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Research Article

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Safe Practices in Drilling and Completion of Sour Gas Wells

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Abstract

This paper examines the current status of the global market of sour fields. In particular, it clarifies on the existing methods, standards, and technologies applied for drilling, cementing, and completing a well with high H_2S concentration, with view of recommending the minimum health, environmental, and safety (HSE) protocols or standards required when dealing with sour environments.

The overall approach for this study was literature review. This will involve exploration of various exploitation case studies from the region and the globe meant for improving the economics of developing sour reservoirs in this cost sensitive time for the industry. Literature on current status of methods and technologies applied for drilling, cementing and completing high H_2S concentration wells will be reviewed. Standards and recommendations set by the American Petroleum Institute (API) and National Association of Corrosion Engineers (NACE) on the minimum Health, Environmental, and Safety (HSE) for use in sour environments will also be reviewed.

The findings of this study informed of the fact that there is very small even any room for error when it comes with exploiting high H_2S concentration well reservoirs. The results of the study established that dealing with sour fields is a challenge the industry will face more often, and in increasing magnitudes over time. In particular, it was established that the best approach for meeting this challenge is for companies in the industry to acquire knowledgeable personnel, an element that dictates for consulted investing in the proper training of employees. In order to ensure proper training of personnel, core areas of the training should encompass best practices on the selection of materials, planning operations, and the swift planning and executing of operation plans and incidents.

This study will have implication for unlocking the full potential of the sour environments frontier for the region. The findings of this study will provide drilling and completions engineers with insightful knowledge on best practices in dealing with sour fields.

Keywords: Drilling; Gas-wells; Petroleum; Environmental; Oil; Bacteria

Introduction

Sour service refers to a well environment containing significant amounts of Hydrogen Sulfide (H_2S). H_2S is hazardous to human health, living organisms, and the environment in general. Failures in sour environments are a major concern to Oil & Gas companies due to the higher risk, cost, and lost time associated with these failures [1]. There is no set cut off point to classify whether a field is sour or sweet. The threshold differs from one area to another. In majority of areas, gas is qualified as sour gas if H_2S makes for more than 2.5% of gas contents. The Middle-East region isn't strange to highly sour fields with H_2S up to 30% in some fields. Canada is one of the first locations to discover sour fields in and is notorious for high H_2S content with one well containing up to 90% H_2S. H_2S isn't restricted to a certain type of field. It can be found in oil and/or gas fields, onshore and offshore, HPHT and conventional, etc. Even if a field starts with no H_2S content, the H_2S content keeps on increasing as the field is aging.

The International Energy Agency (IEA) published in their 2014 medium term gas market report a 1.2% growth in global natural gas demand over the span of 2013. And BP forecasts in their energy outlook an increase in global natural gas demand by an average of 1.9% per year to 2035. With increasing demand of gas worldwide, some highly sour oil and gas reservoirs are being explored, mainly in Russia, the Middle East, China, North America, and are now more and more associated with complex well profiles – such as deep reservoirs or extended reach wells. As time passes, more of the previously uneconomical sour fields will become viable development projects. The Oil and Gas industry will need to step up its game and address the challenges associated with developing such fields.

Reservoir souring

The process of introducing or increasing H_2S in a reservoir is called "Reservoir Souring." Reservoir souring can be attributed to a number of factors. It can happen due to poor microbial treatment in pipeline or topsides facilities, the addition of bacteria to the reservoir through poorly treated injection water, and use of sour gas for gas lift [2]. When injection water isn't treated properly, it can introduce Sulfate-Reducing Bacteria (SRB). SRB are present almost everywhere including injection water (seawater). In seawater, SRB is inactive due to the oxidizing environment but under reservoir conditions, SRB becomes active. SRB are bacteria that breaks down organic material while reducing sulfate and producing H_2S instead. SRB are tolerant to high pressures but are less tolerant of high temperatures. SRB can survive under pressures up to 7500 psia but thrives in pressures below 4000 psi. Most common SRB can't grow in temperatures above 113° F. However, there have been reports from oil fields about SRB that can grow in temperatures above 158° F [3]. Even if reservoir temperature is above SRB limit, SRB would grow near the injectors and continue to generate H_2S (Figure 1) [3].

Once SRB is introduced to the reservoir it is impossible to fully treat it. If the biocides even leave a small fraction of SRB in the reservoir, it's

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still enough to sour it. Under favorable conditions, a bacteria colony can double size in 20 minutes. Still, it's useful to maintain biocide injection especially in injection fluid and packer fluid to decrease SRB effect. One of the recent methods to control reservoir souring is injecting nitrates with seawater (injection fluid) [3]. This method encourages Nitrate-reducing bacteria (NRB), a competitive bacterium, that produces nitrogen instead of H_2S. NRB will consume the organic compounds, denying SRB from them. This method is widely used yet its potential corrosion side effect is still under study.

Pitting corrosion and sulphide stress cracking

H_2S in produced fluids reacts with steel to form a semi-protective film of iron sulphide (FeS). Unfortunately iron sulphide is rarely uniform and can be removed by flow exposing fresh metal to H_2S. The exposed metal rapidly corrodes causing pitting similar to Figure 2. Pitting corrosion is a localized form of corrosion by which cavities or "holes" are produced in the material. Pitting is considered to be more dangerous than uniform corrosion damage because it is more difficult to detect, predict and design against. Corrosion products often cover the pits. A small, narrow pit with minimal overall metal loss can lead to the failure of an entire engineering system.

H_2S can also cause sulphide stress cracking (SSC). SSC is a form of hydrogen stress cracking. The role of H_2S is to provide hydrogen at the metal surface by corrosion and to prevent hydrogen from escaping into the production fluid. The hydrogen then finds an alternative route by migrating through the metal structure; this is possible due to small size of the hydrogen atom. In the absence of H_2S, normally, hydrogen atoms would combine to form the larger hydrogen molecule and just bubble off instead of migrating through metal. This migration is temperature dependent, the higher the temperature the easier the migration. Under low stress blistering will occur while under high stress cracking occurs [3]. Brittle metals are more prone to cracking. SSC is more critical than pitting corrosion caused by H_2S because it happens suddenly while corrosion is a relatively slower process. While coating and continuous corrosion inhibition through chemical injection can lower H_2S pitting and cracking, The National Association of Corrosion Engineers (NACE) doesn't qualify them as mitigation measures due their low reliability. Coating can be removed and inhibitor injection can stop due to low supply or downhole injection valve failure. NACE provides a guideline to labeling sour service. Sour service severity is split into four regions based on pH versus H_2S partial pressure as in Figure 3.

a. Region 0: H_2S partial pressure below 0.05 psi is considered to be non-sour.

b. Region 1: characterized with low partial pressure and relatively high pH is considered mildly sour.

c. Region 2: is considered moderately sour and requires API N80 and C95.

d. Region 3: the highly sour level which requires API L80 and C90.

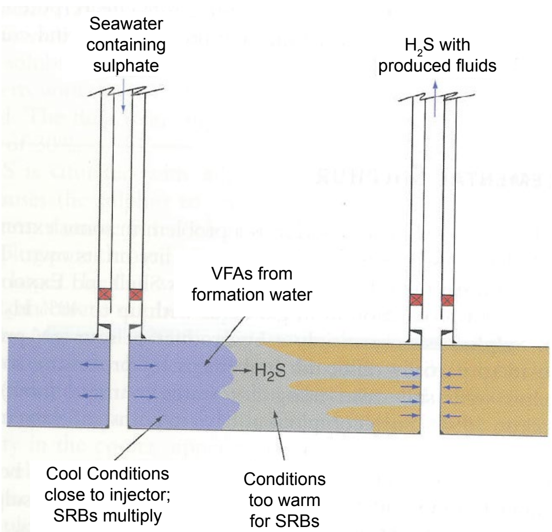

Figure 1: H_2S factory.

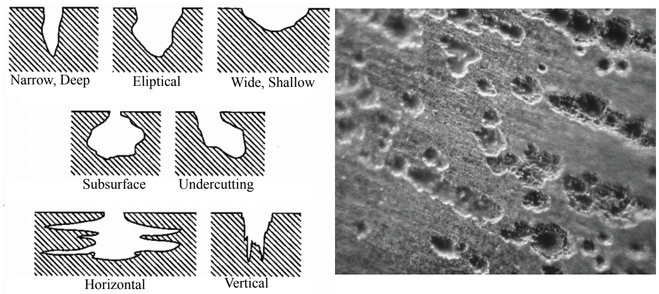

Figure 2: Pitting corrosion.

Materials

The metallurgy of the drilling equipment has evolved over many years and keeps on evolving to meet new challenges. Proper material selection is the main line of defense against H_2S pitting and cracking. A prime example of the importance of correct material selection would be the recent pipe leak in Kashagan field in Kazakhstan. After only a few weeks from inauguration of the field, production was shut after discovering H_2S leakage from the pipelines. The solution is to replace 200 km of leaking pipe which is estimated to cost more than $3.6 billion [4]. The most important drilling equipment selections in a sour environment are drill pipe, tool joints, drill collars, blowout preventers, and wellheads. These equipment have the highest chance of suffering from corrosion or cracking during drilling. The emphasis for these equipment is on strength (pressure containment) and fracture resistance (SSC and corrosion resistance). Choosing the correct pipe strength and composition is a very case explicit choice. There is no one specific grade to cover all possible applications and being over conservative can make a project uneconomical. For example of grade selection diversity, SSC reduces at high temperature and low-alloy steels have different temperature constraints. L80 pipe is suitable for sour service (Region 3) under all temperatures whilst P110 only above 175° F and Q125 only above 225° F. These temperature constraints render P110 and Q125 generally unsuitable for sour service tubing but useful for liners and lower sections of production casing strings [3]. Another example, while L-80 is suitable for sour service, it isn't suitable in the presence of high CO2 concentrations. The combination of H_2S and CO_2 creates a harsher environment than L80 can deal with. That's why a (2Mo-5Ni) 13 Cr pipe was designed to cope with the combination of H_2S and CO_2. On the other hand, the more costly alloys a pipe contains, such as chrome and nickel, the more expensive it becomes. Table 1 presents the pros and cons of different types of drill pipe material available in the market.

When designing tubing for sour environment, one must consider the increasing levels of H_2S; especially in water flooding reservoirs. NACE

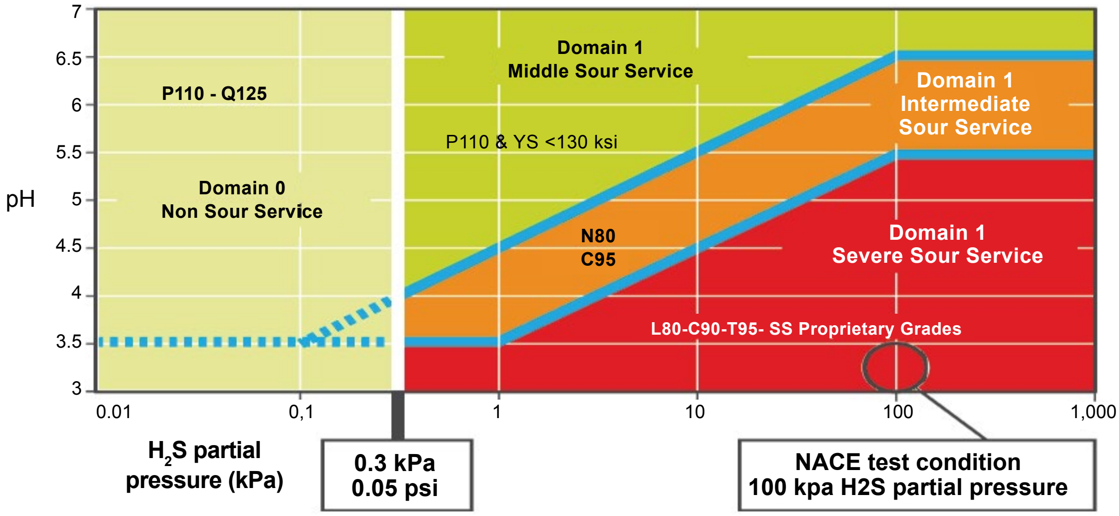

Figure 3: NACE sour service definition.

	Steel Drill pipe	Aluminum Drill pipe	Titanium Drill pipe
Advantages	• Strength • Low Cost • Multiple Grades	• Lighter weight • Deeper drilling with mixed strings • Better fatigue life than steel • More resistant to H_2S and CO_2	• High strength • Light weight • Corrosion resistance to most drilling muds • Resistance to H_2S and CO_2 • Excellent fatigue life • Good high temperature strength
Disadvantages	• Susceptible to corrosion • Susceptible to SSC • Brittle fracture • Wear	• Low resistance to mud with pH > 10.5 • Susceptible to pitting in chloride • Susceptible to chloride stress cracking in oxygenated brine muds • Limited to 250 F • Galvanic corrosion • Lower abrasion resistance	• High cost • Wear

Table 1: Pros and cons of different drill pipe materials.

has developed a standard governing the material recommendations for sour environment in their NACE MR0175/ISO 15156 document. The standard is divided into three parts. Part one is general, part two covers carbon and low-alloy steels and part three covers corrosion-resistant alloys (CRAs). Adhering to the recommendations in this document is crucial for safe and long life equipment. In the United States, this standard is legally enforced.

Completions

Tubing material and design

In tubing, a design philosophy that ensures that the safety of the immediate areas and that of the well bore should be considered. Next, one should come up with the largest possible practical tubing that can achieve the highest possible flow rates [5]. The most suitable solution for the tubing material and design is the use of corrosion resistant alloy tubing string with corrosion resistant alloy components. This is the optimal solution because the tubing will exceed the field's productive life and it will lead to a low maintenance and low risk production. Although this selection is expensive when compared to other tubing options, the net result is comparatively cheap because it will not require frequent maintenance [6].

Among other corrosion resistant alloys, the Alloy C-276 can be selected. However, this should not be restrictive. Other alloys can be selected as long as they are corrosion resistant. The material should have a superior strength to weight ratio. It should also be resistant to the corrosion and stress cracking. The potential failures in the wells are from corrosion and chloride stress cracking. As well, in wells with temperatures less than 180 degrees Fahrenheit, embrittlement of the alloys can occur. As such it is vital to pay attention to the selection of materials for the tubular goods. The materials should be cracking and corrosion resistant. This will prevent mechanical failures [5].

Tubing connections and field handling procedures

Handling of the joints of the tubing, the torque requirements, the rig supervision and the cleaning of pipe threads should be given close attention. These should be maintained at the highest level. This will ensure proper makeup and protection of the tubing when run into the hole [5]. A coupled and threaded tubing connection should be used. It should make use of the metal to metal nose flank seal and the interference fit threads. A secondary seal should be provided by a Teflon ring in threads. Most of the tubing used in this case will be gall sensitive. There is a likelihood of galling during the connection makeup. It should thus be noted that the engineers should use proper makeup procedures and connection preparations to eliminate the galling problem. An anchor pattern should be applied to the box and the pin surfaces through sand blasting. This will help smooth the rough edges. It will also provide a textured surface that will help retain the pipe dope [6]. It is worth remembering that the proper handling of tubing is essential to ensure the integrity of the sour well. If the pipes are handled poorly, this could lead to the failure of the tubing or the connection. There should be no metal contact between the tubes. The connections should be protected using nonmetal thread caps.

Tree, tubing hanger and production choke

The upper sections of trees and the tubing spools should be manufactured from materials that are suitable to resist the sulfide stress cracking. This is outlined in the NACE Standard number MR-01-75. The valve bodies should be fabricated using stainless steel with gates, seals and packing materials that are compatible with sour environment and with the amines used for inhibition. In case of wells with high pressure and situated in sensitive environmental areas, a surface circulating system should be constructed at wellheads. This will provide a way of controlling the wellhead from remote location if the gas release occurs. Such a system should have three separate lines. The lines can be used to pump fluids in the well for purposes of reduction of pressure and to kill the wells. Behind the production choke, a pump in should be made. It should also be made into the casing annulus or into the injection string. Surface system should be monitored for corrosion information, safety status and wellhead data. This should be carried out using a scheduled manual inspection and electronically. Vital information that should be monitored includes flowing and injection pressure, pneumatic power supply, injection pump status and temperatures [5].

As well, it should be noted that the tree should be fitted with an Alloy C-276 autoclave needle piping and valves. The tree valves should be manufactured with metal single slab seats and gates. A heated Alloy 718 can be used as the material for stems, gates and other internal components of the valves. This is because of their corrosion resistance and high strength. The hangers should be constructed using Alloy 718 material. They should be sealed below and above with a plastically deformed metal to metal seal [6].

Design of the down-hole production seals and PBRs

The design philosophy to be adopted here is that there should be minimized cases of leaks in this system over the well's life. This helps maintain the seals of the tubing in a static position in all production conditions and routine operation. For safe and reliable operations, the tubing casing annulus should be sealed downhole via the use of polished bore receptacle system. The system's elements should have a continuous polished bore run. It should also have a set of elastomeric seals and a locator on the completion tubing. The polished bore receptacle should be constructed using Alloy C-276 material. This should help in corrosion resistance and durability. This system is one of the most reliable in the completion components [6].

The packer design should be considered. The packers should be used to isolate the casing annulus from the corrosive gas produced from reservoirs. It should also be used to isolate the annulus from pressure. Here, the use of long seal elements on the tubing string is desired. With high surface temperatures and high bottomhole experienced during the production, there should be compensations for the large tubing movement. Still, allowances should be made in the seal length to compensate fracturing, potential acidizing and reverse flowing [5].

Corrosion control and surface control systems

There are problems associated with sour wells and they include corrosion caused by carbon dioxide, hydrogen sulfide, precipitation of the scales and the SSC. Problems caused by SSC should be solved using proper selection of the materials used for wellheads, tubulars and surface facilities. The presence of carbon dioxide and free water in the production wells causes the formation of low pH surroundings. These surroundings produce conditions that are extremely corrosive. The presence of carbon dioxide also causes erosion phenomenon that result from the high pressures production. The high pressure production causes high velocities that cause the erosion. This problem can be combated using inhibitors and internal coatings. As well, the use of internal coatings can help provide extra protection in the hot sour environments. The coatings should however be used alongside good inhibitor programs. The inhibitors that should be used in such wells include water dispersible and oil soluble systems. Oil soluble system is much desired because it provides a film that is more tenacious that the other systems. An oil soluble amine can be used in conjunction with hydrocarbon carriers [5].

As stated by McDermott & Martin III (1992), the nearness of the wells to areas that are environmentally sensitive, the corrosive nature of the gas and the need for the safety of the workers calls for enhancements to the surface control systems. The wellhead needs to be fitted with electronic sensors for measuring the tubing and the casing pressures and the temperature of the well. The sensors should be remote. The use of this system is vital because it helps come up with early detection of problems in the wellbore. It also comes up with the necessary information about the next course of action should there be a problem. There should be a complete kills system that can help facilitate an immediate reaction to a wellbore problem. Such a system should have permanent piping, high pressure pumps and weight fluid.

Displacement technique

Oil or fresh water that is treated with a corrosion inhibitor, oxygen scavenger or bactericide should be used as the annulus fluid. These fluids should be used to offer protection to the production casing made up of the carbon steel. They also prevent external corrosion of the corrosion resistant alloy tubing string for the entire life of the well. After the installation of the tree and the landing of the tubing, the pressure should be applied down the tubing. This will help expel the plug and thus allow the well to flow [5].

H_2S

H_2S is an extremely toxic and flammable gas. Inhalation at certain concentrations can lead to injury or death. The human body can cope with small amounts of H_2S but an air concentration of 100 ppm is currently considered as Immediately Dangerous to Life and Health (IDLH) by the American Conference of Governmental Industrial Hygienists. H_2S is colorless, has a rotten-eggs odour and is heavier than air. At levels as low as 10 ppm, eye irritation can occur and nausea and dizziness can occur at higher levels. Even though the distinctive smell of H_2S can be an indicator of its presence, it mustn't be depended on as it can lead to rapid paralysis at high concentrations. That's why most H_2S detectors are set to alarm at concentration of 10 ppm. One of the mitigations to H_2S risk is orientating of the rig heading according to the prevailing wind to locate living quarters upwind of the well. Another mitigation is through adequate training of onsite personnel. API recommends a minimum training that discusses the hazards, proper use of H_2S detectors, emergency response, breathing equipment utilization, wind direction awareness, and importance of pre-job meeting. This training need to be given to visitors just as it's given to regularly assigned personnel, no exceptions. This training needs to be taken on yearly basis to keep all personnel's awareness at highest level. In addition, API emphasizes the importance of regular H_2S drills. The aim of the drills is to familiarize the crew with the necessary steps during an emergency [7].

RIG

A rig used for drilling sweet fields can't be used to drill high H_2S wells without upgrading and adjusting it to mitigate the H_2S risk. This part of the paper considers offshore rigs because of the additional complication and risk. However the points in this section still apply to onshore rigs.

The living quarter is the most crucial facility to upgrade due to it being the nerve system of the rig with majority of on-board personnel residing in it. The fact that its occupants might be sleeping makes it even more vulnerable. Every HVAC intake inside the living quarter needs to be fitted with an H_2S detector. The living quarter also needs to be tight in order to fight gas ingress. This can be done by ensuring a pressure greater than the outdoor atmosphere by minimum of 50 pa throughout the living quarters. The living quarter doors the main and weakest points against gas ingress. Thus, optimizing the number of doors, renewing the seals on the doors and adding a second sealed door behind each door can greatly increase the protection against gas ingress [7].

While most rigs are equipped with H_2S detectors, BA sets, and gas & H_2S detection system, their amount needs to increase to suite sour service operations. Number of H_2S detectors need to enough to cover every personnel exposed to mud flow or reservoir fluids. A complete breathing air cascade system composed of compressors, airlines, and breathing apparatus (BA) sets needs to be implemented to cover all critical areas. One of these critical areas is inside the lifeboat. The breathing air manifold will greatly increase the time of breathing air in case of lifeboat boarding during rig abandonment. All these detectors and breathing equipment require regular tests to ensure proper function and calibration. The same requirements regarding living quarters, detection system and breathing system must be implemented on supply vessels as well [7].

Recommended practices

API recommends a few additional measures than the ordinary while performing the following operations in an H_2S environment [1].

Venting operations: Any venting operation that has a likely release of H_2S should use correct piping to vent to a remote location.

Wireline operations: The minimum lubricator equipments are wire-line valve (blowout preventer), lubricator riser, pressure bleed valve, and stuffing box. If pressure bleeding was necessary and can't be vented to a remote location, then all personnel must wear breathing protection equipment. If permissible, wire-lines and slick-lines should be treated with corrosion inhibitor before running in the hole. After operation completion, wireline should be inspected on site for pitting, surface damage, and embrittlement. Regarding positioning the swabbing unit, wind direction should always be taken into consideration first. The swabbing unit needs to be placed upwind from well, swabbing tanks, and mud pits.

Snubbing operations: Snubbing operations should be limited to daylight hours only unless an emergency snubbing intervention is required. The number of personnel should be kept to essential personnel only. Every worker on the snubbing basket must have a BA set and an escape device.

Coiled tubing operations: The placement of coiled tubing unit should be upwind of the well. The unit should be effectively secured in order to avoid harmful movement. It is recommended to consider a pump cross and a second ram preventer below the pump cross when operating underbalanced. Wellbore fluids shouldn't be circulated back to the coiled tubing unit.

Valve drilling and hot tapping operations: All equipment used in these operations should have a working pressure rating higher than the anticipated pressure inside tapped equipment. The lubricator assembly should be equipped with two valves in series on each bleed-off port. The inner valve is for emergency use and the outer valve is mainly operated instead to preserve the inner valve. These valves should be suitable for sour service and pressure rated to the same or above working pressure of the lubricator.

Coring operations: All members involved in coring operations should don protective breathing equipment at least 10 stands before the core barrel reaches surface. H_2S detectors need to be used on the core sample. Sample containers must be made of H_2S resistant materials and labeled accordingly.

Well evaluations and testing operations: A pre-job meeting focusing required PPE, no-smoking rule, and emergency procedure is a must. Personnel performing the operations should be kept to a minimum and carry H_2S detectors at all time. All produced gas should be safely vented and fluids samples are handled and stored using H_2S resistant materials.

Wellbore fluids: The recommended practices to mitigate sulfide stress cracking using the mud system are:

a. Minimizing formation fluid influx.

b. Using H_2S scavenger and constantly monitoring its level.

c. Maintaining the mud system at pH of 9 or higher.

d. Adding diesel oil or other protective fluid to the mud.

Coiled tubing in sour environment

Introduction: Coil tubing has been used in sour well environments for over two decades. The advances made in the coil tubing technology make it an economical alternative when compared to other alternatives in the oil field operations. This is the result of research whose aim is to understand the response of coiled tubing (CT) when exposed to sour down-hole conditions [8,9]. This paper analyzes the specifications, limitations, new improvements, tests, and applications of CT.

Specifications: The purchase specification is the heart of the management system and it is also the chronological starting point, At this point, the strings ordered are assumed to be fit for use in the sour wells. The specifications are also important because strings that are obtained specifically for sour service are thought to be less susceptible to catastrophic sour degradation. Generally, there are two types of strings purchased for work-over operations [10]. The first is the non-taper 400 m standard string which has a wide range of uses such as acid stimulation, milling operations, wellbore cleanouts, gas lifting, cementing work and fishing. The second is the tapered string. For both of them, different purchasing specifications are recommended. After a scientific testing, the following purchasing specifications of pipes were introduced into the market. For standard strings, the maximum allowable fatigue is 70% while the taper strings have fatigue allowable being up to 60%. For Sour fatigue, current industry standards allow up to 20% for standard strings but for the tapered strings the specification is 48%. As for sour jobs, the standard requirement is 19% when using standard string while taper string requirement is 87%. Corrosion fatigue requirements are a standard of 25% for normal string while taper requirement is 40%. The standard requirement for acid pumped is 117 m^3 while the taper requirement is 1450 m^3 [8]. Normally, the standard number of jobs a CT should carry out is 37. However, when using tapered string, the requirements restrict it to 15 jobs. The standard time of service is 5 months for standard non-tapered strings while for taper strings requirements allow up to 20months. Finally, standard field requirements for inspection stand at 2 while for taper string they stand at 10.

Limitations: Initial JIP considered only CT strength grades ranging between 70 and 80 ksi and the resulting conclusion was that sour service CT strings should be limited to a maximum strength of 80ksi yield. Though the 80 grade sour CT limit served well, it imposed undesirable limitations on sour well interventions which resulted in requirements for higher strength CT. In earlier publications, the use of butt welded joints had been advised on the basis of engineering judgments in sour service strings [8,9]. Based on the current JIP testing results, it is clear that 100% H_2S sour environments reduce the range of bend fatigue performance for butt welds in ranges of 35% to 75% of the achievable performance for these welds in sweet conditions.

New improvements: As a result of the growth in technology, there have been new improvements in the CT field. The first improvement is the use of electronic inspection. Electronic inspections have proven to be effective in identifying both the actual and potential flaws that can result in pipe failure. The nature of H_2S results in a magnification of some pipe flaws that could not have escalated in non-sour conditions. The pipe inspections currently form an integral part of the management system [11]. Current efforts in the electronic inspection area are geared towards identifying the criticality of different flaw types, orientation with reference to tube axis orientation, and the rate of occurrence. The second improvement is the use of inhibition. Different inhibitors are applied to the tubing to protect it from sour attack. Currently, there are a number of application methodologies that have been identified. In most cases, the inhibitor is applied externally to the tubing as it enters into the well. Before any treatment, a slug of inhibitor is also pumped through the string [12]. The decisions on how the slug is applied are dependent on the nature of work and exposure. Another development is in the area of fatigue monitoring. Today, it is common practice to apply low-cycle fatigue monitoring of CT. There are a number of guidelines that have been applied to limit the acceptable fatigue life of CT [13]. The suggestions are that the maximum fatigue life allowable should be a fraction of the sweet service. Another development is in the area of stewardship. The introduction of stewardship in the area of management was prompted by a high number of CT failures which pointed fingers more to human errors than industrial standards. As a result, the introduction of the management system required that only one or two individuals should be involved in the process of ordering strings, maintaining strings, and selecting strings for a given operation. These individuals, stewards, acquire an intrinsic understanding of strings and the type of service that they have seen. This has resulted in the stewards gaining inherent knowledge of strings to an extent that their intuitive decisions correspond to analytical decisions made in laboratories. For example, laboratory tests can recommend the removal of a string only to find that the stewards have already retired it.

Tests: The main test protocol is one that includes a custom test procedure that involves either a single-sided or double-sided sour exposure of around 1.25 m length of full size CT. Single-sided exposures were found to be more representative of field exposure. One common test is constant load test without inhibitors. This is performed on the higher strength grades for high concentrations of 100% H_2S in a NACE "A" solution. The maximum permissible working load used is equal to von Mises strength of 80% of SMYS [14]. Using new CT90 grades, tensile failure was realized after 48 hours for combined constant hoop and 44 hours for axial tensile hoop. These were half of the desired survival period. The second test performed was incubation times from AE Corrosion Cell Tests. In the test, external services of cycled CT70 showed spots of hydrogen blistering which was likely to have been caused by plane AE signals. For cycled CT80, an exterior crack on the radial direction of the outer CT surface was observed.

Exploitation of high H_2S fields

Developing high H_2S fields isn't a new thing. It is resourceful to learn from peer experiences around the world. This section aims to provide a couple of cases and present the challenges faced and actions taken.

Example 1: As argued by Malik et al., the supper Giant Kashagan oil field is one of the most important sources of crude oil in the world. Discovered in 2000 in Caspian Sea, it is known to be the most significant discovery in the world for the last 30 years. The contents of this field include light oil made up of 5% carbon dioxide, 15% hydrogen sulfide as well as huge amounts of associated gas. The most significant challenge faced by the consortium of companies developing this field is how to manage the enormous volumes of associated gas, which are highly sour. To overcome this challenge, the consortium had two basic options. One of the options was to evacuate the sour gas to the field's shore. This gas is treated before being sold out to interested parties. Although this was found to be technically unchallenging, it is an expensive approach. The second option, re-injecting the sour gas into the reservoir, was found to be cheaper despite being technically challenging.

When embracing the gas injection option, the consortium found it important to understand the cap rock integrity in order to avoid its breach. Geo-mechanical studies are necessary in ascertaining how the *in-situ* stress is distributed. The stress distribution was better understood through collection of well data by conducting a series of injection, leak-off and mini-frac tests. Additionally, geo-mechanical models were used to determine the best injection pressure at the bottom of the hole. Laboratory tests were also important in determining the possible effects of gas injection on cap rock integrity as well as detection of any present micro-fractures that can lead to gas slippage. These studies included mechanical failure, threshold pressure, gas bubble migration, geochemistry and petrography. The initial field data about the oil well was used together with laboratory measurements to develop geo-technical models important in evaluation of gas injection, natural depletion and end members at very high pressures.

Since there was the risk of asphaltene precipitation and deposition, the consortium conducted an asphaltene stability study. This gave them an opportunity to evaluate the well's fluid stability as far as asphaltene precipitation was concerned. They were also able to assess how the asphaltene behavior is affected by the sour gas flood. It is through the same stability study that the consortium was able to do validation of thermodynamic modeling that revealed how asphaltene stability is affected by the gas injection. The asphaltene stability study was made possible through dead oil screening and live oil depressurization test. Reservoir management is another important activity at the Super Giant Kashagan. Two aspects are used in this management to make sure that miscible gas injection is possible. Major aspects of this management include injection gas front monitoring and gas shut-offs comprising mechanical and chemical options.

Example 2: As presented by Hrncevic et al., Croatia had developed large natural gas fields by the beginning of 1980's, including Kalinovac, Stari Gradac and Molve. For all these fields, the engineers were faced by the challenge of great initial reservoir pressures which exceeded 450 bars. They were also faced by the problem of high temperature and high levels of carbon dioxide and hydrogen sulfide. Additionally, presence of additional non-carbon compounds such as mercury and mercaptans in high levels was a great challenge. Table 2 describes the fluid composition of each reservoir. Currently, the Croatian petroleum industry has great experience on how to process sour natural gas with minimal effects to the environment.

The mentioned challenges were experienced by the individuals working in the Croatian petroleum industry as well as international technologists and experts. Among the challenges, the most significant one was how to determine and apply appropriate mechanism to prevent corrosion when dealing with chloride, mercury, hydrogen sulfide and carbon dioxide. This necessitated the need to device ways to avoid chloride stress cracking, sulfide stress cracking hydrogen sulfide corrosion and carbon dioxide corrosion. This was made possible through the use of injection valves at specific depths to continually inhibit this corrosion. However, this strategy produced poor results since there was corrosion of the valve after a short period of time. The corrosion was caused by some aromates present in the inhibitor. Additionally, the effect of the inhibitor was reduced by the high temperature through disintegration. Since the anticorrosion protection was associated with great damage, the experts were forced to replace the production equipment. This was followed by the use of high alloy steel grades to make it possible to resist various types of corrosion under diverse conditions of pressure, stress and temperature. The materials used for the production casing were the following:

a. Production casing above permanent packer was carbon steel.

b. Production casing below the packer was made of duplex steel with 25% Cr in gas wells and 13% Cr in gas condensate wells.

c. Production tubing was made of high-alloy duplex steel with 25% Cr in gas wells (Molve gas field) and high-alloy steel with 13% Cr; Hardness HRC < 23 in gas condensate wells (Kalinovac and Stari Gradac gas field).

d. Subsurface equipment (packer, SCSSV) is made of Incoloy 925 material.

e. The thread joint of the production string and production casing are gas tight premium thread with three to four sealing elements, one of them being metal to metal.

Just like in the Giant Kashagan oil field, the natural gas extracted from the Podravina's gas fields could not be used directly due to the presence of noxious substances. This led to the construction of the CGS Molve (Molve Central Gas Station) consisting of three plants for gas processing. The three plants have different gas processing capacities and rely on a number of technological procedures to achieve natural gas purification. The technologies are also relied on when preparing the gas for distribution. The specific process of natural gas treatment on CGS Molve involves separation of natural gas, hydration of natural gas, carbon dioxide and hydrogen sulfide extraction. Furthermore, the treatment involves mercury removal and extraction of hydrogen sulfide through its oxidation into elemental sulfur.

One of the plants (GPP Molve III) uses an amine solution to get rid of acid gases (carbon dioxide and sulfur dioxide). The other two plants use potassium carbonate instead of the amine solution. After removal,

Composition	Molve	Kalinovac	StariGradac	Goladuboka
Methane	69.22%	69.97%	66.5%	41.04%
Ethan	3.26%	6.76%	7.19%	1.76%
pro ane	1.02%	2.35%	2.83%	0.66%
Isobutene	0.20%	0.63%	0.92%	0.17%
n-butane	0.23%	0.75%	1.21%	0.18%
iso-pentane	0.09%	0.39%	0.67%	0.05%
n-pentane	0.06%	0.34%	0.63%	0.08%
Hexane and C_6+	0.53%	5.26%	9.09%	0.02%
Nitrogen	1.64%	1.3%	0.94%	2.38%
Carbon dioxide	23.75%	12.17%	9.02%	53.64%
Hydrogen sulfide	80 ppm	100 ppm	400 ppm	900 ppm
Mercury	1000-1500 ug/m^3			
Mercaptans	20-30 mg/m^3			

Table 2: Fluid composition of Molve, Kalinovac, Stari Gradac and Gola Duboka reservoirs.

these gases are directed into a unit meant for elementary sulfur recovery. This is where hydrogen sulfide is converted to elemental sulfur and water. The purified natural gas is then directed into a dehydration processing system in which water vapor is eliminated by solid desiccant-molecular sieves. It is important to note that natural gas extracted from the well has several natural liquids that need to be removed. These liquids are known to have a higher value when used as separate products. This explains why they are isolated from the well's gas stream. Cryogen is an important substance in the removal of these liquids at Molve III. The natural liquids are then converted into the basic components through fractionation. Fractionation is used due to the fact that the natural liquids have hydrocarbons with different boiling points.

Conclusion

Dealing with sour fields is a challenge the industry will face more often. A challenge that will keep on increasing in difficulty. The key to facing this challenge is knowledgeable personnel who have received the proper training. The proper training to select material and plan operations. The proper training to execute a plan safely and react swiftly. There is very little room for error when it comes to dealing with H_2S.

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