. #1), filter separators of some type (#2) and, high efficiency coalescers (#3). Scrubbers are generally considered 10-micron devices, and are used to remove continuous liquids from the feed gas. Filter separators are normally 0.5 to 1-micron devices and are used to polish the solids and gas borne liquid aerosols. Gas coalescers are considered high efficiency devices used to polish the gas of liquids to the 0.3-micron level. Manufacturer's specifications for gas coalescers vary, but may promise outlet gas quality ranging from 0.1 micron droplet removal at greater than 99.90% to 3.0-ppb (wt) total entrained liquids.

When the sweetening system encounters a contaminating event that the separation devices cannot handle efficiently, the result is solvent contamination and an eventual unit upset. For example, the activated carbon adsorber is designed to remove soluble chemical contaminants, e.g., amine degradation by-products, and "trace" liquid hydrocarbon.

It performs this function very efficiently if operated and maintained properly. However, the guidelines for determining its exhaustion are so vague that most plants don't know when it should be replaced.¹⁶ Consequently, activated carbon doesn't get changed and doesn't function properly most of the time. The consequences of inefficient activated carbon treatment include; increased amine foaming tendency due to immiscible and miscible liquid hydrocarbon, increased corrosiveness due heat stable salts and precursors in the solvent, and reduced solvent activity.

There are also conflicting functions among the contamination control devices. An example of a common conflict would be activated carbon's positive use to remove unwanted organics from the solvent, and it's negative ability to remove antifoam additives.^{17,18} If the activated carbon were being maintained properly, antifoam would probably not be necessary.¹⁰ However, the plant's carbon costs would increase significantly. Particle filters are not designed to remove deformable contaminants like liquid hydrocarbon. The deformable droplets spread out over the surface and prematurely plug the filter. An example of a deformable particle often removed by mechanical filters is antifoam. It is desirable for the filters to remove particles, but not the expensive antifoam added to the system.

Flash drums are usually designed as 3 phase separators. They flash dissolved gas from the amine by pressure reduction. Liquid residence time in the flash drum is normally between 15 and 30 minutes by design. This allows time for the liquid hydrocarbon and large solids contaminating the solvent to settle and be removed. Poor design or inadequate maintenance can cause flash drums to contaminate fuel gas and flare systems. Further, they can dump concentrated liquid hydrocarbon and gas into the process amine flow when they fail to operate properly.¹⁹

Liquid filters protect whatever is located just downstream of them. In figure 6, the particle filters (#4, #6) are located in front of the activated carbon beds on both the rich and lean solvent streams. In this position the particle filters are designed to remove solid particles that would mechanically plug the activated carbon adsorber. If the carbon were on a slipstream, the full stream particle filters would be protecting the downstream lean/rich exchanger and stripping tower internals.

The actual brand of particle filters used in amine systems varies widely, and is normally determined by either the lowest bidder, a recommendation from a trusted vendor, performance history, or on-stream testing. Although not communicated well by filter companies, the most economically efficient filters for amine service depend on the contaminants in the system. If there are shear sensitive or deformable particles present in the solvent, a depth filter of some type would probably be most economical. Surface filters tend to either pass the shear sensitive solids, or plug due to the formation of an impermeable surface cake. If the contaminants being removed are not shear sensitive, surface filters are generally

successful, and allow smaller vessels at higher flow rates.

There is no hard and fast rule for choosing the particle size range that most economically protects the plant. Solvent and filter vendors usually recommend a particle removal level in the 5-micron range.^{17,20} The reason for this recommendation is that the downstream carbon bed is about a 10 - 50 micron mechanical filter depending on the carbon granule size used. One filter manufacturer recommends solvent filtration as fine as 0.2 micron.¹⁷ This is the removal level of sterilizing filters used in pharmaceutical manufacturing. In the not too distant past, 25-micron filtration was the standard. Plant upsets and tolerable economics normally end up determining the particle removal range employed.

Two of the biggest particle filter problems faced by amine plants are the size of the particles that actually enhance foaming, and the unwanted removal of immiscible liquids suspended in the solvent. 5-micron particle filters can remove liquid hydrocarbon and antifoam even in extremely low concentrations. The liquids coat the fibers and tighten an already tight filter matrix. The results are premature filter plugging and minor foaming upsets caused by antifoam removal. The best particle filter for sweetening systems would be immune to liquid hydrocarbon, and remove the small particles while leaving the larger ones behind.²¹ Mechanical particle filters cannot do this. Try asking your filter vendor for a particle filter that will remove 0.2-micron particles and leave the 2 microns in the solvent. This is one reason filtration costs have increased so dramatically. In general, the smaller the particles removed, the higher the unit cost, and shorter the service life.

Activated carbon (fig. 6, #5,#7) is present in the system to remove dissolved organic acids produced by amine degradation, and "trace", e.g., <2.0 ppm(wt) liquid hydrocarbon. The organic acids are precursors to heat stable salts. Removing these soluble contaminants reduces system corrosion, reduces foaming tendency, and maintains solvent activity. Activated carbon beds are also seldom changed at the proper time. There are no quantitative tests that can be run, on-stream, that indicate bed exhaustion. How many adsorption isotherms have you seen for your carbon used with your solvent? Hence, most plants change their carbon based on time in service, differential pressure, solvent color change, or system performance. Since system conditions vary, changing carbon on a time schedule normally results in wasted adsorption capacity. Changing carbon based on differential pressure means that the level of prefiltration is too low. If a plant waits to change their carbon until the heat stable salt concentration is high, i.e., > 10% of the amine concentration, the pH goes down or a tower begins to foam, it's too late. The upset would already be occurring or eminent. At the present time research is being done in the areas of on-line liquid conductivity and surface tension measurement to determine carbon exhaustion.

Foaming Under Plant Conditions

Every plant, by virtue of its design, service and age, will be sensitive to different degrees of solvent foaming. A solvent that shows a low foaming tendency may function well in one plant yet cause massive solvent carryover in another. There may be a recurring cause for amine foaming reported by a single plant, but rarely is this true for every plant. The formation or intrusion of all foam causing contaminants in the solvent cannot ever be completely eliminated because they are inherent in the system, i.e.; solvent degradation, corrosion, and the devices used to remove the contaminants cannot be 100% efficient. Solvent degradation products that attack protective corrosion layers in system piping generate solid particles.¹⁵ Erosion corrosion also adds to entrained solid particles that act as contaminants. Being a recirculating system, even small levels of inefficient contaminant removal result in increasing concentrations and unit upsets.

Foaming under plant conditions is most often attributed to solvent contamination by solids, liquid hydrocarbon, well treating chemicals, corrosion inhibitors, lubricants, acidic amine degradation products, and antifoam additives.^{2,19,22} Most of these compounds are known to be, or to contain surfactants. Solvent foaming under plant conditions can be difficult to recognize. This is especially true if it is localized at one high turbulence point in the system. For example, if liquid hydrocarbon is being carried into the contactor with the inlet gas it will most likely flow into the flash drum with the rich solvent, not up the tower with the gas. Foam created in the flash drum might show up as variation in liquid level, booster pump cavitation, unusual vapor space in the rich side particle filters, higher differential pressure across the carbon bed, or possibly even a change in heat transfer efficiency at the lean/rich exchanger. Hydrocarbon mists might be carried further into the contactor with the gas. They would eventually be scrubbed from the gas by the solvent. Once in the solvent, surfactants in the liquid hydrocarbon could cause solvent foaming. A list of common foaming symptoms is given in table 1. The large number of symptoms makes identifying the problem quickly difficult at best.

Most plants have their solvents analyzed at least once per quarter, and some once per month. A typical analytical report is shown in table 2. Foaming tendency data are generated by bubbling atmosphere through a room temperature sample of the solvent, at a specific gas rate, and measuring the height of the foam column produced (see table 3.) An accepted guideline for determining if a problem might exist is a foam height of over 50-ml with a break time of less than 5 seconds. There are no reported correlations between foaming tendency data and tower design or dynamics. Colder testing temperatures and lower gas pressures favor lower foaming tendency which can skew analytical results. Also, laboratory air rates can be lower than tower vapor velocities. Relying on these data to solve foaming problems is difficult because they normally take a few days to get. Besides, they don't identify the actual foaming contaminant. Although

Table 1. *Foaming Symptoms*

1. High foaming tendency and break time.
2. Unexplained solvent losses, or high make up requirement.
3. Higher than normal contactor differential pressure.
4. Liquid hydrocarbon in the regenerator/stripper overhead cooler or reflux samples.
5. Unexplained low flash drum liquid levels.
6. Foam present when the solvent sample is agitated.
7. Increased liquid level in the contactor overhead knockout.
8. Decreased liquid level and higher than normal differential pressure on the activated carbon bed.
9. Foam in the liquid hydrocarbon blow down lines from the flash drum.
10. Constant gas pockets in the rich solvent filters and/or activated carbon vessels.
11. Decreasing tower differential pressure with the addition of small volumes of antifoam.
12. Constant charge and booster pump cavitation.
13. Gas carry under from the flash drum to the rich solvent filters or activated carbon.
14. Visible liquid hydrocarbon settled in solvent samples with or without added water.
15. Solvent carryover to the fuel gas system.
16. Liquid hydrocarbon in the rich solvent filters.
17. Liquid hydrocarbon visible in the surge drum.

qualitative, foaming tendency data are probably the best way, at least at this time, to baseline a system's tendency to produce foaming problems.

Foam can form anywhere gas and liquid coexist in a turbulent environment. It can also form when gas comes out of solution due to process pressure or temperature changes. The highest amount of turbulence where gas and liquid coexist occurs in the process towers. As the gas encounters the solvent in the contactor, a gas - liquid interface exists. Towers are designed to provide as much of this mass transfer interface as possible. This is true for both trayed and packed towers. Surfactant in the solvent forms film by concentrating at gas - liquid interfaces. Turbulence at the interface causes gas to be encapsulated in the film. Normally the film breaks, separating the gas and liquid in the vapor spaces between the tower internals. If the film is stable enough it will persist and form a foam plug that will carryover into the next higher tray, or create a restriction that floods the tower at that point. If the foam is stable enough it can fill the entire vapor space above the tray and restrict both gas and liquid flow. This restriction to flow causes an increase in tower differential

Table 2. Amine Analytical Report

Parameter	Rich	Lean
pH	8.5-10	>10
Chloride [mg/l]	<600	<600
Hydrocarbon [ppm]	<10	<10
Iron [ppm]	<15	<15
Acid Gas Loading [mol%]	0.3 - 0.6	0.3 - 0.7
	0.3 - 0.45(MEA)	
Suspended Solids [ppm]	<200	<200
Heat Stable Salts	<10% of solvent concentration	
Foaming Tendency		
Foam Height [ml]	<50	<50
Break Time [sec]	<5	<5
Amine Concentration [wt%]		
MEA	15 - 20	15 - 20
DEA	25 - 30	25 - 30
MDEA	20 - 40	20 - 40
DGA	35 - 60	35 - 60
Ucarsol	50 - 60	50 - 60
TEA	10 - 30	10 - 30
Sulfinol	various	various
SIPA	30 - 50	30 - 50
Selexol	10 - 30	10 - 30
Normal Operating Reboiler Range [deg F]	225 - 280	

pressure. Plugged or undersized inlet distributors can cause jetting at the top and bottom of towers. If foaming occurs at the gas or solvent inlets there will probably not be a detectable differential pressure across the tower.

Tower mist eliminators can create foam with surfactant concentrations below the level that would cause problems in the tower itself. They continuously operate in a saturated condition due to the normal liquid mist in the treated gas. The mist droplets carry surfactant to the mist eliminator where they concentrate. Eventually, foam forms on the overhead side of the mist eliminator. Having little to no draining time, the mist eliminator foam would contain a significant volume of clean solvent. This mixture of concentrated surfactant and clean solvent would carryover into the overhead scrubber or filter separator. Some of the foam will break in the separator, and be collected as carryover liquid. This liquid is normally reintroduced into the rich solvent stream where it continues to cause solvent foaming.

The mist eliminator foam generation scenario can occur in any device that concentrates solvent and produces turbulence. System differential pressures created at these points would be low, making it extremely difficult to identify as foaming sources.

Foam can form in the flash drum. As the pressure is reduced to flash dissolved gas extremely small bubbles are

Table 3. Solvent Foaming Test Procedure

Determination of Foaming Tendency and Stability¹⁸

SCOPE

This test is designed to determine the foaming tendency and resultant foam stability of pure liquids or mixtures.

PRINCIPLE

Air is sparged through a measured amount of solution at a specified rate for a specified period. The difference between initial and final foam height is measured. The air is stopped and the time required for the foam to collapse is reported.

APPARATUS

- (1) 1,000 - 2,000 ml graduated cylinder.
- (1) Gas flow meter, rated up to 5,000 ml/min.
- (1) Sparger tube, either sintered glass or metal.
- (1) Length of surgical rubber tubing to connect air source.
- (1) Timer or stop watch.

PROCEDURE

Step 1: Preset the flow meter to allow 2,000 ml/min. of air to sparge into the graduated cylinder.

Step 2: Pour 200 ml of TEST SOLUTION into the graduated cylinder, begin air flow, and start watch or timer.

Step 3: After five minutes, record the foam height then terminate air flow. Immediately reset and restart the stop watch or timer.

Step 4: Record the time required for the foam to break back to the initial level in the graduated cylinder.

Step 5: Thoroughly clean the graduated cylinder and sparger before reuse. Very small amounts of surfactant may affect the test.

CALCULATION & DATA HANDLING

Report initial liquid level in milliliters, final foam height in milliliters, and break time in seconds.

formed in the solvent. When surfactants are present in the liquid they will concentrate at the bubble interface. If there are stabilizing agents in the bubble's film, it won't burst as it rises through the liquid surface in the tank, and stable foam will be produced. Extremely small gas bubbles produce extremely dense foams. Being a relatively low shear environment, flash drum foam can be stable for hours and can be carried over into the fuel gas system with the flash gas.²³ Surfactants will concentrate at the gas - liquid interface, gradually increasing the foam break time.

Particle filters are often blamed for solvent foaming incidents due to surfactant present on the fibers. One plant actually washes their filters prior to putting them in service.²⁴ It seems more likely that the particle filter's role in a sustained foaming problem would be their tendency to remove suspended antifoam droplets rather than leaching a small amount of surfactant. Shear sensitive solids, i.e., sulfides and carbonates, might also be broken up into smaller particles as they encounter particle filters. These smaller solids tend to enhance foam stability in a low foaming tendency solvent.

Activated carbon is also blamed for causing foaming problems. Again, it is more likely that the antifoam droplets are adsorbed and removed from the flow stream, or the carbon is exhausted and not adsorbing surfactants. Having low superficial fluid velocities, carbon adsorbers also “vapor lock” or show increased differential pressure when foam or gas enters from upstream equipment, e.g., particle filters or flash drums.

Stripping towers have a lower tendency to create foam because of their higher operating temperatures and lower pressures. However, they are notorious for concentrating surfactants. Higher temperatures and lower pressures reduce the solvent’s surface tension which reduces the filming tendency of the surfactant. Organics with vapor pressures close to that of water may be flashed in the still and condense overhead. These surfactants would be collected and reintroduced into the tower with the reflux.⁵ The foaming tendency of the solvent at the top of the stripper would increase until it became stable and carried over as foam. The foam would carry over with the acid gas. This is a good reason to have reflux samples included in the routine solvent analysis for foaming tendency. Also, if gas coming out of solution after the lean/rich heat exchanger is mixed with the solvent prior to the stripper’s inlet distributor, foam can form before the tower’s inlet. In this case the foam would have a higher likelihood of passing through the overhead condenser and into the downstream equipment, i.e., flare knockout drum, SRU, etc.²⁵ Jetting solvent through a mechanically plugged inlet distributor will also create foam at the top of the stripping unit. Again, foam created at the top of the tower can easily carryover into downstream equipment.

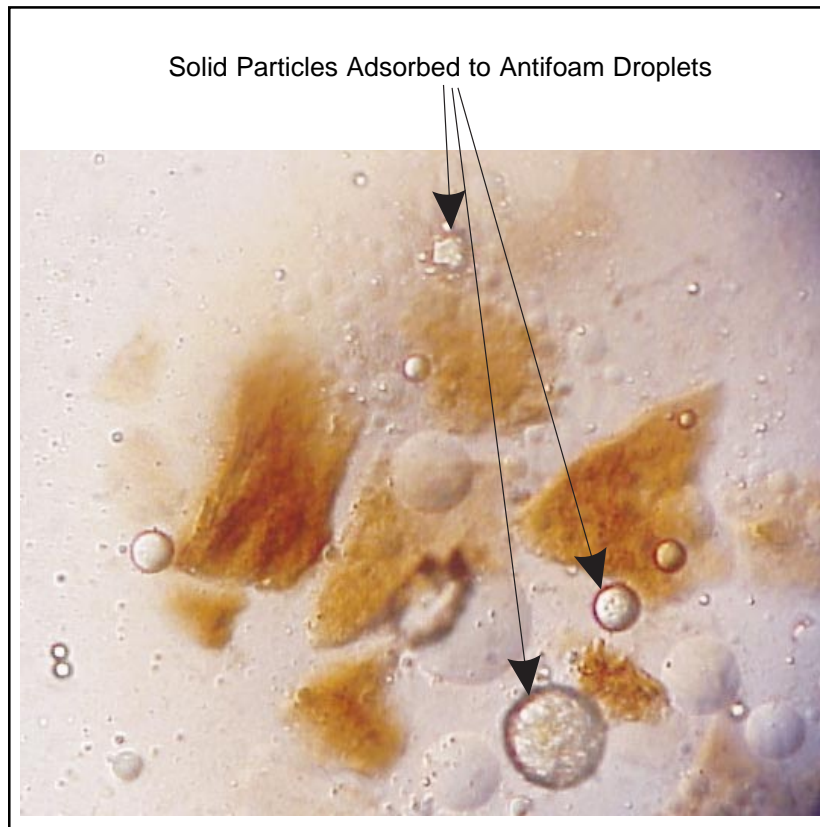
Solvent make up water can be a major source of foaming contaminants.²⁶ Condensate from steam systems is especially risky. Corrosion inhibitors and chelating agents used to treat boiler feed water can concentrate in this water. Corrosion inhibitors are surfactants, and can cause foaming. Chelating agents attack the protective corrosion layers established on system piping, and cause increased suspended solids in the solvent. These solids stabilize foam and increase particle filter costs.

Plant Responses to Foaming Upsets

Responses to questions about foaming problems are surprisingly consistent. “*We add a little antifoam to the unit and it settles right down.*” The single most common reaction to unit foaming symptoms is to add antifoam to the solvent. Most other responses take longer and require data of some kind.

There are several problems created when antifoam is used. The first destructive action of antifoam is the inhibition of foam formation. Foams form because of the presence of surfactants. Surfactants have been shown to reduce

Figure 7. Antifoam - Solids Agglomeration



solvent activity. Masking the presence of surfactants in the solvent allows their concentration and subsequent solvent activity loss. It should be noted that the solvent activity reduction would take place prior to the surfactant concentration reaching a critical foam producing level.

Antifoam is a surfactant itself and can enhance foaming. If the concentration is high enough, antifoam will film like other insoluble surfactants. Further, as is shown in figure 7, antifoam will also agglomerate with solids and be removed by the particle filters. Activated carbon will also prematurely plug with these agglomerates. Finally, antifoam no longer acts to reduce foaming when agglomerated with solids.

Silicone antifoam has been seen to coat hydrophilic surfaces. The hydrophobic antifoam coating can reduce solvent wetting of the packing surfaces, thereby reducing mass transfer area. If mass transfer area is reduced tower efficiency is also reduced.

Silicone based antifoams are manufactured with chemical compounds called siloxanes. If exposed to heated surfaces, i.e., flash gas used as fuel, and SRU burners, siloxanes will form silicon based deposits. These deposits have been known to permanently damage the heated surfaces.²⁷

Antifoam addition should be considered a warning sign. The solvent is contaminated with surfactants to the point where the basic hydraulic function of the system's towers is being affected. It is also a warning that the solvent's acid gas transport activity has been reduced. Antifoam chemicals should only be used on a temporary basis.⁶

Activated carbon and liquid filters are normally changed when a foaming upset starts. Since activated carbon is known to remove antifoam it may be temporarily taken off line. This is a mistake. Activated carbon may remove the surfactants that cause the foaming problem. The carbon unit should remain on line during the foaming upset. Samples of bed effluent should be tested for foaming tendency. Increased foaming tendency would indicate a carbon changeout was necessary. The carbon effluent should be monitored and the carbon changed out until the foaming upset is over.

Some plants lower rates until lab results arrive. The data that is examined first include iron, liquid hydrocarbon, suspended solids, and foaming tendency, with the hope of finding a significant data point that identifies the problem. The contaminants actually causing the foaming are not identified or reported. A procedure for isolating the actual foam causing contaminants will be presented later in the paper.

Another common reaction is to inspect the inlet gas separation devices for signs of carryover. Few plant engineers have been trained to diagnose scrubber, filter separator, or coalescer failure. Low level bypass may be virtually impossible to detect.

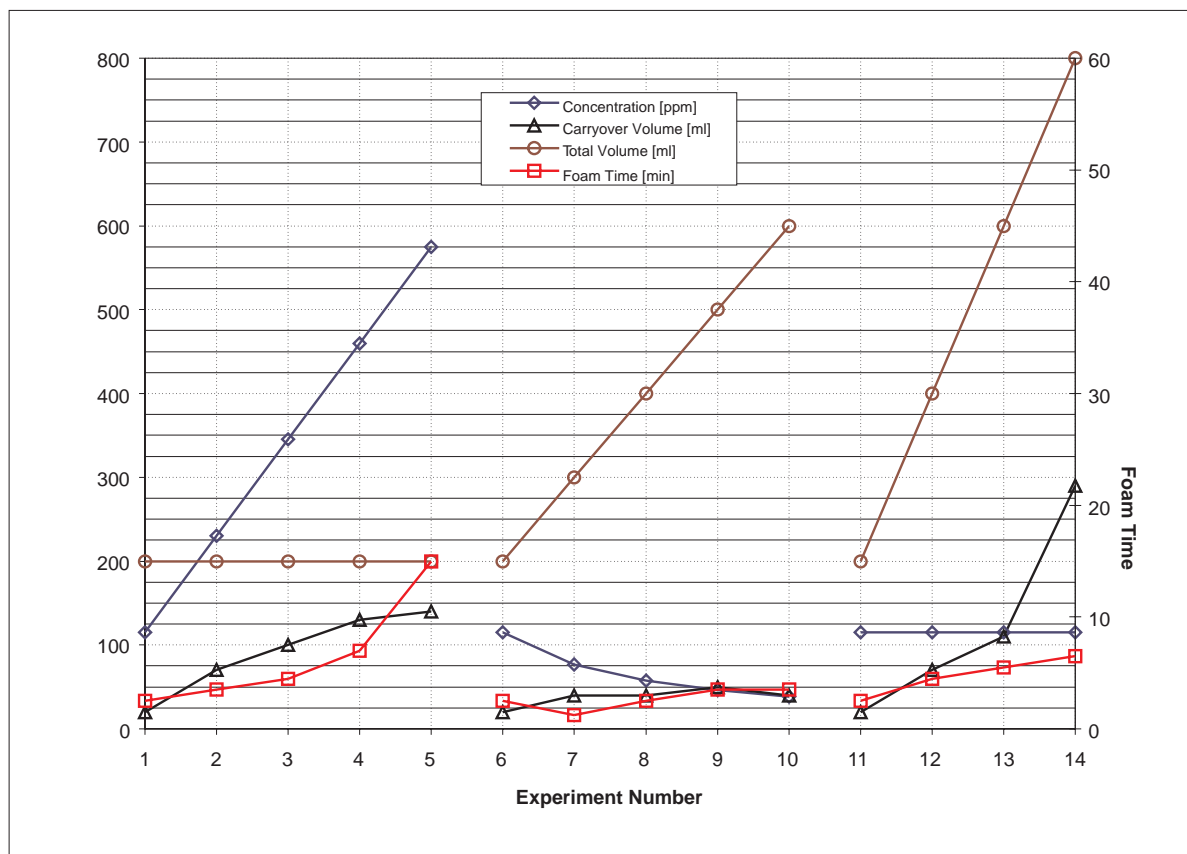
Lastly, most plants return the liquids taken off of the contactor overhead knockouts to the rich solvent stream in an effort to reduce solvent losses. This practice produces the same surfactant concentration loop described previously with contaminated stripper reflux. Without running foaming tendency tests on this liquid prior to putting it back into the system, it isn't known if the carryover is normal or surfactant from broken foam.

Foaming and Carryover Relationships

Figure 8 shows data collected during a series of preliminary experiments that were run to investigate the fundamental relationships between foam evolution and carryover volume. If the foam's structure is surfactant and free solvent as previously described, can the surfactant in a solvent be removed by producing and removing the foam? Does foam structure change with surfactant concentration? Since foaming in sweetening plants is thought to be the main cause of clean solvent loss in the form of carryover, is there a relationship between surfactant concentration and carryover volume?

In experiments 1-5 the volume of surfactant added was increased while the total solvent volume was held constant. Solvent samples of 200 ml were contained in a 1000 ml graduated cylinder, and were contaminated with incremen-

Figure 8. Foaming and Carryover Relationships



tally increasing amounts of surfactant. Air was bubbled through each sample at a constant rate of 1680 ml/min. The solvent - surfactant mixture was allowed to foam until an end point was reached. In each case the solvent stopped foaming after a period of time. The remaining solvent was unable to produce foam upon repeated exposures to air bubbles. The time it took for the solvent to stop producing foam was reported as *foam time*. The liquid level was recorded after each run and subtracted from the initial 200 ml starting volume. This difference was reported as *carryover volume*.

Experiments 1-5 show that the foam time appeared to increase exponentially as the surfactant concentration was increased. The carryover volume appeared to increase logarithmically with increasing surfactant concentration. The texture of the foam was also observed to change during the foam time. Initially the foam appeared dense with small uniform bubbles dominating the structure. Toward the end of each run the foam structure became less uniform with a variety of larger bubbles being produced. The larger bubbles were considerably less stable than the smaller. Regardless of the bubble size however, plug flow was observed in each case. The foam structure moved up the column as a front, conforming with the diameter of the graduated cylinder. In some cases, a single horizontal film moved up the column.

High density foam is produced by high surfactant concentration. High density foam contains more clean solvent.

Foam textures change with concentration. Lower surfactant concentrations produce larger, less stable foam. Low density foam breaks, concentrating surfactant at the bulk gas - liquid interface until enough surfactant exists to form stable high density foam.

In experiments 6-10, the volume of surfactant added was held constant while the volume of solvent was increased. The foam time and carryover volume remained relatively constant with decreasing surfactant concentration. These data indicate that the foam density and subsequent carryover volume were more dependent on the volume of surfactant added to the system than the actual concentration. Further, foam time remaining constant indicated that the foam evolution was also dependent on the surfactant volume added, not concentration or solvent volume. The increased solvent volume reduced the distance from the liquid surface to the top of the column, thereby reducing the foam draining time.

The third set of experiments, 11-14, were run with the surfactant concentration held constant. The volume of surfactant added to the system and the solvent volume were increased proportionally. The foam time appeared to increase linearly with the surfactant volume added as the concentration remained constant. This further substantiates the hypothesis that foam time is independent of surfactant concentration, and depends on the amount of surfactant in the solvent. The carryover volume increased exponentially. These data also indicate, once again, that the carryover volume is dependent on surfactant volume added, not concentration.

The data in trial 14 show a dramatic increase in carryover volume relative to foam time and surfactant added. This indicates that a critical system volume can exist for any volume of surfactant in the system. This data point reiterates the effect of foam residence or drain time mentioned previously. Because the increasing liquid volumes brought the gas - liquid interfaces closer to the top of the column, the residence time of the foam in the column was decreased. Therefore the drain time was also decreased. Younger, higher density foam was produced close to the top of the column. Consequently higher clean solvent volume was carried over.

The experimental data given in figure 8 show that surfactants can be separated by foaming the solvent and removing the foam. The surfactants were removed from the system with the foam. The carryover volume associated with the foam varies exponentially with surfactant volume present in the solvent as opposed to surfactant concentration. Gas bubbles passing through the solvent volume concentrate surfactant at the liquid - gas interface. There is a critical drain time for each volume of surfactant contained in the solvent above which the carryover volume increases exponentially. The dependence of carryover volume and foam time on surfactant volume rather than concentration can be explained by

the surfactant tendency to adsorb to gas - liquid interfaces. The foam time would be limited by the time it took for the bubbles to scrub it to the bulk gas - liquid interface where it produced foam. This would mean that the density of the foam formed would be more dependent on gas rate and concentration.

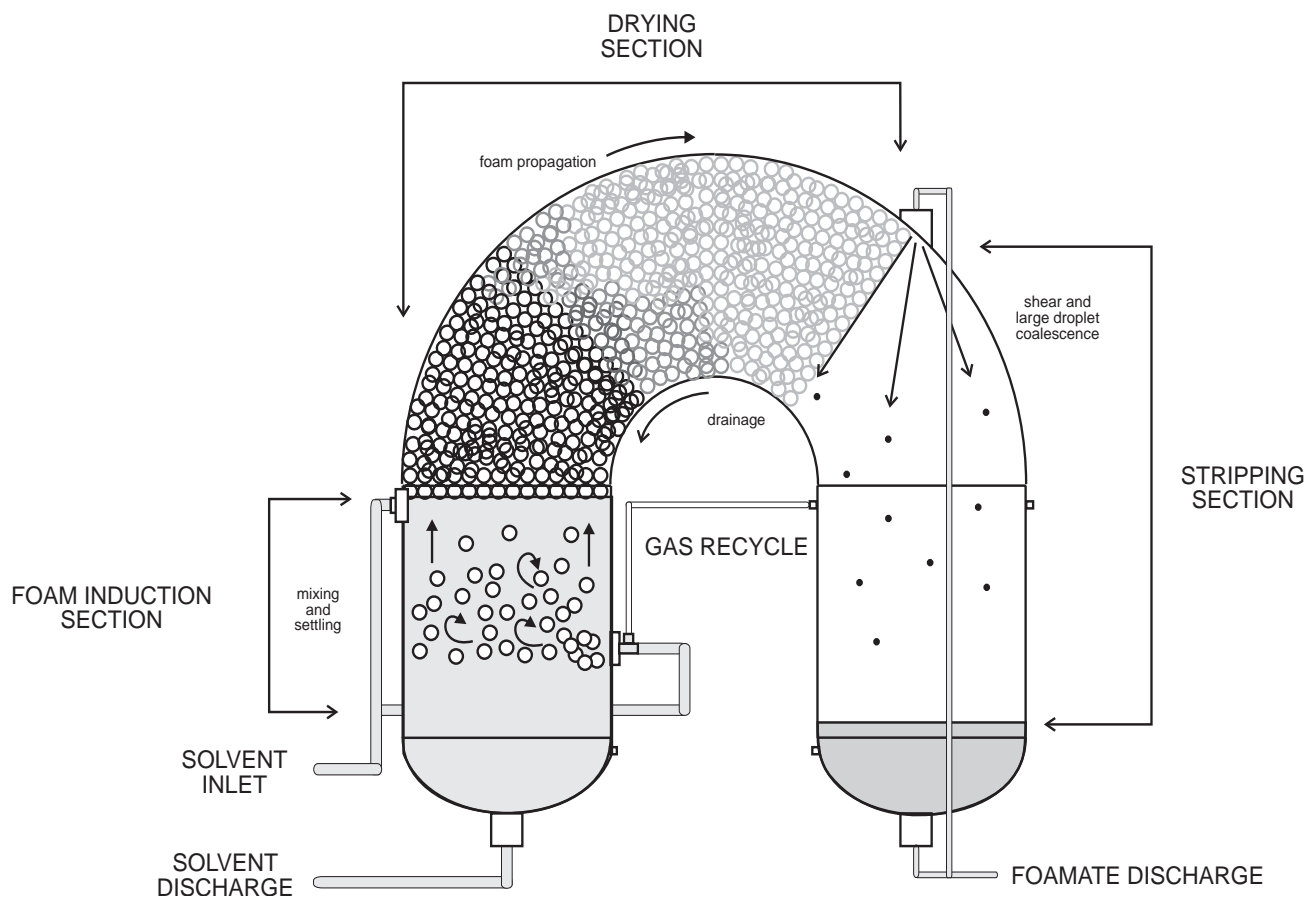
Removing Only Foam Causing Contaminants

It has been well established in the literature that a large number of contaminants, either combined or alone, cause system foaming. It has also been shown that there are several contaminant removal devices installed in sweetening plants. Each with its own special family of contaminant. If any one or a combination of these devices allows contaminant to remain in the system a foaming upset will eventually occur. Foaming abatement can be complicated. The prevalent constant among foaming upsets is the presence of foam. It may sound redundant, but the foam contains all of the contaminants that cause foaming. The film that makes up the bubble walls is surfactant(s). The stabilizing compounds and particles are also incorporated in the foam structure. It has been shown that if the foam is removed, the foaming stops.

Figure 9 shows a new development in separation technology for hydrocarbon treating systems that makes it possible to indiscriminately remove only foam causing and stabilizing contaminants. That is, it separates and removes foam causing contaminants without regard to type. It removes only those contaminants in the solvent that are responsible for foaming and foam stability by foaming the solvent under controlled conditions. Solvent components that don't cause foaming won't be removed. The system separates the continuous solvent from the foam by allowing it to drain as it progresses up the column. This minimizes clean solvent loss. After stripping, the concentrated surfactant is collected for examination and disposal. The system doesn't utilize disposable internals and works on-line under plant conditions. This system is commercially known as the SigmaPure™.

Contaminated solvent is mixed with a nonoxidizing gas, i.e., flash gas from the system, or nitrogen, at the solvent inlet, and jetted into the foam induction section. Under these conditions even low foaming tendency solvents are forced to foam. As the bubbles produced by this mixing rise through the solvent in the column, surfactant dispersed in the liquid adsorbs to the gas bubbles' surfaces. The gas bubbles scrub the surfactant from the continuous liquid. Any immiscible or soluble liquids with an affinity for the interface or the surfactant stick to the bubbles and are carried to the continuous liquid's surface to produce foam. The bubbles can also scrub the solids from the solvent as well. Any stabilizing compounds are adsorbed to the bubbles. Foam is produced as the gas bubbles exit the continuous liquid, separating all of the adsorbed materials.

Figure 9. SigmaPure™ System



The unique arch in the system piping creates the drying section. The foam being produced is displaced upward through the unit's piping by the new foam being formed at the continuous liquid - gas interface. As the foam follows the piping, the free "clean" solvent incorporated in the foam's structure is allowed to drain back into the continuous liquid. The draining liquid acts like reflux, and refreshes the bubble walls below, stabilizing the foam. This ensures the most efficient foam production environment near the continuous liquid interface. By the time the foam reaches the top of the arch it is extremely dry. The dry foam is rigid and therefore shear sensitive.

The stripping section of the unit consists of a high shear producing liquid spray. The liquid used in the spray comes from a small volume charge of contaminated system solvent. The spray shears the foam bubbles releasing the encapsulated gas. The liquid film from the bubble walls coalesces and drains into the stripping section sump. This liquid is recycled to the spray head. The gas released from the bubbles is recycled to the solvent inlet jet. When the concentrated contaminant level builds in the stripping sump it is discharged from the system.

If the foam being produced isn't stable enough to make it to the stripping section before breaking, the surfactant drains back into the foam structure below. The surfactant will continue to form foam at the gas - liquid interface and cycle

back in liquid form until the concentration is high enough to form a stable foam structure.

Although the system is novel in design and application, the basis for using surfactants to produce foam for the flotation separation of solids and chemicals has been utilized for hundreds of years. In the mining industry foam flotation has been used to recover particles as coarse and as concentrated as ore fines. On the other hand, particles as small as molecules and ions have been concentrated in pharmaceuticals industries through foam - ion flotation. Liquid - liquid separation, i.e., oil in water, has been accomplished with dissolved air flotation. Foam drying and shearing has been used to dispose of unwanted foam in waste disposal and food processing industries.

This separation unit is the first to utilize the surfactant already present in the continuous solution to remove foam causing and stabilizing contaminants in hydrocarbon sweetening solvents. Further, it is the first unit that doesn't utilize oxidizing gases in bubble formation, and incorporates an arched foam drying section in a single communicating unit. The system can be small enough to be portable, as is the case with the service unit, or scaled up for full stream plant installations. The unit can be designed for manual operation, or it can be fully automated incorporating DCS interface.

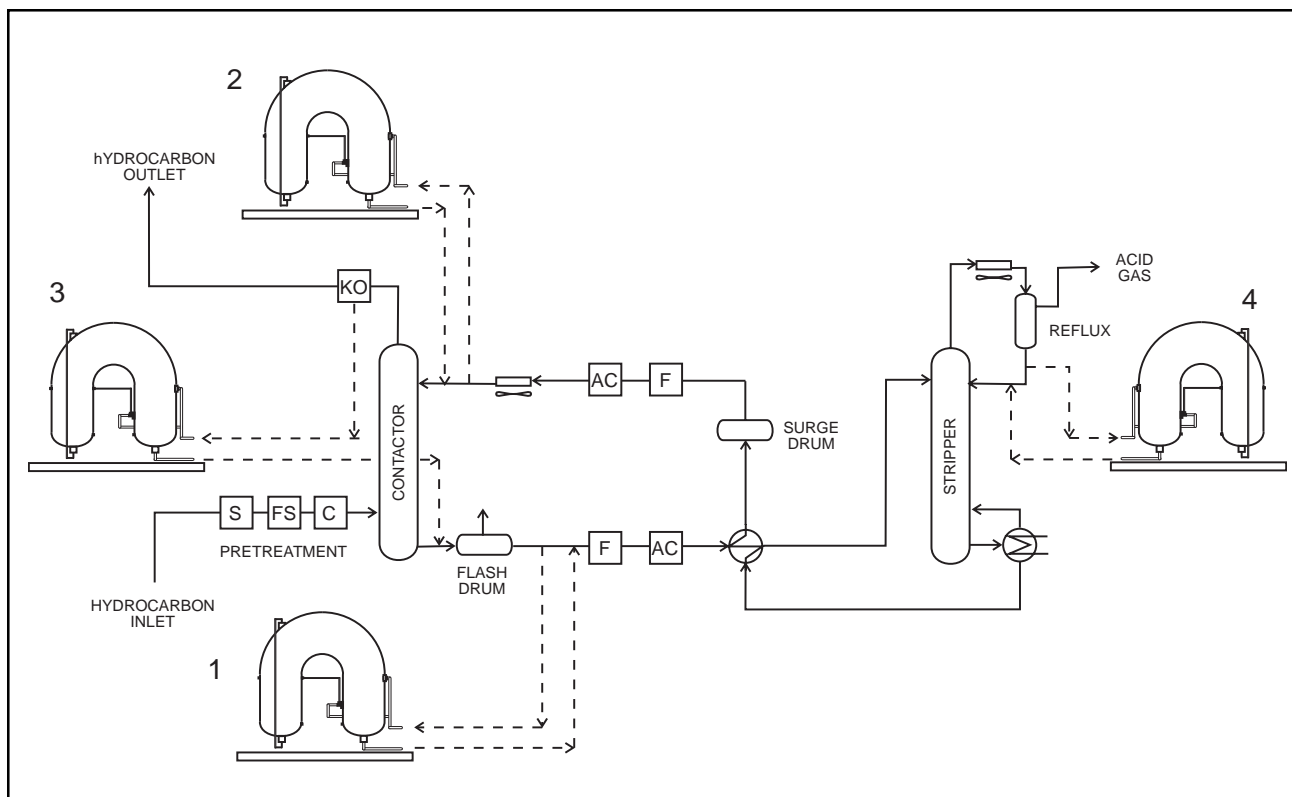
SigmaPure System Application

The system was designed to be used in any amine system location, regardless of temperature or pressure (fig. 10). Process conditions dictate that some locations are more favorable than others due to their effects on solvent foaming tendency. Because all plants react differently to surfactant contamination, the best location for the SigmaPure System in each plant would be just upstream of the location showing the highest solvent foaming level.

If the unit were to be located down stream of the flash drum, it would act as a pretreater for the particle filters and/or activated carbon bed. Solid particles from microscopic size to several hundred microns have been seen incorporated in the foamate discharge. It will also separate liquids that have an affinity for the foaming surfactant that would prematurely foul the particle filters and activated carbon bed. If even low levels of foam were forming in the flash drum, they would be removed with the SPS. Unlike rich side vessels that have to be opened for maintenance, this system doesn't pose an operator exposure hazard because it doesn't have to be opened to change disposable internals. As is the case with most large refinery amine systems, if both particle filters and activated carbon are on a side stream, locating the equipment after the flash drum would remove foaming contaminants prior to the stripping unit. This is the preferred location for the SigmaPure System if a single unit were installed.

There are two other locations that are considered at least as important as the solvent inlets and outlets of the

Figure 10. SigmaPure System Placement



towers. These are points where solvent is recovered from overhead gas and sent back to the recirculating solvent, e.g., contactor overhead knockout drum, and reflux accumulator. Liquid recovered from the contactor overhead knockout drum is, almost always, sent back to the rich solvent stream without treatment to reduce solvent losses. If this liquid consists of normal solvent hydraulic carryover it won't cause problems. However, if the solvent is foaming, the overhead liquid will contain concentrated foamate from broken foam being carried overhead. Sending this liquid back to the recirculating system without treatment is probably the most frequent cause of extended foaming upsets. If this knock out liquid were pretreated through a SigmaPure unit the concentrated surfactants would be removed, rendering it safe to be sent back to the main solvent stream.

The second most overlooked location for surfactant concentration is the stripper overhead condenser. If the surfactant contaminants have vapor pressures close to or higher than the solvent, the overhead condenser can act like a fractionator and actually concentrate the surfactants in the reflux. A concentration loop is established from the top of the stripper through the reflux accumulator. If the surfactant concentration in the rich feed solvent is low or if the inlet distributor is restricted, it can produce low level foaming that is undetectable and carried over to the cooler. If the foam is unstable it will be concentrated in the reflux accumulator and sent back to the top of the stripper only to be sent overhead

again. Eventually, the surfactants will reach a concentration that produces stable foam, and it will carryover to down stream equipment. Plants that actually have their reflux analyzed do not normally include foaming tendency. If the reflux were diverted through a SigmaPure™ unit, the surfactants would be removed and the concentration loop interrupted.

One of the additional benefits of the SigmaPure System is its help in troubleshooting foaming problems. Extremely low levels of surfactant contaminating a large solvent inventory can cause foaming. Trying to determine the actual foam causing contaminant can literally be like looking for a needle in a haystack. The problem causing surfactants can be in solution, or immiscible. Try finding a 100 gallon problem in a 100,000 gallon liquid inventory when both liquids are full of mixed organic compounds. Which peak in the GC data is the culprit(s)? This device concentrates only the foaming contaminants regardless of their chemistry or the location of the unit in the process. An analysis of the concentrate would reveal the problem contaminant and allow a focused abatement effort.

Comparative Upset Economics

Table 4 shows realistic cost examples that could be incurred addressing an unremarkable foaming upset. The amine unit used in this example has a flow rate of 813 gallons per minute and a total inventory of 65,000 gallons. The particle filters are sized for full stream operation and the activated carbon for a 10% slipstream. The solvent represented in the example contains 1000 ppm(wt) light liquid hydrocarbon, and 1000 ppm(wt) solid particles over 5 micron.

The left column in the table outlines the cost for particle filtration. Most 5-micron depth filters are sized at 3 to 10 gallons per minute per 30 or 40 inch tube. A flow rate of 813 gpm would require a minimum of 81 filter cartridges. During an upset it is not unusual to change the particle filters more often, but in our example we will only change once per shift. At \$25/cartridge, the daily cost to change the filters once every 5 hours would be \$9,750.00. The labor rate and time to change the filters adds \$40.00/changeout, or \$192/day. Spent filter element disposal is often equal to the filter purchase price because they are considered hazardous waste. Disposal adds another \$9,750/day to the total cost. The total particle filter cost would be \$19,692/day, or \$137,844/week. Since most plants operate at some constant level of upset, it's easy to see how technical papers can be written boasting hundreds of thousands of dollars in filtration savings when the filters are changed to a type more tolerant of the specific contaminant causing that particular upset.^{8,11,23}

The center column in Table 4 shows the activated carbon cost for treating the hydrocarbon condensate portion of the upset. These numbers represent likely reclamation as well as in-plant unit cost. The conditions are the same as those given for the particle filters. Major activated carbon manufacturers recommend sizing carbon beds with superficial liquid

velocities from 1 to 10 gpm/ft² of bed area. This example used 5 gpm/ft². The bed's carbon volume is 147 ft³, or 4,355 lbs. The organics being adsorbed by the bed vary in molecular weight, so we used a general rule of thumb for adsorption capacity of 10:1 (wt), e.g., 10 grams of carbon to adsorb 1 gram of organic contaminant. At 1000 ppm (wt) of organic contaminant adsorbed, the bed would be exhausted in one day. With the carbon changeout cost at \$2.00/lb, labor, and disposal cost being equal to the purchase price, the total changeout cost would be \$17,578 per day. If the upset lasted a week the cost would be \$121,588.

Since most plants contain both particle filters and activated carbon, and each device targets different contaminants, the costs would be combined. The combined costs equal \$37,270/day, or \$259,432/week.

The application of cost to each of these devices by contaminant removed is extremely qualitative. The reason is that part of the contaminant targeted by the carbon, i.e., liquid hydrocarbon and surfactant, would foul the particle filters as they were removing the solids. Likewise, some of the solids targeted by the particle filters would foul the carbon bed. If, as is often the case, the solids were oil wetted, both devices would remove them and have to be changed.

The right column in table 4 shows the cost if the SigmaPure System were employed to remove all of the foam causing contaminants. At a continuous flow rate of 30 gpm, the 65,000 gallon inventory would be treated in 1.5 days. Since the SigmaPure system doesn't use any consumable internals to produce the contaminant separation there would not be any purchase price, changeout labor, or internals associated disposal costs. At the time of this writing the service cost for the system is \$0.23/gallon treated, or \$9,936 per day. The total treatment cost for the 65,000 gallons would be

Table 4. Separation Economics Under Upset Conditions

Solvent	Amine		
System Inventory	65,000 gallons		
Recirculation Rate	813 gpm		
Single Contaminating Event			
Filters [Solids]		Activated Carbon [Liquids]	
Number of Vessels	1	Number of Vessels	1
Flow Rate/Filter Element, [gpm]	10	Flow Rate, [gpm]	81
Filters/Vessel	81	Carbon Bed Volume, [ft ³]	147
Service Life, [hrs]	5	Service life, [days]	1.01
Number of Filters/Day	390	Carbon required, [lbs]	4,355
Cost/Cartridge	\$25	Cost/lb	\$2.00
Cost/Day	\$9,750	Carbon Cost/Day	\$8,710
Changeout Labor/hr	\$20	Changeout Labor/hr	\$20.00
Changeout Time, [hrs]	2	Changeout Time, [hrs]	8
Labor Cost/Vessel Changeout	\$40	Labor Cost/changeout	\$160
Disposal Cost/Day	\$9,750	Disposal Cost/Day	\$8,710
Total Filter Cost/Day	\$19,692	Total Activated Carbon Cost/Day	\$17,578
Total Cost for Particle Filters and Activated Carbon/Day		\$37,270	
		SigmaPure System [Solids & Liquids]	
		Number of Vessels	none
		Flow Rate, [gpm]	30
		Treatment Time, [days]	1.50
		No. of Filters	none
		Carbon Required	none
		Cost/Gallon	\$0.23
		Changeout Labor/hr	none
		Changeout Time, [hrs]	none
		Labor Cost/changeout	none
		Disposal Cost	none
		Total Treatment Cost	\$14,950
		Total SigmaPure Cost/Day	
		\$9,936	

\$14,950. Assuming that the 2,000 ppm (wt) were the total contaminant load being removed by the SigmaPure system, there would be an additional cost to dispose of 65 gallons of hazardous waste liquids and solids. At \$10/gallon for disposal, the SigmaPure system would remain thousands of dollars less expensive to use. If the upset lasts for a week, the service cost of the SigmaPure system could revert to a lease basis, which would reduce its daily cost to \$800/day, or \$0.02/gallon.

This scenario doesn't account for the significant costs in engineering and operations hours spent trying to identify the contaminants, and whether or not a separation device or a system component failed. It doesn't account for disruption to other plant operations during the upset, for the lost fluid, or for reduction in unit capacity while trying to stop the upset. None of those unaccounted costs would be applicable to this foaming abatement system. Examination of the concentrated contaminant and assistance from our process engineering personnel would help identify the root cause(s) of the upset in a timely manner. In the mean time, the plant would be operational.

If the unit were on-line in the plant as a permanent installation, foam would be produced in the SigmaPure System before it formed in the process towers. This would either eliminate the foaming upset completely or forewarn operations and engineering that a system failure had occurred before the problem became acute.

Solvent Reclamation Units

Traditionally, reclamation units have been used to remove heat stable salts and solvent degradation products. Reclamation currently exists in the forms of ion exchange, vacuum and thermal distillation, and membranes. All of these technologies generate significant volumes of liquid waste that include the contaminants and other liquids like backwash, regeneration, or neutralization chemicals added by the operators. The effluent generated by these devices normally has to be disposed of as hazardous waste. These devices require a high level of solvent pretreatment prior to use.

The SigmaPure System is not a reclamation unit in the traditional sense. It was designed to perform as a solvent foaming abatement device. This system will only remove the heat stable salts associated with solvent foaming. We feel that the prevention of heat stable salts is more important than their removal. The need for a HSS reclamation unit should be reduced or eliminated when this equipment is employed. It removes the organic compounds, i.e., surfactants and liquid hydrocarbon that compete with the activated carbon's capacity for HSS precursors. These are the culprits that force the need for antifoam, and unnecessarily waste the carbon's adsorption capacity. The service life of the activated carbon adsorber should therefore be increased which will result in lower HSS formed and lower carbon costs.

Conclusions

Surfactants concentrate in films at gas liquid interfaces, and reduce solvent activity by inhibiting mass transfer. Surfactants are also responsible for foaming in sweetening solvents. Foams are stabilized by liquid and solid contaminants in the solvents. Each tower will exhibit its own sensitivity to foaming. The complete removal of all foaming related contaminants with the current separation technologies used in solvent treatment has proved impossible due, for the most part, to the intrinsic nature of the contaminants. Foaming problems will continue to plague sweetening plants in refineries and natural gas processing plants until the consequence of contamination, rather than the specific agents, is addressed.

Experiments have shown that foam causing contaminants can be removed from a solvent by removing the foam that is produced. Foam stabilizing contaminants are also removed when the foam is separated. Carryover volumes are exponentially related to surfactant concentration and column volume. The closer the location of foam initiation is to the outlet, the greater the volume of carryover fluid will be.

Surfactant films inhibit gas to liquid mass transfer. The result in amine systems would be a loss of solvent activity or treating efficiency. The solvent acid gas loading would probably remain unchanged since the film doesn't cause chemical changes in the solvent. The greatest impact would be absorption kinetics. The improvement of solvent activity and its impact on gas treating costs with the removal of surfactants will be the subject of a future study by D-Foam, Incorporated.

A device has been developed to indiscriminately remove the contaminants that cause stable foam formation in sweetening processes. It has been shown to separate solid, liquid, and soluble contaminants from the solvent. The device utilizes the problem itself, i.e., foaming tendency and foam stability, to produce the separation. It targets all of the contaminants that cause foaming, not specific contaminant families. Clean solvent losses and the energy consumed in cleaning the solvent are minimized. The SigmaPure System will operate with minimal maintenance, and has no disposable internals. It can be used as a temporary or permanent part of the sweetening system, and can be designed for manual or automatic operation under any plant condition.

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