

Effect of mechanical damage during well completion activities on high chrome steel tubulars in high H₂S and CO₂ environments

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Abstract: High concentrations of H₂S and CO₂ make oil producing wells highly corrosive to normal steels alloys, such as carbon steel. The usual solution to this is high chrome steels alloys, such as ferritic stainless steel, i.e. 13Cr. These steels have a good service record in such environments, especially at operating temperatures below 150°C. However the passive film which provides protection can be easily damaged by mechanical activities such as wirelining. The lack of repassivation in these environments means that once damaged by mechanical action these tubulars suffer extensive localized corrosion. A comparison is made of the different workover methods which can exacerbate this problem, particularly wirelining. Where possible we recommend the use of coiled tubing.

Keywords: 13Cr, Wirelining, Coiled Tubing, Sour Service

1. Introduction

The corrosivity of hydrogen sulfide is a recognized phenomenon. It has been the subject of extensive research and recommended practice reports, possibly the most useful being NACE MR0175, also known as ISO 15156². Most oil wells are therefore constructed from materials resistant to the damage caused by H₂S. One solution which has developed widespread support has been 13 Cr^{1,8,10}. This is a stainless steel with a ferritic crystal phase. Austenitic stainless steels, such as 304 or 316 have been used in the past, but these are particularly susceptible to chloride cracking in fluids containing more than 200 ppm of chlorides and so find limited current application.

One of the main damage mechanisms caused by hydrogen sulfide is hydrogen damage. In the reaction of iron with hydrogen sulfide, iron sulfide and hydrogen gas are generated:



Neutral radical hydrogen atoms are usually extremely reactive and will normally combine to form hydrogen gas.

However, during the time the radicals reside on the metal surface there is a possibility for the radicals to dissolve into the metal. This is because hydrogen radicals are effectively metallic hydrogen. Metallic hydrogen is usually formed at very high pressures (>150k atmospheres). Hydrogen damage can occur whenever hydrogen gas is generated on metal surfaces. Common examples are the reaction of acids with metals, excessively reducing environments, or excessive cathodic protection (voltages lower than -1100 mV_(CSE)). All of these processes can cause hydrogen damage. This may be observed as blistering or Hydrogen Induced Cracking, (HIC). However, when the causative mechanism is the reduction of hydrogen sulfide, there is a further complication in that the sulfide scale that precipitates during the reaction is a cathodic poison. This makes it harder for hydrogen radical combination to occur. The increased residence time caused by the presence of sulfide scale increases the probability that metallic hydrogen will dissolve into the metal. The dissolved hydrogen changes the microstructure of the steel, either by causing hydrogen blistering or hydrogen embrittlement. The extent of embrittlement depends upon many factors, the most predominant of which is the hardness. NACE MR0175 specifies specific hardness limits for steels in sour environments based largely upon experience and a

requirement for qualification testing. For this reason of corrosivity we find that carbon steel alloys usually perform poorly in sour environments. The presence of carbon dioxide complicates the story, since it can form a protective scale in combination with hydrogen sulfide, but the mechanism and composition of protection is poorly understood. Some combinations are protective, some are not. Further complications come from the non uniform coverage of any scale. The scale is brittle and it can flake off, exposing clean metal. The protected area acts like a cathode, since the scale is often a semiconductor. Large surface area cathode, small surface area anode will also accelerate the corrosion.

For all of these reasons, carbon steel tends to perform poorly in these environments. Experience has shown that ferritic stainless steels, such as 13 Cr stainless steel perform very well in this environment. This alloy achieves corrosion control by the formation of a passive film which prevents corrosion of the underlying metals. Since it is a ferritic stainless steel 13Cr is largely immune to the chloride cracking that austenitic stainless steels suffer from.

2. 13 Cr Tubing Damage

In normal service, 13 Cr tubing performs with very low corrosion rates and a good life is obtained. To achieve this, however, it is crucial to keep the material free from stress concentrators or any form of work hardening. Most suppliers of 13Cr tubing have extensive and very detailed handling precautions that prevent mechanical damage^{3,4}. Any damage can trigger corrosion^{11,12}. Most manufacturers specify that during installation there shall be no metal – metal contact, polymer slings shall be used to move each pipe section individually.

Impact damage which can trigger Stress Corrosion Cracking can result from such simple mechanical effects as a dropped spanner, or the use of tongs or clamps.

Once installed in service the material is even more susceptible to mechanical damage¹³, not only from the point of view of increased stresses due to work hardening or impact damage, but also as a consequence of the difficulty of repassivating the alloy if the passive film is lost, for instance in a scratch.

The passive film which protects 13 Cr tubing is a complex chromium oxide. If the material is scratched by for example a tool passing along the pipe, a scratch may develop. Once mechanical action removes the passive film, the underlying metal will undergo corrosion. The lack of oxygen in the system means that repassivation is extremely difficult to achieve and a significant amount of corrosion will occur before repassivation is finally achieved. In the picture reproduced from reference 10, (fig. 1) for example there is clear evidence of mechanical damage due to wireline activity. If the damage was only mechanical, then a cut would be observed. However, it is clear in the picture that the edges of the cut are irregular and this would not be anticipated from mechanical damage alone. The irregular edges are due to corrosion of the metal. The mechanical

damage removes the passive film, allowing for attack until repassivation occurs. This phenomenon has been extensively reported in the literature^{5,6,9,10}.



Figure 1. Wirelining damage leading to localized corrosion. From Reference 10.

3. Comparison of Well Completion Procedures Suitable for Sour Service

3.1. Wirelining

There are many operations which need to be performed on an installed oil well. The vast majority of which require the lowering of a tool to the producing formation. If a well is perfectly vertical, then it is possible to lower the tool on a control wire, in a process known as *wirelining*. This is the standard approach used for well completion activities. The tool is lowered on a flexible wire under gravity. If as is the case for most modern wells, there is significant deviation or even horizontal sections then it can be a challenge to get the tool to the bottom of the well. This is usually achieved by allowing the tool to fall under gravity so that it builds up sufficient momentum to overcome any deviations. The danger here is two-fold.

Firstly during the drop, the tool can impact the wall. This is especially common on the outside radius of a curved deviation, as shown in fig 3. Secondly, the inside radius side wall can have the wire rubbing against it as the tool falls. This can cause mechanical abrasion damage to the tube wall, as observed in fig. 1. Wirelining was an extremely popular technique in the past, as it was a relatively simple way of getting well completion tools down to the formation. However, as more and more wells are constructed for sour service, and need 13 Cr, this technique is less and less favored. For sweet wells that don't need 13Cr, then wirelining is still a viable technique that is used widely to this day in the industry as it has a lower headline cost than the alternatives. However, it is being used less and less for sour service. For offshore applications the smaller footprint and space requirements means that even for wells which are

sour it is being used as there is no space on the platform for any alternatives. Wirelining remains to this day a very popular techniques for well completion activities and providing that the way the wirelining is conducted it will have many years of activity left. Wireline applications have also been found to damage organic coatings used to try to prevent corrosion damage.⁷

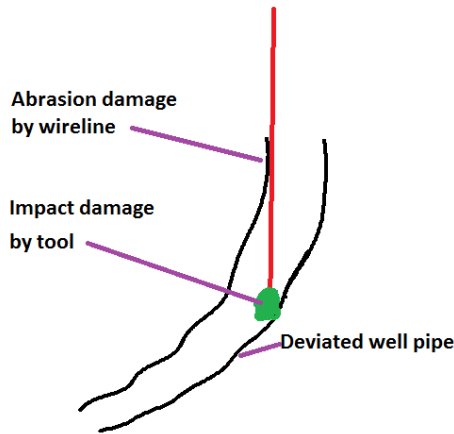


Figure 3. Damage mechanism for wirelining.

3.2. Narrow Diameter Well Pipe

A lower-cost alternative to wirelining is the use of narrow diameter drill pipe. For example, for an 8" diameter well, it may be possible to use 1 or 2" diameter well pipe to lower the tool. This is a low cost option as it uses pre-existing drilling pipe. The technique allows the operator to perform completion activities on significantly deviated wells, or wells with horizontal sections, which would be a challenge if wirelining were to be used. Since the drill pipe is rigid, it can be used to push the tool along horizontal sections and so has application in significantly deviated wells as it does not depend on gravity. However, there are several problems with this approach:

Firstly, one of the main design requirements for drill pipe is to have high torsional strength. The pipe sections have relatively thick walls, to provide the stiffness required for drilling operations. This means that the pipes tend to be of much higher strength and rigidity than is needed to lower a tool to a formation. Also each section is joined by a collar. Which protrudes. The consequence of this high rigidity is that as the well deviates the drill pipe will require considerable force to cause it to deviate and follow the well. This force will be applied to the well casing and it will scrape against the side walls of a deviated well causing mechanical damage. For carbon steel casing pipes in sweet reservoirs this will not be a problem, but for 13 Cr pipes, the mechanical damage will damage the passive film, as discussed earlier, leading to extensive corrosion damage.

Secondly, the pipe comes in standard 10 m lengths. Each pipe section has to be joined and the pipe lowered section by section. This is a standard technique so there is no problem with this except the amount of time required to lower the pipe and recover it. The time factor must be included in any

economic comparison of well completion techniques.

3.3. Coiled Tubing

Coiled tubing (CT) was first introduced to the oilfield in the 1960's¹⁴. It was originally considered for only specialized tasks. However, by the 1990's, CT was used widely in the industry because of the lower overall cost advantage. Diameters of between 1- 4 ½ inch are commonly used.

Coiled tubing refers to the idea of a single continuous pipe which is flexible enough to be spooled for storage and transport. Strings seamless pipe without any joints of up to 31,000 feet (9,450 m) or more are available and advances in manufacturing have seen improved operational efficiency.

Tools can be lowered without the need for gravity feed, and unlike narrow diameter drill pipe, the tubing is flexible enough to follow the direction of a well without significant impact or abrasion damage to the casing. There have been no reported cases of coiled tubing causing damage to well casings.

The lack of casing damage is a major advantage of CT workovers, especially for sour service where 13Cr pipe is used. There are other advantage to coiled tubing, especially the speed of operation. Because the tube is in one piece, it can be lowered quickly, giving similar workover times as wirelining.

Coiled tubing is much safer than any other approach, both for the risk of a kick and the risk of formation damage. Coiled tubing can be injected through the BOP with the well under pressure in a live condition. Indeed, it is possible to do workover operations using CT whilst the well is still producing¹⁵.

For wirelining and drill pipe workovers, the well is often set up in the overbalanced condition. This simply means that the pressure of the fluids at the bottom of the well, or at the formation level, is greater than the formation pressure. Fluids from the formation, whether they be gas or liquids are thus held inside the formation and so the fluids cannot enter the well. If this were to happen, fluids would rise up the well column. As the fluids rise the pressure drops. If there are any gases in the formation fluids, they will rapidly expand, reducing the pressure and causing a cascading rapid volume increase. If uncontrolled, this "kick" can lead to a blow out. Overbalancing prevents this process. However, an overbalanced well means that the well completion fluids can enter the formation with the potential to cause formation damage (usually some mechanism which blocks the pores in the formation, either particulates physically blocking the pores, the promotion of precipitation reactions or a change in the wettability of the rocks. There is usually therefore a balance that has to be achieved. Overbalanced wells are safer, but cause more formation damage. Underbalanced wells cause no formation damage but run the risk of a kick or even a blow out. One of the main advantages of CT operations is that because the tubing can be passed through a BOP and a good pressure seal can be achieved, operations can be safely run underbalanced since the wireline passes through the BOP. One example of how effective coiled tubing can be is that well activities using coiled tubing can be run whilst the well is producing, a major advantage as there is

no loss of production.

CT workovers do have some disadvantages. The equipment cost is more than the other alternatives, but lower down time and faster completion means cost savings overall. The main problem however is the amount of space required for the equipment. This can limit CT workovers to onshore wells only. Offshore platforms have a lack of space so even if CT is the preferred choice, wirelining is done because of space issues.

4. Conclusions

Sour gas wells are highly corrosive and require the use of corrosion resistant alloys, such as 13 Cr. Alloys such as these provide excellent resistance to this environment. However, 13 Cr is susceptible to mechanical damage. If damage occurs and the passive film is damaged, it can be difficult for repassivation to occur. During this time, the pipe will be corroding extensively, leading to localized damage. During workover operations it is important to consider the mechanical damage that can occur and choose the best alternative workover technique. The amount of well deviation is an important factor to consider when choosing between the three workover techniques discussed here. Where possible coiled tubing provides the best solution and the least amount of damage potential. Wirelining is also possible but the operator should be careful especially for deviated wells. The speed at which the wireline is run has the potential to trigger the mechanical damage which can thus cause problems for the well casing. Further research should be undertaken to investigate what constitutes a safe operating envelope for wirelining. The velocity and bend radius are important factors which need to be investigated.

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