Inorganic scale control during ASP flooding, coreflood to field implementation – a case study

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Inorganic scale associated with conventional hydrocarbon extraction has been well studied over the past 50 years and the mechanisms of formation, inhibition and removal are now well understood within the industry. For enhanced oil recovery (EOR) significant changes occur within the reservoir as a result of injected chemical or changes in fluid type that are used to increase the oil recovery.

In the case of alkali surfactant polymer (ASP) flooding, the current industry understanding of scale prediction models for such systems is discussed, along with the current inhibitor screening tests to qualify scale inhibitors for squeeze application in a Middle East field. The design of the different squeeze treatments applications for treatment of formation water and injection water production are presented.

Geochemical consequences of ASP flooding

A general statement that describes the impact of ASP flooding is the application of low salinity brine to displace oil in reservoirs which typically have formation waters with low salinity also with additional alkalinity, commonly in the form of Na_2CO_3 at a pH of 10-11.

In the ASP flooded fields, the principle issues with formation of inorganic scale will be within the production wells and topside process. The generation of the ions required to create the silica scales and carbonate scales ($CaCO_3$) occurs close to the injector well and these ions are transported to the production well and proceed to form scales as the conditions change, such as declining temperature (silica scales), declining pressures (carbonate scales).

Laboratory evaluation of squeeze chemical suitability of ASP flooded wells

Inhibitor Performance

Table 1 shows the formation water (FW) and injection water proposed for the ASP flood. 1% Na_2CO_3 would be added to the IW to create the alkalinity during the flood. This addition of Na_2CO_3 increased the pH from 7.5 to 11.

Table 1. Formation Water and Injection water compositions for the field in this study

Ion	FW	IW (softened FW)
Na	1720	1813
K	28	28
Ca	35	0.5
Mg	14	0.2
Ba	0.3	0.3
Sr	1.5	1.5
Cl	2150	2150
SO_4	166	166
HCO_3	968	968
pH	7.6	7.4

<u>Test results</u>

The results presented in Table 2 show that the phosphonate chemicals ATMP having the lower minimum inhibitor concentration (MIC). This chemical was taken onto coreflood performance testing

Table 2. MIC values for the two FW/IW ratios valuated in this study

Chemical type	80% FW:20% IW +1% Na_2CO_3	50% FW:50% IW +1% Na_2CO_3
ATMP	15-20 ppm	0-10 ppm

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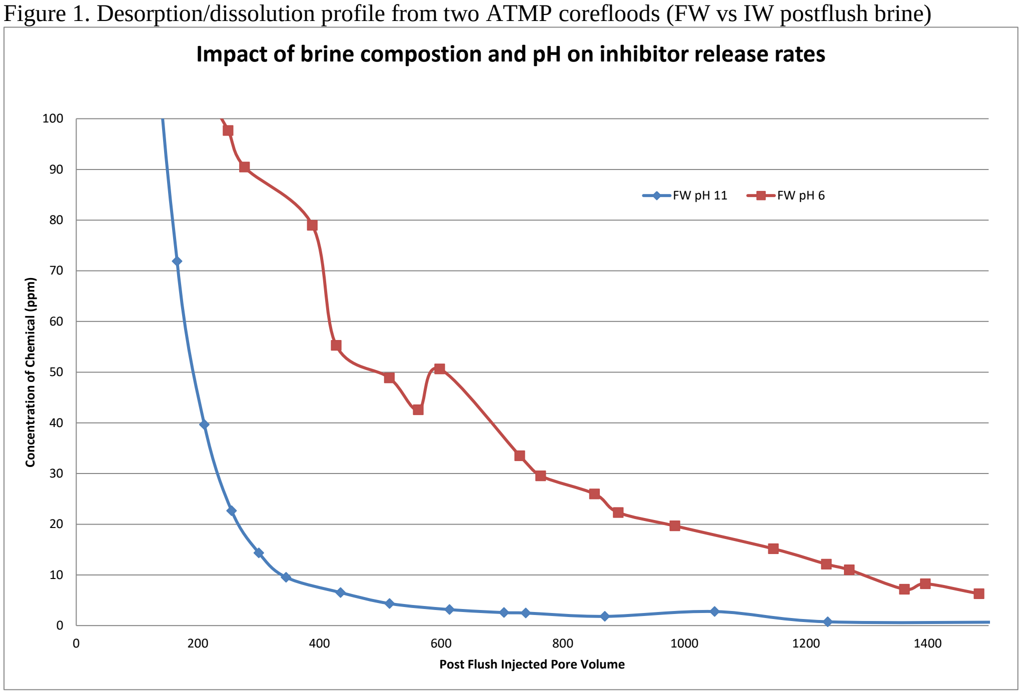
Coreflood results
Test Conditions
50ºC, two cores were treated with 10% ATMP in 3 wt.% KCl; Two post flush brines were tests FW (pH 7) and IW with 1% Na_2CO_3 which resulted in a pH 11 brine. Previous publications have shown excellent retention for phosphonates in these types of test[34].

Test Results for ATMP Coreflood Tests
From the data presented in Figure 1 it is clear that flooding the core with the 1% Na_2CO_3 injection water at pH 11 causes the inhibitor concentration to very rapidly decline. It would appear that the combination of lower calcium and higher pH relative to the formation water cause the inhibitor to desorb/dissolve more rapidly; the salinities of both brines are very similar, so this factor is not playing a role in the differences observed. The impact on squeeze life of the IW will be explored later when the resulting isotherm profile is discussed.

Figure 1. Desorption/dissolution profile from two ATMP corefloods (FW vs IW postflush brine)



In the case of the ATMP coreflood, due to the pH 7 FW and its higher calcium concentration (36ppm), it would be expected that the inhibitor be better retained than for the pH 11 IW with 0ppm calcium in the brine.

Implication of FW vs IW in the Produced Water Stream on Squeeze Treatment Volumes
Two potential scale squeeze treatments have been calculated using the SQUEEZE code based on the two coreflood isotherms (100% FW, 100% IW) for the ATMP scale inhibitor. The assumptions for the designs are as follows: the production well flow rate is 150m^3/d and a single water cut has been used to design the treatment volumes (60% BS&W). The MIC for the ATMP has been set at 10ppm (50% FW:50% IW +1% Na_2CO_3), the squeeze life time has been calculated to protect the well to 10ppm scale inhibitor for 12 months at 60% BS&W (cumulative volume 32,850m^3) based on the FW and IW isotherms. The only factors that is impacting the squeeze life is the retention/release of the inhibitor chemical, which is due to the produced water chemistry and pH. The potential treatment volumes and simulation of the expected return profiles are presented in Figures 2 and 3.

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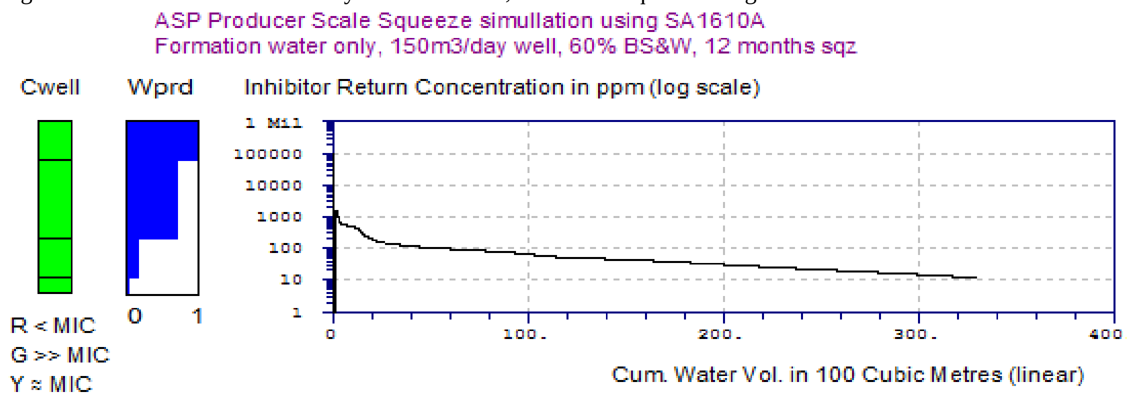
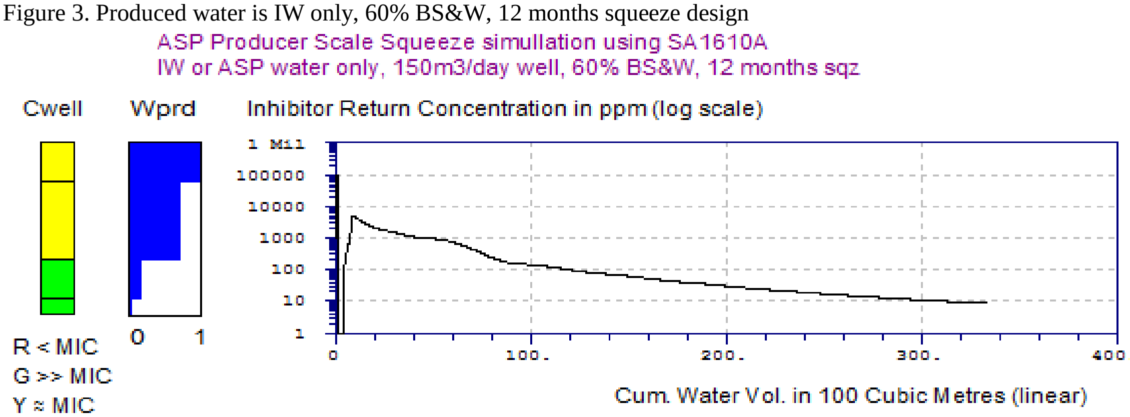
Figure 2. Produced water is FW only at 60% BS&W, 12 months squeeze design



Preflush stage	1m^3 injection quality brine, 0.5% ATMP
Main Treatment stage	25m^3 injection quality brine, 10% ATMP
Overflush stage	75m^3 injection quality brine, 0.1% ATMP

Figure 3. Produced water is IW only, 60% BS&W, 12 months squeeze design



Preflush stage	3m^3 injection quality brine, 0.5% ATMP
Main Treatment stage	120m^3 injection quality brine, 10% ATMP
Overflush Stage	360m^3 injection quality brine, 0.1% ATMP

Inorganic scale control during ASP flooding

It is clear from Figures 2 and 3 and the chemical volumes used in the simualtions that 5 times more inhibitor chemical is required to treat the same volume of produced water when the produced brine change from 100% FW to 100% IW. Along with the increased chemical cost the carrier brine volumes required have increased, so each treatment would take longer to deploy and longer for the well to clean up following the treatment.

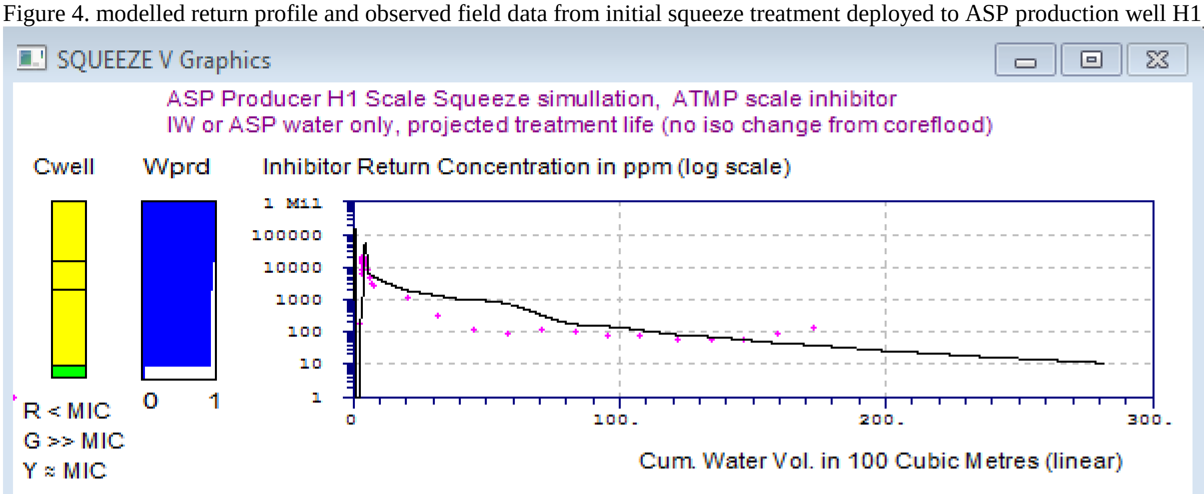
Squeeze returns from field treatments to ASP flooded wells

Four production wells were treated with scale squeeze treatments using ATMP scale inhibitor prior to the onset of the ASP flood. The reason the wells were squeezed just prior to the ASP flooding started was to ensure the wells would be protected against carbonate scale expected to occur with ASP fluid breakthrough and the treatment volumes were sized to treat a water volume that would take the well from formation water production prior to ASP breakthrough and through ASP breakthrough to the end of ASP trial period without the need to disrupt the wells production with any additional squeeze treatments.

All four squeeze treatments were effective against downhole carbonate scale over the design life which ranged from 19,000m^3 (119,450bbls) to 28,000m^3 (176,100bbls) produced water over the design life of 9 months to an MIC value of 10ppm ATMP scale inhibitor. The isotherm used in the squeeze designs was that taken for the "IW" coreflood returns data and the well model used for the injected fluid placement and water production distribution was based on k.h data taken from each wells log data.

The early return periods of all the squeeze treatments (an example is presented in Figure 4) shows a higher predicted chemical concentration (black line) than was in fact measured in the field samples (pink dots). This difference this would be expected as the early flowback period occurred during FW production. The period when the field data and the model prediction values agree is later in the squeeze treatment during the period of time when IW is breaking though, and the isotherm used more closely matches the IW retention properties as shown in Figure 2 and 3 simulations.

Figure 4. modelled return profile and observed field data from initial squeeze treatment deployed to ASP production well H1



Conclusions

High pH brines created during ASP flooding may result in elevated silica, calcium and bicarbonate

pH modification due to interactions in the reservoir not currently modelled for scale management purposes presenting a gap in scale management programs this can lead to pessimistic chemical retention data from end member coreflood and higher than will be observed MIC values

Squeeze treatment volumes that are required for ASP production wells are larger than would be expected if injection fluid was just formation water brine, due to a range of factors low salinity (especially low calcium and magnesium) and elevated pH reducing inhibitor retention.

It is clear while technical challenges remain in the correct selection methods of scale squeeze chemical for ASP flooded production wells the four wells treated in these field treatments show control is possible via squeeze treatment to an MIC of 10ppm and treatment lifetime of 9 months.

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