Volver

The Dawn of the Latin American Shale Revolution

Jeffrey A. Zurlo – Sr. Project Manager, GE Water & Process Technologies – Jeffrey.zurlo@ge.com ; Tatiana Barbosa – Product Applications Manager – Latin America, GE Water & Process Technologies – Tatiana.barbosa@ge.com

Abstract

North America has enjoyed a crude oil revolution the latter part of the last decade with the proliferation of shale gas and oil production, leading to increased profit margins and lower operating costs for refiners. Recent studies show that shale gas and oil reserves in Latin America to be some of the largest in the world, positioning the region as a potential global shale gas and oil superpower. As example, according to the US Energy Information Administration (EIA), Argentina holds the world's fourth largest shale oil reserve and Venezuela the seventh largest.

Processing shale oils, especially when mixed with the more traditional heavy oil crude slate that makes up much of the current South American refinery diet, brings a complex set of processing challenges in several areas of the refinery such as desalters, tank farm management, corrosion and fouling control, product yield, and waste water treatment plant operations.

This paper will highlight the lessons learned over the last decade from processing shale oils in North America, compare and contrast North American and Latin American shale oils, show actual challenges that refineries are already facing in South America and discuss how to successfully increase shale oil in the Latin American refinery diet.

Introduction

A net importer for over thirty years, the North America refinery market had focused on heavy gravity, high sulfur crude oil processing to take advantage of the lower prices offered on these crude categories. The extreme proliferation of shale oil and gas production in North America within the last decade has literally changed the refinery landscape in this region – seemingly almost overnight. The US is now a net exporter of hydrocarbon products and may be on the road to energy independence. North American refineries have significantly changed operating conditions, are reconfiguring their equipment, expanding production, and new facilities are being built specifically to handle the lighter gravity, low sulfur characteristics of the shale oils that are now abundantly available.

In Latin America, and specifically Argentina, the conditions are ripe for a similar shale revolution. In 2014, the US EIA confirmed Argentina's hydrocarbon reserve potential, ranked the country as having the third largest technically recoverable shale gas resource (11% of total world) and the fourth largest technically recoverable shale oil resource (8% of total world).[i] In addition, Venezuela has the seventh largest technically recoverable shale oil resource (4% of total world).[ii] Geologically, the shale formations discovered in Argentina's Neuquén province have been deemed an excellent thickness and pressure for favorable shale oil and gas production. The terrain is fairly flat, which helps well pad placement and equipment movements. The province is also has a relatively low water-stress level – key for the large quantities of water needed to conduct hydraulic fracturing.[iii] Since the Neuquén province already has significant hydrocarbon production, the gathering and infrastructure in place is more developed than was in North America at the start of their major shale production increases.

The revolution, in fact, has already begun. Argentina is one of only four countries to produce commercial quantities of shale oil or gas, the others being the United States, Canada, and China – and the only shale producer in Latin America.[iv] Several joint ventures between Argentina's national oil company, YPF, and international producers have been ramping up production. Also, the introduction of newer technologies is reducing the cost of drilling and producing from shale oil and gas reserves. A number of Argentina refineries are already processing some level of shale oil, or are in serious discussions on how to start processing this local resource.

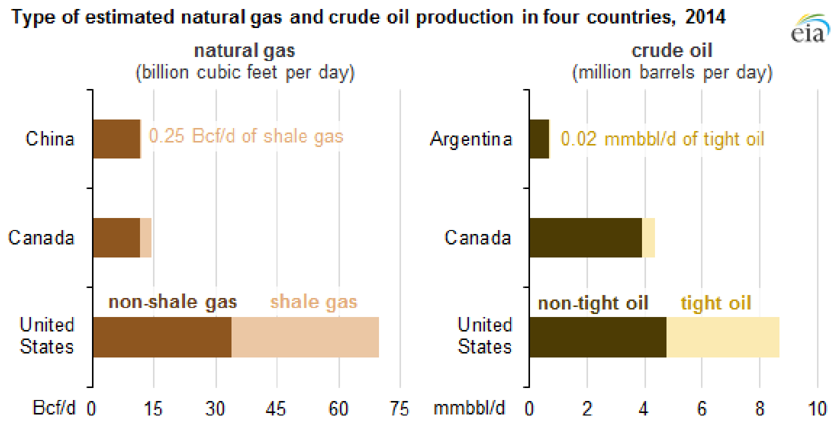

Figure 1 - Shale Gas and Oil Production, Source: US Energy Information Association (2015)

Being of light gravity, low sulfur, and lacking a large residuum cut, shale oil certainly breaks the mold of historic characteristics of "opportunity" crude oils. Processing this new crude oil, however, is not without certain challenges and pitfalls. The remainder of this paper will show the crude oil characteristics, identify the major challenges, and show some potential methods to successfully process shale oils in existing refineries.

Measuring Shale Oil Quality

The term "shale oil" is derived from the fact that the oil and gas deposits are tightly held within geological shale rock formations. Unlike conventional production, this oil is not free-flowing, as the shale rock is very dense and not porous. Horizontal wells are used to greatly increase well surface area exposed to hydrocarbon-rich deposits and hydraulic fracturing is used to increase the porosity of the formation and allow the hydrocarbons to flow. Production of shale oils would not be economically viable without these technologies.

The techniques used to extract shale oil supplies often result in the oil containing more production chemicals, and increased solids that have smaller particle size than conventional crudes. When introduced to the refining process, shale oils can significantly alter the distillation cut volumes produced by the crude and vacuum units, stabilize emulsions in the desalter, increase the potential for system corrosion and fouling, as well as negatively impact waste water treatment.

Shale oil characteristics can vary greatly from batch-to-batch, even within the same type of crude oil supply. For example, Figure 2 is a photo of crude oil samples that were all sold as "Eagle Ford Crude." Although Argentina's shale crude is produced in a similar manner to Eagle Ford, the gathering and transportation systems in Argentina's Vaca Muerta area are more advanced than current capabilities in the

Eagle Ford formation, so actual variation to Argentina's refineries is not expected to be this dramatic – but variation in crude quality between shipments has been observed. In addition, the range of API gravity for shale oils can be quite wide, from 20-55 degrees, with most at 40 degree gravity and above.

Figure 2 - Eagle Ford Shale Oil Samples

Shale oils, in general, have low nitrogen and high paraffin content. Heavy metals, such as nickel and vanadium, are generally low, but alkaline metals (calcium, sodium and magnesium) may be high, but not consistently so. Filterable solids can be higher than conventional crude oils, with greater volume and smaller particle size.

In general, today's refiner is continually adapting to increasing variability in crude oil quality. Combine this with the blending of shale oils into the standard crude slate, and normal refinery operations can be difficult to maintain. Processing these difficult blends can have a significant negative impact on overall profitability; affecting product quality, unit reliability, and on-stream time. Determining how a new crude oil fits into a refinery operation requires a comprehensive understanding of the physical properties and unique characteristics of that crude and how it will interact with the rest of the typical crude slate.

Figure 3 highlights Argentina shale oil distillation cuts compared to the US shale crudes and several conventional crude oils. For the shale oils (two left bars), note that residuum production is low, compared to high volumes of gasoline and distillates. For refineries that are configured for bottom-of-the-barrel upgrading, this can be a negative and limit the amount of shale oil that can be added to the crude blend. In order to balance the mix of products of the crude distillation tower to fit many refinery operations, blending shale oils with heavy asphaltic crudes makes sense, as the blend can result in a desirable distillation profile for many refiners. However, this practice is likely to produce blend compatibility issues that can negatively affect refinery operations.

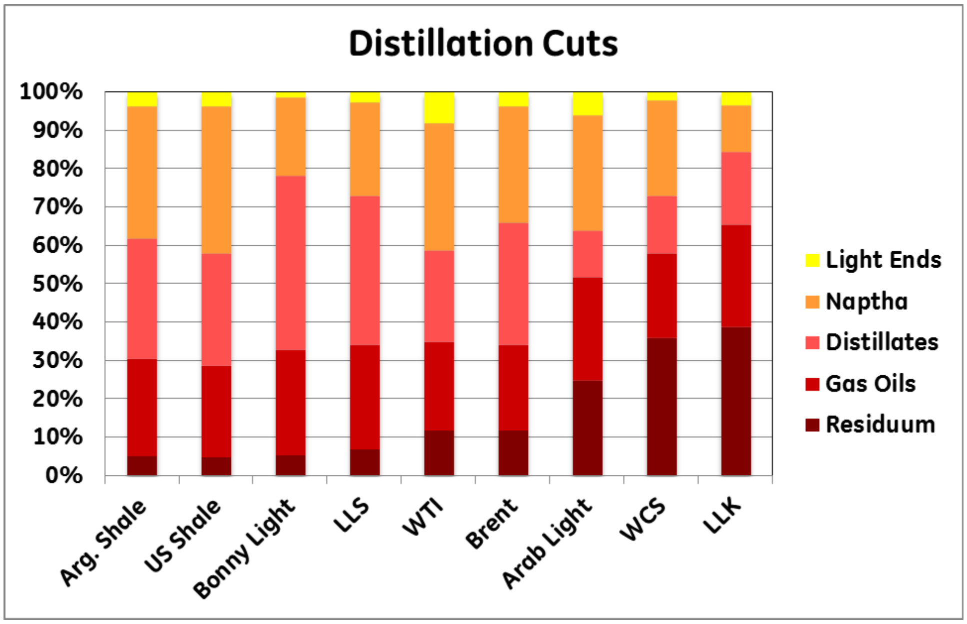

Figure 3 - Distillation Cuts of Various Crude Oils

Although asphaltene stability has always played a role in crude blending, the high paraffin content of shale oils greatly increases the potential impact of blending asphaltene precipitation and negative impact on the refinery process. To illustrate, Figure 4 shows the saturates and asphaltene component content for various crude oils. While the asphaltene content of commercially produced shale oils is low, the saturated hydrocarbon components are markedly higher than most other crude oils. As mentioned earlier, the typical refinery configured to process heavier feeds will need to blend shale oils with other, heavier, and likely more asphaltenic crude oils. Since asphaltenes are, by definition, insoluble in paraffinic hydrocarbons, blending shale oils typically have a significant impact on the stability of the asphaltenes in the other oils in the blend.

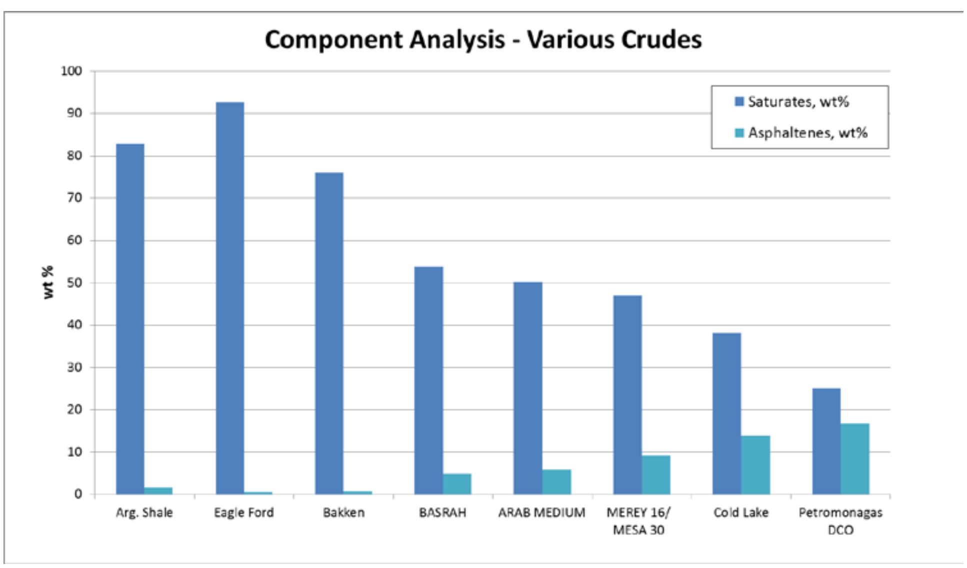

Figure 4 - Saturates and Asphaltenes of Various Crudes

There are several established and developing test methods that can evaluate an individual crude oil, or a blend of two or more crude oils, for asphaltene stability. The photos in Figure 5 show the progression (from left to right) of a compatibility test performed on incompatible blends of oils that generate agglomerated asphaltenes. The initial mixing of the oils produces a homogenous mixture. Over time, asphaltenes start to agglomerate such that they form a separate detectable phase in the fluid. Finally, significant agglomeration has occurred and asphaltene particulates are forming larger particles. These precipitated asphaltenes contribute to fouling and can also stabilize desalter emulsions.

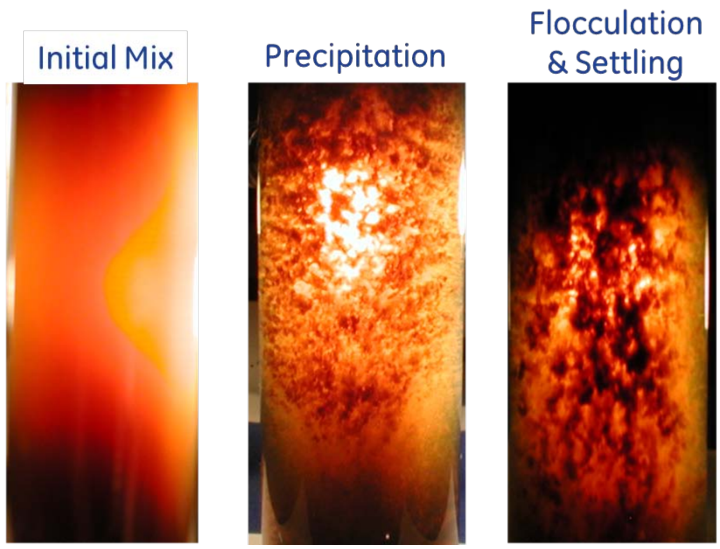

Figure 5 - Asphaltene Precipitation

Another concern with shale oil handling and processing is the potential for low temperature waxes to form. These waxes can contain very long-chain paraffin and isoparaffin compounds. The subsequent formation of waxy sludge can be problematic in transportation; in storage tanks, impacting storage capacity and tank drains; as well as increasing the potential for fouling in the crude unit cold heat exchanger preheat train upstream of the desalters. Figure 6 shows a gas chromatograph of a wax extracted from an Argentina shale oil sample. Note that paraffins over C70 are present in the sample. For reference, a C50 isoparaffin will typically melt around 100°C.

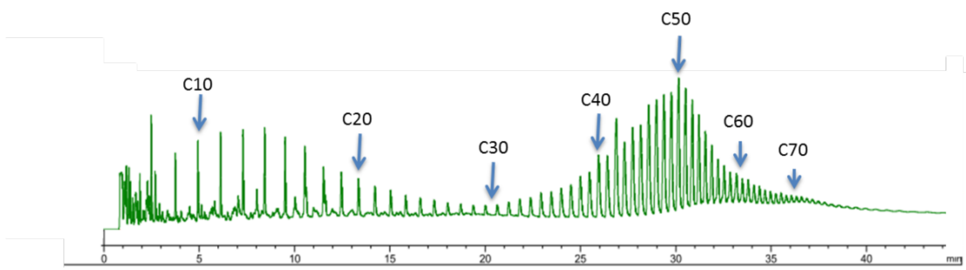

Figure 6 - Chromatograph of Shale Oil Wax Deposit

Shale oils are typically low in sulfur but may, nonetheless, have high H_2S (hydrogen sulfide) levels that could require treatment for personnel protection during production, transport, and storage. Triazine-based H_2S scavengers are commonly used upstream for EHS (Environmental, Health and Safety) compliance.

However, the triazine and its reaction products contaminate the crude oil and can contribute to emulsion stabilization, amine halide salt fouling, and under-deposit corrosion throughout the refinery. More recently, deposition of the reaction products when treated at high levels (see Figure 7) has contributed to equipment plugging.[v] pH modification in the desalter can be very effective in removing these amines from the crude oil and preventing downstream impacts.

Figure 7 - Deposits from H_2S Scavenger Treated Crude Oil

Particulate content in shale oils varies considerably, relative to conventional crude oil sources. In addition, the particle size of the solids is often very small, possibly a result of the fracturing process. Small particle size solids can increase solids-related emulsion formation in the desalter, can be more difficult to remove due to the effect of their small diameter on Stoke's Law, can increase fouling in the preheat system. When solids are removed in the desalter and transferred to the brine directed to waste treatment, they can cause difficulty in settling in the primary waste treatment unit processes. Settling issues can increase chemical cost and/or cause solids related issues in the biological treatment process. To illustrate the extent of the issue, Figure 8 charts the results of a filterable solids test on a shale crude, using different micron rated filter pads (the standard ASTM D4807 test uses a 0.45 μm pad). Notice that the small size pad captures solids an order of magnitude higher (in weight) than the standard test pad.

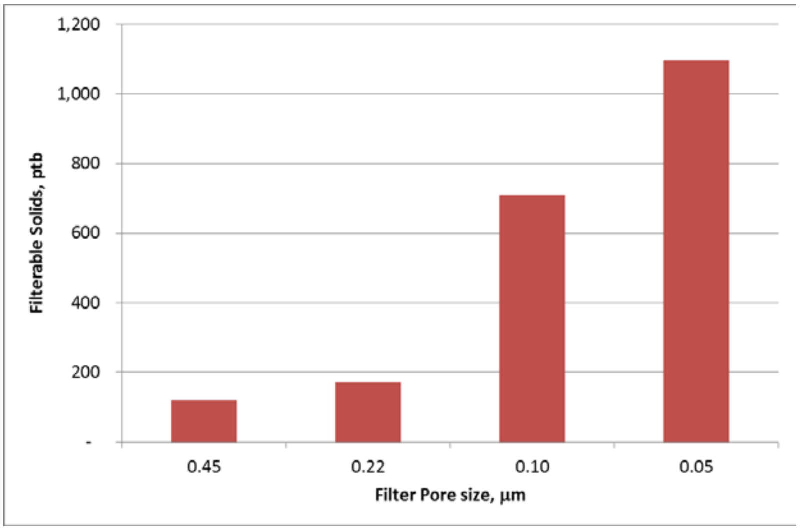

Figure 8 - Filterable Solids Test using Various Pads

In addition to asphaltene instability and solids, shale oils may introduce other contaminants that can adversely affect heat transfer throughout the refinery. Chemical treatment programs can effectively address many of the issues related to processing shale oil blends, although the best treatment program for one blend may be very different from the best for the other. Critical understanding of the characteristics of the oils, as well as the blends being processed is needed to properly address poor desalter performance, corrosion, and fouling.

Shale Oil Challenges - Overview

Figure 9 highlights the main areas throughout a refinery that can be impacted by the introduction of shale oils, beginning at the tank farm. The presence of waxes, solids and blend compatibility issues can lead to unloading problems, wax sludge build up, and tank drain plugging. Increased solids, salts, and other contaminants contribute to fouling in hot and cold exchangers, furnaces, and atmosphere columns. The waxes, precipitated asphaltenes on blending, and solids can also cause issues with emulsion stability in desalters, making controlling desalting and brine quality more challenging.

Low yields of gas oils and residuum may mean that production rates of heavy ends may suffer; asphalt volumes will likely decease. Likewise, low utilization of heavy-end upgrading and sulfur plants, due to shortage of feed volume, can also lead to turn-down limitations for these units.

Gasoline reforming can be negatively impacted because shale oils typically do not produce high-octane products. In contrast, catalytic cracking units may benefit, as shale oils produce good gas oil feed stock for these operations.

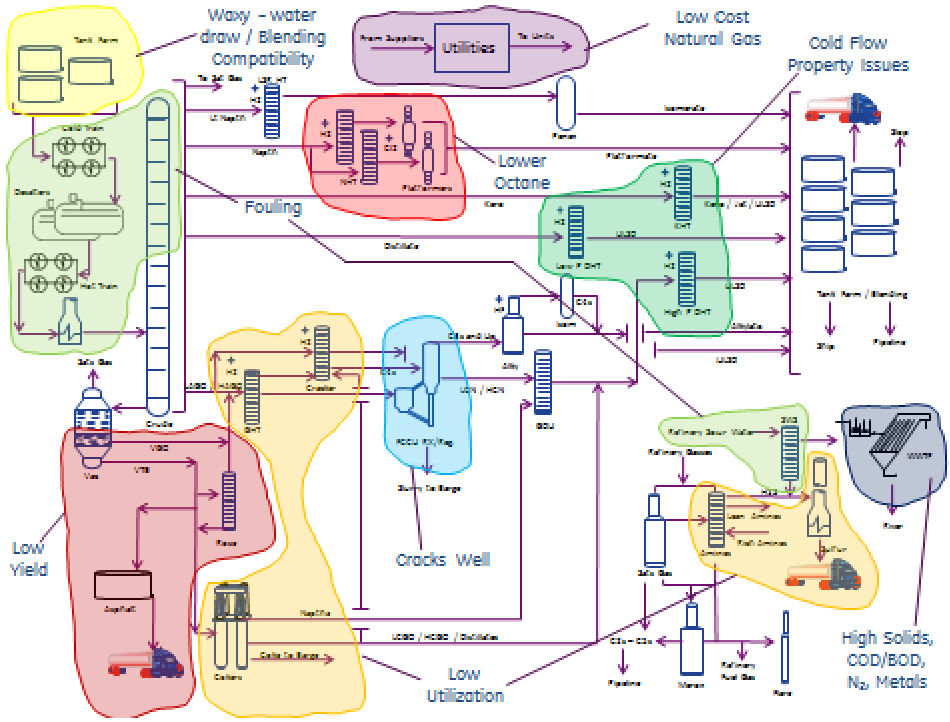

Figure 9 - Impact Areas in the Refinery from Shale Oils

In addition, the low porphyrin metal content may open up residuum cracking as a viable new option for the refiner. Shale oils tend to make a bit less jet-fuel, and cold-flow properties of middle distillate products may change that require new blending recipes and/or changes to cold flow property treatment programs. Since the production of both shale oil and shale gas are so closely aligned, as shale oil production increases, natural gas prices will typically decease due to increased supply. If this occurs, purchased fuel gas economics will also improve.

Finally, the wastewater treatment plant may experience operational difficulties when blending shale oils into the supply. High levels of solids and smaller particle size may challenge the primary waste treatment equipment, which may require a redesign or a change in the chemical treatment program. Increased levels of COD, BOD and nitrogen load into the waste plant from contaminants removed in the desalter, such as solids, other contaminants and the H_2S scavengers introduced into the crude supply upstream of the refinery can place an additional load on the biological system.

Using the learning experiences of North America, the main approaches to processing additional shale oil crudes successfully can be described in a few bullet points. Those approaches include:

- Enabling better blending strategies to identify and respond to compatibility issues,
- Define new operating envelopes for unit operations and challenge the markets to test production volume changes,
- Adopt different treatment approaches – from tank farms to waste treatment – the traditional chemical treatment approach does not always work with this new crude, so a paradigm shift is often required, and

- Identify capital expenditures needed to remove the bottlenecks of bringing shale oils into the refinery crude oil diet.

More specific details associated with the processing of shale oils will be presented in three different sections: desalting challenges, corrosion, and fouling. Practical field experiences with these crudes highlight what they have in common, as well as what sets them apart.

Crude Oil Desalting

Desalter performance has traditionally been measured by salt removal, oil dehydration, and crude tower chloride control efficiency. However, the influx of opportunity crudes, including shale oils, has introduced tremendous variability in the quality of the crude blends, prompting many refiners to rethink the role of the desalter. Refiners are now often running this equipment more as an extraction vessel, removing many more contaminants than just salt. While the individual desalter challenges may not be particularly new, the combination of issues is.

Compatibility problems can result from blending highly paraffinic crudes with asphaltenic crudes, which lead to asphaltene destabilization that can stabilize emulsions, as well as accelerate preheat and furnace fouling. Shale oils can also cause wax precipitation, which can produce a waxy sludge in storage tanks, degrade desalter temperatures and plug cold train exchangers. Variability, due to raw salt and BS&W, can stabilize emulsions in the desalter, as well as impact corrosion control in the overhead system. Increased solids loading may exceed the desalter design capability; resulting in emulsion control issues, accelerated fouling of the preheat train and furnace, as well as more difficult phase separation downstream in the primary wastewater and slop oil handling systems.

One effect observed in Argentina refineries processing shale crude oils is relatively low desalter temperatures – as low as 100°C. Low desalter temperatures can make successful desalting more difficult by creating more stable emulsions, reducing fluid mobility due to increased fluid viscosities, and inhibit efficient crude oil scrubbing. It is generally desirable to operate desalters at higher temperatures – above 120°C for the typical crude slate seen in Argentina containing shale oils.

"Tramp" amines are defined as those amines not intentionally introduced to the crude unit distillation tower overhead system for halide neutralization. Tramp amines found in shale oil crudes are predominantly the result of triazine-based H_2S scavengers, but can be present from other upstream treatments – amines are not typically naturally occurring in the crude oil formations. These amines can cause emulsification issues at the desalter, as well as increase the salt potential in the crude tower and overhead system. If not properly managed, severe corrosion can result from amine salts formation. Additional amines and ammonia in the process water streams increase nitrogen loading on the waste treatment systems. Variable metals can cause catalyst poisoning at the FCCU, as well as impact coke quality. As a result, a new paradigm to treat desalters is suggested. It calls for the use of "multiple levers" of select for-purpose chemistries to address issues specific to a refinery site. The old approach of a single chemistry injected in a single location often does not lead to the most efficient operational performance when processing shale crudes. These "levers" may include options such as demulsifier split-feed - injecting the primary emulsion breaker into both the oil and the water, crude stabilizers, wetting agents, reverse-emulsion breakers, amine/metals removal aids, and pH modifiers.

As always, chemical programs have to be carefully evaluated. One should take into account several considerations, including: crude tank dewatering, slop system management, and wash water quality. Even the makeup of the chemistry selected has to be considered when accessing the overall treatment program. Application technology is another variable that can impact program performance. So, how and where chemical treatment is applied is almost as important as the selection of the chemistry itself.

Amine and ammonia removal can be improved by reducing the pH of the water and thereby help more basic compounds partition into the water. There is tremendous benefit associated with removing amines at the desalter. If the amines or ammonia are not partitioned into the water, they remain in the crude and form amine-hydrochloride salts in the crude tower and overhead system. They are especially troublesome when they form in the top pump around sections.

Wetting agent adjunct chemistry can also be very helpful when processing shale oils. The fracking process used increases the amount of entrained solids. Compared to those found in traditional crudes, these solids are smaller and, consequently, the volume is typically higher as well. The increased solids loading can easily overwhelm the ability of a desalter to effectively remove them. Loadings as high as 300 pounds per thousand barrels (ptb) in the raw crude have been documented when processing certain shale oils. Solids contamination can cause stabilized emulsions that can lead to water carry-over in the oil out of the desalter and oily effluent brine. Oily brine can be a major source of problems in the wastewater treatment plant, and reduce overall refinery capacity by increasing slop oil reprocessing volumes. The solids are inorganic particles that are coated in oil. Wetting agents help strip the oil layer from the particles and make it easier for them to be removed from the desalter.

Desalter treatment programs can be combined or modified to enhance solids removal. One US Gulf Coast refiner wanted to improve solids removal to address downstream heat exchanger and furnace fouling. The modifications at the desalter included changes to the chemical program and to the operating parameters. Prior to the modifications, the desalter program had performed successfully with respect to salt removal and dehydration. However, Figure 10 clearly illustrates the benefit of the program modifications, with solids removal efficiencies approaching 90%.

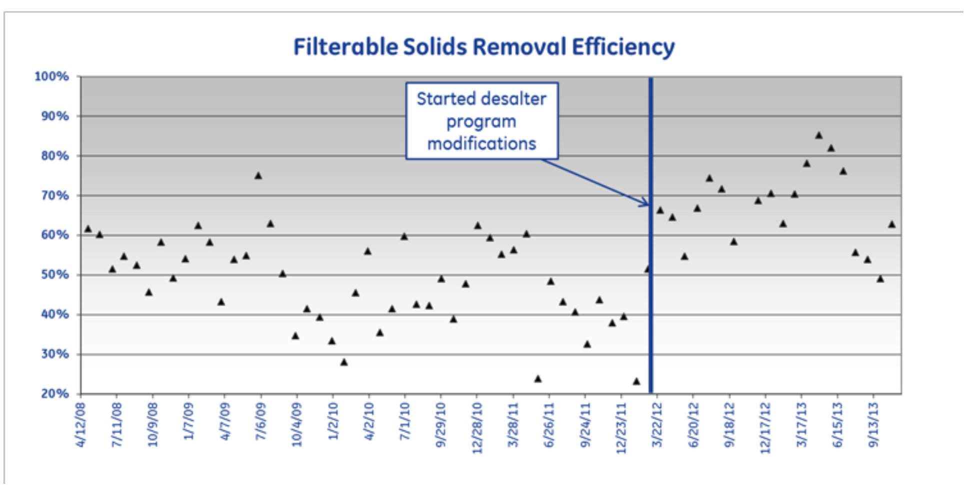

Figure 10 - Improving solids removal

When paraffinic shale oils are blended with asphaltenic crudes, the asphaltenes can destabilize and agglomerate, leading to emulsion stabilization; increased oil in the effluent; as well as preheat exchanger and furnace fouling. The photos in Figure 11 illustrate the benefit of applying an adjunct chemistry, called a crude stabilizer, designed to condition the crude oil and keep asphaltenes from precipitating. Here the adjunct chemistry is used independent of the emulsion breaker to minimize the rag layer build-up in the desalter and to control the effluent water quality. The chemistry is injected only when needed, based in the stability of the blend that is being processed at any given time.

Figure 11 - Desalter brine quality improvement

Corrosion and Distillate Maximization

Increasing distillate production yield is an overall global refinery trend. Some refiners are lowering tower top temperatures to increase straight-run distillate volumes. While this will yield higher distillate production, it may also increase corrosion potential, and reduce unit reliability. Corrosive salt formation and/or shifts in salt point temperatures can compromise crude unit integrity.

Due to better wash water systems and reduced use of ammonia as primary neutralizer, the industry has witnessed a dramatic shift from traditional ICP (Initial Condensation Point), or dew point, corrosion mechanisms to amine salt corrosion. Tramp amines are becoming considerably more prevalent, contributing to salt-induced corrosion, and increased fouling in overhead exchangers and fin fans.

In addition to overhead and tower top corrosion concerns, high temperature naphthenic acid corrosion may be an indirect concern when processing shale crude oils. As mentioned previously, blending shale oils with heavier crudes is a typical practice to achieve the needed volume of the various refinery distillation cuts. It has been observed in Argentina that the crudes being blended with shale oils often contain high levels of naphthenic acids, resulting in a net increase in TAN values. While beyond the scope of this paper to detail, increased naphthenic acids in the crude supply can increase high temperature corrosion in the hot sections of the crude and vacuum distillation systems, stabilize emulsions in the desalter, and increase the toxicity of the refinery waste water as some of the naphthenic acids are absorbed into the brine leaving the desalter.

Tramp Amines

Depending on the amine properties and concentrations, amine salts can form at, or even above, the system dew point, making it difficult to control salt deposit related corrosion. In addition, when tramp amines are introduced, uncontrolled acid neutralization can occur and further contribute to salt build up in the tower top and/or overhead system. In some instances, overhead systems become so loaded with these amines that the traditional neutralizers are actually turned off. Even with no neutralizers added, the pH remains well above control limits in some of these systems. The amine hydrochloride salts that form in this situation can produce corrosion rates in excess of 1,000 mils per year under some conditions. Because of the concentration of the tramp amines and subsequent salt formation, total system amine management is extremely critical to equipment reliability.

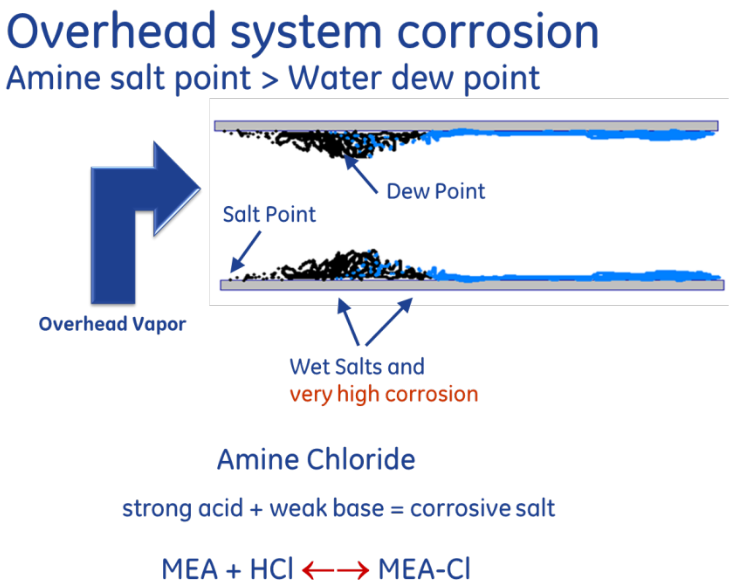

Figure 12 - Overhead salt formation

Figure 12 illustrates how and where these very corrosive salts might begin to form. In addition to H_2S scavengers, there are several other sources of tramp amines. They can enter the system via:

- Steam neutralizers
- Slop oils charged back to the desalter
- Sour waters used as desalter wash water
- Atmospheric tower reflux streams

Cold, wet atmospheric tower reflux streams can exacerbate this problem by recycling the various amines in the overhead system. Unless adequately purged, these recycled amines can concentrate up and lead to higher salt points and increased corrosion potential in the overhead.

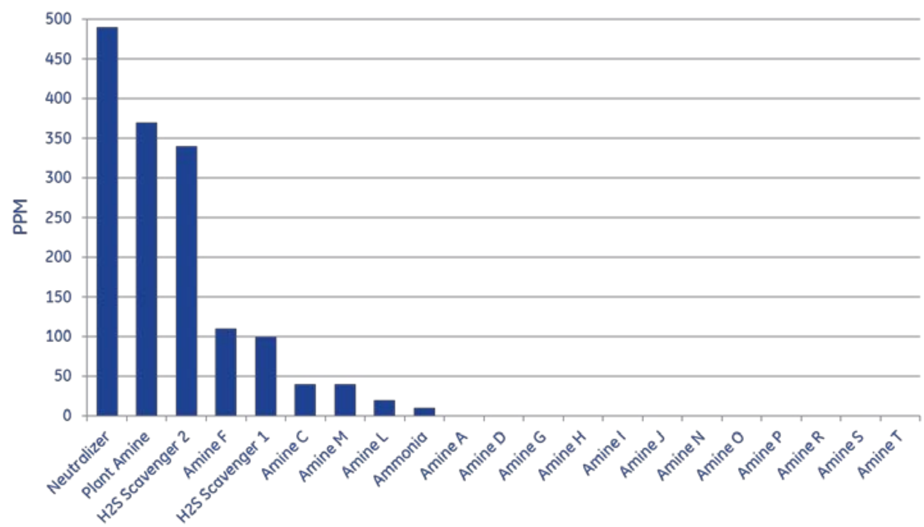

Figure 13 - Deposit amine analysis

Figure 13 details a deposit analysis from a failed pump around exchanger at a US Gulf Coast refinery. The overhead system had experienced 3 corrosion-related failures within a 2-year period. Prior to that time, they had not experienced an unplanned corrosion event for decades. The results of the deposit analysis revealed that the neutralizer amine, probably from wet reflux, was the highest concentration; the second highest was the plant amine used for acid gas sweeting, coming in via the slop-oil system; and the third highest amine concentration was from an H_2S scavenger treated crude oil source. The plant had previously been unaware of the amines from the H_2S scavengers. The plant had maintained good desalter performance and chloride control in the overhead, yet the elevated amine concentrations increased the salt formation temperature to the point where it formed in the tower's top pump around section, resulting in the high corrosion rates.

As mentioned earlier, salt initiated corrosion is becoming more prevalent in the industry. Refiners that are considering processing the lighter shale crudes or lowering tower top temperatures have to be aware of the change in monitoring that should occur to optimize the economic benefits while managing the corrosion.

The following shows how GE assisted a refiner define a new operating envelope in order to limit overhead corrosion and improve the unit's economic balance. First, the relationship between and the salt-point and the water dew-point was calculated using an ionic equilibrium overhead model. Corrosion in the overhead was identified and quantified by overlaying the data with operating conditions. Each one of the bars in Figure 14 represents temperature differences in degrees between the water dew-points and the salt-points.

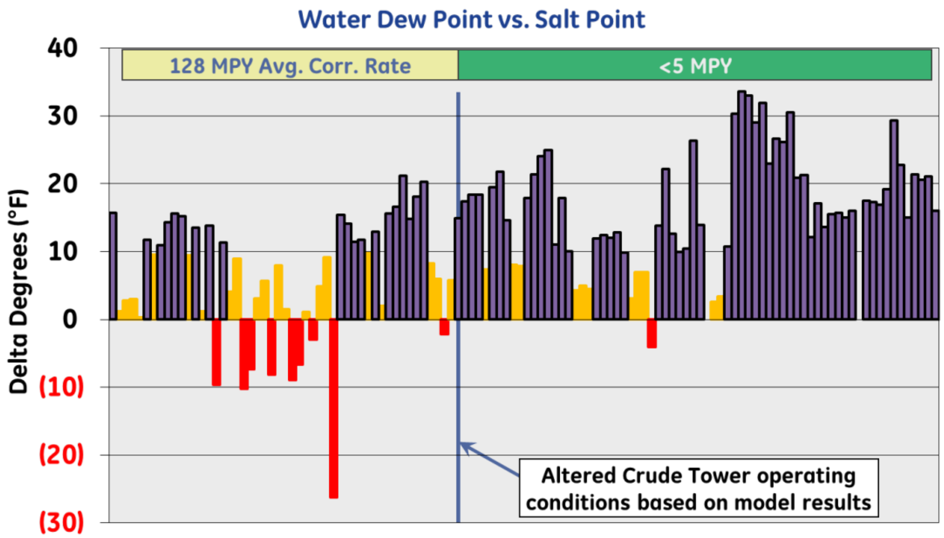

Figure 14 - Crude tower condition assessment

The blue bars represent measurements where the water dew point is 10°F or greater than the salt point temperature. Yellow indicates 0-10°F differential. The red bars are instances when the salt-point actually fell below the water dew-point in the system. Prior to December of 2010, the refiner had experienced very high corrosion because of several instances when the salt-point dropped below the water dew-point. Recognizing the impact salt-point had on corrosion control, the output of the ionic equilibrium model was then used to establish a new, safer operating envelope to minimize system corrosion. Since that time, corrosion rates have been maintained at 5 mils per year or less, and the operating envelope is actively managed based on the calculated salt points as the system conditions change.

Fouling

In addition to the desalting and corrosion challenges associated with processing shale oils, equipment fouling can also be a major concern. The processing of lighter crudes, with low asphaltenes, is not typically thought of as being particularly problematic. However, there are specific issues associated with these crudes that have been identified to cause issues in the refinery process.

The cold train can experience wax precipitation, with the resultant loss of heat transfer causing low desalter temperatures in addition to increased pressure drop across the cold train heat exchangers. Also, increased preheat and furnace fouling potential can be experienced with these crudes due to asphaltene precipitation, metal catalyzed polymerization, and/or solids deposition.

There are typically 2 types of fouling in the hot train and furnaces. Coke and inorganic solids are the primary culprits. The coke can result from asphaltene precipitation or polymerization byproducts that fall out of the bulk fluid onto the tube surfaces and dehydrogenates. Metal catalyzed polymerization is somewhat rare in crude oil, but does occasionally occur due to sporadic spikes in the levels of reactive metals. Finally, high solids loading, common with these crudes, along with any carryover from the desalter can significantly contribute to fouling issues. Most refiners run years before fouling requires the furnace to be cleaned. Some US refiners have experienced as little as 3 months between turnarounds to clean the crude furnace when trying to process shale oils from their regions. Run lengths were increased with a combination approach – chemistry, furnace design modifications, crude source control, and aggressive burner management.

Asphaltenes and Asphaltene Precipitation

Asphaltenes are compounds that are n-heptane insoluble yet soluble in toluene and are believed to be suspended by resins. Resins are polyaromatic compounds that are considerably lower in molecular weight than asphaltenes, and help to suspend the asphaltenes in the crude. When these resins become destabilized, such as upon heating or mixing with paraffinic crudes, agglomeration can occur in the desalter, the bulk fluid, the preheat train, or the furnace and cause fouling. The photos in Figure 4, mentioned earlier, show the results of a lab technique GE developed to help predict asphaltene stability. This test can be performed on-site to help determine the asphaltene precipitation potential of a specific crude or blend of crude oils, allowing refiners to better predict the behavior of crude blends, as well as help set blending strategies. Figure 15 shows the Asphaltene Phase Separation Index – a measure of a crude oil or blend to cause an upset in asphaltene stability when mixed with other crudes. As compared to the other benchmarks, it can be seen that the Argentina shale oils analyzed are very high on this scale – exceeded only by the US Eagle Ford shale oil.

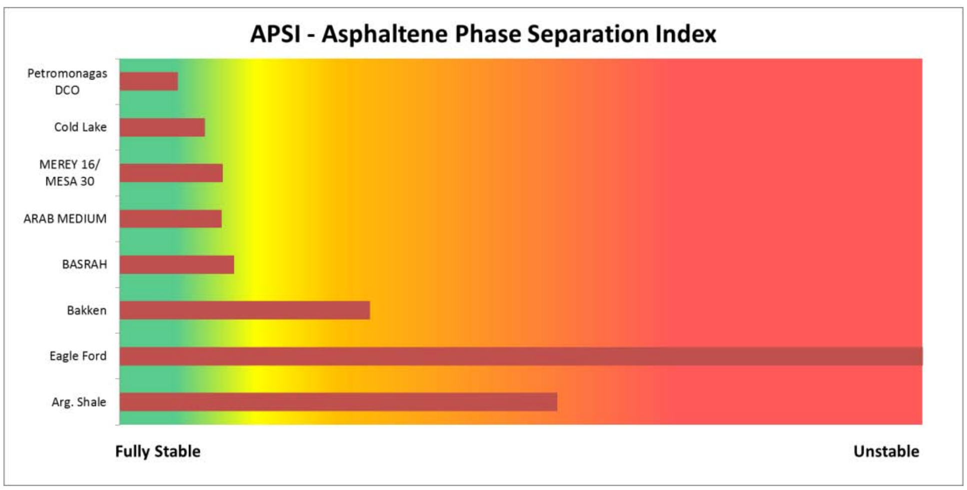

Figure 15 - Asphaltene stability index

Refiners employ many performance management strategies to reduce or mitigate equipment fouling, including operational and mechanical adjustments as well as anti-fouling chemistries. Some of the common operational or mechanical approaches are: reducing solids and salts by optimizing desalter performance, increasing fluid velocities to minimize deposition potential, and modifying furnace flame patterns by cleaning or changing burner tips to maximize performance and minimize impingement that can cause coking.

Chemistries have been used successfully through the years to help reduce equipment fouling. A multi-functional approach has been recommended for shale oils due to multiple mechanisms in play when processing this crude oil type, tailored to the individual refinery and focused on addressing each specific issue with the most cost-effective program.

Using proper characterization methods to understand the root cause of the fouling can help determine the most appropriate management strategies. When starting to process problematic crude blends or increasing a problematic crude type in a blend, effective baseline monitoring is extremely important to understand the status of the current system, as well as to anticipate what limitations may develop.

Conclusion

In closing, the unique challenges associated with processing shale oils can be overcome with a combination of baseline and ongoing monitoring; defining and implementing new operating envelopes; investing in capital to alter the equipment configuration; and utilizing multi-functional chemical treatment programs that provide refiners with the tools and the flexibility to address the specific process problems as they arise. The shale revolution in North America has truly changed the face of the energy industry there; the potential exists to do the same in Latin America.

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[i] "More about Shale" Azabache Energy Inc. web article (www.azaenergy.com/more-about-shale/), 2014
[ii] "Technically Recoverable Shale Oil and Shale Gas Resources : An Assessment of 137 Shale Formations in 41 Countries Outside the United States", US Energy Information Administration, Jun 13, 2013
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Jeff Zurlo

- BE (ChE) degree from Stevens Institute of Technology - New Jersey, United States.
- Prior to joining GE Water & Process Technologies in 1997, Jeff held various process engineering positions at Sunoco Inc, Koch Refining, and Hercules Incorporated.
- Senior Project Manager - Jeff currently provides global technical support to the Refining Industry and gas plant processing, with a principal focus on best practices, knowledge management, web-enabled analytics, technology development, and amine sweeting programs.

Tatiana Schmitt Barbosa

- Chemical Engineer in Universidade Federal do Rio Grande do Sul - UFRGS
- MBA in Marketing and MBA in Business at FGV – Brazil
- Prior to joining GE in 2010, Tatiana held various position in Chemical Department in UFRGS , Petrobras S.A. , Petrolite – Petreco Inc , Nalco-Exxon Chemicals Co and Nalco Corporation.
- Product Application Manager - Tatiana currently provide technical support for refineries and petrochemicals in Latin America with focus on best practice , knowledge management and technology development.