LONG TERM SCALE PREVENTION WITH THE PLACEMENT OF SOLID INHIBITOR IN THE FORMATION VIA HYDRAULIC FRACTURING

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ABSTRACT

Mineral scale formation is a problem for oil and gas operators that can result in deterioration of assets, increased lifting costs and lost production.[1] Scale which forms in or at the perforations can only be prevented by placing scale inhibitor in the producing formation via some type of reservoir displacement technique commonly referred to as a squeeze. Operators desire inhibition that will last as long as possible and minimize the production interruption for treatment. In reservoir formation types that exhibit known scaling problems, scale inhibition treatment can be initiated during the completion stage using a solid inhibitor integrated into the hydraulic fracturing program. Treatments of this type can result in deep reservoir placement of inhibitor without large amounts of introduced water frequently needed with traditional squeeze treatments. Data presented in this paper illustrate the superior performance and longevity of these types of treatments.

Keywords: scale inhibition, scale squeeze, hydraulic fracturing, proppant.

INTRODUCTION

Scale formation is a problem throughout the oil field. Traditionally, operators have primarily treated for scale with liquid chemical inhibitors. These chemicals can be administered through batch, continuous or squeezed applications. The choice of treatment choice depends on where the scale is occurring. If scale is forming at or before the formation perforations, a scale squeeze has traditionally been the only treating option. In a squeeze treatment a chemical scale inhibitor is pushed back into the formation and the chemical either adsorbs or precipitates onto the formation surface. As the well produces water the precipitated scale inhibitor slowly dissolves and is available to prevent scaling.

For an inhibitor to be effective at preventing scale it must be present at a level above the minimum effective concentration (MEC) prior to the onset of conditions that cause scaling (compositional, temperature, pressure or pH changes).[2] The effectiveness of the scale inhibitor is determined by analyzing the produced water for evidence of the scale inhibitor. This is called a residual test. When the scale inhibitor residual falls below the MEC, the operator is informed that the well must be re-squeezed. In the case of batch or continuous treatment the residuals are not as critical since the well undergoes treatment on a much more frequent basis (usually for batch treatments the first few treatments are measured for residuals in order to ascertain the treating frequency). Experientially, wells that have been squeezed maintain an acceptable residual level for approximately one year or less.

A special class of treatment candidates is represented by new wells that require stimulation and for which there is an expectation of water production with associated scaling problems. Stimulation by hydraulic fracturing often utilizes a slurry of solid proppant. The proppant fills the voids created by hydraulic fracturing and provides a permeable conduit for production fluids to reach the wellbore. Although the wells selected to date have been new wells, there is no reason that existing wells that are amenable to hydraulic stimulation could not also be considered candidates. For these wells a new approach to scale inhibition is available. Rather than use a liquid chemical inhibitor (longevity of one year or less) these wells can be treated with a solid inhibitor that is absorbed onto an inert solid substrate that is incorporated into the proppant slurry. Through the use of a solid inhibitor a more active product can be applied to the well. The improvements on both the level of active inhibitor in the well and the prolonged longevity of the application are significant. At the time of this publication the subject wells are into the second year of treatment and still demonstrate residual levels above the MEC. The MEC for this application is 1 ppm of residual inhibitor.

Background Information

In the case of the subject wells it was theorized that the application of a solid scale inhibitor administered in conjunction with a fracture job would result in sufficient chemical applied in the likely path of produced water, i.e. along the fracture conduits. The volume of inhibitor that can be applied is limited only by economics, compatibility with the fracturing fluid and impact upon the conductivity of the proppant bed.

The calculation for determining the amount of scale inhibitor necessary to prevent scale deposition uses water production as the primary determinant in combination with a theoretical inhibitor return concentration. For new production it is best to use offset well production figures to estimate water production. The selection of the correct inhibitor is also critical. A water analysis of the produced water or another water from the same formation will determine the potential for scale formation as well as the probability that scale will deposit.

The maximum amount of scale inhibitor that can be used in a fracture treatment was determined by rheology testing of the fluid systems and the conductivity testing of sand packs at varying inhibitor loading and closure pressures. Liquid scale inhibitors can be incompatible with some gel systems because of their interaction with metal crosslinking agents. Reports of interference between scale inhibitors and gel breaker systems have also been noted.[1] The solid phase inhibitor described here overcomes this problem because of its delayed solubility in the fluids. Testing has found that inhibitor loadings of up to 2% by weight of the sand do not exhibit any negative effects on the proppant conductivity. The chemical concentration represented by a 2% loading has proven to be more than sufficient in all chemical demand calculations, even when based on achieving a five-year life of the scale inhibition program. There is evidence in the literature of alternative approaches to developing a solid scale inhibitor capability. Collins, et al have reported on the development of a solid scale inhibitor designed to be applied via water injection wells.[3]

Once the chemical is placed in the formation it is necessary to monitor the concentration of inhibitor in the produced fluids. Scale can only be inhibited if a scale inhibitor is present prior to the onset of scaling conditions. Once the scale inhibitor is exhausted then scale will form and begin to precipitate in the formation and/or in the tubulars. Although a well failure would tell the observer that the scale exhibitor was exhausted that is not a viable economic manner by which to ascertain the remaining inhibitor potential.

The accepted manner to determine if scale inhibitor is present in the formation is to run a scale inhibitor residual test. The field personnel collect a water sample from the subject well and analyze it for ortho-phosphate (PO_4^{-3}). The measured phosphate level is then converted to ppm of inhibitor based on the chemical composition of the product. Theoretically, as long as a scale inhibitor residual value is observed then the well is still protected for scale. Some newer polymeric types of liquid inhibitors used in conventional scale squeeze treatments are problematic for determining inhibitor residuals. Analytical methods for measuring small amounts of polymers in produced brines are not sensitive enough to provide for accurate monitoring of squeeze life. The solid inhibitor described here is a conventional aminophosphonate that exhibits broad-based efficacy on all oilfield scales and is easily monitored via phosphate residual testing.

The formation of inorganic scale in an oil field environment is a thermodynamic process that requires both the conditions for scale formation and sufficient quantities of the scale components. Scale in the oil field is only a problem if the scale precipitates somewhere undesirable. Scale forming in perforations, tubulars, flowlines, treating vessels and on valves is problematic. Scale precipitating in a water treatment pond is not a problem. The industry only treats for scale when it is viewed to be a problem.

Oilfield mineral scale deposition is usually a result of mixing of incompatible waters from different parts of the formation, temperature changes, pH changes, pressure changes or any combination of these.

EXPERIMENTAL

This solid scale inhibitor technology was specifically developed for integration with propped fracturing applications. As mentioned earlier, the solid scale inhibitor is added at between 1% and 2% based on the volume of proppant. In these applications the chemical was distributed evenly throughout the fracture. Fluid compatibility testing confirmed that the material is inert during the fracturing treatment and does not affect the gel systems or breakers. The addition of the solid scale inhibitor to the fracturing treatment was relatively simple from an operational standpoint. Chemical addition, liquid or solid, is a normal step in a fracturing stimulation. In this case the chemical was transferred to a hopper and fed into the proppant stream at a rate consistent with the rate of proppant. This was done to insure an equal distribution of the chemical throughout the fracturing treatment.

RESULTS AND DISCUSSION

The nature of the solid scale inhibitor is such that both the inhibitor and the substrate upon which it is absorbed are not as strong as the proppant. This sets up the potential for a problem related to conductivity. Conductivity is the measure of the expected rate of flow through a proppant matrix versus the actual/reduced flow that is a result of fines accumulation in the proppant matrix. This accumulation results in less flow through the matrix. Less flow means less production. Too much loss of conductivity means that oil, gas and water production is inhibited to the point that the well has lost its economic viability. For that reason it was important to measure the effect that the solid inhibitor might have on conductivity. That point at which the conductivity was negatively affected would indicate the upper limit of the solid scale inhibitor in the fracture.

An API crush test was performed using the 20/40 proppant sand and the solid inhibitor (See Table 1). While crush tests do not provide data regarding the conductivity of a fracture they can provide a qualitative indication of proppant degradation. The results of the crush testing indicated that the inhibitor did not significantly impact the integrity of the proppant at loadings less than 4%.

Two wells, A and B, near the border of Virginia and West Virginia were fracturing using 20/40 sand as proppant. These are shallow (<2000') coalbed methane wells. Well A was fractured on 4/19/05 and well B was fractured on 5/25/05. These are multiple stage treatments using approximately 150,000 lbs of sand. The wells in this area are typically long perforated intervals across multiple producing zones. The large intervals are not practical to treat using conventional squeeze treatments because of the large amount of fluid that would be required for overdisplacement of the inhibitor. Treatment with the solid inhibitor incorporated into the proppant sand was the only practical option. The solid inhibitor was added at 0.5% based on weight of the sand. The recommendation for the job was in excess of 1%. Since this was a novel application the operator opted to go with less product in order to test the product. Subsequent to the success of the application, current jobs are using 0.9% to 1.0% solid inhibitor based on proppant. The expectation is that these subsequent jobs will display even longer inhibition lives.

The scale inhibitor was added to the proppant at a constant rate based on the proppant feed rate. The design called for an even distribution of solid inhibitor throughout the fracturing treatment. Based on the concept that the proppant distribution in the fracture was commensurate with the size of the fracture opening and thus commensurate with the resulting production flow, the decision was made to put the inhibitor with the proppant in a direct proportion.

The operator deemed the stimulation successful. The stimulation fleet left the site. Traditionally this would be the end of a stimulation job. In this case, there was a requirement to monitor the well for water production in order to ascertain the benefit of placing the inhibitor with the stimulation application. As stated earlier and as noted in the literature, scale inhibitor squeezes have been a long accepted practice to place inhibitor in the formation near the well bore. Liquid inhibitors are also used in fracturing fluids to achieve deep reservoir placement.[4] The use of a liquid inhibitor in a squeeze or fracture as well as the use of the solid inhibitor in this case are all driven by the same need, i.e. increase the volume of active inhibitor in the formation so as to prolong the period of time for which scale is inhibited.

In order to compare the relative staying power of a liquid to that of a solid inhibitor, an offset well (Squeeze) that had been squeezed with a liquid scale inhibitor was selected. Table 2 and Figure 1 offer the comparison of this well and Well A that was fractured with the solid inhibitor. It is obvious from the figure and graph that the liquid inhibitor squeeze lost significant inhibitor early in the life of the squeeze. Although is it not the purpose of this paper to address the reasons why a liquid inhibitors has less staying power than a solid inhibitor, it is instructive to note that relative slopes of the liquid versus the solid tell the story. Others have reported on liquid inhibitor squeeze treatments.[5,6] Since a minimum residual value (for the sake of this exercise use 10 ppm as the point at which inhibition may start to diminish) is all that is necessary for scale protection, any residual in excess of that value is wasted. Thus the goal of any long term scale inhibitor exercise is to place an inhibitor into the formation such that the residual value starts low, i.e. at the minimum level threshold, and maintains a straight horizontal curve for as long as possible. That would be the ideal curve for long-term scale protection.

In the absence of the ideal placement and the ideal residual curve one must work towards reducing the slope of the residual curve so as to approach the ideal. When the liquid inhibitor curve is compared to the solid inhibitor curve it is obvious that the solid inhibitor curve is heading in the right direction.

Figures 2 and 3 are the actual residual readings over time. As one can see the latest results are somewhat unexpected. Based on the water production rates (they have remained fairly constant) there is not a good explanation for the precipitous fall off in residuals and the subsequent recovery. The wells have not shown any overt signs of scale deposition, e.g. pressure changes due to deposition. Webb et al [1] report seeing an unexplained shift in the inhibitor residual figures. In the case of Wells A&B there was a significant drop in residuals at the one year anniversary of the treatments. Well A saw two consecutive samples that were at the 1 ppm level (1.2 & 1.8 ppm). Well B saw a drop to 1.5 ppm, but then recovered to a 10.8 ppm residual on the subsequent sample. The fact that Well B dropped and then recovered to the 10 ppm range is an indication that the product did not mysteriously solubilize and deplete. There are explanations available, e.g. water production form a non-fractured area or fines migration affecting slow, but no work is planned at this time to examine this excursion from the earlier trend. As stated earlier these wells only saw half of the recommended dose. Also the loading was based on an expected water production rate. An examination of the operator's well records is underway to look for causes of this down turn.

CONCLUSIONS

The industry continues to search for technologies that prolong scale inhibition and extend the period between costly interventions. This is particularly true in deep water and remote environments. However, as the period of prolongation increases and as operators view the total cost of inhibition in light of the cost of deferred oil during an intervention, this technology offers a new approach to solving an old problem. The applications upon which this case history are based are just now into the second year after treatment. Based on using 1 ppm as the MEC there is evidence that the effective period will continue through that second year. Bear in mind that in the two wells discussed (Well A & B) the operator opted to use 50% of the original recommendation. Crush studies and subsequent applications in other wells treated in the past year show that a higher percent of solid inhibitor can be used.

The greatest indication of acceptance of a new technology is use by the operator. This solid inhibitor technology is only 18 months old. In that time it has been used in over ten fractures. Two of those applications are in deep water. One is producing, but has not yet produced water. The other has not yet been put on production. Additionally, product designed to handle an additional thirty fracture stimulation jobs has been delivered to operators. It is expected that future papers will report on the results of these applications that will use a higher percent of product.

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TABLE 1
Crush Results Of 20/40 Econoprop With 2% Or 4% (Wt) Solid Scale Inhibitor (Not Sieved)

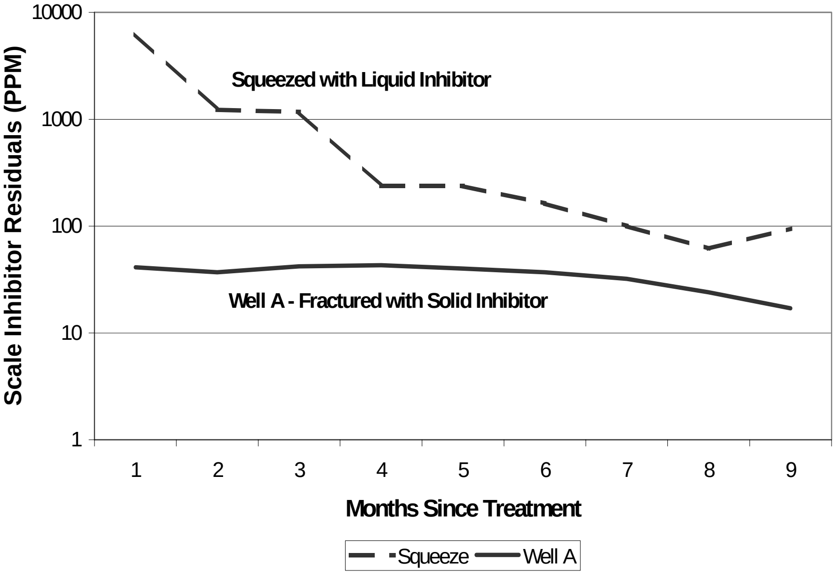
API Crush at 4 pounds/ ft2

% Inhibitor	**Stress (kpsi)**	**g Inhibitor**	**40 mesh (g)**	**% Crush**
0	1	0	0.03	0.08
2	1	0.8	0.1	0.25
4	1	1.6	0.1	0.25
0	4	0	0.31	0.8
2	4	0.8	0.55	1.4
4	4	1.6	0.89	2.3

TABLE 2
Scale Inhibitor Residuals (Ppm) For A Well Squeezed With A Liquid Inhibitor (Squeeze) And A Well Fractured With A Solid Inhibitor (Well A)

Months Since Treatment	**Squeeze**	**Well A**
1	6275 ppm	41 ppm
2	1228	37
3	1169	42
4	237	43
5	237	NS
6	163	NS
7	NS	32
8	61	NS
9	95	17

FIGURE 1. **Comparing Scale Inhibitor Residuals: A well squeezed with a liquid inhibitor and Well A fractured with a solid inhibitor**



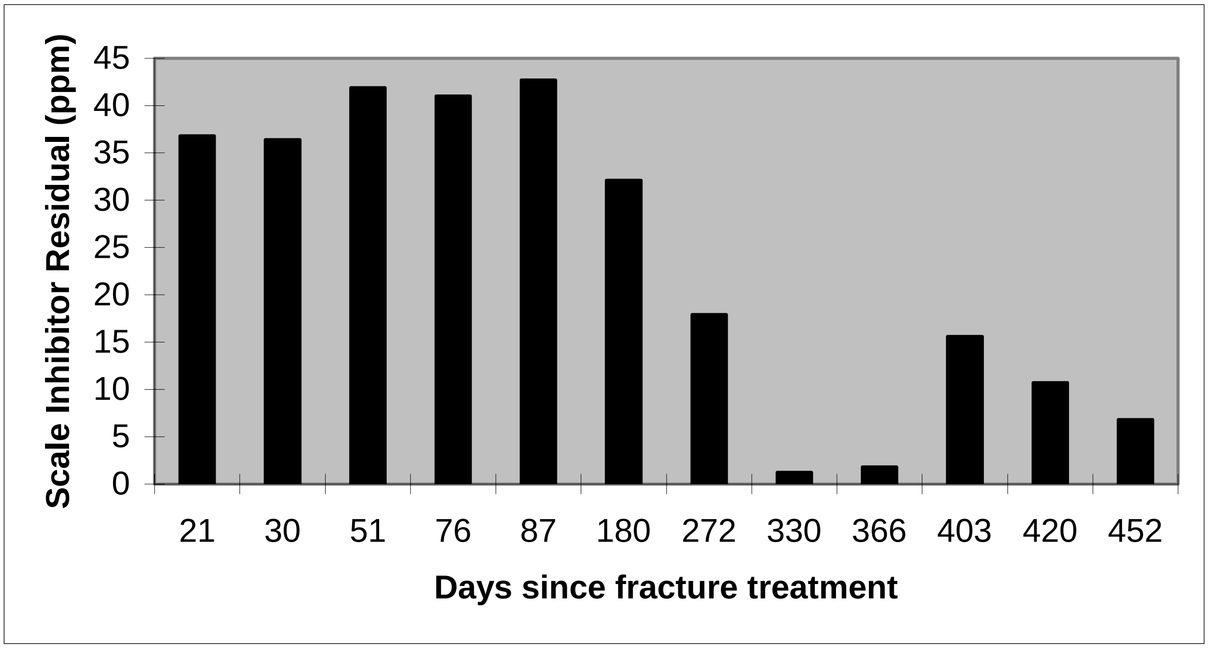


Figure 2 - Well A Inhibitor Residuals vs Days Since Treatment

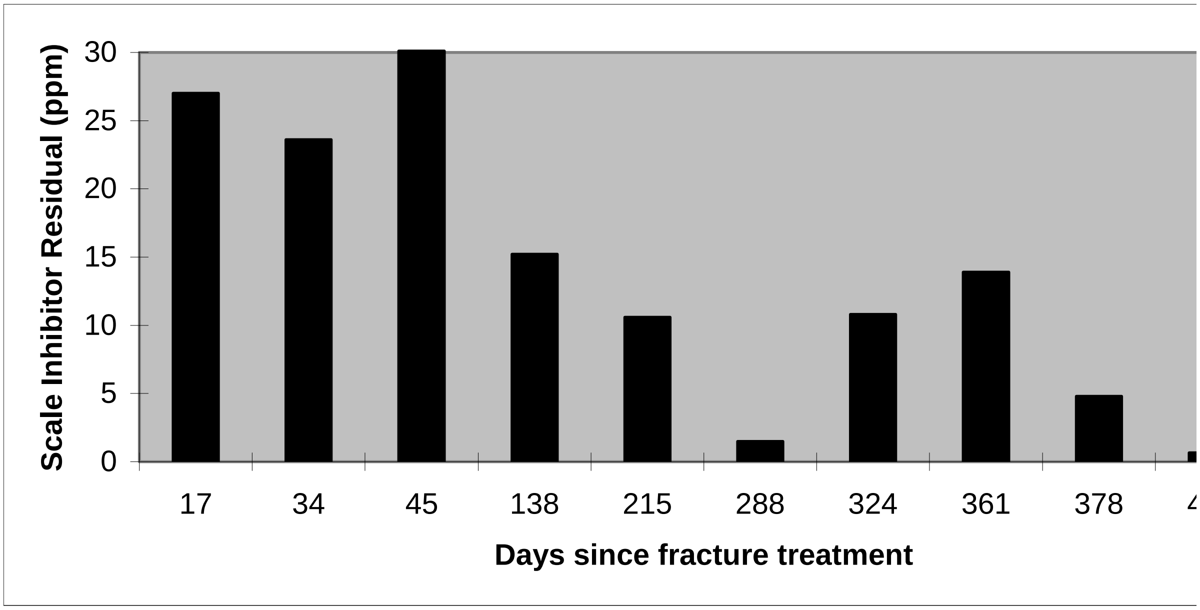


Figure 3 - Well B Inhibitor Residuals vs Days Since Treatment