

Mitigation of Scaling Challenges for Long-term Well Shut-ins under Ultra-High Temperature

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ABSTRACT

Long-term well shut-ins have become a common practice for operators to defer oil production in an oversupplied market. This paper discusses several scale challenges that are expected under such circumstances. Two specific cases were explored in detail in terms of product development and performance validation under various scenarios. The first category of wells had high-water production, featuring extreme levels of calcium and iron, as well as an ultra-high, bottom-hole temperature of 350°F. These wells began experiencing significant calcium carbonate scale precipitation when bottom-hole conditions reached extreme temperatures of around 400°F. To solve this issue, this study utilized laboratory examination to determine the most effective scale inhibitor chemistries and evaluate the thermal stability and restartability in a capillary injection system, before and after an extended period of heat stress. The second group of wells had a moderate bottom-hole temperature but were not equipped with capillary tubing. Scale inhibitor was historically dripped in neat forms through the annulus and had caused significant corrosion issues on the production-tubing, which was composed of carbon steel. The corrosion induced by scale inhibitors was expected to become more severe when the well was shut in, during which little to no water would be produced to flush the concentrated product off the pipe and equipment surfaces. Through literature review and a pre-screening of common scale inhibitor

chemistries, it was confirmed that essentially all scale inhibitors had very high corrosion rates on carbon steel (5-100 mpy), heavily dependent on the temperature, pH, and the product formula in the testing. Therefore, an approach using a small percent additive was selected to address this obstacle. The final candidate was able to effectively lower the corrosivity to negligible levels of far less than 1 mils per year (mpy) at 180°F but could also be used in an ultra-high temperature application. It is a stable standalone formulation that could be delivered to the location separately and convert the corrosive product into a noncorrosive combination through simple onsite mixing. The combination package retained high effectiveness over iron and calcium carbonate inhibition at very low treatment rates.

This study utilized a systematic approach to solve various scaling issues for wells selected for extended shut-ins. A highly effective scale inhibitor was developed for use in capillary injection systems exposed to ultra-high bottom-hole temperatures. It had validated formulation integrity and was considered least likely to cause capillary tubing plugging during the shut-ins. With the incorporation of 1% or less additive, it could even be used as a non-corrosive approach for direct annulus injection.

Keywords: scale control, carbon steel corrosivity, ultra-high temperature, calcium carbonate, iron carbonate, well shut-in

INTRODUCTION

Shut-ins in the oil and gas industry are the implementation of a production restriction for the producing wells. They can be a part of the routine well services that aim to solve certain production issues such as the prevention of scales, treatment of paraffins, or buildup of reservoir pressures, which usually take between a couple hours and a few days.¹ Long-term well shut-ins are those designed to defer production for weeks or months, usually due to non-technical circumstances, such as crew evacuation ahead of natural disasters or an oversupplied market. Stopping the production flow for an extended period of time can expose the reservoir and the well to a series of risks, including water blockage related to pressure depletion, problematic crossflows between producing layers, remixing of multiple connate fluids within non-indigenous rocks, destabilized formation, hydrate formation and induced corrosion.² Among them, interlinking incompatible formation waters from different producing zones is a well-known, scaling mechanism that leads to the potential formation of in-situ sulfate scales within the reservoir rock pores, a problem that has proven to be difficult and costly for remediations.³ Pressure depletion may flash-off CO₂ from the produced water, which promotes the deposition of calcium carbonate and iron carbonate scales; or lead to dehydration of the formation water, which could contribute to halite formation.⁴ Moreover, previous studies have demonstrated that iron can impair the performance and stability of many scale inhibitor products.⁵ During the prolonged shut-in period, the elevated iron concentrations from insufficient corrosion control will bring additional challenges for the scale mitigation program. Finally, high levels of solids of different matrices (e.g., scales, sand fines, crushed rocks, paraffin and asphaltene, etc.) are expected to form in the water during the incubation process of a long-term shut-in. Suspended particles can serve as seeds to promote faster growth of the scale crystals; therefore, extra cautions may need to be taken in performance testing and for the treatment plan.⁶ Overall, there appear to be very limited resources of prior publications specifically focusing on scale mitigation for wells under a shut-in stage. In this paper, a series of laboratory experiments were designed and conducted to address several of these oilfield concerns.

The oilfield of interest had two types of wells selected as candidates for the shut-in process. The first group were typical high water-producing wells with a bottom-hole temperature (BHT) of up to 350°F. When they were producing, chemicals such as scale inhibitors were injected downhole through an elongated capillary tubing, utilizing high grade alloys for better corrosion resistance. The chemical's residue time in the tubing typically ranged from hours to days, depending heavily on the injection depth, tubing configurations, barrels of water per day (BWPD) or barrels of oil per day (BOPD), and the desired

treatment rates. Furthermore, the scale inhibitor injection would stop during the shut-in and be encapsulated inside the long capillary strings until the well restarts. The primary challenge for this scenario is to ensure the integrity of the product under such a high BHT over an extended period of time so that the delivery of inhibitor will not be interrupted by potential tubing blockage. Inappropriately formulated inhibitor packages can cause feed-line deterioration as well. During shut-in, BHT should gradually cool down to correlate with the well's geothermal gradient;⁷ however, an additional concern is that it may climb up temporarily to a higher level when the well restarts and quickly introduce hotter fluids from zones deep into reservoir. Thus, the ideal scale inhibitor needs to perform well not only at the BHT of 350°F but also under some extreme conditions. The other category of wells had moderate BHTs and were not equipped with capillary tubing. Chemicals, in neat forms, were dripped through the annulus and had direct contact with the casing and production-tubing that are typically composed of carbon steel, such as C1018 steel. It is well understood that carbon steel is much more vulnerable than other alloy steels (e.g., SS304, SS316, Inconel625, etc.) to corrosion attacks.⁸ And this scenario is also distinguished from the circumstance of capillary injection, where the scale products won't have a chance to come in contact with the carbon steel tubing until they are quite diluted with the produced water to ppm levels.

Many scale inhibitor chemistries (both phosphonates and polymers) have been claimed to express dual-function for corrosion inhibition, such as polyaspartic acid derivatives and ethylenediamine tetramethylene phosphate (EDTMP) series.^{9,10} Scale inhibitor molecules interfere with the metals in scale nucleation using the chelation functional groups of aminocarboxylic or aminophosphonic acids that also possess high affinity for the Fe-oxide layers, which could potentially form a protective film on metal surfaces under desired conditions. Unfortunately, in the case of the exposure of mild steel to concentrated chemicals, most scale inhibitors with short backbone chains behave similarly to a metal-oxide dissolver, stripping off the surface protective film; therefore, promoting corrosion issues instead of preventing them. The process is obviously pH-dependent but cannot be solved simply through neutralization of the product formulations.¹⁰ Figure 1 displays a piece of a production-tubing joint and its collar that was retrieved during a workover from wells utilizing a scale inhibitor dripping into the annulus for months. The product (pH 7) left noticeable corrosion-related grooves on the outer surface of the collars through the downwardly flowing path. As a long-term, well shut-in will stagnate the inhibitor consumption while stopping producing streams (brine and gases) that help wash-off or dilute the injected inhibitors, it can potentially exacerbate corrosivity issues. Therefore, there is an urgent demand for less or non-corrosive scale products. Previous publications included the use of higher cost polymeric scale inhibitor chemistries and/or additives such as carbohydrazide or zinc.^{11,12} A new approach will be discussed in this study.



Figure 1: Imprints on production-tubing collar by direct contact with scale products for months

The ideal product(s) to solve the aforementioned challenges for long-term well shut-ins needs to possess the following features:

1. Iron tolerance at high dosages. The entire oilfield produces water with high iron counts; thus, the inhibitor must have sound compatibility to avoid forming precipitation in the flowing path.
2. For wells with high BHT and capillary tubing – formulation integrity under dynamic conditions at 350°F, injection restartability after shut-in, and scale inhibition performance at 400°F (higher than BHT per discussion) for the water chemistry from Well HT in Table 1.
3. For wells with moderate BHT utilizing annulus injection – non-corrosivity (≤ 1 mpy) on C1018 carbon steel for an extended period of 28 days, scale inhibition performance in the presence of high iron counts (200-300 ppm) for the water chemistry from Well MT in Table 1.
4. One product for all wells. This is optional but facilitates and streamlines logistic and inventory management, which, in turn, lowers the treatment costs both for the operators and service partners.

Table 1. Representative water chemistries for the studied wells

Ion Speciation *	Well HT	Well MT
Sodium (Na^+)	48,700	13,300
Potassium (K^+)	726	1,530
Magnesium (Mg^{2+})	1,470	370
Calcium (Ca^{2+})	23,800	1,800
Strontium (Sr^{2+})	1,770	42.7
Barium (Ba^{2+})	610	ND
Iron (Fe^{2+})	200	302
Chloride (Cl^-)	124,000	25,000
Sulfate (SO_4^{2-})	10.0	825
Bicarbonate (HCO_3^-)	317	1,710
TDS	202,000	44,900
pH	7.0	6.9

* unit in ppm for all species except pH

EXPERIMENTAL PROCEDURE

Iron Tolerance Testing

The static bottle test was applied to evaluate the inhibitors' brine compatibility and iron tolerance using freshly collected field brine, containing 18,000 – 25,000 ppm of calcium and 100-200 ppm of iron. The brine was quickly dosed with 10,000 ppm of the selected products at room temperature, then sealed and placed in a water bath heated at 200°F for one hour. The solubility and precipitation of inhibitors were recorded and evaluated against the untreated sample (blank).

Coupon Corrosivity Testing

The material compatibility tests were conducted to evaluate the corrosive behaviors of the selected scale inhibitors on various types of metallic coupons. The corrosion coupons were pre-weighed on an analytical balance to the fourth decimal place, submerged into the neat products, then placed in the heating vessel for the desired period of time as detailed in the “results” section of this paper. The moderate temperature experiments (lower than 190°F) were carried out in sealable bottles/beakers; whereas, the high temperature testing was processed in a mud aging cell that was pressurized to 300-400 psi with nitrogen