Monitoring and simulation resolves overhead corrosion

Online corrosion monitoring in tandem with simulation modelling identified the root cause of corrosion in a crude unit overhead

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Corrosion of crude unit overhead exchangers continues to be a significant concern towards integrity and reliability within the refining industry; failure mechanisms have been the subject of many technical papers over the years. For many crude units, good desalting and caustic injection practices are first lines of defence in managing overhead corrosion issues while injection of organic amine neutralisers and corrosion inhibitors is also applied in order to keep corrosion rates to a minimum. Additionally, many refiners look to control corrosion through non-chemical means by installing continuous wash water systems and metallurgy upgrades, replacing carbon steel sections with alloys that provide enhanced corrosion protection.

Regardless of the corrosion control strategy employed, one fundamental consideration is use of the correct diagnostic tools to allow monitoring of process conditions and corrosion rates in susceptible parts of the system. This monitoring provides a thorough understanding of corrosive species present in the system as well as operational factors that contribute to corrosion.1

Traditional corrosion monitoring and control revolves around periodic sampling and analysis of overhead sour water to determine the corrosive nature of the process and to give an indication of corrosion rates by the measurement of iron in sour water. This process stream analysis is often complimented by online corrosion monitoring in order to correlate changes in process conditions to subsequent changes in observed corrosion rates.

However, even with frequent analysis, corrosion monitoring and good management of the desalter operation and the overhead corrosion control programme, there remain many instances where high corrosion rates are observed that are difficult to explain and result in equipment failures, unplanned shutdowns and increased maintenance costs.

Herein lies the challenge since refiners are being increas-ingly tasked to find a balance between two competing objectives.

On the one hand, refineries are being asked to process more challenging crudes and while these present a price advantage they also increase the risk level. In conjunction with processing a more challenging crude diet, process conditions in the top sections of the atmospheric tower are being adapted to produce more valuable distillates and less naphtha in order to maximise margins. This can cause elevated levels of corrosion in parts of the system where none has been previously observed.

The other side of the challenge is that refiners are facing continuing pressure to reduce costs through increasing run length between turnarounds and reduction in head count and contractor use, often including inspection department and chemical vendor resources. Ultimately, this can compromise the ability of a refiner to maintain an appropriate level of surveillance of plant integrity.

Given these challenges, crude
units previously able to operate with minimal issues are now facing challenges from increased crude unit overhead corrosion, which is resulting in serious economic penalties. Therefore, a more proactive approach to asset integrity management and crude unit overhead corrosion is required.

In order to successfully mitigate high overhead corrosion rates, the refiner and the chemical vendor are required to undertake a rigorous audit of the operation to identify all root causes that are contributing to the issue. A number of factors can contribute to this problem, therefore a total system approach needs to be taken and the mechanical, operational and chemical aspects of the unit’s operation need to be reviewed to obtain an in-depth view and understanding.

This thorough understanding of the underlying root causes aids in the selection and implementation of a correct corrosion control strategy. The primary tools for diagnosing root causes fit into two categories: analytical testing, which can be used to identify the responsible corrodents; and a modelling technology, such as Nalco Champion’s Pathfinder, that provides a means to understand the environmental factors that dictate the conditions under which corrosion occurs. These methods are used together not only to investigate the factors influencing corrosion but they are also utilised to define the operating envelope through which corrosion can be effectively controlled.

As well as utilising analytical testing and process modelling, online corrosion monitoring is used to complement these tools in order to link process conditions to actual corrosion events happening in the overhead system and to assess the success of corrosion mitigation methods. The move towards real-time online corrosion measurements with permanently installed UT thickness measurements, such as Permasense, has provided a significant improvement in the quality of the corrosion monitoring data, allowing cross correlation with process data, identifying corrosion events and helping facilitate root cause analysis.

This article will discuss techniques that can be used to monitor corrosion and determine the mechanisms in near real-time, including permanent UT thickness monitoring and computer simulation of the overhead condensing system and how these tools were used to effectively troubleshoot previously unexplained high rates of CDU overhead corrosion at a European refinery.

The continuing challenge: crude unit overhead corrosion and its control

Corrosion due to strong acids in crude tower overheads is a problem that all refiners face. The most prevalent cause of strong acid corrosion in crude unit overheads is due to hydrochloric acid condensation in the overhead system.

Hydrochloric acid is formed because the desalter operation is not wholly efficient, leaving residual amounts of hydrolysable salt, specifically calcium and magnesium chlorides, entrained in the crude oil. These salts are passed through the preheat exchangers and ultimately to the fired heater where they hydrolyse to form hydrochloric acid (HCl). The generated HCl and other acidic species like sulphur oxide (SOx) based acids and low molecular weight organic acids enter the atmospheric distillation column where they end up in the overhead condensing system.

The presence of these acids in the overhead system will result in a very low pH at the initial water dewpoint and, without adequate control measures, this results in very high corrosion rates.

Caustic is frequently added to the desalted crude in order to lower the effective salt hydrolysis rate by converting Ca and Mg chloride salts to non-hydrolysable sodium salts. This effectively reduces the amount of hydrochloric acid produced. However, the use of caustic can lead to increased furnace fouling as well as reduced catalyst activity if residue is fed to a FCC or hydroprocessing unit. While caustic use can be beneficial, it is desirable to keep the injection rate to a minimum.

A variety of techniques is employed to control corrosion in the overhead system, the most common being chemical corrosion control programmes which utilise neutralising amines to control pH (typically between 5.0 and 6.5) and filming corrosion inhibitors to create a protective barrier on the metal surfaces.

Neutraliser rates are typically manually adjusted based on pH measurements by either an
operator or the chemical supplier with most applications controlling dewpoint pH to greater than 5.0 to limit strong acid corrosion potential. However, it is accepted that the dose rates are best calculated by using modelling software to determine the correct amount of neutraliser based on conditions found in the condensed sour water. Additionally, there are many properties of neutralising amines that must be considered since each one has unique properties that govern how rapidly it will evaporate, its potential to form solid or liquid salts above the water dew point and how rapidly it will partition into the first drops of condensing water. Generally, we are trying to find a compromise of the properties of the neutraliser such that undesirable characteristics are minimised. As will be discussed later, computer simulation is used to predict these phenomena and these models are used to calculate the propensity of ammonia/amine hydrochloride salts to precipitate and the conditions at the initial water dewpoint.

Filming amine corrosion inhibitors are the last piece of the corrosion control programme and they are used to further reduce corrosion rates to an acceptable level consistent with the operating goals of the refinery. The corrosion inhibitor is typically kept at constant ppm injection rate based on the volume of overhead liquid. The presence of inhibitor ‘films’ has been shown to provide further significant reductions in corrosion rates in susceptible areas of the overhead condensing system.

For both the neutraliser and the filming amine, proper design and operation of the injection system is critical to the success of the overhead corrosion control programme. When the injection system is designed according to industry best practices, the correct chemistry is in place and the application is managed correctly, the corrosion control programme has been successful in minimising corrosion.

**Computer modelling**

Changes in crude quality and crude tower operations (overhead pressure, stripping steam rate, temperature, and so on) can have a variety of impacts on crude unit operations. One area that can be impacted is a change in the corrosivity of the condensing water in a tower overhead system from increases in hydrochloric acid, other mineral acid species ($\text{H}_2\text{SO}_3$ and $\text{H}_2\text{SO}_4$ for instance), organic acids, and weak acids such as $\text{CO}_2$ and $\text{H}_2\text{S}$. Another change can be the formation temperature of ammonium chloride or amine chloride salts. Some of these changes can be significant and result in increased corrosion rates. For many, the strategy has been a wait-and-see approach when changes of this nature occur, often with damaging results.³

Modelling of CDU distillation tower overhead systems allows the user to simulate the impacts of these changes on corrosive conditions. Because of this, they are now a critical element of the corrosion control programme as they are used to help proactively develop and manage corrosion mitigation strategies.

The vapour leaving the top of the crude tower is complex and is a mixture of hydrocarbon, water vapour, strong electrolytes ($\text{HCl}$, $\text{H}_2\text{SO}_3$, $\text{H}_2\text{SO}_4$) and weak electrolytes ($\text{NH}_3$, $\text{CO}_2$, $\text{H}_2\text{S}$, amines, low molecular weight organic acids). Computer simulation considers the interaction of all of the species and phases across a range of temperatures and pressures in order to simulate the whole condensation profile of the vapour. These thermodynamic equilibrium models simulate the vapour-liquid (VLE), solids-vapour (SVE) and solids-liquid (SLE) equilibrium behaviour of the various components and are used to calculate the critical parameters of the overhead operation and factors that contribute to overhead corrosion, such as:

- Water dewpoint temperature and its location in the system
- Vapour-liquid equilibrium (VLE) behaviour of ionic species as the water condenses
- Interaction between the acids and bases present
- Conditions at the initial water dewpoint (pH, concentrations and so on)
- Thermodynamics and kinetics of amine/ammonium chloride salt formation.

A number of overhead computer modelling programs are used in the refining industry, typically split into two categories: detailed use and general use models.

Detailed use models are typically built around commercially available software; they were originally developed as comprehensive process model-
ling tools to be used in the oil and gas industry but with the generation and incorporation of specific data, such as the VLE, SVE and SLE data for acidic/basic species, they have found use in modelling the phenomenon found in crude unit overhead systems. Given that they are complex simulation tools originally intended for process design and optimisation, they require extensive data collection and sampling that is not routinely taken. Because of their complex data requirements, these models take some time to construct and validate and as a consequence they are neither suitable nor practical for tracking trends or making rapid decisions. However, this should not detract from their usefulness since these models can be a vital tool in troubleshooting corrosion events and assessing the impacts of long term strategic operational changes.

General use models, such as Nalco Champion’s Pathfinder, use the same rigorous thermodynamic calculations but are built around readily available process and analysis data meaning that they can be used on a more frequent basis (daily, weekly) and as such they are able to provide routine monitoring in near real time. The database capability of Pathfinder also allows for trending data which can help in highlighting the root causes of corrosion related issues such as shifts in water dewpoint and salt formation temperatures. With their incorporation into the regular service schedule, the general use models can also be used to calculate neutraliser dose rates based on the concentrations of strong acid species, thus controlling the dewpoint pH within acceptable parameters and allowing the refiner to make short term adjustments in response to changes in the overhead system.

Lastly, as with detailed models, general use models can also be used to model what-if scenarios to determine the impact of changes in crude diet or process conditions, with both types of models providing detailed information to enable informed decisions.

**Corrosion monitoring**

Corrosion monitoring is required in order to understand the variability of corrosion rates over time, as the variables that affect the likely corrosion outlined above change. Monitoring requires frequent high quality measurements to be able to spot changes quickly and to have enough data with which trends can be reliably calculated.

Several types of instrument have been used for monitoring corrosion in oil refineries. Two of the most common are intrusive corrosion probes and manual ultrasonic inspection.

**Corrosion (or electrical resistance, ER) probes**

Corrosion probes have been in use since the 1960s and are a well established technology. They rely on an intrusive element with a sacrificial tip, which sits in the process fluid and is (normally) made from the same material as the surrounding equipment. As the sacrificial tip corrodes, its electrical resistivity changes; this is recorded externally (usually on a locally mounted data logger but they are increasingly wirelessly connected). Corrosion of the sacrificial tip is used to infer the level of corrosion being experienced by the surrounding equipment. While being simple to use, corrosion probes suffer from a number of disadvantages:

- Centre line-measured corrosion may not be the same as the corrosion rate at the wall, due to shear velocity effects causing elevated corrosion rates where flow velocity is highest.
- The tip often corrodes away after two to three years (or even less in ‘high sensitivity’ applications), while many refineries are now operating five-plus years between major turnarounds. Thus, the corrosion probe tip will usually need to be replaced ‘on the run’. Careful safety procedures and intensive technician training are required to avoid any danger to personnel. In spite of this, there have been several well documented safety incidents caused by probes being ejected at high velocity under residual pressure. Several international oil companies have banned removal of intrusive probes while the plant is running, with the result that they operate ‘blind’, from a corrosion standpoint, for the final and most critical one or two years of the cycle between turnarounds.
- The intrusive nature of these probes means that they cannot be installed during normal operations, since they require specialist mounting flanges to be bored and welded to the piping.
- The intrusive probe creates a
disturbance in the flow of the fluid that can induce corrosion to occur further downstream.

- Many of the older type, data logger based probes require an engineer to visit the equipment to download data. They therefore require physical access to the probe’s location and have an inherently low acquisition rate. This latter point is an important issue for crude overhead systems, such as the overhead line itself, as these are often physically remote – the probe data connection then has to be cabled to a nearby platform, increasing installation costs and opening the possibility of the cable being damaged.

**Manual ultrasonic inspection**

Ultrasound is a well established technique in the oil and gas industry. The technique involves the generation of ultrasound from a transducer that is placed directly onto the metal surface. Ultrasound is transmitted through the metal until it is reflected off the inside back wall. The reflected ultrasound signal (or A-scan) is recorded and the time difference (the ‘time-of-flight’) between the sent and reflected signals provides a measurement of the wall thickness. While the technique can be reliable, completion of a full set of measurements for a medium sized refinery with 80 000+ corrosion measurement points is very time consuming and labour intensive, such that the wall thickness at an individual low to medium risk point may only be measured every two to five years. It is therefore very difficult to take measurements in key locations with enough frequency to measure corrosion rates with any confidence, or to link periods of high wall loss to specific feedstocks or process operations (which require measurement intervals of days to be useful).

In addition, while being relatively simple, manual ultrasound methods have the following disadvantages:

- **Repeatability and reproducibility errors:** it is unlikely that consecutive measurements will be taken in precisely the same location by the same NDE technician using the same equipment. As the handset requires careful calibration and there is skill in interpreting the ultrasonic waveform, this can cause errors in thickness measurement. **Figure 1** shows manual measurements at a single (nominal) location over time from 1984 to 2013. It is clear that different conclusions regarding wall thickness and corrosion rate can be drawn over time. From such data, it could be inferred that the accuracy of manual ultrasound is +/-0.5 to 1 mm (+/-20-40 thou).

- **High temperatures:** temperatures above 100°C (212°F) can permanently damage the electronics of an ultrasonic transducer.

- **Physical access:** a technician needs access to the equipment at the measurement location of interest, therefore requiring scaffolding (possibly permanently installed if measurements are frequently required) and stripping of insulation to expose metal to make manual measurements.

**Permasense corrosion monitoring system**

The Permasense system has sensors that use the same proven measurement method as manual ultrasound, but deliver a quality and frequency of wall thickness measurement that is unachievable with manual inspection and without the safety risks of intrusive probes. The sensors are left in
situ, thus allowing consecutive wall thickness measurements to be perfectly co-located. The sensors can be left in place on pipework operating up to 600°C (1100°F), because of the patented waveguide technology that holds the sensor head (with ultrasonic transducers, electronics, battery) away from the hot metal.

The sensors’ measurements are transmitted wirelessly back to a gateway (wireless access point) mounted near the process unit. A system schematic is shown in Figure 2.

Since there is no cost associated with measurement acquisition or measurement retrieval, the frequency of measurement can be configured to be as frequent as every 15 minutes. Connection of the gateway to the refinery operator’s existing IT infrastructure allows the data to be viewed from the desks of those who need the data to be able to make better informed decisions about operation of the plant. Sensor battery life of up to 10 years allows continuous data delivery between turnarounds without access to a sensor’s location.

Monitoring crude tower overhead systems
These permanently installed, ultrasonic, wireless, wall thickness monitoring sensors are suitable for crude overhead dewpoint corrosion monitoring in view of their sensitivity to small changes in wall thickness, robustness to extreme plant conditions, extended battery life (enabling reliable operation over the entire cycle between turnarounds) while being simple to install.

Figure 3 shows an example of a monitoring system for a crude tower overhead system using the technology.

A typical overhead monitoring system would consist of 20-30 measurement locations, with 2-5 sensors per location, for a total of 40 to 150 sensors, depending on the system configuration, specific metallurgy and operating conditions.

Case history: increased overhead corrosion rates at a European refinery
Consistently high rates of corrosion were being observed in the overhead condensing system of the refinery’s crude distillation unit. The unit processes low sulphur crudes. However, the blends are highly variable in their crude composition, with feeds changing every 2-3 days.

Corrosion had been observed in critical exchangers at previous turnarounds and this led to the use of enhanced metallurgies to mitigate. In the face of ongoing corrosion issues, the refinery installed Permasense sensors in key sections of the overhead to monitor the ongoing corrosion in the system.

Nalco Champion is the chemical vendor at the refinery and provides the chemical corrosion control programme as
well as routine analysis of the overhead sour water and modelling with the Pathfinder simulation program. Sour water analysis data showed no obvious reason for elevated levels of corrosion and, generally, the key control indicators for the corrosion control programme have been within acceptable levels.

However, even with frequent analysis and seemingly good control of the corrosive environment, high rates of corrosion were still being observed in Permasense data, which was difficult to explain. These high rates of metal loss were becoming a critical issue to the refinery and a root cause investigation (RCA) was convened to discuss and develop hypotheses to explain the causes of increased corrosion in the CDU overheads. A thorough audit of the unit, reviewing in detail the process and analytical data, provided insight into the potential causes of corrosion in the CDU overhead system.

The following sections outline the refiner’s RCA activities as the investigation tried to correlate changes in corrosion rates to changing process conditions on the unit.

**Crude unit overhead system overview**

The overhead system of this unit (see Figure 4) comprises two parallel overhead lines exiting the main fractionators, with each line leading to two sets of two shell and tube heat exchangers operating in series. After these exchangers, vapour is fed into a set of air coolers. The vapour-liquid mixture for the air coolers is then separated in the overhead accumulator.

The bundles in the shell and tube heat exchangers were upgraded from carbon steel to Hastelloy C-276 due to previous corrosion events, with a view to increasing run length and avoiding frequent replacement.

The unit has a chemical overhead corrosion control programme in place; a neutralising amine is injected into each of the overhead lines coming from the crude column. The neutraliser injection rate is adjusted to maintain a pH of 6.8 +/-0.4 in the overhead sour water.

An oil soluble filming corrosion inhibitor is also added in each of the overhead lines and this is injected with a naphtha slipstream and an injection quill in order to provide good distribution.

Corrosion rate monitoring on this crude unit was provided by Permasense sensors placed in approximately 200 locations throughout all sections of the unit. Several of these sensors were installed to monitor the thickness of the shells of the heat exchangers in areas where corrosion damage had been identified by previous manual inspections during shutdown.

These manual inspections showed continued corrosion on the Hastelloy bundles but the major concern to the refiner was the elevated rates of corrosion being observed on the shells. Replacement of shells is a much more expensive and complex task than replacing a
bundle and this would require an extended unit shutdown which would have significant financial implications for the refinery.

Figure 5 shows that there has been a significant rate of metal loss from the shells of both exchangers. The corrosion rate increased by a factor of 2.4 and 4.0 in the A and C exchangers respectively. This significant increase in corrosion activity caused the refiner to initiate a root cause analysis.

Analytical testing
Routine analysis of overhead sour water is considered to be an important component of a crude unit overhead corrosion control programme. Therefore, a review of this data is often the first step in most investigations into increased rates of overhead corrosion.

The concentration of acidic components, along with the pH control of the condensed waters, is probably the most vital aspect to consider. A review of overhead chloride levels (see Figure 6) showed that conformance to the KPI limit of 15 ppm was approximately 92%, which is indicative of good desalting and caustic management practices. However, it is important to note that there are a number of high chloride excursions that have been captured during the routine sampling. These could be a result of desalter upsets or the presence of ‘undesaltable’ chlorides and may impact on corrosion rates.

Chlorides are only one of a number of acidic species found in the overhead. Therefore, in conjunction with chloride analysis, Nalco Champion runs a proprietary strong and weak acid test (SWAT) to determine the concentration of all the strong and weak acid species. As Figure 6 shows, strong acid analysis had been steadily increasing during the period of increased corrosion and proper neutralisation of all strong acids is critical to good corrosion control.

From the routine computer modelling conducted by Nalco Champion with Pathfinder, the amount of neutraliser required based on strong acid levels is calculated during every service visit. During the RCA, we were able to show that neutraliser dose rates (see Figure 7) had been sufficient to meet demand based on strong acid content and that the pH levels (see Figure 7) of the overhead sour water had been held to an acceptable level within the agreed control band.

Ammonia testing is also routinely conducted on overhead sour water as this can influence the potential for ammonium chloride formation in the overhead system. The analysis data showed a high degree of variability with a typical range of 20-40 ppm but with observed levels as high as 70 ppm. Salt formation, deposition and subsequent under-deposit corrosion is also a major cause of overhead corrosion and this data along
with chlorides levels are entered into the model to determine the risks of salt formation.

**Computer modelling of the overhead system**

By calculating key parameters that cannot be directly measured, like dewpoints and salt formation temperatures, computer modelling gives detailed insight into the corrosive environment in the overhead system and was a critical tool used in the RCA.

The first aspect reviewed was the salt formation potentials for both ammonium and amine chloride salts as this data is essential for determining the potential for under-deposit salt corrosion in the overhead system. By calculating the salt formation temperatures and then comparing this to critical process parameters such as the water dewpoint, we determine the risk of salt formation. By calculating the water dewpoint approach temperatures (see Figure 8), we can determine whether the salt formation temperature exceeds the water dewpoint – that is, the likelihood that solids will form and deposit in the system.

These approach temperatures show that amine chloride salt is below the water dewpoint since a negative approach temperature is rarely observed (the salt formation temperature is less than the water dewpoint temperature). This is due to the selection of an amine neutraliser for this particular system ensuring that the negative effects of salt formation are minimised. Conversely, the ammonium chloride approach temperatures are frequently less than zero (the salt formation temperature is greater than the water dewpoint temperature), suggesting that there is a risk of salt formation, deposition and subsequent under-deposit corrosion.

However, looking at the salt formation temperatures in isolation can be misleading; while conditions in the system can lead to a calculated salt formation temperature above the water dewpoint, it is also important to consider the calculated mass of salt deposit that can potentially be generated under these conditions in order to provide proper context to the results. When this parameter was calculated, the amount of salt deposit that could be generated in the system was low and typically <5 kg/day. When considering the potential mass of salt generated versus the overhead flow, it highlights that the risk of salt deposition, based on experience, is low. From this we can conclude that good control of chlorides in the overhead limits the amount of salt that can be generated.

While the RCA established that the correct amount of neutraliser was being dosed to...
This case comparing the water dewpoint temperatures to the outlet temperatures of the shell and tube exchangers (see Figure 9).

It can be seen that there is a significant variation in the approach temperature. The value swings from values less than zero, where the water dewpoint is inside the exchanger, to values $0<T<14$, where the water dewpoint temperature is very close to or just below the outlet temperatures.

Like the salt formation temperatures, one has also to look at the calculated volume of water condensed in the shell and tube exchangers (see Figure 10) in order to provide further insight and context to the results.

The data points close to zero are not in fact zero values but periods when the amount of water being condensed is $<100$ kg/h.

When this data was reviewed and then compared to the Permasense corrosion monitoring data (see Figure 11) there was an interesting correlation which provided critical insight into the corrosion problem.

According to the data, there was a distinct increase in the rate of corrosion around August 2013. At this point, there was a significant increase in the rate of metal loss and this coincided with a distinct change in the water condensation profile in the affected exchangers.

Pre-August 2013 corrosion was taking place but at a much lower rate. Considering the volume of water being condensed in the exchangers, a bulk water condensation mech-
anism was taking place (that is, a high proportion of the water was condensing in the exchangers). Post-August 2013, there was a distinct shift in the volume of water being condensed. The points highlighted in the graph are not zero values but rather days where the calculated volume of water being condensed was <100 kg/day. In conclusion, there had been a change from bulk water condensation to a more localised water condensation regime.

If water is present through a localised or shock condensation mechanism, the liquid water readily absorbs HCl from the overhead vapour, leading to low pH conditions. Additionally, because the bulk vapour temperature is above the dewpoint, localised water accumulations can boil away leaving behind corrosion byproducts and/or salts that have formed in the water film. Many of these salts and corrosion byproducts are hygroscopic and absorb water under these conditions. The result is that an effective electrolyte is created where water does not exist and corrosion can continue.

While a chemical corrosion control programme is designed to mitigate corrosion where bulk water condensation is taking place, it is well documented that instances of localised water condensation are difficult to treat successfully.1 Much of the HCl will dissolve into a localised accumulation of water but a little of the ammonia or neutralising amine does not partition into the water phase at these elevated temperatures due to their vapour/liquid equilibrium. This results in the formation of a water phase at a pH significantly lower than it would otherwise be if the bulk of the water had condensed.

Hence, a change in the water condensation regime is the most likely cause for increased rates of corrosion.

**Conclusion**

Permasense sensors placed in areas that had previously experienced corrosion damage were used to monitor online corrosion damage in a crude overhead system. These sensors identified a significant step change in corrosion rates in the overhead system. A step change in corrosion rate occurred in two exchangers of the overhead system at the same time. From the initial review of the process and analytical data, the root causes for this step change were not evident and this prompted Nalco Champion to work with the refiner to identify the root cause.

By using advanced computer modelling that is able to simulate the overhead system utilising historical process data, Nalco Champion was able to calculate changes in key process parameters that contributed to the corrosion mechanism.
These techniques can also be used on a continuing basis to highlight changes in overhead conditions conducive to elevated rates of corrosion and allow the refiner to take mitigating action, optimising process conditions in order to avoid prolonged periods of corrosion.

References
1 NACE International Publication 34109, Crude Distillation Unit — Distillation Tower Overhead System Corrosion.

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