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Severe Under-deposit Corrosion Damage in Suction Headers of Compressor House in LPG Recovery Unit

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ABSTRACT

Corrosion plays a vital role in the petrochemical industries because of several factors, but it is mainly dependent on process parameters, equipment design, piping layout, metallurgy of the used component, and finally the age of the plant. At the same time, impact of corrosion severely impairs the economy and profitability of the plant. This paper deals with the corrosion mechanism due to sour water acid corrosion in the presence of coke fines deposits in the suction header of the compressor house in the LPG Recovery Unit (LRU); its damaging effect is also a major concern. Failures due to under deposit corrosion and sour water acid corrosion have also been reported worldwide in petrochemical industries. An attempt was made to investigate the cause and effect analysis by optimizing the critical design process along with its operating parameters and using better material selection. To facilitate the investigation process, analysis of collected deposits, failed equipment inspection, inspection history and process data /trends were carried out. This paper also highlights the possibility of design changes with respect to the knock out drum and its demister pad upstream of the compressor, in order to minimize the coke fines and moisture carry over along with process fluid in the suction headers, thereby leading to prevention of the corrosive effect in the inlet circuit of compressor house. The proposed remedial measures will be beneficial to improve the reliability and integrity of the compressor house and hence LRU.

Keywords: Sour water, compressor, LRU, Under deposit

INTRODUCTION

Sour water acid corrosion due to H_2S in process streams is very common in the fluidized catalytic cracking (FCC) unit. As a result, general thinning and localized corrosion, or localized under deposit attack in some instances can take place, which leads to unwanted unit interruptions.

The corrosion problem due to sour water acid in overhead systems has been widely reported and discussed for the FCC unit. Sour water acid corrosion in the delayed coker unit (DCU) is also experienced at many refinery installations. Process fluid with high H_2S are subjected to sour water acid corrosion at temperatures up to approximately 60^0C and pH up to 4.5. This damage mechanism is attributed for general as well as pitting corrosion and it is based on H_2S content, pH and temperature. Under lesser acidic conditions, a protective layer of iron sulfide limits the corrosion. But under some instances, a thick porous layer of iron sulfide can form that promotes under-deposit corrosion.

In DCU and LRU units, coke-fines carrying along with the process stream is very common. The volume of fines can increase with process changes. These coke fines can deposit in horizontal portions of piping or equipment operating at low pressure over time. Initially, coke deposits are dry, but become wet and very corrosive leading to under deposit corrosion in the presence of moisture because of its hygroscopic nature. If this deposition is not prevented well in time by proper monitoring, the deposits can cause plugging along with under deposit corrosion.

The combined impact of the above two damage mechanisms can be severe corrosion characterized by general or localized corrosion in the form of pitting attack under the coke fines deposit in the affected system, and resulting in metal loss up to 2-3 mm per year.

The best way to investigate and inspect this type of corrosion depends on the result of previous inspections, process stream data and experience in the refining industry. This corrosion damage investigation in the compressor house of the LRU is based on the study of the nature of failure, failure location, and morphology of corroded surfaces, process parameters and chemical analysis of sample deposits. This paper describes the causes of the corrosion, and the preventive measures proposed to avoid such occurrences in the future, thereby enhancing the smooth operation and reliability of the plant. The study showed that the failure was aggravated due to presence of coke fines carrying in the process stream.

BACKGROUND INFORMATION

The LRU unit at Guwahati Refinery has been set up for LPG recovery from off gas of the crude distillation unit (CDU) and DCU, Figure 1. In the LPG Recovery unit, off gas from the reflux vessel of the MF column passes through the 1st stage knock drum and strainer and compressed in the low pressure (LP) compressor. Compressed gas cools down in the inter stage cooler and subsequently passes through the 2nd stage knock out drum followed by the strainer. It is then compressed in the 2nd stage pressure (HP) compressor, and the final compressed gas is further processed in the rectifier and absorber column for LPG recovery. *(Ref: 3)*

Severe thinning, i.e., thickness near to failure in the compressor header was observed during the M&I shutdown. However, this is the first time such corrosion occurred in the last 20 years of operation of the line circuit.

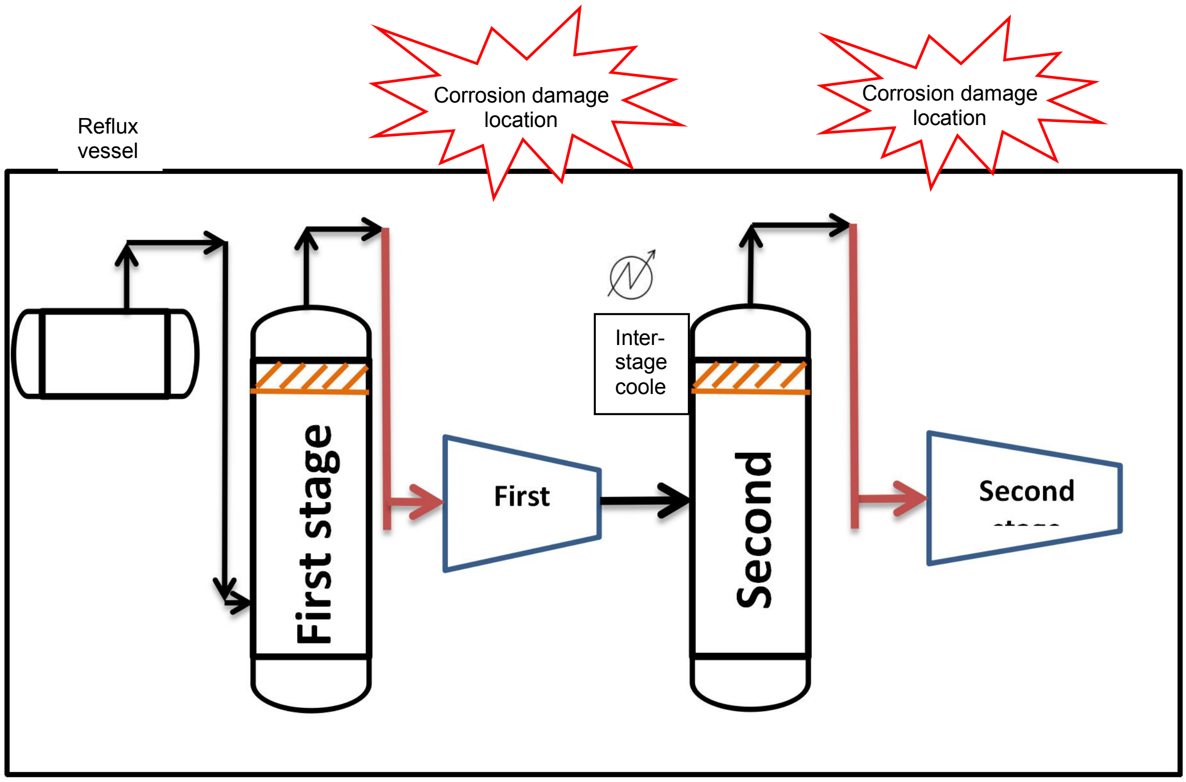

Figure 1: Process flow diagram of suction headers in compressor house in LPG Recovery Unit

PROCESS PARAMETER

Coker off gas is design to have H_2S 0.55 wt%. After passing to KOD, all water of process stream gets removed and at 1 kg/cm2 suction pressure and approx 50^{0}C temperature, it goes to 1st stage compressor followed by 2nd stage compressor. A comparison of different design and operating/observed parameters is tabulated below:

Stream Name	**Coker off gas**	
	Design Data	**Observed Data**
Hydrogen Sulphide	0.551 Wt.%	*Avg 1.8/Max 4.8* Wt.%
Water	0.001 Wt.%	*No analysis done*
Operating Pressure 1st Stage Suction	2.0 kg/cm^2	*0.4-1.2* kg/cm^2
1st Stage Suction/Discharge Temperature	50/120°C	*40/110*°C
2nd Stage Suction/Discharge Temperature	50/90 °C	*40/95*°C

Pipe materials: SA 106 Gr B (Carbon Steel)
Corrosion Allowance: 1.5 mm

PROBLEM

Thinning in the LRU compressor suction headers (12” dia. and 10” dia. lines, Figure 2) was observed between a span of approx. three years 2013 to 2016 during process change. General corrosion was observed throughout the internal surface with severe metal loss noticed at the 6 o’clock location of both the suction headers. The amount of damage was found less severe in the suction piping of the 2nd stage compressor. Corrosion was observed to be aggravated due to under deposit corrosion arising from coke fines deposition.

Since commissioning in 1994, no such case of severe thinning had been experienced in the unit. In-house investigation for the corrosion was carried out and remedial measures were suggested for mitigating the problem.

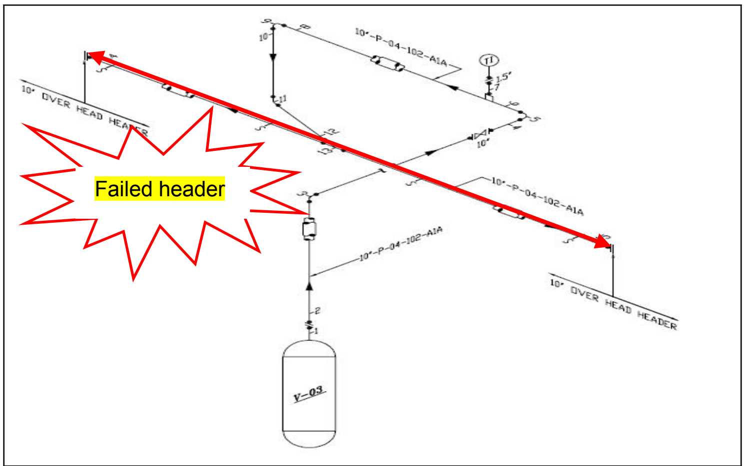

Figure 2:Isometric diagram of failed location

INVESTIGATION AND RESULTS

Visual Inspection (Figures 3-6)

After cutting the header, lumps of black color moist coke fine deposit were observed in both the suction headers, which is in the horizontal section of the circuit. Volume of deposits was less in the 2nd stage header (Figure 3, 4). The deposits were cleaned by water jets, and it was found that the deposits were highly soluble in nature.

Figure 3: Deposits in1st stage suction header

Figure 4: Deposits in1st stage suction header

A sample of the damaged pipe piece was split for internal inspection. The internal surface of the pipe was found severely rusted (Figure 5). General corrosion and pitting were observed throughout the internal surface with severe metal loss noticed at the 6 o'clock location of both the suction headers. Pitting depth was approx. 1.5 to 2.0 mm (Figure 6). Minor corrosion was observed in the upper half section.

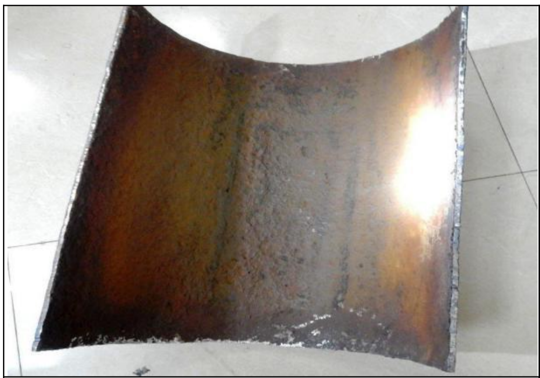

Figure 5: Split half portion of corroded pipe

Figure 6: Close view of corroded surface

Chemical Composition Analysis of Deposit Material

Chemical analysis of the deposit sample was carried out by analytical titration. Following is the result:

Solubility:	Partially Soluble in water
pH of solution(1wt%)	4.3
H_2S (content reflective of S)	2.1 wt %
Iron (Fe)	4.2%

Thickness Measurement

Ultrasonic thickness gauging of the circuit was carried out. Severe thickness loss was noticed in the 3 to 7 o'clock section of the header. No major appreciable metal loss was observed in the vertical/branch connections of the header. No appreciable thickness loss was observed in the discharge headers also.

Annual thickness trending was done to calculate short term corrosion rates. It was found that during 2012 to 2016 over all thickness loss in the header was up to 4 mm.

Graphical Analysis of Data

Different process data, i.e., H_2S in process fluid, suction pressure of the compressor, throughput, process fluid flow rate, report of sample analyses were collected for the period and comparative graphs were drawn for H_2S in process fluid, suction pressure, and process flow rate over the time duration. The objective of making these graphs was to establish the relation between process changes and condition promoting corrosion damage.

Figure 7: H_2S level in process fluid vs. Time

Figure 7 depicts that against the design limit of 0.5% H_2S in the process fluid, the system had been operated with up to 4 wt% of H_2S over the time period. High H_2S favors the corrosion mechanism taking place in the system.

Figure 8: Suction presser vs. Time

Figure 8 shows that the compressor had been operated at low suction pressures up to 0.4 kg/cm^2 versus the general recommended suction pressure of ~1.0 kg/cm^2. Low suction pressure operation resulted in operation of the unit at high throughput.

Figure 9: Flow rate vs. Time

Figure 9 describes that; unit was operated with flow rates up to 6200 kg/hr against the design capacity of 4400 kg/hr. This high flow was favorable for carryover of extra moisture and coke fines.

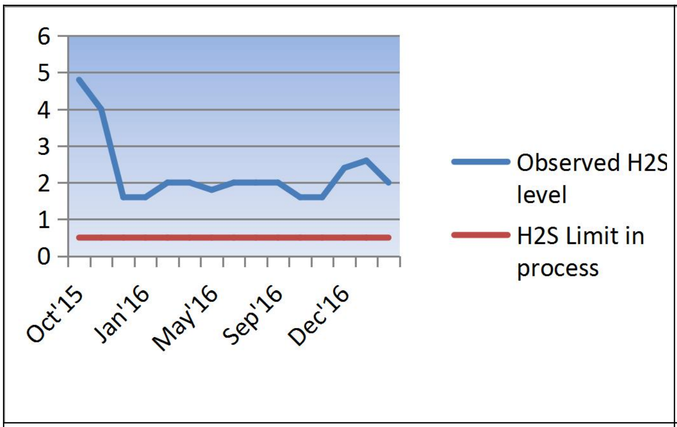

Figure 7: H_2S (wt %) Vs Time

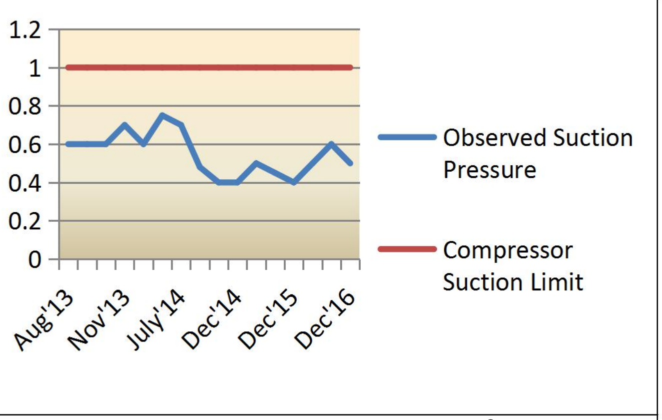

Figure 8: Suction pressure (kg/cm^2) Vs Time

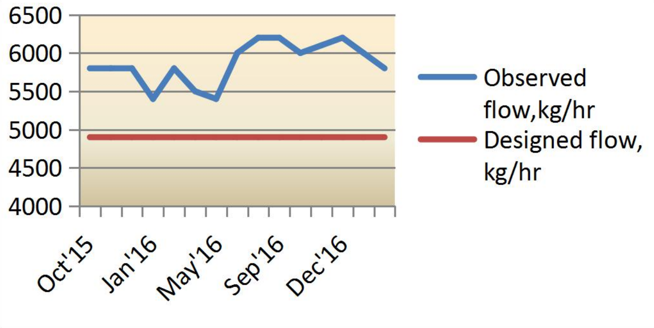

Figure 9: Flow rate (kg/hr) Vs Time

DISCUSSION

The feed of LRU, i.e. Off gas, is designed to have a maximum limit of 0.5 wt% of H_2S whereas Figure 7 revealed a higher limit of H_2S up to 4.8 wt%. The compressor of the unit was operated at a low suction pressure 0.4 kg/cm^2 (Figure 8) to maximize the process flow and increase the LPG production. The unit was operated with a flow rate up to 6,200kg/hr. Moisture separation near to 100% from the stream is designed to be carried out in the KOD vessel with the help of a demister pad for a process flow rate 4,400kg/hr. Higher flow (Figure 8) led to extra moisture and coke fines carryover with the stream. Coke fines carried with the fluid kept on accumulating and depositing in the horizontal portion of the circuit, i.e., the headers. Coke fines were observed in the 2nd stage headers also but to a lesser amount due to the use of a strainer, but of lower mesh size.

H_2S of the fluid in the presence of moisture at temperatures of 40-50^{0}C resulted in sour water acid corrosion of the piping with the characteristic of general corrosion. The corrosion was aggravated due to coke fines deposits in the headers with the characteristic of severe under deposit pitting corrosion.

High concentration of H_2S tends to increases the acidity of the solution. With higher temperature, concentration of H_2S decreases and hence the acidity of solution. At pH value 4.5 or more, a thicker porous sulfide film layer forms *(Refer: 2)* which lead to under deposit pitting corrosion, which is further multiplied by hygroscopic coke deposits.

No such corrosion was noticed in the legs of header due to no deposition because of vertical installation. Vertical installation will be having minimum deposition of coke fines. In the discharge header no corrosion was observed because the operating temperature is higher in the range of 110-120^{0}C.

For better understanding of the corrosion mechanism with different affecting factors, a corrosion triangle was made, Figure 10.

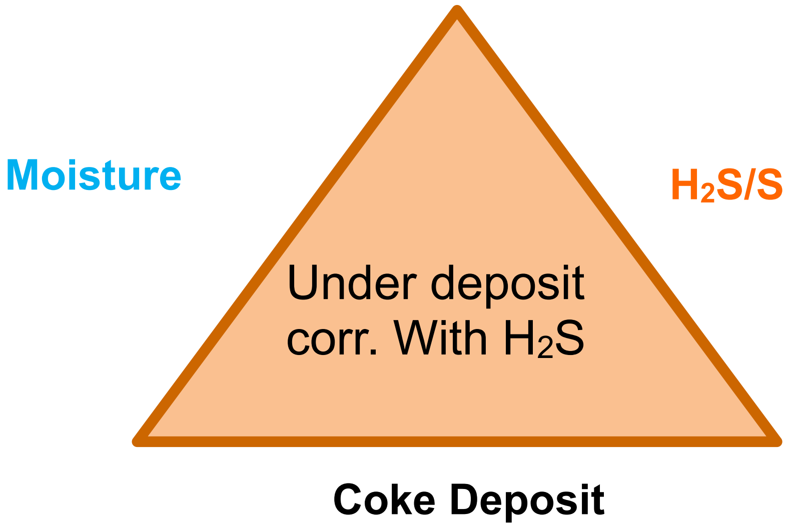

Figure 10: Corrosion Triangle

To prevent the moisture and coke fines carryover in the system, the stream flow should be maintained within designed limits, and the removal of the deposited coke at a fixed frequency is highly desirable.

CONCLUSION

Process data, graphs and wet analysis in the laboratory revealed that high H_2S of the system in the presence of moisture caused corrosion in the headers. Additionally, severe under deposit corrosion was facilitated due to favorable hygroscopic coke fines deposits coupled with favorable temperatures in the range of 40-50^{0}C. It is clear from the corrosion triangle that among the three conditions, preventing at least any one will minimize the damage impact.

Deposits flushing/washing in the system are an accepted practice to prevent the deposition. Had there been a provision of a flushing facility, the deposits could have been completely removed, thereby preventing the corrosion damage.

JOBS CARRIED OUT

As a short term measure, the corroded headers have been replaced with new ones with existing carbon steel metallurgy and put in service.

PROPOSED REMEDIAL MEASURES

Discuss internally the consequences of operating at much higher flow rates compared to design, and analyze the consequences. Implement required modifications.

1. Operate the unit within design pressure condition i.e. >0.75 kg/cm^2.
2. Maintain H_2S within design limit (0.5 wt %) although this is inevitable as presently there is no any facility of reducing H_2S in the stream.
3. Effectiveness of demister pad meeting with the high flow should be reviewed to ensure maximum elimination of moisture
4. Flush headers annually during the steam air decoking shutdown.

5. Monitor critical Corrosion Monitoring Locations (CMLs) with higher inspection frequency.
6. Metallurgy up-grade of suction header to SS 316 to accommodate process change.

ACKNOWLEDGMENT

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REFERENCES

1. ASME Handbook Volume 13.

2. API RP 571, “Damage Mechanisms Affecting Fixed equipment in the Refining Industry”

3. P & IDs of M/s Vaulter Engineering Services Pvt. Ltd. for DCU & LRU Unit, Guwahati Refinery.