Question 46: What is your design service life of atmospheric tower overhead heat exchangers? How does that compare to actual service life? What do you do to better manage corrosion and improve reliability of these heat exchangers?

McDANIEL (KP Engineering, LP)

I will try to keep it quick because I know it is almost 11:00 now. Everyone is already starting to think about lunch, and we have not even started our Town Hall.

The quick answer is that if I am going to look to design or spec out a new exchanger, I will design for 10 to 15 years. The second part of that question is: How does that relate to what actually happens in the field? Well, we all know that does not happen a lot. If it does, then you should be really proud.

Really, that turns out to be “sometimes” for a lot of operators. Sometimes there are as little as two years, or even less than one year, that they are getting out of their overhead exchangers before they have to take them out and clean them due to fouling. So, what you can do? Well, it depends on how your unit is set up. There are lots of factors that impact what introduces possible corrosion and different ways you can mitigate it.

One of the variables to think about at your current unit is the type of overhead product you are producing. Are you producing a full-range naphtha? Are you producing a light straight-run that will affect your overhead temperatures? That type of naphtha could affect how close you will get to that dew point of water and HCl (hydrogen chloride), which will create that strong acid and introduce that corrosion.

Then, do you have a one-stage or two-stage overhead system? Obviously, which one is better is open for debate. Everyone has a different opinion, but more important is understanding how that choice will impact your overhead system. Where you would introduce treating is based on whether it is a one- or a two-stage system. Also, if you have a well-optimized unit, you will likely go against raw crude charge. That exchange is usually up towards the front of the preheat train, so then you would be introducing the possibility for low tube wall temperatures and corrosion situations there.

The third part of that question is: What can we do to mitigate it? A normal mode of mitigation is pH control. This pH control gets tricky because caustic can introduce its own troubles – as we can all attest – to certain situations. Then on top of that, where should it be introduced? Do we introduce it before the desalter? After the desalter? Just before the heater? Regardless of where you introduce it, solid pH control is one way to protect against corrosion.

Overhead washwater injection, again, goes back to what type of system you have. Whether you have a one-stage or two-stage will determine where you introduce that waterwash. The key is to target that 30 to 50% excess water and avoid getting to the dew point on HCl in the overhead around 230°F. So, you should introduce that water injection before you get to that point.

Desalter operation: Obviously, that is a whole topic in and of itself. Good, solid, steady desalter operation is ideal. If you are running heavy sour crudes, you will already be doing all of these mitigation modes; however, you will still have corrosion. The question is: At what rate is it happening? If you are experiencing high rates of corrosion, the next step is metallurgy: stainless steel, alloy, or even titanium. When reaching out to operators, I was told by many of them that they have experienced this problem, chose to go to use titanium, and have not had any problems since. That methodology has worked well for them. But then, some Operations folks may just decide that they do not want to spend that money; rather, they would choose to invest in a new bundle every turnaround.

The last variable is a good chemical vendor. I am not a chemical vendor, so this is not my sales pitch; that will be Kevin's job next. However, I can attest to the value of having a good chemical vendor in-house, one who can introduce you to a good desalter program and a good overhead chemical protection program. These in-house chemical vendors become invaluable.

McDANIEL (KP Engineering, LP)

That was interesting. There was a study conducted a few years ago that said that the average is just around seven years, so those results seem to be consistent. We usually see that lifespan of the overhead bundle.

GAMBOA-ARIZPE (CITGO Refining & Chemicals, L.P.)

So, no one should go buying titanium stock just yet.

SAM LORDO (NALCO Champion)

Metallurgies are not the final solution in a lot of cases. I have seen people go through titanium bundles in less than a year. I have seen them go through Alloy 925 in less than a year. Then what they do? They put 925 back in to repeat the process. So, pick your metallurgy appropriately. Not all of them are the best solution.

TARIQ MALIK (CITGO Petroleum Corporation)

On design service life, we go turnaround to turnaround without any leaks. I have been at this facility for a long time. We have never seen an overhead exchanger leak; or at least, I have not seen an overhead exchanger leak. We have had that bundle in there probably since 1991, and it is carbon steel. It is a different design from others because we have the overhead in the tubes, not on the condensing (shell) side. It is the overhead condenser versus crude, and the crude is on the shell side. So, that is one little difference in this exchanger. We do have an overhead waterwash of the system, so we force the dew point before the overhead gets into the exchanger.

All of our other facilities have given up carbon steel and gone to Alloy 2205 Duplex. You would not put in just any stainless steel because chlorides in the overhead would eat it up. It has to be a Duplex 2205 or another variety of Duplex stainless steel, such as 2507, I think is the number.

TARIQ MALIK (CITGO PETROLEUM CORPORATION)

I think one of the facilities I have seen also has Hastelloy C, and that will also probably survive. What do you do to better manage the overhead? We use the program that has a filmer and a neutralizer on the overhead system. I think the other exchanger is a fin fan before it gets to the reflux drum. We have two drum cooling systems, and the fin fan does suffer a lot of corrosion. We do get bundle leaks on the fin fan; but they have individual isolation valves, so they never hold us up. That is my experience.

ANDREW SLOLEY (Advisian WorleyParsons Group)

I think you need to use some caution when interpreting the survey results. They are not surprising, but I believe what you are seeing is a multipart effort by the refiners to make sure that the overhead condensers do not shut down the unit or that they will try to run it five to seven years or four to seven years, which are the run-lengths you are seeing. They do whatever is needed – in terms of materials, corrosion control, operating conditions, and feedstocks – to maximize the possibility that the unit will achieve a target run-length. That is the economic breakpoint. As long as you can make the run, replacing the exchanger is actually a relatively low-cost item compared to shutting down. It is not that we are using a design point that results in five to seven years. We are seeing an experience result of a combined series of actions to not shut down during the run.

JOEL LACK (Baker Hughes, a GE Company)

I want to echo that each situation will be different, depending on your goals. Some places look for more than 10 years; some places are happy if they could just make it five. It just depends on what you are processing. Often when asset life is long, there can be pressure to increase risk to drive profitability.

When it comes to controlling corrosion in the overhead, most places have a good handle on general acid corrosion. As long as they are maintaining the pH control, that mechanism is usually quashed.

The salt formation is usually the culprit, when it comes to a failure in crude distillation overheads. I do not know if we will get to talk about it in the Town Hall. These contaminant amines are what are really giving refiners trouble, not just in the overhead exchangers but also in the top of the tower. The key to meeting your operational and financial targets is being able to stay on top of what is going on in the plant, understanding how the level of your contaminant amines contribute to the risk of salt corrosion, and managing your process to where that risk is understood and controlled. Even with the contaminants present, it is possible to manage corrosion risk by either applying methods of contaminant removal or applying chemistries that can slow down the corrosion rates of those salts. Those technologies exist today where we can significantly reduce salt corrosion rates to, hopefully, avoid an unplanned shut down and get you to the end-of-run time you are targeting.

SOLOMON (Athlon Solutions)

Very good job, Ross. You gave a complete answer. All I want to add is that we need to make sure we are getting good contact with the wash water and that our vapor velocities are somewhere around 60 to 80 feet per second for most of the units. Also, we often see – and I am sure you are very aware of it –the need to avoid MEA-based (monoethanolamine-based) triazines that are coming through in the crude and which are also finding their way through stripping steam. So, being conscious of and on the lookout for contamination is essential. And obviously, on the chemical side, be sure to properly select neutralizers and filmers, and then apply them in the correct manner.

KEVIN SOLOMON (Athlon Solutions)

Heat exchangers are designed for heat recovery and only rarely for corrosion control. The designer's tool for reliability is to use upgraded materials of construction. Over the years, those on our team have seen even Hastelloy C276 and titanium being used. One risk from titanium is that it can be brittle, but the higher grades have somewhat mitigated that for exchangers. It is also a flammable metal; and with improper shutdown procedures, the titanium exchangers can catch on fire and turn a shell into a blow torch. The cause is usually improper cleaning ahead of opening.

Some years ago, NACE did a survey of crude units and found that the average life of an overhead exchanger – many with multiple tubes plugged – was seven years before replacement. That timeframe was considered, by the members, to be the acceptable life for a bundle at that time. In practicality, bundles are designed to make it through two turnarounds but will be changed with a shorter life, based on an inspection during an opening and length of time to next scheduled outage.

Keys to reliability are:

1. A good waterwash,

2. Vapor velocity of 60 to 80 fps for most units,

3. Avoidance of MEA-based triazine in the crude feed,

4. Proper amine selection for boiler and steam condensate treatment programs, and

5. Properly selected neutralizers and filmers.

W. ROSS McDANIEL (KP Engineering)

The quick answer to the original question is that the typical design life of an overhead crude exchanger is probably between 10 and 15 years from when it is originally designed and specified. How this compares to actual service life becomes a bit harder to determine because the answer depends on what has been done to mitigate corrosion. Some operators experience bundle lives of less than two years, or even less than one year.

Corrosion control starts with understanding your current system and the variables that directly affect the overhead corrosion rate. Some operational questions to ask yourself about your unit are:

- What is your crude overhead product?

- Crude overhead product being made is important because it can affect the crude tower top tray and overhead temperature. It is possible that a light naphtha overhead product can lead to a lower OH temperatures and possible temperature below the dew point of hydrochloric acid (HCl) – typically around 230°F – where corrosion begins in the OH system.

- Do you have a one-stage or two-stage overhead system?

- There are mixed opinions on whether a one-stage or two-stage system is best for preventing corrosion. It is important to understand the impact having one or the other has on your overhead system. One point of interest is that one-stage systems can introduce the possibility of “shock” corrosion on your top tray where cold reflux enters the tower.

- Does the crude overhead exchange against raw crude?

- Well-optimized and heat-integrated units usually have crude tower overhead go against crude charge to recover the overhead heat, but they yield low tube wall temperatures at the outlet of the crude versus OH exchange.

Regarding how to better manage corrosion and increase reliability, there are multiple options to consider, including:

- Proper pH Control

- Caustic (sodium hydroxide) injection in the front end of the crude unit is a way to mitigate hydrochloric (HCl) attack, resulting from unstable chloride carryover. The point of injection is another debate and could be its own discussion. Some people choose to inject before the desalters, some just after desalters, and others just before the charge heater. Regardless, replacing concentrations of unstable calcium and magnesium chlorides for stable sodium chlorides is a way to help mitigate the formation of HCl. However, implementing the proper design is essential for avoiding further damage from concentrated caustic.

- Also, if atmospheric residue is processed in the FCCU, caustic injection is not a preferred practice.

- Overhead Wash water Systems

- Overhead wash water systems, also known as “forced condensation,” employ the practice of adding more water to the process to ensure that the overhead process stream has 30 to 50% excess water where temperatures fall below the dew point of HCl at the point where the strong acid forms and causes corrosion.

- Desalter Operation

- Obviously, steady and efficient desalter operation is essential to the crude tower overhead fouling and failure.

- Metallurgy Upgrades

- If desalter operation is steady, good pH control is in place, and a good waterwash system is in service, carbon steel overhead exchangers should last a long time. However, even with all these steps in place, corrosion will still take place; but hopefully, only at a controlled rate. Another step to take to prolong the life of overhead exchangers is to choose to upgrade in tube metallurgy to stainless steel, alloy, or even titanium bundles. Operators running very heavy sour crudes with well-controlled overheads that come down frequently due to overhead fouling from corrosion may see the incentive to go up in metallurgy. Multiple clients have experienced exchangers needing cleaning every couple month and with very short bundle life; but after going back with a titanium bundle, they have had no issues with corrosion in the overhead exchangers or with the CS shells.

- Working with your Chemical Vendor

- I can attest to the value of finding a good chemical vendor who understands desalting and overhead corrosion control. Please understand, I am not a chemical vendor; so, this is not a sales pitch, but rather a recommendation to find one you trust and who understands desalting and overhead treatment and work with that vendor to help implement the best control plan for your unit.

CHRIS CLAESEN (NALCO Champion)

The design service life will depend on the operating conditions such as temperature, having a waterwash or not, chloride and salt levels, and the metallurgy and exchanger design. In some cases, the design can be based on a 10-year lifetime and the real lifetime can vary significantly from that. Using Pathfinder ionic modelling and proper corrosion control with filmers and neutralizers will help control corrosion. Proper control of dew point conditions and salt formation with the control of OVHD chlorides, tramp amines, and NH3, in addition to the implementation of a good waterwash, can significantly reduce corrosion and extend lifetime.

GREG SAVAGE (NALCO Champion)

Given the inherent tradeoffs between mitigation strategies used to accomplish multiple goals, a systematic approach should be used to evaluate options for overhead reliability control. Identification, collection, and analysis of the risks versus rewards for each strategy and program performance should be evaluated so that the optimum program decision can be made, even as conditions change. The following concerns are all interconnected and highly affected by changes in crude slate:

- Equipment limitations such as undersized overhead receivers,
- Desalter performance,
- Crude overhead corrosion,
- Amine and ammonium chloride salt formation,
- Jet and diesel production optimization,
- Top and jet pumparound heat transfer limitations, and/or
- Wet reflux.

The principal concerns are that some of the tools used to reduce salting potential and increase distillate production can increase corrosion potential in the overhead system and potentially effect water content in the reflux, as well as add significant operational costs. Therefore, accurate measuring and modeling of the overhead salt points/potential, total acid content in the condensate water, and corrosivity measurements associated with the use of differing strategies is recommended.

NALCO’s Best Practice is to monitor systems to identify and address asset risks using a combination of laboratory testing, automated monitoring, simulation, and corrosion probe readings. Routine samples and tests of the overhead receiver boot water for pH, ammonia, sulfide, and iron are recommended. Additionally, measuring all of the acid species is strongly recommended to determine overall corrosion potential and neutralizer demand, which is accomplished with a field test: the Strong and Weak Acid Test (SWAT). These acids, along with other strong acid contributors, are important to understanding the overall overhead condensate acidity. Organic acids in the overhead buffer the overhead pH in the acidic range and can drive up neutralizer demand, increasing neutralizer salt potential.

Along with the SWAT, a periodic comprehensive speciation of all the acids and bases should be performed. In order to assess the risks of tramp amine salting, a field test for MEA and MMA should be tested routinely. Periodic total amine speciation is recommended to inventory all of the base's present in the overhead condensate water. Utilizing the analytical results, along with process data, the NALCO Pathfinder simulator can calculate water dew point, wash water requirements, salting temperatures points, and salt deposition potential for these systems. This simulator is used to identify asset reliability risks, as well as recommend potential operational and chemical solutions. Salt deposition temperature and potential is calculated through partial pressures of the reactants and other vapors and liquids. A salt deposition temperature greater than water dew point indicates the beginning of salt lay down that will continue to form until water condenses at the water dew point, whereupon the ionic species that form the salt will migrate to the water and continue to the receiver water boot. Both kinetics and thermodynamics play an important role in the rate of salt deposition: the higher the reactants measured in the water boot, the greater the partial pressures of the reactants; and therefore, the higher the salt deposition temperature. Ammonium chloride salts deposited close to the water dew point are hydroscopic and can absorb water, forming wet deposits which greatly accelerate the corrosion rate. Consequently, waterwash is an important part of controlling overhead corrosion risks.

However, measurement of iron in the boot water and simulation of the corrosion risks do not provide a full picture and should be routinely confirmed through direct measurements. So, the use of E/R probes on the outlet of the fin fan banks and overhead exchangers at a minimum, or on both the inlet and outlet of the banks, can provide valuable information as to changes in the corrosivity of the fluid processed through the air coolers. Additionally, the use of an overhead corrosion simulator (OCS) can provide valuable information on changes in corrosive conditions inside the fin fan banks, as well as the top pumparound. The OCS is a patented miniature heat exchanger consisting of two passes and eight cells allowing corrosivity measurements in both the liquid and vapor phases throughout the temperature profile of the overhead or measure salting and corrosion risks in the top pumparound circuit.

Increased corrosion rate in the overhead system, necessitates an increase in corrosion inhibitor, which both increases operational costs as well as the risk of water content in the reflux. Wet reflux can carry salts into the tower and the top pumparound. The use of an alternative corrosion inhibitor designed for high organic acid loading with a reduced risk of water emulsification would reduce the risk of both corrosion and wet reflux. Additionally, the use of caustic can lower salt point without the added risk of overhead corrosion, but it can contribute to downstream heater fouling rates.

The evaluation methodology above can be simplified, and the chemical programs optimized through new automation technology where desalter brine pH levels are measured on a continuous basis, as well as crude overhead pH, iron, chloride, and ammonia. These data points can be collected and processed through the Pathfinder model, which is then used to set chemical injection limits in response to changes in analytical results. Automation in the brine can be used to pick up pH increases indicating an increase in tramp amines, oily solids events, monitor changes in corrosion or scaling risks, and automate chemical injection rates. Online measurements can provide an understanding of operational or crude changes in order to make proactive operational or chemical adjustments, thereby improving system reliability. Fluctuations in the number of acids present in the overhead system vary the neutralizer and filming amine demand. The 3D TRASAR for Crude Overhead Systems (3D TRASAR for COS) enables real-time measurements of key parameters that promote corrosion in the overhead system and is a recommended tool for identifying mechanical, operational, and chemical root causes of corrosion, especially for refineries concerned with routine changes in salting and corrosion potential.

DENNIS HAYNES (NALCO Champion)

Crude unit distillation column overhead corrosion management is founded in minimization of the causes (contaminants) coming into the process. Crude tankage treatment – including dehydration, desalting for contaminant removal (acids and bases), and caustic utilization, where possible – are primary areas to optimize. In the overhead system, waterwash use and optimization where possible and the application of appropriate neutralizer and filmer technologies with appropriate monitoring are methods used to manage corrosion in overhead heat exchangers.

PHILLIP THORNTHWAITE (NALCO Champion)

The service life of overhead heat exchangers can vary significantly from crude unit to crude unit, and their longevity is reliant on a continuous, well managed, and comprehensive corrosion control strategy that considers all the associated risks. Upgraded metallurgies are increasingly used to reduce the threat to the crude unit; however, these do not eliminate the risks completely.

The major issue centers around the levels of contaminants in crude unit feed streams, the degree to which they vary, and the difficulty in monitoring and eliminating them. All of these contaminants can end up in the top of the crude tower or its overhead system where effectively controlling corrosion can be a major challenge. The problem with the variability of the process is exacerbated by the low frequency of measurement of key corrosion overhead control variables like pH, chlorides, and iron levels. The reality is that it is very difficult to catch the right sample at the moment of an upset. By utilizing innovative analyzers like NALCO Champion’s 3DTrasar for Crude Overhead Systems, the refiner can increase the frequency of measurement of these key variables, with the increased volume of data providing a clearer operational picture. With the potential to catch unit variation with little time lag in results, it allows the possibility of automating the control of key corrosion control chemistries such as caustic, neutralizer, and filmer, adjusting dose rates at the actual moment of demand.

By applying the appropriate chemistries at the moment of demand, corrosion rates can be more effectively controlled thus increasing the lifespan of overhead condensers.

GLENN SCATTERGOOD (NALCO Champion)

We have increased the frequency of overhead analysis with an emphasis on chloride concentration of the atmospheric and vacuum overhead waters which allow us to control overhead corrosion. With more frequent overhead chloride data, our caustic injection is more tightly controlled, which results in lower and less variable overhead chloride, finally resulting in lower overhead corrosion rates.

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