

REFINING OF KUWAIT'S HEAVY CRUDE OIL: MATERIALS CHALLENGES

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ABSTRACT

It is known that the global energy demand is increasing and this is putting pressure on the oil producing countries to increase their production capacities. With regard to Kuwait, the production capacity is expected to reach 4 million barrels per day (MBPD) by the year 2020. In order for Kuwait to maintain its market share, not only the production capacity must increase but also heavy crude oil (API < 20) must be used as gap filler. Kuwait is expected to produce 900,000 BPD of heavy oil by the year 2020. These current events are facing the oil industry in Kuwait with many decisions and technological challenges, including counteracting expected increased risk of corrosion and equipment failures during the production and refining of heavy crude oil. The most damaging impurities are inorganic salts, organic chlorides, organic acids, and sulfur compounds. To make matters worse, many of the compounds are unstable during refining operations and they break into smaller components or combine with other constituents, concentrating corrodants in certain units, such as the breakdown of sulfur compounds and organic chlorides.

The paper presents the current situation of Kuwait's heavy crude oil, background of the problems encountered during refining and mitigation methods in addition to a failure investigation of 321 stainless steel tubes used in a charge heater handling heavy crude oil. The investigation shows an un-usual form of sulfidation, which was a result of the combined effects of the nature of the crude and the operating conditions.

Keywords: Heavy crude oil, crude impurities, failure cases, charge heaters, refinery operation

STATUS OF HEAVY CRUDE OIL IN KUWAIT

The increasing world energy demand has pushed the oil producing countries, including Kuwait, to start exploiting heavy oil reservoirs, which had been neglected or little used and to increase the oil exploration activities. Currently, some heavyweight producers such as Saudi Arabia, Venezuela and Iran produce large quantities of heavy (\approx API < 20) sour crude with high sulfur content. Others such as Nigeria, the United Arab Emirates, Angola and Libya pump a higher quality, light sweet crude, with low sulfur content.

Kuwait's current oil production is about 2 million barrel per day (MBPD). Kuwait exports and refines a crude termed Kuwait Export Crude (KEC). KEC (API 32 and 2.7%

sulfur) is actually a blend of crudes from several oilfields. However, Kuwait's light crude is becoming sour and some of the reservoirs are depleted to the extent that Kuwait is now relying for the first time on secondary oil recovery approaches, such as water injection. As a result, the Kuwait oil industry is finding it more difficult to maintain the characteristics of KEC.

Kuwait's market share is expected to reach 4 MBPD by the year 2020. However, in order for Kuwait to achieve this market share, not only the production capacity must increase but also Kuwait must rely on heavy oil to fill the gap. Accordingly, Kuwait's heavy oil production is expected to reach 900,000 BPD by the year 2020, which will be mostly Lower Fars from north Kuwait.

Most of the world refineries, including Kuwait, are equipped with alloys capable of handling sweet light crude, which is most suitable for refining into petrol, gas oil and heating oil. On the other hand, refining of heavy crude is difficult and is associated with operational problems. The problems arise from the increased risk of corrosion, equipment failures, and downtime of process units. These effects are caused primarily by the high sulfur and salt contents of these crudes, including organic chlorides [1, 2]. To make matters worse, many of the compounds are unstable during refining operations and they break into smaller components or combine with other constituents, concentrating corrodants in certain units, such as the breakdown of sulfur compounds and organic chlorides.

These current events are facing the oil industry in Kuwait with many decisions and technological challenges not only regarding the methodologies of producing heavy oil, transportation and refining of heavy oil, but also evaluating the value and optimum utilization of this produced oil, including crude oil segregation, up-grading and blending approaches. In fact, Kuwait is now building a new refinery, which is planned to refine 600,000 BPD of blends containing heavy crudes. Table 1 shows key properties of the Eocene and Ratawi-Burgan crudes along with KEC.

Table 1. Key Properties of Eocene, Ratawi-Burgan and KEC Crudes [3]

Test	Test Method	Unit	Eocene	Ratawi-Burgan	KEC
Density at 15°C	IP 160	g/ml	0.92-0.98	0.91-0.95	0.82-0.91
Gravity	IP 1200	API	15-20	17-24	29-40
Total Sulfur	D 3120	wt%	4.0-4.5	3.8-4.4	2.2-3.0
Total Nitrogen	D 3228	ppm	1500-2500	1600-2500	1200-1800
Water Content	D 1774	wt%	0.01-0.12	0.02-0.15	0.002-0.01
Conradson Carbon Residue	IP 189	wt%	9.0-13.0	9.0-12.0	4.5-6.0
Asphaltenes	Cosmo Analyzer	wt%	3-7	3-6	1.5-3.5
Metals	D 5185				
	Ni	µm/g	15-30	20-30	5-18
	V	µg/g	40-60	50-70	20-50

MAIN PARAMETERS AFFECTING CRUDE CORROSIVITY

Inorganic Salts

Crude oil is a mixture of many different compounds, generally combinations of carbon and hydrogen, all with their own unique physical properties. Crude oil as such is not corrosive. However, it contains corrosive impurities, such as inorganic salts.

Inorganic salts are present in the brine produced with the crude oil or picked up as a contaminant. The bulk of the salts are sodium chloride (NaCl), magnesium chloride (MgCl₂) and calcium chloride (CaCl₂), reflecting the composition of seawater. However, the total salt content by weight can vary from less than 3 pounds per thousand barrels (PTB) of crude oil to 300 PTB or more in heavy crude oil [1].

When the crude oil is preheated, most of the MgCl₂ and CaCl₂ begin to hydrolyze at about 120°C and form hydrogen chloride (HCl) vapor. At 370°C, approximately 95% of the MgCl₂ and 15% of the CaCl₂ have hydrolyzed. The chemical reaction for MgCl₂ is:



A similar reaction occurs for the CaCl₂. The NaCl, being more temperature stable, does not hydrolyze to any appreciable extent [1].

The HCl vapor thus formed is not corrosive at temperatures above the water dew point. For this reason, there is no corrosive acid attack in the pre-heat system where no liquid water is present. However, in the pre-flash and atmospheric columns of crude units, the HCl is carried up the columns with the hydrocarbon where being highly water soluble it dissolves in the condensing water to form hydrochloric acid. This highly corrosive acid can create severe corrosion problems in the top of column, the overhead line, the overhead exchanger and condensers. The source of the condensing water can be the crude oil, stripping steam, or carryover from the desalter [1, 4]. The resulting corrosion reaction with steel is:



The presence of H₂S keeps the reaction going as follows:



The formation of additional HCl thus perpetuates the cycle.

Ammonia is often added to neutralize HCl. Other sources of ammonia include carry-over from desalter wash water and streams imported from hydrotreating units. However, above the water dew point, HCl can react with NH₃ to form solid ammonium chloride (NH₄Cl). The temperature at which NH₄Cl forms is dependent upon the partial pressures of HCl and NH₃. NH₄Cl is hygroscopic so may absorb moisture even though water is not condensing. Wet NH₄Cl is highly corrosive to many materials. NH₄Cl deposition can occur in the tops of the columns as well as in overhead and reflux piping and overhead condensers [1, 4].

To minimize the effects of inorganic salts, the refiner often washes the crude oil with water and uses a desalting vessel to remove the added water and most of the inorganic contaminants from the crude prior to distillation in the crude unit [1, 5].

Organic Chlorides

Organic chlorides (often called phantom chlorides) constitute a contaminant in crude oil. Organic chlorides are also known as “undesaltable chlorides” or “rogue halogens.” The sources of these chlorides vary considerably and are always different for each case. However, they often result from the carry-over of chlorinated solvents, which are used in the oilfields. They can also be picked up by the crude during transportation in contaminated tanks or lines. Organic chlorides are not removed in the desalters, thus their presence does not become evident until it is too late. Organic chlorides can decompose in the heaters, forming HCl, causing erratic pH control and accelerated corrosion in crude unit overhead system as well as downstream units [1, 2].

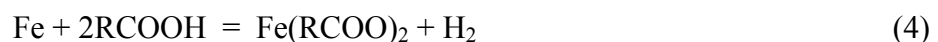
Organic Acids

Many crude oils contain organic acids, but seldom do they constitute a serious corrosion problem. However, a few crudes contain sufficient quantities of organic acid, generally naphthenic acids, to cause severe problems in units operating above 230°C. Naphthenic acid corrosion (NAC) often occurs in the same places as high temperature sulfur attack such as heater tube outlets, transfer lines, column flash zones, and pumps [1].

The term naphthenic acid, as commonly used in the petroleum industry, refers collectively to all of the organic acids present in the crude oil. The name is derived from the early discovery of monobasic carboxylic acids in petroleum. These acids are based on a saturated single-ring structure [6]. Later, more extensive laboratory studies showed an astonishing variety of organic acids to be present in crude oil. These include fatty acids as low in molecular weight as formic and acetic as well as saturated and unsaturated acids based on single and multiple five and six-membered rings. The general chemical formula of naphthenic acids is $R(CH_2)_nCOOH$, where R is one or more cyclopentane ring and n is typically greater than 12. The amounts of the naphthenic acids present in crude oils vary from one crude to another around the world. Since the naphthenic acids are organic acids, variations in molecular weight, boiling point, and ring structure can influence both their fraction characteristics and chemical reactivity [7].

The naphthenic acids content in crude oils is expressed as the total acid number (TAN), which is measured in units of milligrams of potassium hydroxide required to neutralize a gram of oil. The common values of TAN range from 0.1 to 3.5, but severe situations have been found for some hydrocarbon fractions having TAN values in excess of 10 [8]. It is not unusual, however, for crudes from a given oilfield to change acid number over a period of years [6].

The corrosion reaction processes are described typically by:



The iron naphthenates are soluble in oil and the surface is relatively film free. In the presence of H₂S, a sulfide film is formed which can offer some protection depending on the acid concentration [7]. A major controversy in the prediction and control of NAC is that at low temperatures, certain sulfur compounds may reduce the severity of NAC [9].

For many years, conventional wisdom held that NAC generally did not occur in crudes with a TAN less than 0.3 or 0.5 mg per gram [6, 10]. However, there has been some discussion that crude with TAN of less than 0.5 could still cause significant corrosion problems depending on the specific acids found in that crude and the sulfur content of the crude [11]. Since the naphthenic acids are a mixture in any particular crude and vary considerably from crude to crude, two different crudes with the same TAN will not necessarily have the same corrosivity [12]. In discussing acid content and corrosivity, Craig [13] has reported data showing that typically only about 5% of the naphthenic acids present in crude are corrosive. Thus, where NAC is found, corrosion rates are affected by the activity of the particular naphthenic acids present, as well as by their concentration.

NAC occurs primarily in crude units and vacuum units. NAC in fluid catalytic cracking units and in units that handle cracked products is negligible since these acids decompose between 400°C and 480°C. Catalysts also decompose the acids in hydrodesulfurizer units. Problems with NAC can occur in the feed preheat sections when the oil starts to vaporize, and in the lower and side stream equipment of naphthenic acid-containing streams [11].

NAC typically has a localized pattern, particularly at areas of high velocity and, in some cases, where condensation of concentrated acid vapors can occur in crude distillation units [14, 15]. The attack also is described as lacking corrosion products. Damage is in the form of unexpected high corrosion rates on alloys that would normally be expected to resist sulfidic corrosion (particularly steels with more than 9% Cr). In some cases, even very highly alloyed materials (i.e., 12% Cr, type 316 stainless steel (SS) and type 317 SS, and in some severe cases even 6% Mo SSs) have been found to exhibit sensitivity to corrosion under these conditions [16].

In Kuwait, the refineries did not report major NAC attack with regard to KEC, Eocene and Ratawi-Burgan crudes, suggesting low TAN values for the Kuwaiti crudes. However, testing is needed to confirm the TAN values as the quality of the Kuwaiti crude is changing in addition to the production of other heavy crudes.

Sulfur Compounds

Most crude oils vary greatly in both the amount of sulfur and the type of sulfide species present [16]. Because sulfur is the primary corrodant, the corrosion that these species cause is referred to as sulfidic corrosion. Sulfidic corrosion is another type of high temperature attack. Its temperature range overlaps NAC, starting at about 260°C and increasing from there [17]. The total sulfur content usually does not accurately predict the level of the sulfur-caused corrosion. Not all of the sulfur is in a form that is potentially reactive with the metal [5]. The more important factor may be the capability of the sulfur compounds to form H₂S, which usually is a more reactive compound [18]. H₂S can occur naturally in crude oils or can be formed during the refining process by thermal decomposition of sulfur compounds (Fig. 1). As shown in Fig. 1, H₂S evolution behavior (and most likely

corrosiveness) does not accurately relate to the sulfur content of the crude [18]. Despite this limitation, the sulfur content of crude oil or hydrocarbon fractions has been used to indicate the potential for sulfidic corrosion in refinery equipment. Sulfidic corrosion usually is a general mass loss or wastage of the exposure surface, with the formation of a sulfide corrosion scale.

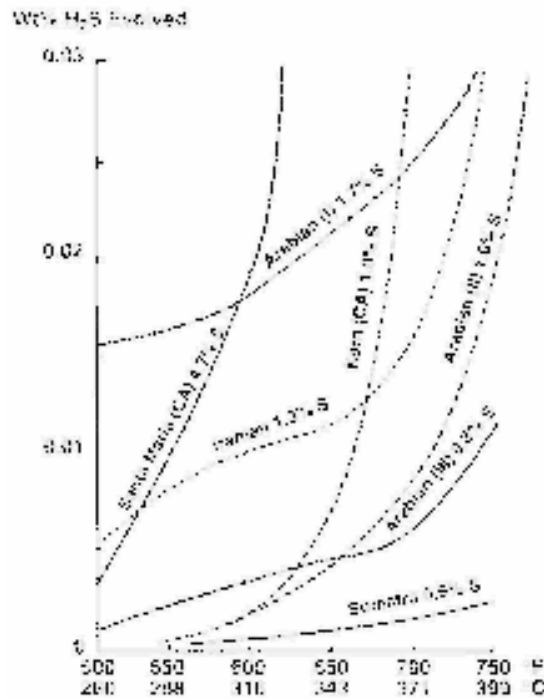


Fig. 1. H₂S released from crudes as a function of temperature [18].

Sulfur at a level of 0.2% and above is known to be corrosive to carbon and low alloy steels at temperature 232°C to 455°C. At high temperature conditions, the presence of naphthenic acids was found to increase the severity of sulfidic corrosion [8]. Presumably, the presence of these organic acids disrupt the sulfide film thereby promoting sulfidic corrosion on alloys that would normally be expected to resist this form of attack (i.e., 12% Cr and higher alloys).

When sulfur is the only contaminant, McConomy curves, with other factors, are used to predict the relative corrosivity of crude oils and their various fractions. The current form of these curves is shown in Fig. 2a, while Fig. 2b shows the relevant correction factors [19]. These curves reveal some of the basic information needed to understand and potentially mitigate sulfidic corrosion in process applications. Important elements include:

1. The increased severity of corrosion with sulfur concentration and service temperature between 250°C and 400°C, and
2. The benefit of increased Cr content in steels to reduce the corrosion rates.

The McConomy curves are useful in estimating the corrosion rate that will be expected based solely on sulfur content. However, for high TAN fractions, laboratory and

plant data [20] show that corrosion rates of carbon steel and 5% Cr were similar. At high sulfur and low TAN, the calculated rates were higher than the actual rates. Conversely, at low sulfur and high TAN, the calculated rates were much lower than actual ones. Also the calculated rates for 9% Cr and 317 SS were very low compared to experimental data. Thus, corrosion data from McConomy curve should be carefully evaluated based on TAN levels [21].

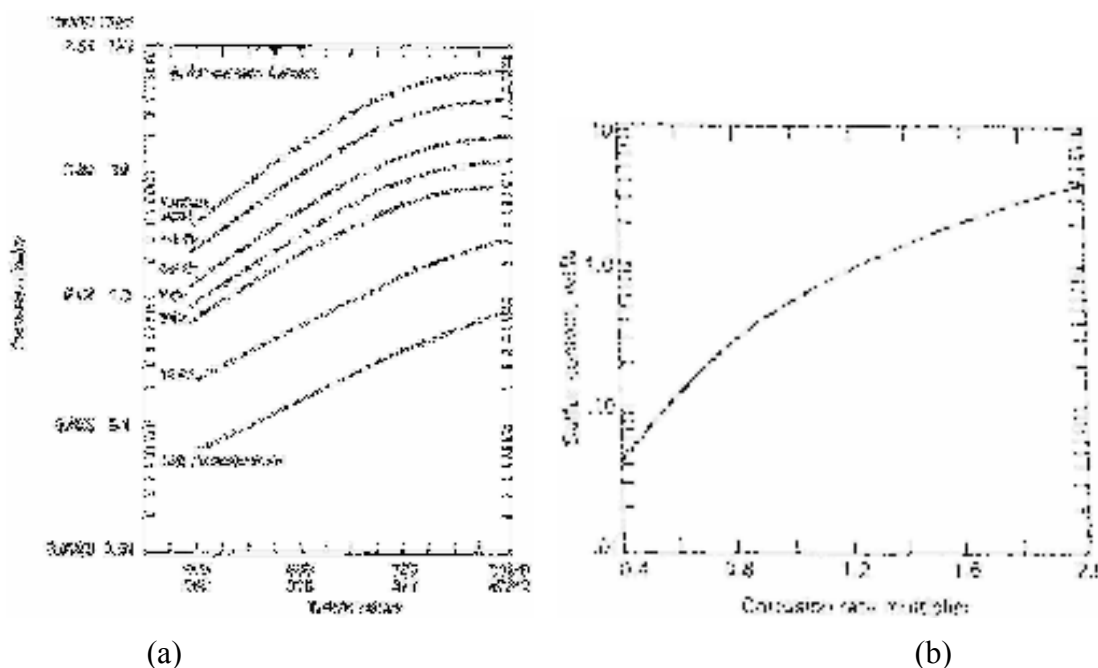


Fig. 2. (a) Modified McConomy curve; (b) correction factors [19].

The McConomy curves do not directly take into account the influence of velocity, which can be significant in some cases, or the effect of hydrogen in the process environment. Sulfidic corrosion rates in hydrogen-containing environments generally are higher than in hydrogen-free process environments [5]. The Couper-Gorman diagrams have been developed to account for hydrogen effects, based on survey information. There are a series of curves indicating the corrosion rates for various steels (0 through 18% Cr) vs. H₂S content and temperatures. Fig. 3 shows curves for 5 and 9% Cr steel in naphtha diluents [22].

Temperature

In addition to the concentration of corrosive acids, the temperature of the fluid has a great influence on the corrosion rate. There appears to be little doubt that NAC occurs over the temperature range of about 220-400°C [6, 12, 23, 24]. Typically, no corrosion damage is found at temperature above 400°C. Most likely, this is because of the decomposition of naphthenic acids and/or the formation of coke on the hot metal surface. At temperatures lower than 220°C, the corrosion rate is not high enough to cause problems. NAC is of most concern in areas of crude distillation units that combine velocity with temperatures. Unlike sulfidic corrosion, which increases in severity with increasing temperature, NAC can vary in severity with temperature, depending on the specific naphthenic acids present in the crude oil [5].

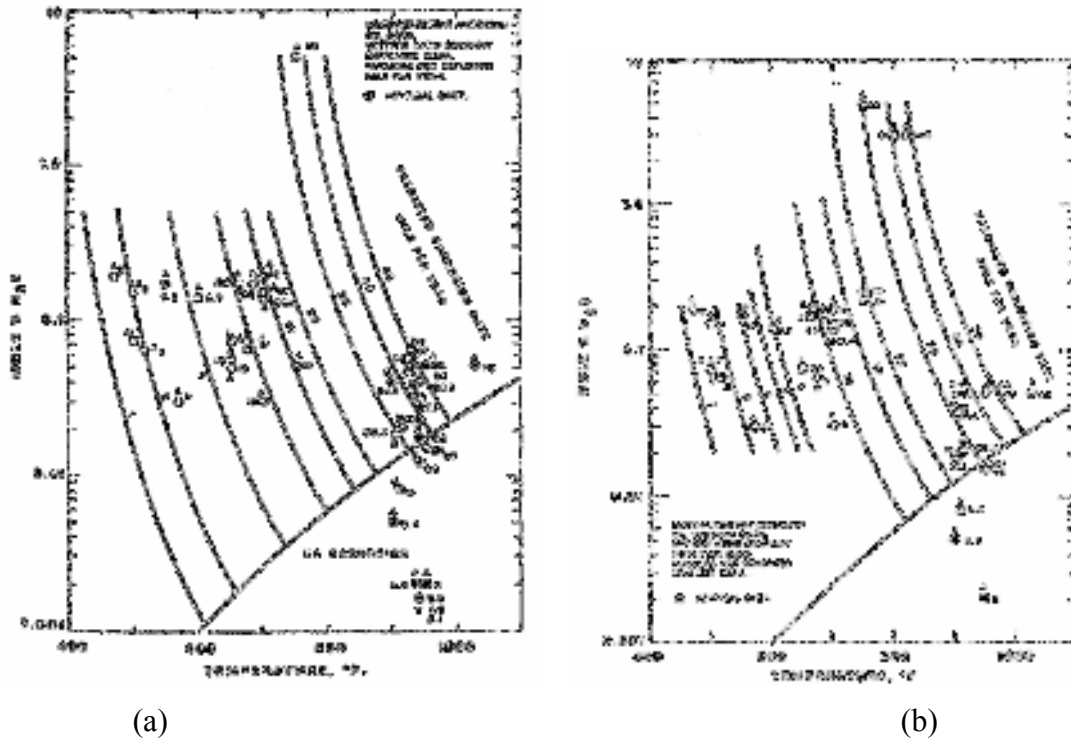


Fig. 3. Couper-Gorman curves for: (a) 5%; and (b) 9% Cr steel in naphtha [22].

Velocity

Both sulfidic and naphthenic acid corrosion can be accelerated by velocity of the flowing process environment or by local turbulence. The wall shear stress produced by the flowing media contributes an added mechanical means to remove the normally protective sulfide films. The wall shear stress is proportional to velocity but also takes into account the physical properties of the flowing media [25]. In general, the higher the acid and/or sulfur content or the lower the degree of vaporization, the greater the sensitivity to velocity. However, an added complexity is that changes in vaporization can influence the partitioning of the acid between the liquid and vapor phases. In fact, in some cases, it appears possible to obtain very high corrosion rates even at very low levels of naphthenic acid content (i.e., TAN ≈ 0.3) and low sulfur content when combined with high temperature and high velocity [5]. Blanco et al. [26] presented corrosion data that had been collected from transfer lines handling crude oils at about 360°C. The data indicated that the corrosion rate of plain carbon steel is considerably higher than that of 5Cr-0.5Mo containing steel when the crude oil flows at high velocities.

MITIGATION METHODS

Blending

Blending is the most common and preferred method of reducing the severity of high-temperature corrosion in crude oil refining systems. It is accomplished by diluting a high TAN feedstock with a low TAN crude or fraction. This technique reduces the overall TAN value to a level that corresponds to an acceptably low rate of corrosive attack [16]. Blending could also be carried out with high sulfur crudes to decrease corrosion of the equipment by forming a protective iron sulfide film [21]. Problems can be encountered, however, when making blending decisions regarding new sources of crude containing significant levels of naphthenic acid or in applying experience obtained from one plant or unit to another.

Corrosion Inhibitors

Injection of corrosion inhibitors may provide adequate and economic protection if it is closely monitored and used for specific fractions that are known to be particularly severe, or that fluctuate with feedstock quality. Experience with inhibitors used to mitigate high temperature crude oil corrosion is limited but growing rapidly. The impact of inhibitors on product economics and on downstream processes needs to be assessed [5]. Traditional filming amine inhibitors are ineffective in this application [27]. This ineffectiveness stems from inadequate thermal stability and the absence of a sulfide scale, which many filming amines require to be effective. Inhibitors, which have been found successful, can be divided into two broad categories, i.e. phosphorus containing and no-phosphorus. The phosphorus-containing formulations are generally more effective than the non-phosphorus, but bring with them the concern about poisoning downstream catalysts [12].

Materials of Construction

The selection of materials of construction has a significant impact on the operability, economics, and reliability of refining units. For this reason, materials selection should be a cooperative effort between the materials engineer and plant operations and maintenance personnel. Reliability can often be equated to predictable materials performance under a wide range of exposure conditions. Ideally, a material should provide some type of warning before it fails; materials that fracture spontaneously and without bulging as a result of brittle fracture or stress corrosion cracking (SCC) should be avoided. Uniform corrosion of equipment can be readily detected by various inspection techniques. In contrast, isolated pitting is potentially much more serious because leakage can occur at highly localized areas that are difficult to detect. The effect of environment on the mechanical properties of a material can also be significant. Certain exposure conditions can convert a normally ductile material into a very brittle material that may fail without warning. A material must not only be suitable for normal process conditions but must also be able to handle transient conditions encountered during start-up, shutdown, emergencies, or extended standby. It is often during these time periods that equipment suffers serious deterioration or that failure occurs [28].

Austenitic stainless steels have excellent corrosion resistance, but are subject to SCC by chlorides. If sensitized, they are also subject to polythionic acids [29, 30]. As the nickel content is increased above 30%, austenitic alloys become, for all practical purposes, immune to chloride SCC. Nickel also forms the basis for many high-temperature alloys, but nickel alloys can be attacked and embrittled by sulfur-bearing gases at elevated temperatures [31].

Materials with high Cr and Mo content are recognized as naphthenic acid corrosion resistant in most cases. In cases where TAN values are low and sulfur is the primary corrodant, 5 to 12% Cr steels are usually used. For severe conditions of sulfidic attack created by temperature and/or sulfur content, a minimum of 9% Cr is typically preferred. Higher alloys, such as type 316SS (with nominally 18% Cr and 2% Mo min.) or type 317 SS (18% Cr with 3% Mo min.) are commonly used when TAN is above 0.5 and in the atmospheric column when TAN is above 1.5 [5].

FAILURE INVESTIGATION OF CHARGE HEATER TUBES

A leak occurred in the charge heater of a plant handling Kuwait's heavy crude oil (Ratawi-Burgan). The crude is the charge (tube side) in the radiant and convection sections. The temperature at the inlet is 130°C, while it is 345°C at the outlet. Visual inspection revealed that some of the 321 SS convection tubes at the inlet had black oil/coke deposits. No leak was detected upon pressurizing the heater at 405 psig. However, when one of the tubes was removed and was lightly grounded externally at the black colored area, a circumferential crack was observed visually (Fig. 4a). The crack was not associated with bulging of the tube. The presence of this crack raised the possibility that the remaining heater tubes in operation may also have cracks.

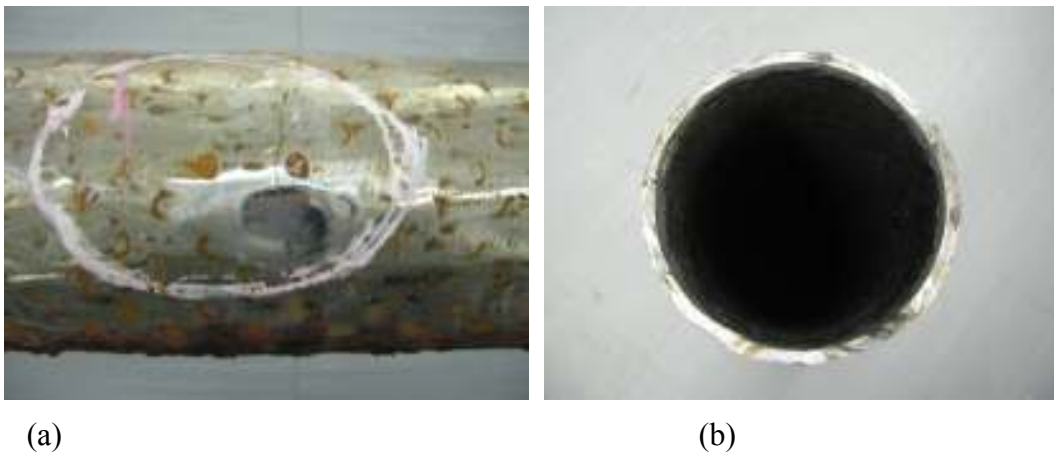


Fig. 4. Photographs showing: (a) circumferential single crack; and (b) deposited black layer on internal surface.

The provided tube was 13.83 cm in outside diameter. The internal tube surface was covered with a non-uniform black deposited layer (Fig. 4b). The minimum thickness of the deposited layer was ≈ 1.86 mm, while the maximum thickness was ≈ 4.61 mm. The maximum deposit thickness was found at the failure location. The minimum tube thickness was ≈ 5.92 mm, while the maximum thickness was ≈ 6.96 mm. Thus, the tube suffered reduction in thickness of ≈ 1.04 mm maximum. The black deposited layer consisted of carbon (coke), iron sulfide, calcite, sodium chloride, hematite and magnetite (see Fig. 5).

Fig. 6 shows optical micrographs taken for a cross-section cut from the tube at the crack location. It can be seen from the figure that only one large size crack existed in the tube with a few short branches. The internal tube surface was irregular in shape and was covered

in some areas with a scale layer (Fig. 6a). In addition, grain separation and subsurface small grain boundary cracking or precipitations were seen at the internal surface. The external tube surface was free of any signs of corrosion damage. The crack and its few short branches were relatively thick and filled with corrosion product scale. The tips of the branches of the crack were blunted (Fig. 6b). The short branches were mostly transgranular in nature. Some grain separation can be seen at the crack walls near the internal surface. The linear marks around the crack near the internal surface appeared like crack branches emanating from the crack.

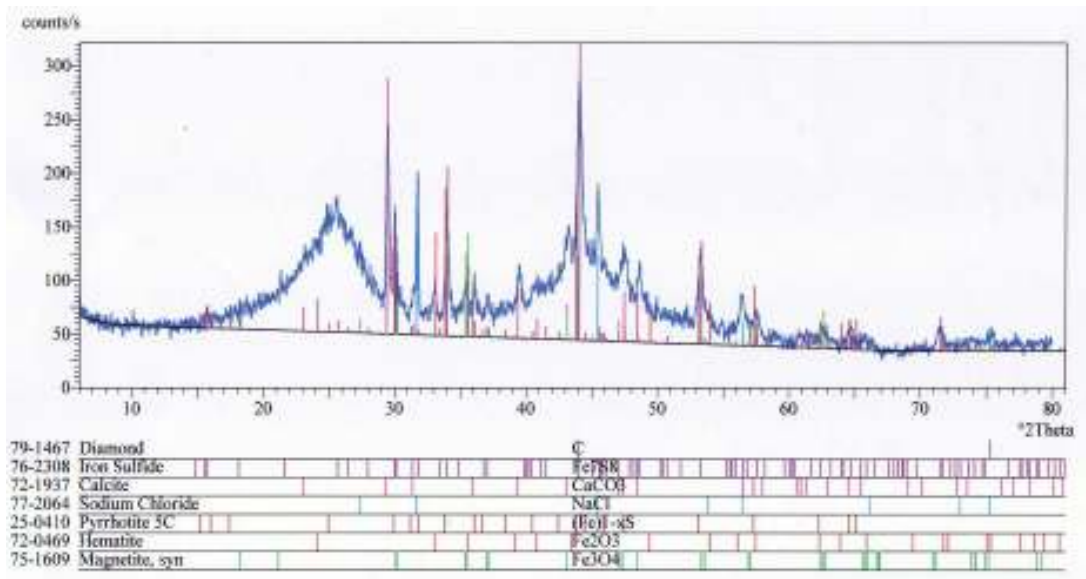


Fig. 5. XRD pattern of black deposited layer found on the internal tube surface.

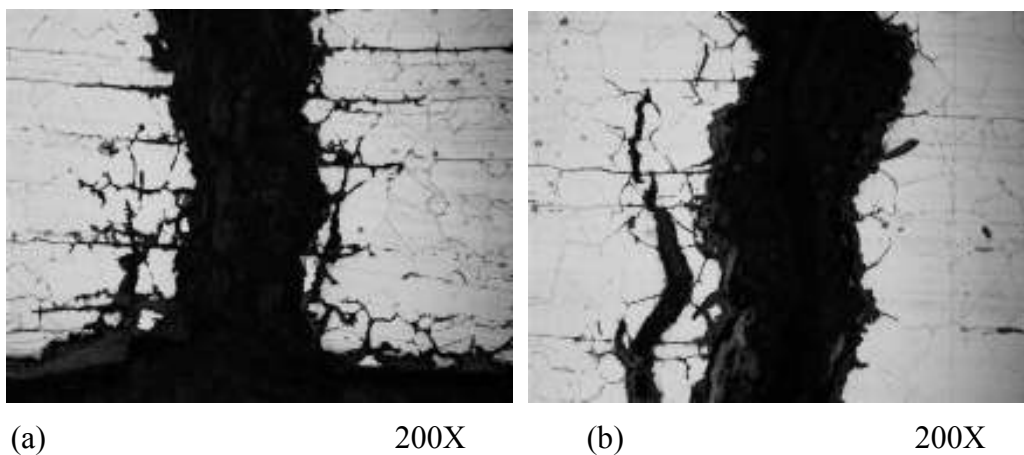


Fig. 6. Optical micrographs of cross-section of failed tube, showing: (a) nature of the crack at internal surface and linear cracks emanating from the walls of the main crack; and (b) transgranular nature of short crack branches near external surface (10% oxalic acid etch).

SEM examinations of the polished cross-section cut at the failure location clearly revealed that the grain boundary separation, the linear marks, and the crack and its branches were a result of precipitation of a corrosion product compound (see Fig. 7). The precipitation appeared similar to those resulting from high temperature reactions, such as oxidation or sulfidation.

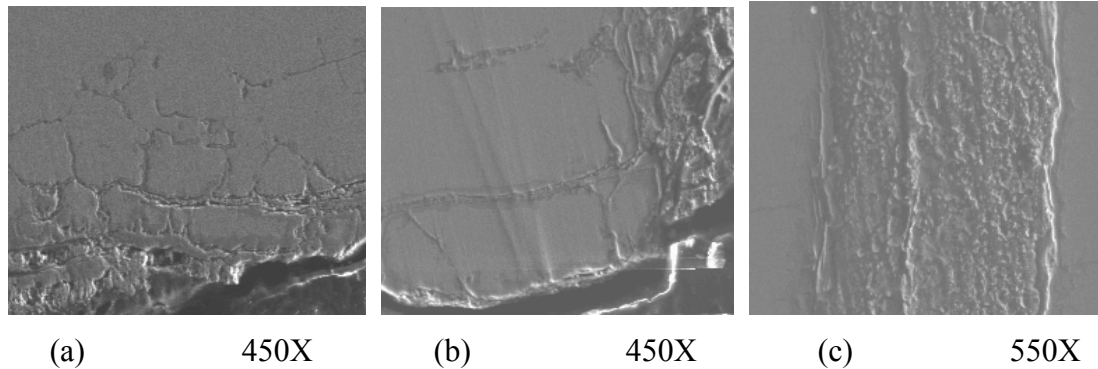


Fig. 7. SEM micrographs of polished cross-section of tube, showing: (a) scale precipitated inside the grain boundaries near internal surface; (b) scale build-up and penetration at the internal tube surface; and (c) scale precipitated inside the crack in mid-section.

EDS analyses of the precipitates inside the crack (or inside the branches) in bulk of the material revealed that the precipitates are rich in Fe and S (Fig. 8a). When the corrosion products inside the crack close to the internal surface were analyzed, the precipitates were found rich in Ca (Fig. 8b).

The investigation clearly indicated that cracking of the tube was due to high temperature sulfidation. This result was rather surprising and unexpected as sulfidation usually causes general metal loss and occurs at temperatures $> 260^{\circ}\text{C}$, which is higher than the operational inlet temperature in the convection section of the furnace, which is 130°C or 266°F .

The only possible explanation for the occurrence of high temperature sulfidation is the formation of a hot spot along the length of the tube. This view is supported by the fact that the internal tube surface was found covered with a non-uniform black deposited layer. The maximum deposit thickness was seen near the failure location. In addition, the layer was very dense and hard that a chisel was used to remove sufficient quantity for XRD. This nature of the deposited layer could be attributed to its composition, which consisted of calcite in addition to coke, iron sulfide, sodium chloride, hematite, and magnetite (see Fig. 5).

According to ASM Handbook [32], the presence of internal scale or deposits causes an increase in tube metal temperature because the scale or deposits have a lower thermal conductivity than the steel tube. Such temperature increase can lead to creep and accelerated oxidation in addition to other failure mechanisms. It appears that in the present case, the increase in metal temperature did not lead to creep, but caused high temperature sulfidation. Thus, it seems that the tube was exposed to temperatures greater than 260°C , but less than 540°C , which is the starting temperature for creep.

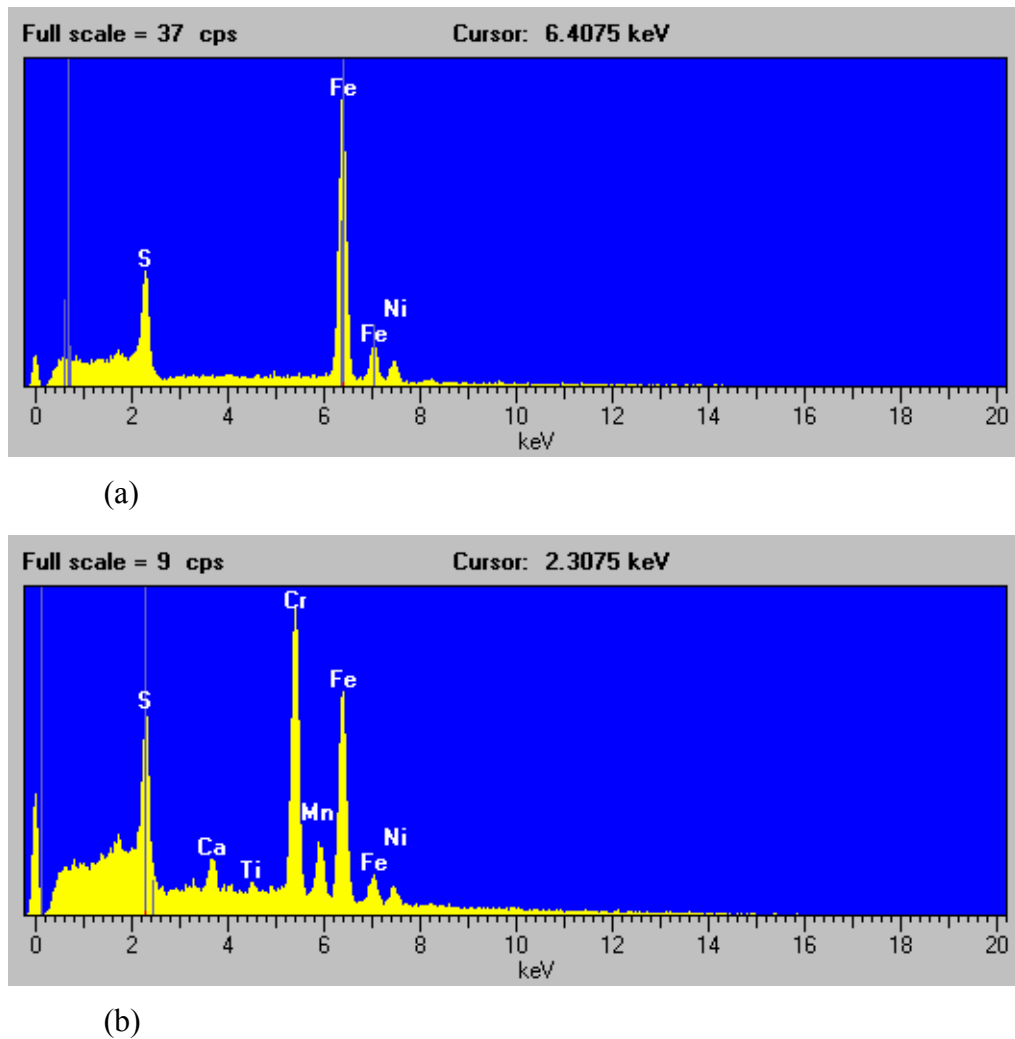


Fig. 8. EDS analyses made for the scale inside the crack in: (a) bulk of material; and (b) near internal surface.

Refinery furnace tubes are usually fabricated from several grades of steels for elevated temperature applications, mainly ferritic, i.e. carbon steels, C-Mo steels, and Cr-Mo steels. The materials are selected for their stress rupture or creep rupture properties combined with corrosion resistance [33]. The tubes are usually designed for limited service time of 10 years [34]. SSs are sometimes used as furnace tubes for highly corrosive feeds. SSs are preferred over high nickel alloys because nickel is prone to form low melting nickel-nickel sulfide eutectic. However, sulfur-bearing gases under reducing conditions greatly accelerate the attack of SSs with high nickel contents. Over the service time, the tubes are subjected to several degradation phenomena that may cause operational problems. Damage to the inside surface of the tube can result from the aggressive action of the feed. The principal corrosive impurity in crude oils is sulfur and sulfur compounds [35]. In the present case, high temperature sulfide corrosion caused by these species resulted in localized sulfide scale formation and formation of subsurface corrosion products (Figs. 6 and 7). Iron sulfide scale precipitated along the grain boundaries and within the grains. The localized nature of the attack led to the un-usual appearance of the crack in the circumferential direction instead of

the usual general metal loss, scaling and thinning of the tube. The crack, thus, appeared to have initiated intergranularly at the internal surface and converted to transgranular or stress-rupture cracking near the external surface.

Ratawi-Burgan crude contains high salt content. This might explain the presence of calcite as part of the scale. This might also explain the occurrence of the failure in the convection section where the operating temperature is suitable for the precipitation of calcite. It can be safely assumed that the nature of the crude was the catalytic factor for the occurrence of high temperature sulfidation and its localized nature.

CONCLUSIONS

The paper presented the current situation of Kuwait's heavy crude oil and background of the problems that might be encountered during refinery operations and the measures to be taken to overcome the problems. The paper also included a failure investigation of 321 SS tubes employed in a charge heater handling heavy crude. The investigation presented an example of an un-usual form of corrosion encountered in heavy crude. This example pointed to the materials challenges that might be encountered during refining of Kuwait's heavy crudes.

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