



Amine Unit Foaming Potential & Response Training

Introduction

The time to troubleshoot foaming incidents is before they happen. That's right, *before* they happen. We have put together a "short and sweet" program to help. Supply us with a few solution samples, and your amine unit operators and support engineers for a short end of shift meeting, and we'll show you where you are vulnerable to potential foaming. If possible, we even want your lab personnel that generate foaming related data to attend one or more of the end of shift meetings. We would love to discuss everything we do with them.

Your people don't have to go anywhere. We come to you.

The main reason plant foaming is so hard to troubleshoot is the same reason it's so hard to study; namely it doesn't last very long. In the lab, foam breaks quickly. In the plant the operators try to make sure it does the same thing! The property that saves our research in the lab is the same thing that hurts you in the field. If it foamed once, it will probably foam again.

Here are a few foaming facts we'll bet you didn't know:

1. *Surfactants, not suspended solids or liquid hydrocarbon, cause solution foaming.* Solids enhance or amplify existing foaming tendencies caused by surfactants in solution. Liquid hydrocarbons actually act like inefficient foam inhibitors.
2. *The surfactants that cause foaming become the foam itself.* You can inhibit the foam, but you can't stop them from coating the gas-liquid interfaces that would normally form the foam. This forces an antifoam addiction. In fact, have a look at #3.
3. *Foaming inhibitors like antifoams only inhibit gas phase or "fluffy" foam, but only for a while.* The bad news is that because foam inhibitors mask the presence of the surfactants, when they accumulate in the solution the foam comes back wet. Liquid phase foam is 100 times more difficult to deal with and isn't usually affected by antifoams. This is why we refer to antifoam injections as "Feeding the Beast".

If your plant is exhibiting minor foaming symptoms that require some sort of mitigation action, now is the perfect time to see what's going on. If you inject antifoam, you aren't going to have a problem, you already have one.

Unit Foaming Potential and Response Training

Purpose: To examine the unit solution's tendency to produce foaming symptoms and to normalize the awareness of unit operating personnel to foaming symptoms to improve mitigation response consistency.

Scope: Part 1 is an examination of multiple amine solution samples to identify foaming causes. Part 2 is meeting with each unit operations shift for a 30 minute training session on plant foaming, and discuss their normal responses to foaming symptoms they experience.

Benefit: Part 1, is preventive identification of potential causes for unit foaming. Examining the samples will show current foaming properties throughout the amine circuit, the presence of hydrocarbon, residual antifoam, and current mechanical filter performance. We will present a comprehensive report, including all data before we leave the plant.

Part 2, Operator training and discussion of plant foaming symptoms and mitigation practices will increase operator knowledge of the causes of foaming, and communicate what they and other amine plant operators are doing in similar circumstances.

Time/Cost: Testing normally takes 3-4 days depending on sampling. We will recommend that our arrival on site coincide with shift changes to expedite operator training. We will be happy to submit a written quote for this program upon your request.

Part 1.0 Unit Foaming Potential

Effects of Contaminants on unit operation:

Soluble (dissolved) surfactants; e.g. organic acids, detergents, cause solution foaming.

Insoluble surfactants; e.g. free liquid hydrocarbon, may inhibit foaming to some degree, but most often contribute a soluble, foam causing fraction to the solution.

Suspended solids; e.g. pipe scale, iron compounds, cause erosion corrosion, process equipment fouling/plugging, and amplify solution foaming tendency.

Sample Examination:

Optical Examination

- A. Indirect Light - determine visual clarity and color
- B. Tyndall Effect - determine suspended particles

2. **Lean Amine/Post Surge Drum** - Settleable solids and insoluble liquids may enter the lean amine stream after accumulating in the surge drum.

3. **Lean Amine/Pre Mechanical Filter** - Settleable solids and insoluble liquids in the lean amine stream may cause premature plugging of mechanical filters. Over dosing antifoam is a major cause of premature mechanical filter plugging. These conditions increase filter costs, but more importantly lead to foaming upsets by effectively removing solution filtration. Operating filters above their changeout DP invites particle bleeding; therefore solution foaming. Changing filters is as bothersome as injecting antifoam is easy. This means they are normally squeezed for every minute of service life. This practice can be far more costly than changing them out before they are spent.

Mechanical filters and carbon beds are normally installed as slip stream treaters. The greater the differential pressure is allowed to rise across these devices, the less solution they are treating.

4. **Lean Amine/Post Mechanical Filter/Pre Activated Carbon Bed** - Insufficient mechanical filtration and/or operating filters in a plugged condition (excess DP) may lead to increased suspended solids that prematurely plug activated carbon beds. Comparing pre and post mechanical filter samples will show actual particle removal, and increases in solution foaming tendency caused by particles that remain suspended in the solution, or soluble surfactants coming from the filters. Activated carbon beds are notorious for removing antifoam. Antifoam, as well as liquid hydrocarbon present in the sample will be visible.

5. **Lean Amine/Post Activated Carbon Bed** - Small particles bleeding from carbon beds may amplify solution's tendency to foam. Comparing pre and post activated carbon bed solution foaming tendencies and microscopic examination will show if the carbon bed is removing the AFA and/or hydrocarbon, and bleeding small solids into the lean stream. Comparing this sample's foaming tendency with #2 will show any soluble surfactants desorbing from carbon beds as well.

6. **Semi Lean Amine to Surge Drum (if applicable)** - Absorbers designed with semi lean amine streams normally do not include additional mechanical filters and carbon on these streams. This means that anything being carried up the absorber with the gas; i.e. gas or liquid phase foam can contaminate the lean stream in the surge.

7. **Rich Amine** - We don't like to ask for, or test rich samples, but it may be necessary depending on plant symptoms. If insufficient, improperly designed, or damaged feed gas separators are allowing small slugs or crawling liquids into the absorber they should be visible here. Comparisons between the lean samples' foaming tendencies and this one will further implicate contamination from the feed gas.

8. **Rich Amine/Pre Mechanical Filter** - see #3

9. **Rich Amine/Post Mechanical Filter/Pre Activated Carbon Bed** - see #4

10. **Rich Amine/Post Activated Carbon Bed** - see #5

11. **Amine Makeup Solvent** - Concentrated make up solvent is normally introduced to the recirculating amine stream in the surge drum, and mixed over a few passes through the system. Small amounts of surfactant can be introduced in this way. We have seen instances where contaminated make up solvent has contaminated entire plant inventories at this point.

12. **Amine Makeup Water** - This is one of the primary ingress locations. Most plant utilize boiler feed water as make up. Chemicals designed to reduce boiler related corrosion and deposits, i.e. inhibitors and chelating agents can cause amine foaming. We can compare a freshly made up solution with #11 and #12 samples with #2 to see if contamination is coming from either or a combination of both.

13. **Reflux return to Stripper** - This is one of the most overlooked sources of surfactant concentration. If foaming is taking place in the top of the stripper, above DP instrumentation, the column could be foaming with only overhead cooler fluctuations as a symptom. Broken foam and amine solution carried over with the foam can concentrate in the reflux being re-introduced to the top of the column. Small amounts of contaminated solution may make its way through the still with each pass across the rich solution introduced at the top of the column.

14. **Contactors Overhead Knockout** - This is the single most commonly overlooked source of process "re-contamination". Most plants allow the liquids caught in overhead knock out drums to be sent back to the recirculating stream without treatment of any kind. If the absorber is experiencing low level foaming, the surfactants being carried over as foam are captured and sent back to the rich stream.

Part 2.0 Operations Training & Discussion

Foaming Fundamentals Training - Operators know how to operate the plant. They understand how each piece of equipment functions, indications of a failure condition, and the treating goal. The same is true with foaming symptoms. Most operators recognize a foaming condition, but have never been told how it happens, or most the probable causes. This lack of knowledge leads to unnecessary and inconsistent mitigation attempts.

Operations Response Survey - Awareness leads to consistency. Responses to foaming symptoms tend to vary with operator experience. This means that a response to an operating symptom can be different with a shift change, or even over a lunch break. Inconsistent responses lead to upsets, and cost increases. This is especially true if the operating condition becomes critical quickly, as is most often the case with plant foaming.