Paper No. 11851

Failure Analyses: In Retrospect

Nurul Asni Mohamed
PETRONAS Group Technical Solutions
asnimo@petronas.com

Co-authors: Norhariti Hassan and Naimah Azizan
Malaysian Refining Company Sdn Bhd (MRCSB)

ABSTRACT

During a failure analysis assessment, the cause of corrosion is ascertained to enable the assignment of corrosion monitoring and mitigations. This paper aims to revisit past failure analyses to validate the damage mechanisms of hydrocracker reactor effluent airfin cooler (REAC) tubes, sour water stripper reboiler tubes and lubricant plant VDU feed bottoms pump-around exchanger tubes leading to loss of containments. The hydrocracker reactor effluent airfin cooler tubes were upgraded to duplex stainless steel for mitigation against ammonium bisulphide corrosion. The exchangers were found to be leaking upon starting up. Root cause of the leaks was attributed to Sulphide Stress Corrosion Cracking due to high hardness of the tube-to-tubesheet weldments. Sour water stripper reboiler is still considered as a corrosion bad actor for the refinery. Various metallurgy upgrades were applied but premature corrosion due to departure from nucleate boiling condition still manifested. The lubricant plant VDU feed bottoms pump-around exchanger tubes were found to display localised corrosion on the tubes external surface. The material of construction for the tubes, TP 316, was found to still be susceptible to Naphthenic Acid Corrosion.

Mitigation against corrosion usually employs the path of least cost in regards to capital expenditures. Hence, corrosion monitoring will be enhanced and inspection frequency will be shortened, where possible. In ensuring adequate attention is given to any particular equipment, a Corrosion Bad Actor list or also known as Critical Asset Integrity list can be compiled for prioritisation of efforts.

Keywords: hydrocracker, sour water treating unit, lubricant unit, sulphide stress cracking (SSC), departure from nucleate boiling corrosion and naphthenic acid corrosion (NAC).

CASE STUDY 1 (HYDROCRACKER REAC)

The hydrocracker unit receives feed from vacuum gas oil from the crude unit and uses hydrogen and catalyst under high pressure and high temperature conditions to produce naphtha, kerosene and diesel. The byproducts of this reaction are ammonia (NH_3) and hydrogen sulphide (H_2S) which are unwanted. Ammonia and hydrogen sulphide combines to form ammonium bisulphide (NH_4HS) salts upon cooling in the reactor effluent air-fin cooler (REAC). Continuous water wash is employed to ensure that fouling does not occur in the REAC tubes. Care must be taken to ensure adequate amount of water is injected to dissolve the salts. Insufficient water can lead to aggressive ammonium bisulphide corrosion as the salts are hygroscopic. Excessive water can lead to erosion corrosion of tube ends as well as elbows of the REAC outlet piping. Figure 1 depicts a simplified process diagram of the hydrocracker REAC system.

The hydrocracker reactor effluent air-fin cooler tubes were upgraded from carbon steel to duplex stainless steel type UNS31803 (22% Cr, 5.5% Ni) or commonly known as DSS 2205. This is to mitigate the effects from ammonium bisulphide corrosion. The REACs are designed for a fluid velocity of between 4.3 m/s and 6.0 m/s at a pressure of 186.4 kg/cm^2, an inlet temperature of 192^{0}C and outlet temperature of 60^{0}C.

During the commissioning of the DSS 2205 in 2002, leak of one air-fin cooler bundle was detected along with the smell of H_2S. Snoop or bubble leak test was performed and leaks were observed to have occurred at various tube to tube sheet welds of all four REAC tube bundles. A detailed root cause failure analysis was conducted with tube samples sent to a third party failure analysis laboratory in the UK. The results revealed that the tube to tubesheet weldments failed due to sulphide stress cracking (SSC) which occurred during the introduction of H_2S containing hydrocarbon gas along with the presence of water.

Dye Penetrant tests were carried out on 237 welds chosen randomly from the four REACs tube to tubesheet welds. 64% were found to exhibit cracks from examples seen from Figure 2. Scanning Electron Microscopy of the fracture surfaces revealed straight angular cracks with no evidence of oxidation. Fracture surfaces indicated mainly brittle fracture regime, with a number of interconnected local defects forming the final fracture surface. See Figure 3 for transgranular cracking observed. No link was found between cracking propensity and hardness as only one sample had hardness value recorded slightly above the specified limit of 310 HV.

Ferrite checks using image analysis found local ferrite volume fraction to be in the range of 82–86% at areas where cracks have been found although ferrite count at other areas averages between 45 – 65%. The fabrication specification required ferrite count to be below 60%. The high ferrite volume fractions were observed mainly at the locations of welds start/stop, considering that it was a two-pass weldment. Hot cracking from fabrication was excluded due to the fact that cracking was primarily transgranular, with no evidence of low melting films at the grain boundaries. At the point of the investigation conclusion, the principal causes of the observed failures were the initiation of Sulphide Stress Cracking at the weld surface, due to the limited tolerance of the localised ferrite content of the tube to tubesheet weldments of DSS 2205 to the process environment.

Repair was carried out via enhancement of the weldment procedure and testing of the mock up welds. Stringent checks were carried out during re-fabrication to ensure the application of minimum preheat temperature of 10^0C, maximum interpass temperature not exceeding 150^0C and that the start/stop of the weldments for the second weldment pass do not end at the same point.

Revisiting this case study, the REACs have been in service since 2003 installation with no other leak incidences reported. The latest tube to tubesheet weldments can be observed from the 2015 turnaround inspection in Figure 4. Corrosion monitoring involves the monitoring of ammonium bisulphide concentration via trending of sulphur and nitrogen in the feed to the hydrocracker unit. The ammonium bisulphide limit is set to less than 8 wt% for DSS 2205 and considering the outlet piping has also been upgraded to Alloy 825. Continuous water wash is applied to dissolve the ammonium bisulphide salts and the amount of water injected is also one of the Integrity Operating Window (IOW) parameter that is closely monitored. API RP 932-B provides an excellent reference for design and corrosion control for REAC system.

CASE STUDY 2 (SOUR WATER STRIPPER REBOILER)

The sour water treating unit treats the sour water streams produced by processes within the sour train refinery. Sour water contains dissolved NH_3, H_2S and phenols. These contaminants are removed from the sour water in two trains where each train incorporates a single stripping column. The heating in the column is provided by the sour water stripper reboiler. The sour gas stream containing the separated contaminants is directed to the sulphur recovery unit. The stripped water is reused within other process units in the refinery, mainly the crude desalter whilst the balance is discharged to the refinery effluent treatment system. Figure 5 shows a simplified diagram of the sour water stripper column and sour water stripper reboiler.

The sour water stripper reboiler operating conditions are as follows:

Shellside Medium	Sour Water
Shellside Operating Temperature (^{0}C)	130
Shellside Operating Pressure (kg/cm^{2}g)	1.8
Shell Metallurgy	Carbon Steel
Tubeside Medium	Medium Pressure Steam
Tubeside Operating Temperature (^{0}C)	181
Tubeside Operating Pressure (kg/cm^{2}g)	11.3

Since its commissioning in 1998, there have been various metallurgy change to the reboiler tubes due to excessive corrosion observed:

1998	Reboiler commissioned. Material SS 304L
1999	Material changed to SS 316L
2002	Material changed to DSS 2205
2006	Material changed to Carbon Steel (SA 179)
2007	Time based replacement with Killed Carbon Steel (thicker thickness: 3.04 mm) every 9 months before leak occurs.

During the earlier stages of analyses for material upgrade to DSS 2205, the initial thought on the cause of failure was the concentration of chlorides as sour water from the crude unit contained quite a substantial amount of chlorides from the crude unit overhead. DSS 2205 can be susceptible to chloride stress corrosion cracking at 140^0C with chloride level of 230 ppm. However, DSS 2205 tubes only managed to last for about four years before leaks were detected. It was then decided for a time based replacements of carbon steel tubes every 6 to 9 months.

Typical inspection findings for the carbon steel tubes as shown in Figure 6, would record that the upper and bend portions revealed relatively severe corrosion wastage around the circumference while the lower portion appeared relatively unaffected with a uniform thin layer of blackish scale/deposits. Cracks were also observed in the upper portion of the tubes. The internal surfaces of the tubes were generally satisfactory, with no significant signs of corrosion. Analyses of the corroded surface did not reveal much in terms of contaminants, probably because leaks from tubeside containing steam could probably have washed away any evidence. Therefore, sour water samples were taken for analyses and test results noted presence of cyanide in the amount of 2.3 mg/L and chlorides 24 mg/L.

Further investigations revealed that the top row tubes that underwent aggressive corrosion because they were exposed to wet/dry condition from the presence of vapour space in the reboiler. Various tube metallurgies corroded due to the condition known as departure from nucleate boiling where chlorides present in the sour water at lower temperature could be manageable but becomes highly concentrated upon boiling at the tubeskin surface where Medium Pressure steam is the fluid, operating at 181^0C. The concentrated chlorides also led to Chloride Stress Corrosion Cracking (CLSCC) of SS 316 and DSS 2205. The non-aged damage from CLSCC made it more challenging with the use of stainless steels.

For the killed carbon steel tube thickness of 3.04 mm, the corrosion rate varied between 2.4 to 3.7 mm/y. Previous checking of tube bundle condition at 6^{th}, 7^{th} or 8^{th} month in service did not exhibit any leaks. Therefore, a decision was made to replace the carbon steel bundles on time-based. It would be highly challenging to find a material that will meet the service requirement as well as providing a low Return on Investment (ROI).

In resolving this corrosion issue, among the main mitigation involves changing the reboiler design from a horizontal type to a vertical thermosyphon. This will require substantial work as it would involve upgrading of the stripper column internals along with the interconnecting piping. Fast-forward to 2017, a project is currently underway to revisit this redesign initiative. A more recent refinery has already incorporated this experience and designed its sour water stripper reboiler as a vertical thermosyphon. It will be commissioned in 2019.

CASE STUDY 3 (LUBRICANT PLANT VACUUM DISTILLATION UNIT (VDU) FEED/BPA EXCHANGER)

The Lubricant plant processes atmospheric residue from the crude unit distillation column. The atmospheric residue is fed to the vacuum distillation unit of the Lubricant plant to produce light, medium and heavy distillates as feedstocks to the Hydrotreating/Selective Catalytic Dewaxing (HDT/MSDW) unit. The light and medium distillates are blended together in the intermediate tank. The heavy distillate feedstock is sent to the intermediate tank and finally to the HDT/MSDW unit.

The vacuum residue is sent to the delayed coker unit for further processing. Figure 7 represents a simplified process flow diagram of the VDU Feed/Bottom Pumparound (Feed/BPA) exchanger.

The VDU Feed/BPA exchanger operating conditions are as follows:

Shellside Medium	Bottom Pumparound (or V3SS)
Shellside Operating Temperature In/Out (^{0}C)	318/262
Shellside Operating Pressure (kg/cm^{2}g)	10.5
Shell Metallurgy	SA 240 Gr 316L (SS 316L)
Tubeside Medium	Atmospheric Residue
Tubeside Operating Temperature In/Out (^{0}C)	213/296
Tubeside Operating Pressure (kg/cm^{2}g)	14.3
Tube Metallurgy	SA 213 TP 316L (SS 316L)

The Lubricant plant was commissioned in 2009. In 2010, during the warranty shutdown, the VDU Feed/BPA exchanger external tubes were discovered to exhibit localised crater-like corrosion attack (refer Figure 8). The nominal tube thickness was 2.03 mm. There was no leak reported of this exchanger. However, a maximum wall loss of 70% was recorded from eddy current testing data. This led to a calculated corrosion rate of 1.4 mm/y, assuming a constant wall loss over the service period of about one year. Opportunity inspection in 2012 and turnaround in 2015 did not find the corrosion to be aggravated.

Tube samples were retrieved and sent for analysis. Results of the crater area did not reveal any contaminants or expected corrosive species like chlorides. Micrograph of the crater area is shown in Figure 9. Micro-pits were observed with branching transgranular micro-cracks. The BPA service is expected to contain some naphthenic acid species and Total Acid Number (TAN) limit has been set to less than 1.5 mgKOH/g. The monitoring of TAN as an IOW parameter has always been below the limit. Another point that was highlighted from the failure analysis was that the molybdenum content at area of localised corrosion was 2.16 wt%. This is considered to be within the acceptable limit for SS 316L where molybdenum content is specified between 2-3 wt%. Nevertheless, the amount of molybdenum required for mitigation against naphthenic acid corrosion is 2.5 wt%.

The most probable damage mechanism that can be drawn from this analysis is naphthenic acid corrosion despite the lower TAN value. Corrosion due to chlorides has been ruled out due to the high temperature of the BPA which falls within the naphthenic acid corrosion range of 220 to 400^{0}C. The cause of the micro-cracks remains to be determined. Analysis of chlorides in the BPA stream has been included in order to understand the possible effects of chloride presence to the tube external. No other equipment in within this corrosion group has exhibited such localised attack.

IOW monitoring of TAN is still being implemented (refer Figure 10). Any future upgrade of metallurgy to SS 317 for mitigation of naphthenic acid corrosion depends on the findings during the next planned inspection in 2019.

CORROSION BAD ACTORS

To manage the occurrences of leaks due to corrosion in the refinery, a guideline document was developed for a systematic listing of problematic equipment and piping known as Corrosion Bad Actors or recently renamed to Top 15 Critical Asset Integrity list which will enable the prioritization of efforts through a more focused and effective approach in solving recurring issues. The list can be ten, fifteen or fifty, depending on the efficiency of tracking and solving of items.

Ten criteria were identified for Critical Assets screening:

1. Consequence of Failure (CoF) – causing unit shutdown or throughput reduction;
2. Probability of Failure (PoF) – where the corrosion rate > 2 times the design corrosion rate;
3. Remaining Life < 2 turnaround cycles;
4. Experience leak/failure;
5. High RBI Criticality;
6. Repetitive or prolonged IOW excursions;
7. Repetitive or prolonged hot/cold spots;
8. Unreliable injection systems e.g. CI efficiency less than design;
9. Tank corrosion;
10. Cathodic protection system with protection levels of more positive than -0.850 V or -850 mV.

Four elements were used to determine the score for ranking determination. They are RBI criticality, remaining life, corrosion rate and whether the failure would lead to a plant shutdown or otherwise. Series of scores were given based on internal discussions and best practices applied. Item with the highest calculated points would be ranked highest. This ranking is used in combination with periodic inspection plan and IOW performance monitoring for inspection prioritization activities.

CONCLUSIONS

From the case studies shared, it can be summarised that analyses and conclusions made were correct based on the available information at the point in time. It would be recommended for facilities to revisit past root cause failure analyses findings to make sure that the decisions still stand firm. Sometimes, recently available information from research or others' experiences may shed new light on the issues and could probably bring about a different mitigation. In the effort of going digital and realising the vision to be the Refinery of the Future, some initiatives have been implemented such as the automated warning email to the respective identified parties in the event of IOW parameter excursions as seen in Figure 11. This effort has allowed faster response time to address any negative deviations of IOW limits set.

ACKNOWLEDGMENTS

The authors would like to acknowledge the support of Nursyazwani Ramli from MRCSB for the assistance in providing data as well as the management of MRCSB for the information shared.

REFERENCES

1. Internal RCFA report on Hydrocracker REAC, 2003.
2. Internal RCFA report on Sour Water Stripper Reboiler, 2006.
3. Internal RCFA report on Lubricant Plant VDU Feed/Bottom Pumparound Exchanger, 2010.
4. API Recommended Practice 571 Damage Mechanisms Affecting Fixed Equipment in the Refining Industry, 2011.
5. API Recommended Practice 932-B Design, Materials, Fabrication, Operation, and Inspection Guidelines for Corrosion Control in Hydroprocessing Reactor Effluent Air Cooler (REAC) Systems, 2012.
6. API Recommended Practice 584 Integrity Operating Window, May 2014.
7. M.J. Nugent, J.D. Dobis, “Experience with Naphthenic Acid Corrosion in Low TAN Crudes”, NACE Paper No. 98577.
8. H.D. Drettman, N.Li, D. Wickramasinghe, Z. Xu, X.N. Chen, G.R.D. Elliot, J. Luo, “The Influence of Naphthenic Acid and Sulfur Compound Structure on the Global Crude Corrosivity under Vacuum Distillation Conditions”, NACE Paper C2012-0001326.
9. G.I.D. Poveda, N. E.M. Cajca, E.A. Morantes, D.Y.P. Ballesteros, “Sulfidation and Naphthenic Acid Corrosion of UNS S31803, UNS S31703 and UNS S44400 Series Stainless Steel in Crude Processing”, NACE Paper No. 2513 (2013).
10. B.D.Craig, L. Smith, “Corrosion Resistant Alloys (CRA) in the oil and gas industry – selection guidelines update”, Nickel Institute Technical Series No. 10073, 3rd Edition, September 2011.

FIGURES

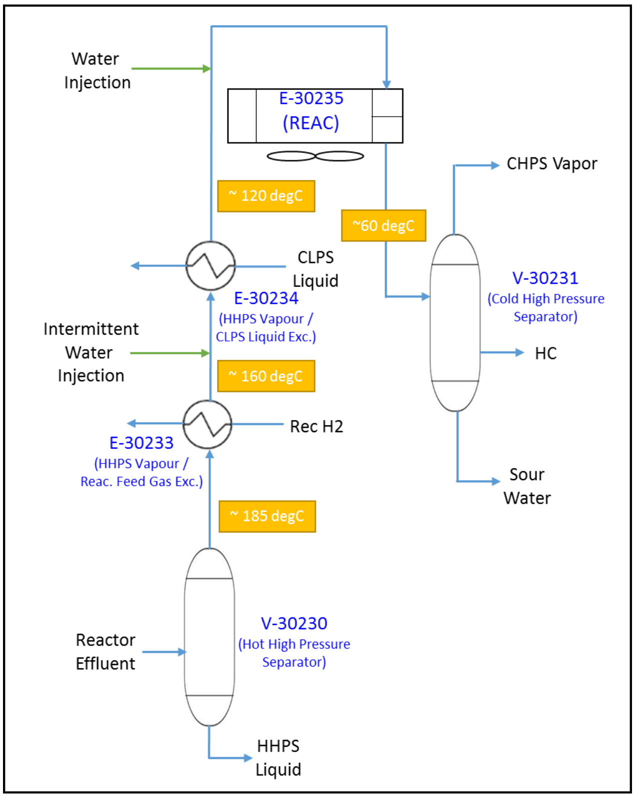

Figure 1 Simplified process flow diagram of the REAC system

Figure 2 Dye penetrant results on the DSS 2205 tube to tubesheet welds

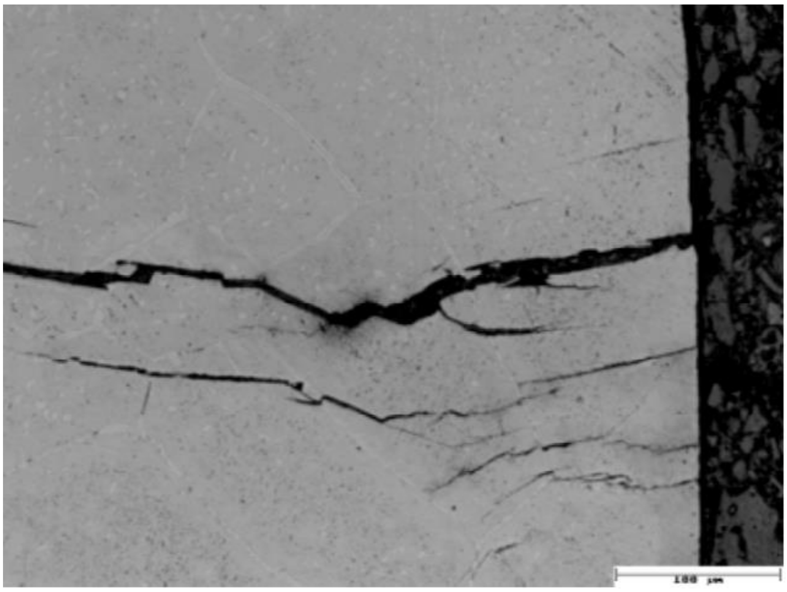

Figure 3 Transgranular cracking (cracking through the grains) from SEM

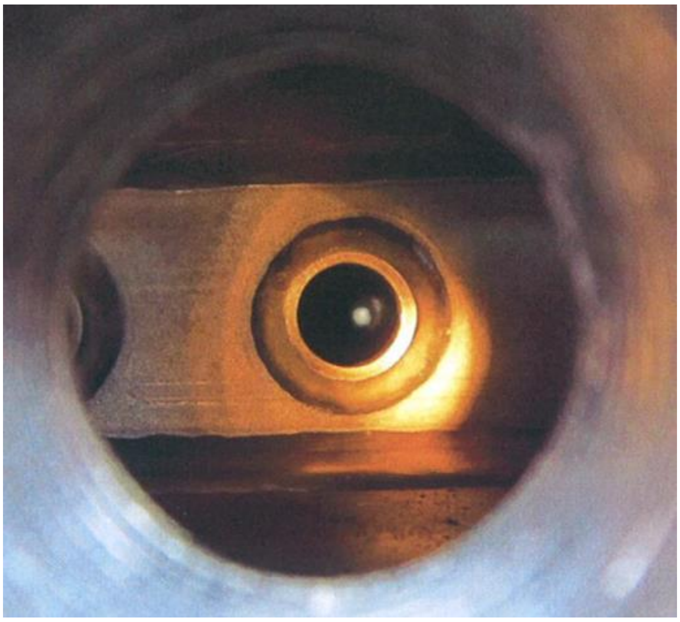

Figure 4 Latest turnaround photo of REAC tube to tubesheet weld in 2015

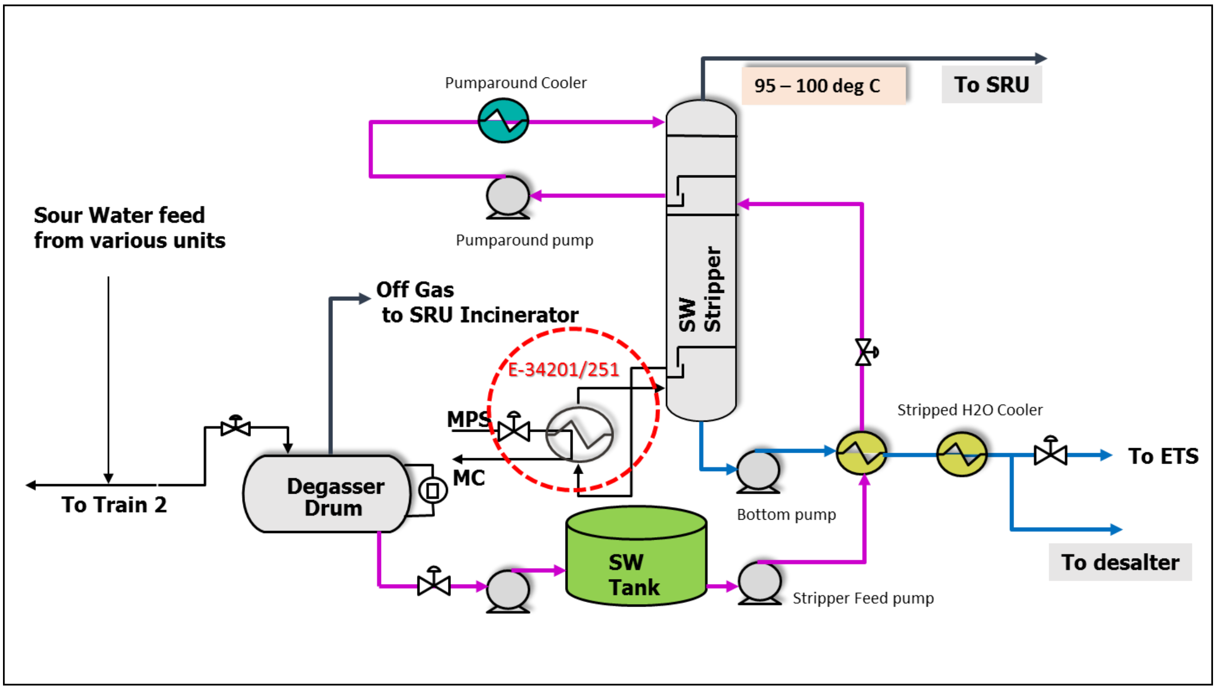

Figure 5 Simplified diagram of the sour water stripper column and sour water stripper reboiler

Figure 6 Sour water stripper reboiler (carbon steel) top row tubes (left) and bottom row tubes (right)

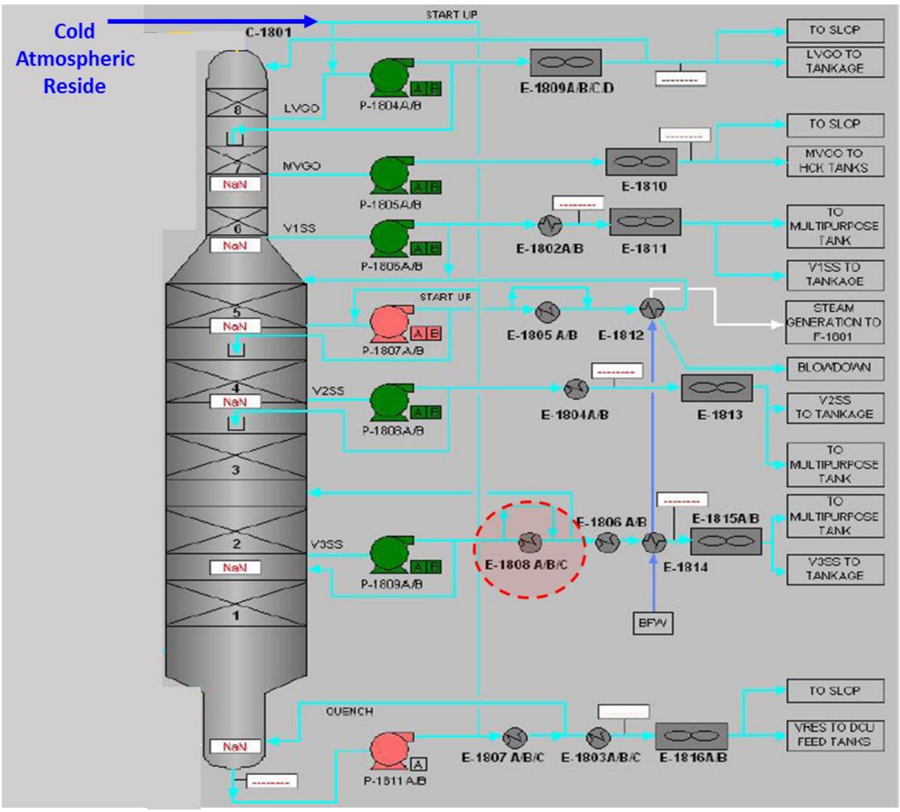

Figure 7 Simplified process flow diagram of Lubricant Plant VDU (showing feed/bottom pumparound exchanger)

Figure 8 Several localised corrosion attack observed on Feed/BPA exchanger tube external as shown in the left picture and close up shown in the right picture.

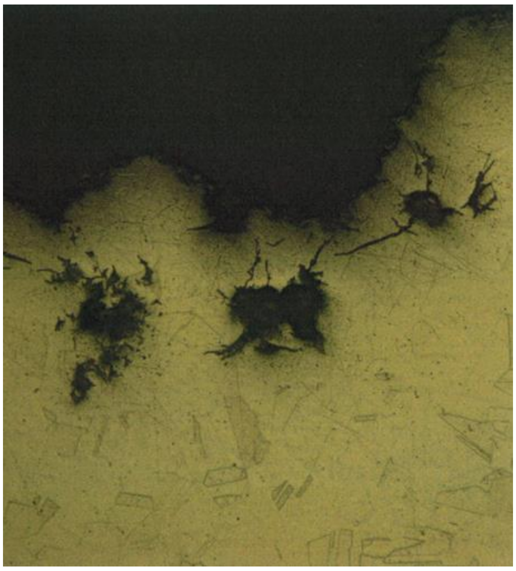

Figure 9 Micrographs of crater showing micro-pits with branching of transgranular cracks (magnification x200)

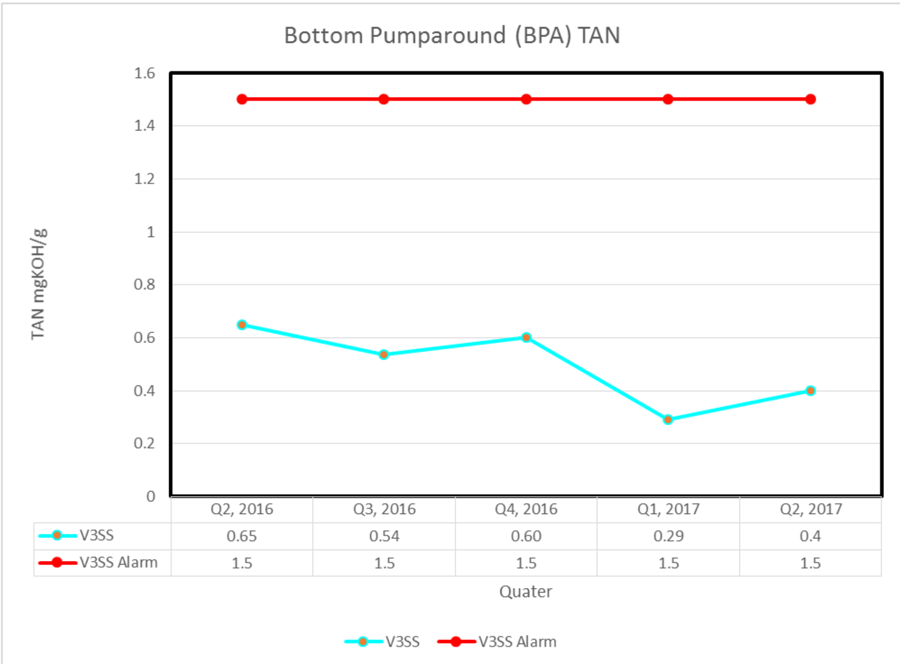

Figure 10 Botttom Pumparound TAN monitoring

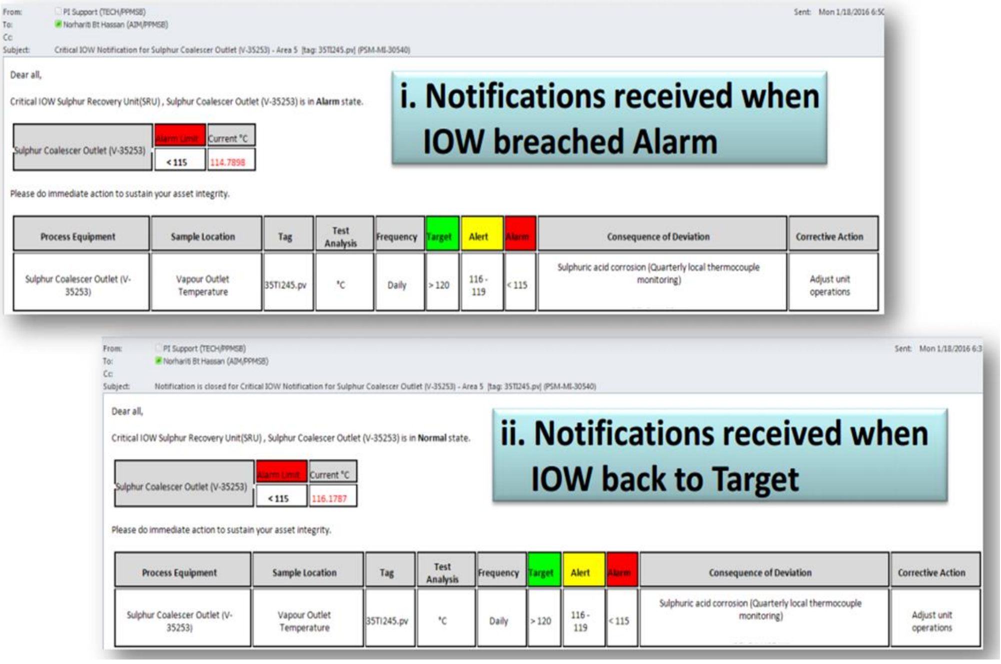

Figure 11 Automatic email notifications during IOW excursions and corrective actions