Failure Analysis of Multi stages Centrifugal Naphtha Pump

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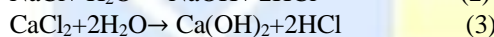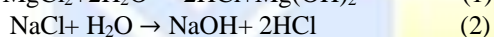
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Abstract: Failure analysis study was conducted on vertical centrifugal pump P-A which was used to pump naphtha from product distillate drum to coalesce. Visual inspection, lab tests, chemical treatment data history, and corrosion monitoring data collected from ER probes installed in the system were all assessed to determine the cause of the failure. The results revealed that the main cause of failure was due to acidic corrosion and the presence of 50 ppm H_2S in the product. Most of ER corrosion monitoring readings were moderately high. The fracture surface of failed impellers indicated the possibility of hydrogen embrittlement and stress cracking**.**

Index Terms - Corrosion, Multi stages pump, Sulfide Stress cracking, Naphtha, Crude Distillation unit, Desalter.

I. INTRODUCTION

Corrosion is described as a material's destruction or deterioration as a result of its reaction with its surroundings. During the processing of petroleum and natural gas, corrosion can occur at any location or at any time. It can be fast or slow. For instance, sensitized 18-8 stainless steel is badly attacked in hours by polythionic acid [1]. Corrosion in the hydrocarbon processing industry can be divided into two forms based on the presence or absence of water: "wet" and "dry." Wet corrosion is defined as corrosion that occurs at temperatures below the boiling or dew point of water. In reality, the maximum temperature for wet corrosion is around 232 °C (Source). Dissolved materials in the water essentially determine its corrosivity to plant equipment. The most important property of the water phase from the corrosion standpoint is pH. With some exceptions, most industrial corrosion in refineries is acid corrosion. For example, steel is very unstable in acids. In the absence of inhibitors, corrosion rates increase sharply as pH falls below neutrality. Hydrochloric acid is formed in refinery operation by thermal decomposition and hydrolysis of magnesium and calcium chlorides ($MgCl_2$, $CaCl_2$). hydrochloric acid vapour condensing with steam and corroding the steel condenser tubes, if these compositions weren't removed during the desalting process of the desalted, in the first processing unit in the refinery, the following reactions will occur.

$$MgCl_2 + 2H_2O \rightarrow 2HCl + Mg(OH)_2 \qquad (1)$$
$$NaCl + H_2O \rightarrow NaOH + 2HCl \qquad (2)$$
$$CaCl_2 + 2H_2O \rightarrow Ca(OH)_2 + 2HCl \qquad (3)$$

The function of the desalter is to reduce the content of bottom sediment and water (B.S. & W) from the crude charge to the crude distillation [2,3]. Expensive neutralizers, such as lime, calcium carbonate and soda ash, often cause scaling problems due to precipitation of insoluble hydroxides and/or carbonates of Mg and Ca. Ammonia is the most common neutralizing material because of its high neutralizing power, low unit cost, easy availability and convenience of handling. Despite the advantages of ammonia as a neutralizer, there are some drawbacks. When ammonia is added excessively beyond pH7, it becomes dangerous to copper alloys. Moreover, the formation of ammonium chloride deposits causes fouling problems. In general, it is more economical to reduce all or a portion of the acid content of treated stream with ammonia or other neutralizer and augment this by using a film forming inhibitor [4].

The oil industry is categorized into three main sections (a) upstream section, (b) mid-stream section and (c) downstream section. Each of these sections has its own task to fulfil their specific purposes. The upstream section of the oil and gas industry is engaged in drilling, exploration, and production. The mid-stream section is concerned with the movement of petroleum products, that is, transmission of the products through pipelines, product storage and marketing of the products. The downstream section is involved in the refining of the upstream products into finished product e.g. kerosene, petroleum, diesel, drugs, and paints [5]. Despite the compliance of the upstream section, oil industries are faced with severe corrosion challenges.

Corrosion of hidden parts, structures, and equipment in the oil industry, such as oil wells and pipelines, is largely influenced by conditions encountered in the operating environment. These parameters are high temperature, carbon dioxide (CO_2), hydrogen sulfides (H_2S), water (H_2O), flow velocity etc [6]. While carbon dioxide can cause severe corrosion (general and pitting) of steels, hydrogen sulphide (H_2S) corrosion is more localized and can result in Sulphide Stress Corrosion Cracking (SSC), Hydrogen Embrittlement (HE), Hydrogen Induced Cracking (HIC), or Stress Orientated Hydrogen Induced Cracking (SOHIC) (SOHIC). As a result, an increase in H_2S does not always imply an increase in general corrosion rate but rather lay susceptible materials prone to catastrophic failure [7].

The presence of hydrogen chloride vapor present as a result of salts hydrolysis in the atmospheric crude distillation unit causes corrosion in crude overhead systems. Corrosion can also be caused by sulfur compounds in oil refinery systems. To counteract the

acidic attack of condensed water containing HCl, a variety of solutions are employed, including neutralizing agents such as ammonia and organic amines, film-forming inhibitors, wash water systems, and fitted temperature control in the overhead circuit. Implementing one or more of these solutions should be done with caution, since they may cause fouling, under-deposit corrosion, and other issues.

II. CRUDE DISTILLATION PROCESS

Crude distillation overhead system helps in the separation of crude oil into fractions based on their different boiling points. It is the first production step in the refinery plant. Crude distillation system is described as the heart of any oil refinery which consist of the preheat train, a desalter, a pre-flash drum, a furnace, an atmospheric distillation column and vacuum distillation column. Crude oil is made up of hydrocarbons that are refined into various oil products by burning them in small chunks to remove the lighter hydrocarbons first, followed by the heavier hydrocarbons. This process undergoes high temperature to be able to break them into their various components.

III. P-A PUMP SYSTEM

P-A is a vertical centrifugal pump, P-103A, a multi-stage vertical centrifugal pump, contains 11 stages, which are part of the crude distillation section of Brega refinery plant. The impellers of the pumps were manufactured from cast-steel and are of the closed type categories. The first stage impeller has 3 blades (vanes) and has a right-hand rotation. The second to fifth stage impellers have 8 blades and a right-hand rotation, while the sixth to eleventh stage impellers have 8 blades and are of the left-hand rotation. Impellers are designed to spin at 3550 revolutions per minute. The discharge pressure is 406 psig while the intake pressure is 18 psig. The operating temperature is set at 125 °F. The working conditions and the pump specifications shown in Table 1.

Table 1 Working conditions and P-A pump specifications

Working conditions	
Discharge Pressure	406 psi g
In Take Pressure	18 psi g.
Operating Temperature	125 °F
Average PH Reading	4.8
P-A specifications	
Material	Cast steel
Position	vertical
Type	centrifugal
Number of Stages	11 stage
Designed Spin	3550 revolutions/minute
Life	In work since 2009 to 2014

This study was conducted in Sirte Oil Refinery, Brega, Libya. Its primary purpose is to reveal the main cause of failure in Pump P-A, a multi-stage centrifugal pump which is part of the crude distillation section of a refinery plant. The main function of P-A pumps is to transport naphtha from the product distillate drum to the coalescing drum. Water, salts, and sulphur compounds are common in overhead naphtha, which contribute to corrosion, especially at high temperatures and speeds. According to the records, the pump was under maintenance in 2014 and it has been working since the plant's opening in 2009. Preliminary investigation showed that the pump P-A was out of order due the extensive damage of its impellers especially on the first five stages.

Based on visual inspection, the severe damage appears to be corrosion related. The recent and previous records of the naphtha and water analysis were reviewed in order to identify corrosive compounds that were causing the increased corrosion. Corrosion rates of the electrical-resistance probe installed in the water draw-off piping on product distillate drum were also reviewed. Damaged impellers from P-A pump were sent to laboratory for analysis. In addition, the hardness of the material was investigated to confirm if it is according to the equipment design and standard.

IV. RESULTS AND DISCUSSION

4.1 Visual Inspection

Based on the visual inspection, the eleven stage impellers were found to be corroded. The first to fourth stage impellers figure1 (a, b) were completely corroded, with the majority of their surface area completely consumed, while the fourth and fifth stage impellers showed evidence of fracture as shown in Figure 1 (c, d); the sixth to eleven stage impellers figure 1e were found to have undergone a lesser degree of degradation. The corrosion damage on the impellers was general or uniform in nature, i.e. it was present all over the most surface area of the pump's impellers, there was also a general thinning, and fractured impeller showed no trace of plastic deformation. Furthermore, the impellers' surface, which was covered in a thin layer of deposit as illustrated in Figure 1e, showed no signs of erosion damage. Corrosion products were not adhering to the impellers' surface and were easily removed.
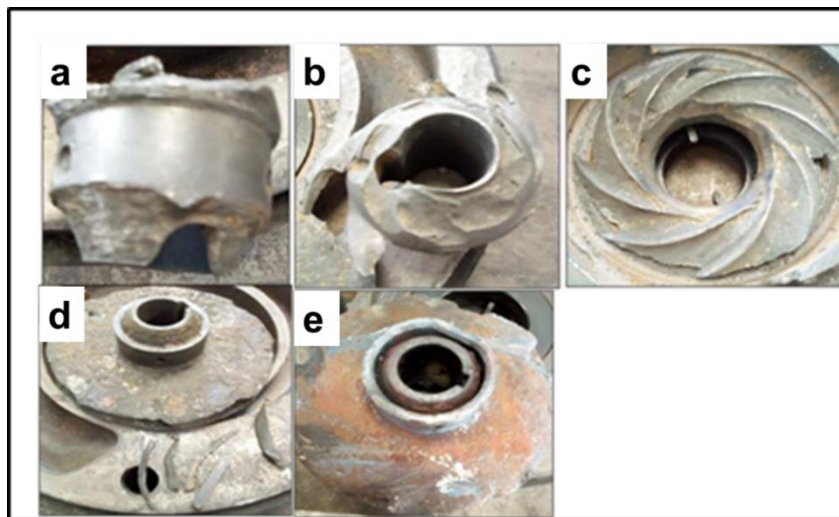
Figure 1 (a) 1st stage impeller, (b) 2nd stage impeller, (c) 3rd stage impeller, (d) 4th stage impeller, (e) 6th stage impeller

The corrosion damage caused by general corrosion is macroscopic and easily identified by visual inspection. While localized corrosion is not easily identified during visual inspection and may be confined to a very small area making the probability of discovery very low. Corrosion within centrifugal pumps can be general in nature, affecting all wetted surfaces and had a macroscopic nature easily identified, or highly localized affecting only a small portion of a single component making the probability of discovery very low. It is often these highly localized forms of corrosion that are the cause of corrosion related pump failure. General corrosion occurs without any localization of attack. This type of corrosion occurs on metals or alloys that do not develop an effective passive film on the surface, carbon steel does not develop a protective oxide film and will corrode at a rate that is dependent upon factors such as temperature, oxygen content, pH, fluid chemistry, and the velocity of the fluid [8].

4.1 Cases of Failure

Based on the visual inspection, laboratory test results on the failed pump samples, and chemical treatment record history, the failure of pumps is most likely due to acidic corrosion attack. Moreover, distillate drum water draw off test record reveal that the pH value was 5.5 which is considered below the lower limit. The average pH readings of 4.8 over the course of three months are shown in **Fig. 2**.
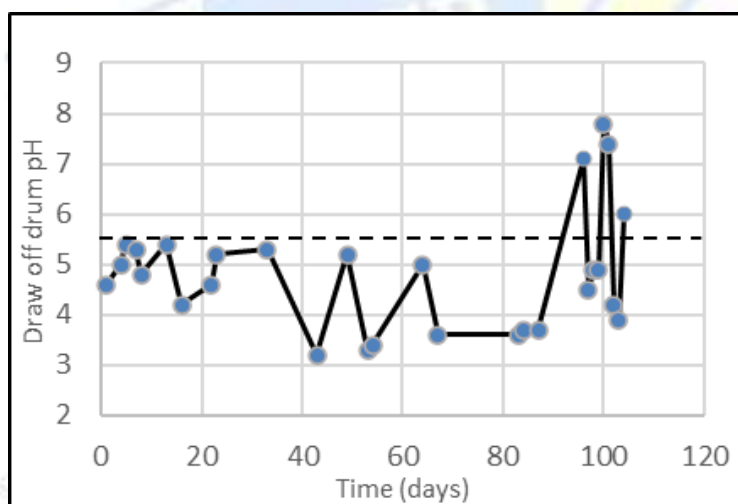

Figure 2 The average pH of D-102 distillate drum water draw off

Fig. 3 shows the chloride content of D-102 distillate drum water draw off. The results showed that the chloride content was frequently below the lower control limit, and the pH was likewise low. This condition is not supposed to be because in reality when the chloride concentration is low, the pH level is greater with adequate chemical dosage in the crude additive system. One possible cause is that a low caustic concentration was employed in conjunction with ammonium hydroxide (or carbonate), or that both chemicals were used at incorrect rates. To a certain extent iron oxide soluble in acid but insoluble in alkaline the corrosion falling with increasing PH to a limiting value between PH 4 to 9 where the rate of attack is sensibly constant. This is attributed to the buffering action on the solution of the product formed, if alkalinity increases and PH to 12 the iron react with strong caustic alkali and form Na_2FeO_2, corrosion rate increases as pH >9. Increases as concentration of metal specific corrosive salts especially chloride and sulfate is increased. With Increases dissolved oxygen concentration [9]. The crude additive system requires the joint presence of caustic and ammonium hydroxide (or carbonate) to take full advantage of their synergistic effect as neutralizers. Serious fouling and/or corrosion may result if these chemicals are injected at incorrect rates and/or ratios due to the formation of ammonium chloride (NH_4Cl). The corrosion rate of carbon steel is generally deemed unacceptable high when wet ammonium chloride salt is present.
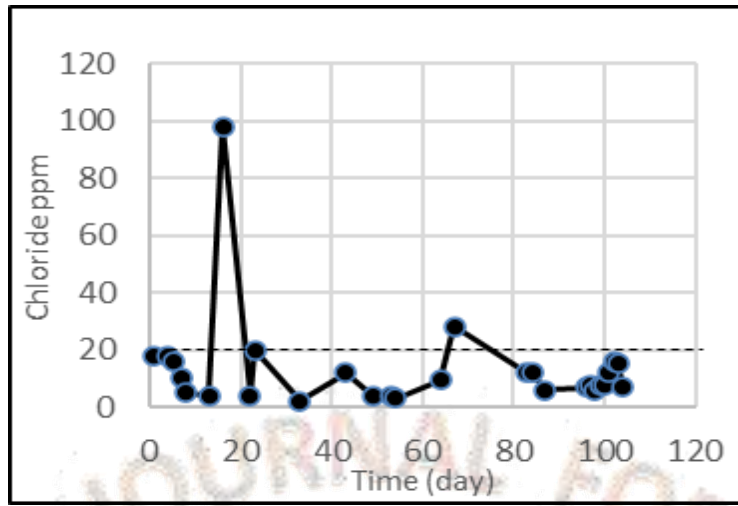
Figure 3 The chloride content of D-102 distillate drum water draw off

Overhead Corrosion is monitored using two electrical-resistance (ER) probes:
1. CP-1, which is located just downstream of E-102 and measures the corrosivity of the condensed aqueous phase,
2. CP-2, which is located in the water draw off piping of D-102 and detects high corrosion, rates due to the presence of aqueous condensate.

Data from previous readings revealed unacceptably high corrosion rates (**Fig. 4 and 5**), indicating that overhead corrosion is present in the system and may have contributed to pump P-103 failure.
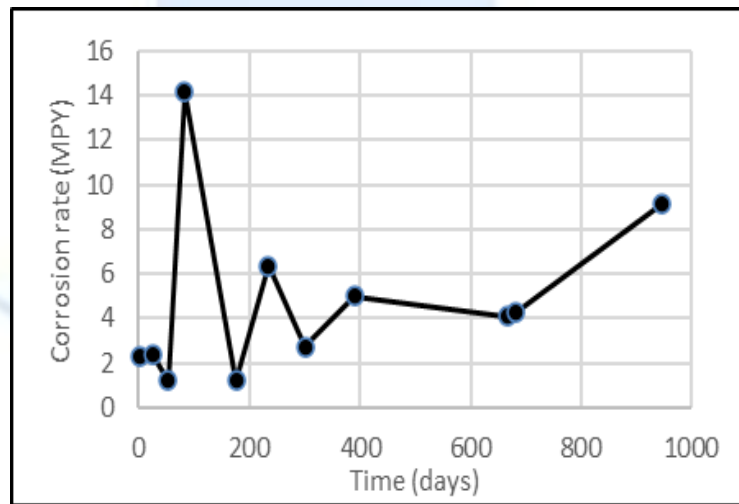

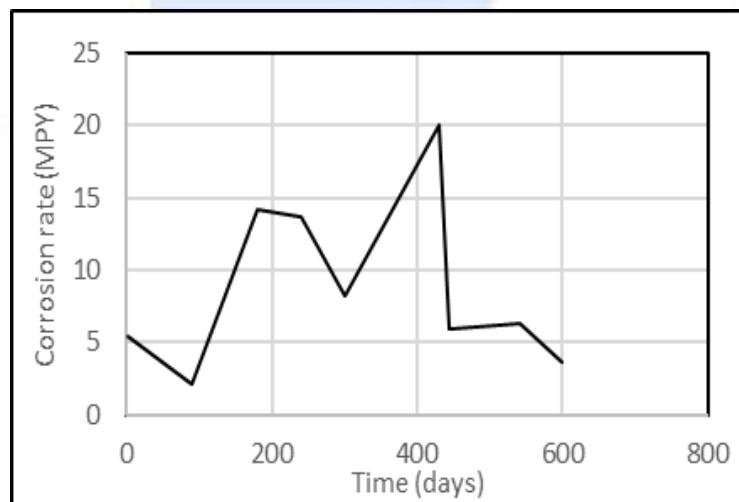**Figure 4 The CP-1 Corrosion Rates**

Figure 5 The CP-2 Corrosion Rates

Different mechanisms of corrosion can occur in the crude distillation unit   (CDU) overhead.

1. HCl Resulted from unstable salts such as CaCl2, Mg Cl2, and hydrolyse when crude oil heated up, HCl vapour dilution into liquied water and it becomes very acidic and can provoke localised but heavy corrosion at very low pH.

2. Other mechanism can cause under-deposit corrosion is the formation of Ammonium chloride (NH$_4$Cl) salt resulted from HCl and NH$_3$ vapours but its non if remains dry, once temperature above dew point, NH$_4$Cl absorb moisture, even if water has still not condensed and resulted NH$_4$Cl salt deposits become wet and corrosive to many kind of material. Even though Amine hydrochloride salt behave similarly to NH$_4$Cl.

3. Wet H$_2$S damage: Under wet conditions and if sufficient H$_2$S is present, blistering and/or cracking can occur, dependent upon water pH, cyanide content, plate metallurgy and welding procedure (mainly regarding post-weld heat treatment) [10].

4.1.1 Sulfide Stress Cracking

SSC is defined as cracking of a metal under the combined action of tensile stress and corrosion in the presence of water and H2S. SSC is a form of hydrogen stress cracking resulting from absorption of atomic hydrogen that is produced by the sulfide corrosion reaction on the metal surface. [11]. According to National Association of Corrosion Engineers (NACE) standard MR0103, Sulfidestress cracking (SSC) is likely to occur in a refining environment where there is >50 ppmw dissolved H$_2$S in the free water or where free water pH is <4 and some dissolved H$_2$S is present. Recent pH analysis of the condensed aqueous phase in D-102 showed that there were several occurrences where the pH was <4 while previous analysis for H$_2$S showed that it reached to 50 ppmw. SSC susceptibility is known to increase with H2S content, e.g., H$_2$S partial pressure in the gas phase, or H$_2$S content of the water phase. In many refinery sour water environments, dissolved ammonia is present, which increases the pH thereby increasing the solubility of H$_2$S that results in a high bisulfide ion concentration [11].

Materials used in sulfur-containing settings must be heat treated and have a maximum hardness of 22 HRC, according to NACE standards MR0103 and MR0175. The hardness of the malfunctioned impeller stages 1 and 2 was found to be higher than what was suggested for impellers used in sulfur-contaminated environments (see Table 2). These impellers will become relatively "brittle" and inappropriate for operation in a sulfur-contaminated environment if they do not receive the recommended heat treatment. As a result, there's a good chance that the cracks seen on some of the faulty impellers were caused by sulfide stress cracking.

Table 2 Brinell hardness test of failure impellers

Sample	HB	HRC Equivalent
Impeller Stage 1	275	29
Impeller Stage 2	249	24

V. Conclusions

The analysis concluded that the impeller blade's failure mode was most likely caused by a combination of incorrect heat treatment of the component and a particularly harsh corrosive environment in the overhead system. The failure was caused by incorrect heat treatment and a lack of chemical treatment, which exposed the material to corrosion in an environment that was corrosive due to the presence of sulfur and acidic water. The impeller blade's service life was shortened due to improper heat treatment and a highly corrosive environment.

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