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Material Selection in Oil Production Unit in One of Iranian Onshore Project

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Abstract: Material selection is one of the important steps in designing of oil production units. The reason is that this step affects on two important parameters: cost and effective design. The main concern of this study is the material selection for all important equipment like: flow lines, separators, tanks and others for an Iranian oil field which now is developing and it's construction is going on right now. The plant produces 50000 BOPD whereas the final treatment plant will produce about 165000 BOPD. The crude oil is sour and has high pressure (140 MPa) and temperature (about 100°C). The crude contains some corrosive elements like H_2S, CO_2 and water, of fluid coming from oil wells. For this reason the references that are used for this purpose are mainly NACE and API standards. For some equipment which work in sour area, according to NACE-MR0175, some special alloys like Nickel alloys are used and for case of using carbon steels the amount of corrosion allowances is calculated.

Key words: Material selection, oilfield, corrosion, hydrogen included cracking

INTRODUCTION

This research is related to one of the Iranian onshore oil project that has been done already. The material selection of the main equipment will be described. In this project the crude oil comes from three wellheads to one header and then from that, it is transferred to oil treatment unit.

Because the fluid which came out from the first appraisal descriptive oil well contains water (production water forecast below 5%) which contains some chlorides, huge amounts of H_2S (5000 ppm at the point of wellhead valves) and also considerable values of CO_2 (4.2 mole percent), then it is corrosive and some special considerations should be taken in the material selection of the equipment.

The CO_2 content in the gas phase is a parameter which is used in calculation models for CO_2 corrosion rate. The amount of this parameter ranges from 3.18 to 4.69% depending upon flash gas conditions.

These data was based on a combination of data derived from the following two samples to define a design basis well stream fluid composition:

- Laboratory analysis of the first appraisal well fluid sample (reservoir Level 1) and laboratory assay of stock tank crude derived from well fluid taken from mentioned well
- Well (reservoir level 3)

A maximum water cut of 15% was initially considered for surface facilities design and for the material selection philosophy used during the early engineering stages, with the agreement to collect new fluid samples during the field appraisal stage in order to definitely assess the concern Field fluid composition. Furthermore, formation water analysis is not available, therefore a water salinity of 27% has been assumed and it is still confirmed.

For presence of the salinity water (may be in future) it is possible to have pitting corrosion which in this case the corrosion will be localized and the result of that is some pits which can lead to very catastrophic failure, specially in pressure vessels. In the concern project, this defect was found in a 6 inches pipe which carries some condense from gas compressor unit to produced water tank.

The Presence of H_2S in the wet environment means that there is possibility of having some kind of hydrogen damages like HIC and SSC.

The term HIC or "Hydrogen Induced Cracking" includes damage and crack phenomena occurring without any applied or residual stress contribution-blistering and as stepwise micro cracks. Such cracks occur when atomic hydrogen diffuses in the metal and since they can not diffuse then recombines as hydrogen molecular in some voids in the steel matrix (Fontana, 1987).

The pressure and concentration of hydrogen gas increases and the equilibrium pressure between hydrogen gas and hydrogen atoms is about several hundred thousand atmospheres and this is sufficient to have deformation or rupture in any engineering materials.

In hydrogen embrittlement phenomena, also hydrogen atoms penetrate in the metal and the result is the loss of ductility and tensile strength (Fontana, 1987).

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Control of the microstructure reduces the availability of crack initiation sites and is therefore critical to the control of SWC. The most susceptible materials are rolled steels containing inclusions in the metal matrix, in particular C-Mn steels containing manganese sulphide Type II inclusions. The likelihood of HIC occurrence in seamless and forged pipes is lower than in welded pipes (Braga and Orlandini, 2004).

SSC or "stress corrosion cracking" is a brittle failure which occurs in the combined action of tensile stress and corrosion in the presence of water and H_2S.

Also in the case of having CO_2 it is possible to have general corrosion which results a uniform wall thinning.

So all the materials which are selected to use in this condition, should be resistant to the mentioned corrosion attacks. In any equipment which is used in the project two standards have been considered for the subject of material selection: NACE MR-01-75 (2000) and NACE Standard TM 0284-96 (1996). The main characteristic for a material to meet the former standard is that its maximum hardness should be 22 HRC. But HIC can occur in steels with no residual stress, and to reduce the possibility of HIC, the steel should be fully killed. Some coatings or liners are often used to prevent HIC. Steel clad with austenitic stainless steel is often used for this purpose. Also rubber or plastic coatings are frequently employed (Fontana, 1987).

Also another way to prevent HIC is to use corrosion inhibitors. Generally corrosion inhibitors reduce the rate of corrosion.

The condition of equipment from view point of physical parameters and composition is illustrated and the material of equipments has been selected.

The main material which is used in this project is carbon steel but with the requirements which meets the NACE MR-01-75 (2000) and ISO 15156 or NACE TM 0284-96 (1996). The first standard is about SSC, the second and third ones are about the requirements about hydrogen embrittlement.

Some different methods have been used in this project for corrosion preventing. In piping and flow lines, the selected material is carbon steel and inhibitor injection supports the system against the corrosives.

But it is protected for example with inhibitor injection in flow lines, with cladding in separators and with sacrificial anodes in atmospheric tank and in vessels which gathers water inside.

MATERIALS AND METHODS

First of all some environmental conditions about the concern project are submitted. For example: the area is mainly desert and grassland. Flooding is observed every now and then and can reach up to 1.5 m over the ground level. No information about dust storms was available before beginning the project but in recent years some has been seen.

Table 1: Coatings in the concern project

Item	First layer	Second layer	Top coat
External coating of equipment	Epoxy (70 μm)	Epoxy (70 μm)	Poly urethane (70 μm)

A maximum ambient temperature of 45°C and about 80% relative humidity have been assumed. In order to have resistivity against the atmosphere corrosion all the facilities were coated with polyurethane coating. Three layers of coating are considered for the external coating of pipes, vessels and all other equipment. It is clear that before coating the shot blast (blast cleaning) process shall be done. It is based on SIS 055900 Grade Sa 2½. The characteristic of coating is explained in the Table 1. The total dry thickness of coating should be about 210 μm. The polyurethane coating is considered of the top coat because it has very good performance in environments with high radiation of sun.

The applications of Duplex stainless steels have tight limitations in some environments which contain chloride ion and H_2S but some Ni alloys like UNS N06625 are too much stronger in the same conditions. The forecast for the amount of the chlorideion is 150,000 mg L^{-1} it and none of the duplex stainless steel will be resistant in these conditions. With considering the amount of H_2S partial pressure in for example separation vessels (2000 and 1000 ppm) no reason for using of duplex stainless steels will remain (Fontana, 1987; Braga and Orlandini, 2004).

Material selection also is a function of that how much of the internal surface of the vessel or pipe is wetted with water. In a separation vessel because the fluid becomes calm and gets approximately static condition, then naturally water settles in the first layer on the bottom of the vessel, so the vessel will be water wetted. But in pipes this matter is based on the Reynolds number and in the turbulent conditions there is possibility of oil wetting, so the corrosivity of the fluid becomes weaker (NACE MR 01-75, 2000).

For example for the flow lines, the Reynolds number can be calculated by E Q.1 as follows: (Arnold and Stewart, 1999; Rassel, 1988):

$$Re = \frac{\rho_k v_m D}{\mu_m} \tag{1}$$

Where:

ρ_K = Density = 931 kg m^{-3}
v_m = Mixture velocity = 3.5 m sec^{-1}
D = Pipe internal diameter = 0.273 m
μ_m = Mixture viscosity = 0.00285 kg m sec^{-1}
Re = $312130 \geq 2000$

Table 2: Fluid properties and corrosion rate in equipment

Items	P (bar)	T (°C)	H_2O (mole fraction)	CO_2 (mole fraction)	H_2S (mole fraction)	V_{corr} (mm y^{-1})
1st stage separator inlet	75.0	98	0.1984	0.0221	0.0029	0.57
2nd Stage separator inlet	25.0	94	0.2593	0.0124	0.0026	0.29
Atmospheric tank	1.25	76	0.000	X = 3.180% P = 0.04	X = 1.25% in gas P H_2S = 0.02	0.02
Oil storage tank	1.8	60	0.0000	0.0000 P = 0.04	0.0000 P = 0.02	0.02
Product water tank	1.0	78	0.9998	0.0001	0.0001	0.29
Produced water pump	1.0	95	0.9998	0.0001	0.0001	0.29

The Reynolds number is more than 2000, so the flow is turbulent and there is possibility of both water wetting and oil wetting, then the condition is better in comparison with the state of water wetting only.

In a crude oil system (like concern system), the sour service is a service which H_2S and water are existing and the partial pressure of H_2S be equal or exceeds 0.0003 MPa. It means the materials which are accepted for using in sour service should meet the criteria of SSC test (stress corrosion cracking test) (NACE MR 01-75, 2000).

If the condition is sour service like the presented condition, all the materials should meet the requirements of NACE Standard MR 01-75 (2000).

It means that all the requirements of the mentioned standard should be followed. For example the maximum hardness of material is not allowed to exceed 22 HRC.

In addition all materials which will use in the sour service condition should be resistant to Hydrogen Induced Cracking (HIC). For this purpose the raw material that is used for making the final product should have minor impurities according to the mentioned NACE standard TM-0284-96 (1996).

In the Fig. 1 the NACE diagram for the multi phase systems is shown. In each system (equipment) if the condition falls in the sour service area, so the related consideration; which exist in the related standard should be followed. As shown in the figure the two axis of this diagram are total pressure of the system and the amount of H_2S concentration (NACE MR 01-75, 2000).

But other kind of corrosion should be studied independently. For example due to presence of some chloride ions it is possible to have pitting corrosion in carbon or stainless steels.

Ordinary steel is more resistant to pitting than stainless steel alloys. Generally the pitting resistance of titanium alloys and nickel alloys are more than stainless steel types 304 and 316 (Fontana, 1987).

Some discussion about materials selection in flow lines: Depending on the fluid crossing the pipe, especially its corrosivity, pressure and temperature, stainless steel or carbon steel can be used in pipe lines but usually it is usual to use carbon steel based on the standard of API-5L flow lines and pipe line (NACE Standard MR0175, 2000).

Also the fabricated pipes which will use in the sour condition, should be resistant to hydrogen induced cracking (HIC). For this purpose the raw material that is used for making the final product should have minor impurities (NACE St TM-0284-96, 1996; Bruno, 1993).

According to the *API-5L* the carbon steel grades that has included for pipes are A25, A, B, X42, X52, X60, X65, X70 and 80. These are difference in yield strength and chemical composition. Also it is mentioned in IPS-E-PI-140 that when the grade of X65 is used for flow lines, it needs some preheating cycle. For this reason, before welding the pipe it should be heat treated just before welding the pipe ends to each other. The temperature of preheating is considered 306 (Braga and Orlandini, 2004; NIOC, IPS-E-PI-140, 1997; Sahu, 2005).

Using the mentioned grade of API also is proposed in the standard of NACE MR-01-75. Figure 1 shows the NACE diagram. With considering the amount of H_2S (2200 ppm) and total pressure (90 bar) in the flow line (Table 2) it can be seen that it is in the severe sour condition. API- X65 with 6 mm corrosion allowance is selected for the flow lines.

In some cases such as the atmosphere containing high CO_2 applications some alloy steels like 22Cr or 25Cr can be used (Russell, 2000).

It is needed to express that using these corrosion resistant alloys (solid or as a clad on carbon steel as backing Material) is not optimized for the concerned project for these reasons (Braga and Orlandini, 2004).

First, according to updated amount of water forecast (5%), turbulent state in the flow line the water wetting condition is reduced and corrosion inhibitor is sufficient to cover the possible uncertainty.

Second, duplex stainless steel is not acceptable, because it is not compatible with the H_2S partial pressure and expected chloride content.

Third, due to the high wellhead shut-in pressure (5600 psi), the wall thickness of pipe should be relevant (about 30 mm) and this includes some problems like welding, pipe price, fabrication, considering the NACE conditions and related expenses.

Furthermore, the facilities are located onshore and flow lines are laid above ground, this providing easy access for potential leak detection and repair.

Table 3: Allowable Pressure Psi (MPa) for some pipe classes in different temperatures (Nayyar, 2002)

Pipe class	20 to 100 °F	100 to 200 °F	200 to 300 °F
900	2220 (15.3)	2025 (13.9)	1920 (13.2)
1500	3703 (25.5)	3375 (23.3)	3280 (22.6)
2500	6170 (42.5)	5625 (38.8)	5470 (37.7)

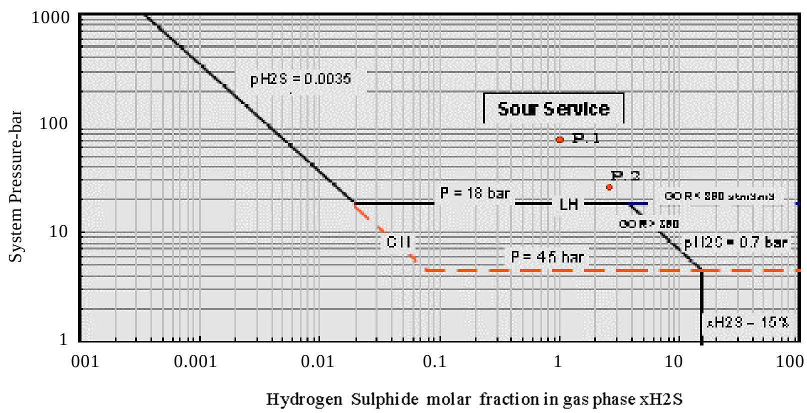

Fig. 1: The situation of separators in NACE diagram, P1 and P2

Then the use of carbon steel with 3 mm corrosion allowance is recommended.

In piping and pipelines design, not only the pipe itself but also all the components like elbows, valves, fittings and flanges should be considered. All of these components should be withstand against internal pressure which is caused by crude fluid. Studying in this field in order to determine pressures values which can withstand contains both pipe (that is straight cylinder) and components like valves (that have complex shapes).

In each design process, it is essential to have knowledge about finite elements and also being familiar with standards." The goal of the standards is to provide the interchangeability between manufacturers, set dimensional standards, specify allowable service ratings for pressure and temperature ranges, specify material properties, and specify methods of production and quality control. The ANSI B 16.5 and API 6A specifications are the most commonly used. By specifying the pressure rating class that is rated for a pressure equaling or exceeding the maximum working pressure of the particular piping system, the designer is assured that all flanges, fittings and valves furnished by any manufacturer will contain the pressure and have interchangeable dimensions. The ANSI B 16.5 specification has seven classes of piping: 150, 300, 400, 600, 900, 1500 and 2500. Historically the class designation was the allowable working pressure at 850°F." (APL 5L, 1992).

Table 3 shows the allowable pressures for some of the material of group 1-1 in different temperatures. The group 1-1 contains A105, A181-[22], A216-WCB, A515-70 and A516-70.

In determining the pipe classes it is essential to consider the weakest point of the system that can be one fitting with weaker material or lower rating classes (Reza and Mohajer, 2006).

The grade of A 106-B is selected for the piping in the oil treatment unit between equipment or vessles. All the pipes are seamless with 3 mm corrosion allowance. It is important to tell that in different areas (based on pressure level), different classes (thickness) of the mentioned grade was utilized. For example before the 1st stage separator the class is 2500 between 1st and second stage separators: 1500 and after the 2nd stage the pipes have the class of 900 in the ANSI class.

Also all the bolt and nuts which exist in the structures the material of A193-B7 has been considered.

It is clear that in the production process of this steel all the conditions which are necessary for the steel to be resistant against HIC an SSC should be concluded.

Some discussion about materials selection of separators: Gas-liquid separation processes most frequently employed in oil and gas industries are based on either one or a combination of "Gravity Settling", "Impingement" and "Centrifugation", principles.

Fluid phases with different densities will have different momentum. If a two phase stream changes direction sharply, greater momentum will not allow the particles of heavier phase to turn as rapidly as the lighter fluid, so separation occurs.

Liquid droplets or solid particles will settle out by gravity of a gas phase if the gravitational force acting on the droplet or particle is greater than the drag force of the gas flowing around the droplet or particle. The same phenomenon happens for solid particles in liquid phase and immiscible sphere of a liquid immersed in another liquid. Rising of a light bubble of liquid or gas in a liquid phase also follows the same rules, i.e., results from the action of gravitational force.

In this oilfield, Well fluids from the production flow lines will be mixed together in the production manifold. Co-mingled fluids from the production manifold will then flow to the 1st Stage Separator. Gas and water from the 1st Stage Separator will be sent to appropriate treatment processes, and oil from the 1st stage Separator will be sent to a second separation stage. All separators are horizontal type. The working pressure of this vessel is 75 bars and the amount of H_2S is 0.1984 mole fraction (about 2000 ppm) so it is positioned in the sour service (point 1) in the NACE diagram (Fig. 1).

The 2nd Stage Separator shall be designed to separate the fluids which comprise the oil product stream from the first stage separator. The fluids are three phase, and consist of an oil phase, associated gas and formation water. Associated gas arises due to the large fall in pressure between the 1st and 2nd Stage Separators. Water is the entrainment from the 1st Stage Separator. The working pressure of this vessel is 25 bars and the amount of H_2S is 0.2593 mole fraction (about 2500 ppm) then clearly this point is also is in the sour service (point 2) region in the Fig. 1.

Corrosion may occur in the gas phase and wet crude/produced water phase during the separation phase and, due to the not negligible amount of water expected in the production fluid (5%), water wetting has been anticipated at the bottom of the vessels. Considering operating conditions such as high pressures (75 and 25 bar) and temperatures up to 80°C but especially the H_2S partial pressure in the gas phase and the high chlorides content in the water phase, the use of nickel alloys is recommended.

It is needed to tell that the two pressure levels have been chosen according to the compression system requirement and to optimize the recovery of gas.

Some materials for the plate of the vessel are introduced in ASME division Ї, part D but in the ELF standard, specification no. SG.MAS.001 is indicated that the plates should be fabricated from unalloyed carbon steels produced by the converter, electric furnace or oxygen furnace process. Plates should be selected from ASTM A 516 or ASTM A 841/ EN10028 or equivalent standards.

This carbon steel should meet all the requirements of NACE MR-01-175, it means that it's hardness is not more that 22 HRC, its nickel content is less than 1%, its tempering temperature is 595°C (NACE MR 01-75, 2000).

Fluid composition requires materials compliance with NACE MR 0175/ISO 15156 for SSC and NACE-TM0177 for HIC.

Also it meets all the necessaries for HIC and SSC tests according to NACE TM0284-96 and NACE -TM0177. Because of having severe conditions in the first stage separator, it is needed to clad internal part of this separator totally. It was done with UNS 06625.

Both separators shall be suitable for sour service. Then finally the material selection of the plates of shell and heads of the separators has been considered: A516 Grade 60 clad with 3 mm alloy 625. According to IPS- G-ME-150 the minimum thickness of cladding shall be 2 mm (API RP 941, 2004; IPS-G-ME-150, 1996).

Also the material for the Fixed and removable internals should be carbon steel (CS) clad 625.

For this nickel alloy there is no practical limit to temperature, H_2S and chloride concentration partial pressure for oilfield service. Also its hardness can be maximum 35HRC (NACE MR 01-75, 2000).

According to ASME (1988), Division 1, the base material which is A516 should comply with the material given in UCL-10, page 229. One of the most important criteria for the carbon steel is that the carbon equivalent of that should not be more than 0.35% and it is considered for the selected carbon steel. The post weld heat treatment (PWHT) is required and was done in the temperature of 595°C.

Also based on this reference, the post weld heat treatment should be done on the whole vessel after doing cladding and all the welding.

The nickel- copper alloys are strong a tough, offering corrosion resistance in various environments, including brine and sulphuric and other acids and showing immunity to chloride-ion stress corrosion (Fontana, 1987).

There are two methods for cladding the nickel alloy on the carbon steel, cold forming and weld overlay. The plates (shells) of vessel were cold formed with alloy 625 and then there will not be any welding problems such as residual stresses. Also for the forgings like flanges the method of weld overlay were done because of their complicated shapes.

For the 1st stage separator the thickness of the plates should be 75 mm without considering the clad thickness. Also the length of the vessel is 15000 mm and its diameter is 2750 mm.

The dimensions of the 2nd stage separator are 10000×2500 and its thickness is 27 mm.

CONCLUSION

The conclusion can be listed in the following items:

- The two base items which have been considered in this project for material selection is cost and required technical properties. The main material which was considered for the utilities was carbon steels which was accepted in ASME and API standards. Also it is a main requirement that the material should be according to the NACE standards to be resistant against the both corrosion types of HIC and SCC.
- The use of duplex stainless steels is avoided because of the high chloride concentration which will exist in the fluid coming from oil wells, then instead of that carbon steel with considering corrosion allowance and also corrosion inhibitor (amine base) was used for the flow lines and piping systems.
- In some cases like separators which there is the state of water settling, nickel alloy lining on the carbon steel base was considered.

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