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Utilizing Oil Soluble Tracers to Understand Stimulation Efficiency Along the Lateral

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Abstract

Chemical water soluble tracers (“WSTs”) have been routinely used in hydraulic fracture stimulations in attempts to verify and quantify load recovery from multi-stage stimulations. Load recovery is often interpolated with production data by assuming percent chemical recovered for a given stage directly correlates to that stage’s production contribution. This assumption is often verified by a running production logging tools. New solid chemical oil soluble tracers (“OSTs”) can now be utilized as a direct indicator of oil flow and production from deep in an individual stages’ fracture. Qualitative analysis gives an early “yes” or “no” to oil flow from each stage, while quantitative analysis may be achieved using relative concentrations of OSTs recovered, and reservoir and flow assumed conditions. OSTs may be used in conjunction with water soluble chemical tracers, or as a stand-alone tracer to determine oil flow from individual stages.

The purpose of this paper is to introduce utilizing solid particulate OSTs as a viable methodology to understand individual fracture stage oil contribution in horizontal wells. The results presented in this paper were derived from a three well pilot project performed in the Lower Marmaton formation in Roger Mills County, Oklahoma.

An investigation of hydraulic fracture stimulation efficiency was undertaken to determine if individual stimulation stages landed in either 100%, or only a portion of the pay sand, were contributing to the well’s oil production. If so, to what extent? The reservoir pay thickness, along with the presence of second sand, influenced wellbore placement in that the drill bit can weave between the sands and the bounding shale layers. Also investigated was the magnitude the stimulation job had on offset producing wells. This was done by collecting and analyzing offset well production for the newly injected WSTs and OSTs. Preliminary results indicate offset communication between certain wells did occur, and the zones experiencing communication appear to have reduced contribution in the subject well’s production.

Introduction

Production contribution from individual hydraulically fractured stages in horizontal wellbores has been a recent topic of much discussion and debate within exploration companies around the globe for some time now. The traditional techniques to improve understanding of reservoir fluid flow in fracture stimulated laterals has been confined primarily to; 1. running production logging tools (“PLTs”); and, 2. utilizing non-radioactive chemical WSTs in the stimulation fluids. Production logs are costly to run, often require cleaning out the lateral, and demand taking a flowing well off production. Additionally, PLTs provided only a limited amount of time sensitive data, with one or two runs being the typical application.

Utilizing tracer chemicals on the other hand requires no wellbore intervention, may be utilized with pumping wells, is extremely cost effective, and can provide valuable reservoir data over much longer time periods. The only requirement post- stimulation is to collect wellhead fluid samples for later laboratory analysis.¹ WSTs are typically extremely hydrophilic; typically being derived from halogenated organic acids.²

OSTs are relatively new family of chemicals derived from very hydrophobic organic compounds. The purpose of this paper is to highlight the successful introductory placement of solid OSTs in proppant packs via a 3 well pilot project. This novel use of particulate OSTs was tested in the Lower Marmaton formation of Roger Mills County, Oklahoma.

Reservoir Description

The Lower Marmaton formation is part of the Pennsylvanian System and the Upper Des Moines Group. The deposition in the study area is a large, submarine fan slope deposit sourced from the North East. It is a complex of several pulses of sand deposits ranging in thickness of a few feet to over seventy feet. It was subsequently overlain by a westerly prograding shoreline deposit of the Deese Shale. This narrow one to two mile wide channel quickly widens into a fan deposit that stretches over fifteen miles wide and fifteen miles in length. The regional fan is composed of very fine grain, well sorted, quartz sands, with quartz overgrowths further reducing reservoir permeability. A few sectional areas have intermingled clays present within the fan, but not in great abundance.

Purpose and Design

The original intent of the study was to understand how hydraulic fracture stimulations are affecting offset wells by utilizing WSTs. The basis of the study was then expanded when solid OSTs were presented as a novel tool to help better understand the individual stages' oil production contribution within a completed lateral wellbore. It was of specific interest to investigate if stages stimulated in higher gamma ray rock were contributing to oil production, and if so, to what extent.

Three wells to be completed in the Lower Marmaton formation were identified as suitable candidates for the tracer study. The R-1H and M-2H pilot wells are located in sections adjacent to one another, and the F-4H well is located in a section diagonal to the M-2H well section. The three traced wells locations in their respective sections are illustrated in Figure 1 in red with surface locations indicated by circles. Each pilot well was drilled with a north/south orientation.

The study design was to trace each stimulation stage in the F-4H well with both liquid WSTs and the solid particulate OSTs, while wells R-1H and the M-2H were to be traced with only solid particulate OSTs. Production fluid from each well and the offset wells would be gathered and analysed utilizing mass spectrometry.

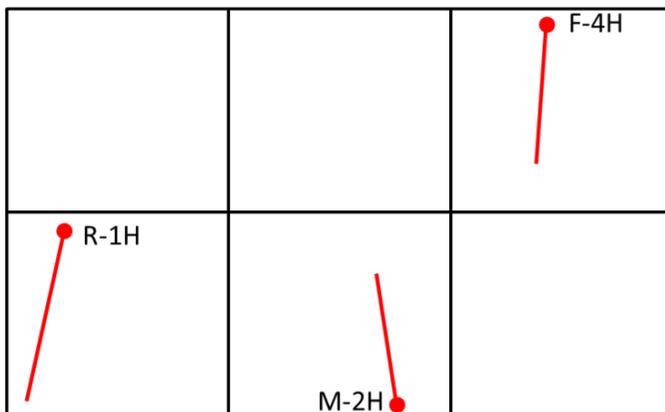


Figure 1 - Locations of Pilot Study Wells in Section

F-4H

The first well of the pilot study to be completed and traced was the F-4H. This well was a good candidate to utilize WSTs in an attempt to identify hydraulic fracture stimulation communication due to its proximity to existing vertical and horizontal wells. Like the other two study wells, solid particulate OSTs were pumped *in situ* along with the proppant deep into the formation fracture. In each stage's stimulation, OST injection ceased after two-thirds of the stimulation stage had been pumped. This was to insure no solid OST would remain in the lateral causing false positive oil flow readings.

Each of the 9 stages of the F-4H well was successfully stimulated and traced with both liquid WSTs and solid OSTs. Production stream samples from the F-4H and the offset wells were collected and analyzed using mass spectrographic analysis. Flow stream sampling continued for each well for 180 days.

The F-4H well is offset in section by an existing horizontal well, the S-2H, and two vertical wells, the S-1, and F-3. The B-2H is located over two thousand feet away in the adjacent section to the West (shown in Figure 2). All the offsets had been on production for over one year before the F-4H was hydraulically fracture stimulated, with the exception of S-1, which had been producing over three years. Each of the existing offset wells was completed and produce from the same Lower Marmaton formation as the pilot study wells.

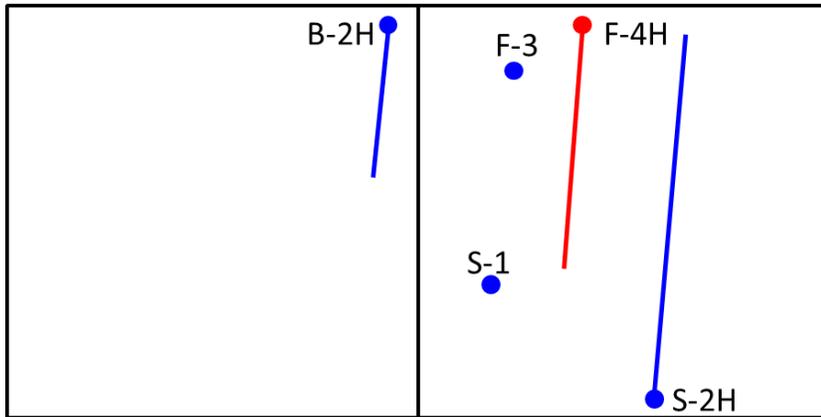


Figure 2 - Offset Well Locations in Relation to F-4H

The F-4H is considered to be Lower Marmaton “A” well, but both the “A” and the lower “B” Marmaton sands are present based on detailed log interpretation. The F-4H lateral landed low in the “A” sand, and the heel stage skimmed the top of the shale zone separating the A and B sands. The remaining lateral of the F-4H was drilled in the center of the “A” sand as intended. Unfortunately, the F-4H casing had to be short set due to loss circulation issues.

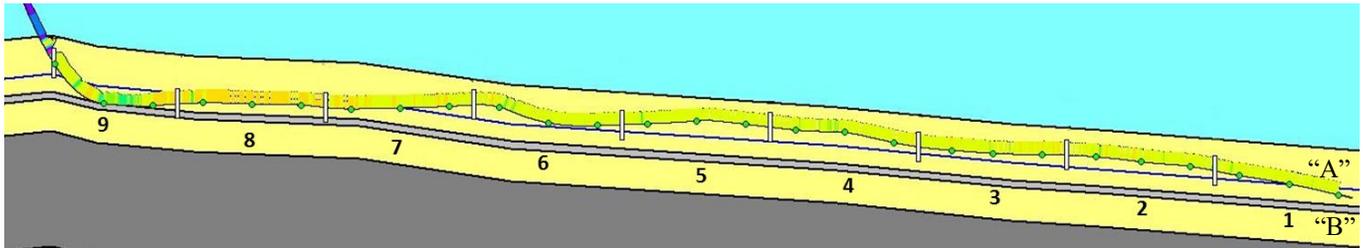


Figure 3 - F-4H Wellbore Interpretation with Plug and Perforation Locations

The F-4H was designed as 9 stage plug and perforation hydraulic fracture stimulation. Figure 3 shows the lateral placement of the wellbore utilizing gamma ray and survey data from MWD measurements. The plug and perforation locations for the F-4H are included Figure 3 as well. Production from stage 9 was of particular interest as the wellbore skimmed between the “A” sand and the shale bed, and was landed in a higher gamma ray area of rock. In previous wells, this stage would have been condemned as non-commercial due to the higher gamma ray values and its proximity to the shale layer.

The fracture stim design was a three cluster perforation scheme utilizing a 25 pound cross-linked borate gel fluid system transporting 20/40 white sand. All 9 stages were pumped as designed, with fracture gradients averaging 0.87 psi/ft. Each stimulation stage included a unique WST identifier, and a unique OST tracer. All plugs were drilled out immediately after hydraulic fracture stimulation operations concluded, and the well was brought on production.

The sampling procedure instituted for the F-4H involved taking surface fluid samples daily for seven days of flowback, as well as sampling the four offset wells. Oil samples were gathered only from the F-4H for a period of sixty days. Additional water and oil samples were gathered from each well at the ninety and one hundred eighty day marks specifically for this study.

F-4H Results

The water samples gathered from the F-4H and the surrounding offsets provided great insight into wellbore communication resulting from hydraulic fracture stimulation.^{3,4,5} Figure 4 shows the WST analysis from the F-4H well. The diameter of each dot is proportional to the concentration of the WST reported in parts per million (“ppm”) from spectrometric analysis. Every stage except stage 3 was determined to have contributed fluid to flowback in the first week. The data shows stage 3 began to contribute to flow sometime between day 7 and day 90. A reasonable explanation of this later time contribution would most likely involve the equalization of different bottom hole flowing pressure regimes. It is interesting to note at the 180 day mark; no WST tracers were present in the water analysis from the F-4H, indicating all possible load recovery had occurred.

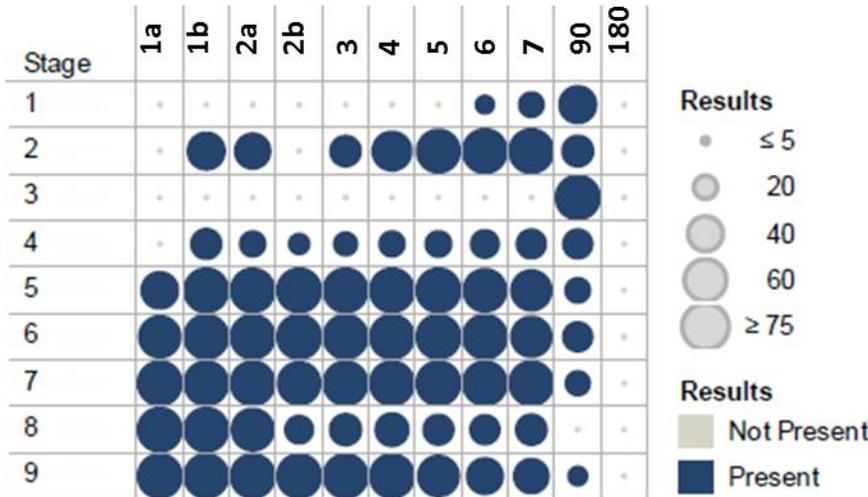


Figure 4 - F-4H Water Soluble Tracer Analysis by Stage and Sample Day

The WSTs analysis from the offset wells provided detailed information on the effect of stimulation communication with the F-4H. The water sample analysis for both the B-2H and S-1 showed no WSTs pumped during the F-4H hydraulic fracture stimulation present. However, the water sample analysis from both the S-2H and the F-3 showed these wells produced WSTs used in the stimulation of the F-4H. Figure 5 shows the WSTs analyzed in the water samples taken from the F-3 well. stage 8 communicated within the first week of sampling, and at the 90 day mark, WSTs used in stages 6 and 7 were also detected. At day 180, only stage 6 and 7 tracers were present in the water samples.

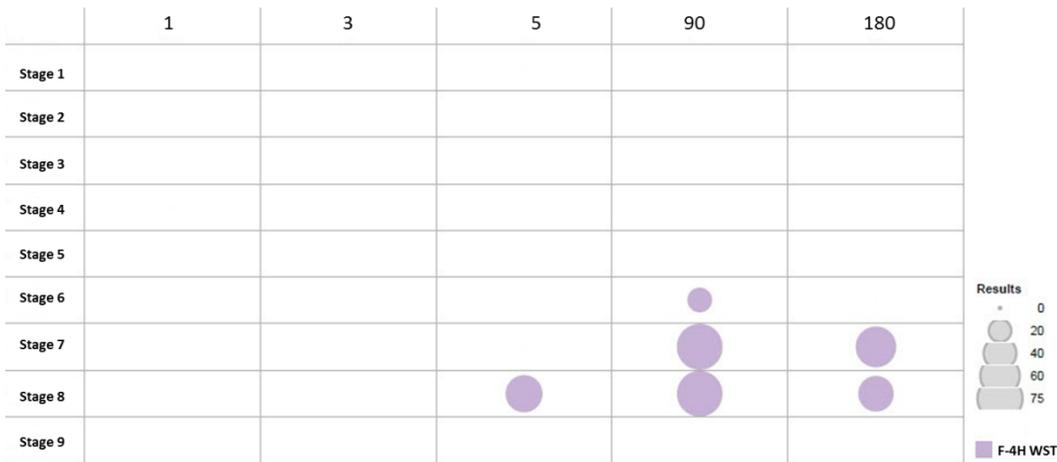


Figure 5 - Water Soluble Tracer Analysis of the F-3 Water Samples

Figure 6 shows the WSTs discovered in water samples analyzed from the S-2H well. The WST tracers used in the F-4H stimulation stages 2 and 3 were detected in the first week of water sampling the S-2H. WSTs used in stages 1, 3, and 4 were detected at the 90 and 180 day samplings, but of note is stage 2 being visibly absent at the later dates.



Figure 6 - Water Soluble Tracer Analysis of the S-2H Water Samples

The OST results from the F-4H are presented in Figure 7. The analysis highlights the fact all stimulation stages did contribute to oil production in the F-4H well. Stages 5, 6 and 9 had the largest concentration of OSTs recovered indicating these were the highest contributing oil productive stages. Stages 1, 2 and 3 did not have a good initial OST recovery, but over time, saw increasing OST recoveries. Combining the WST and OST information highlights the fact the stimulation stages communicating with offset wells also provided less oil production contribution.

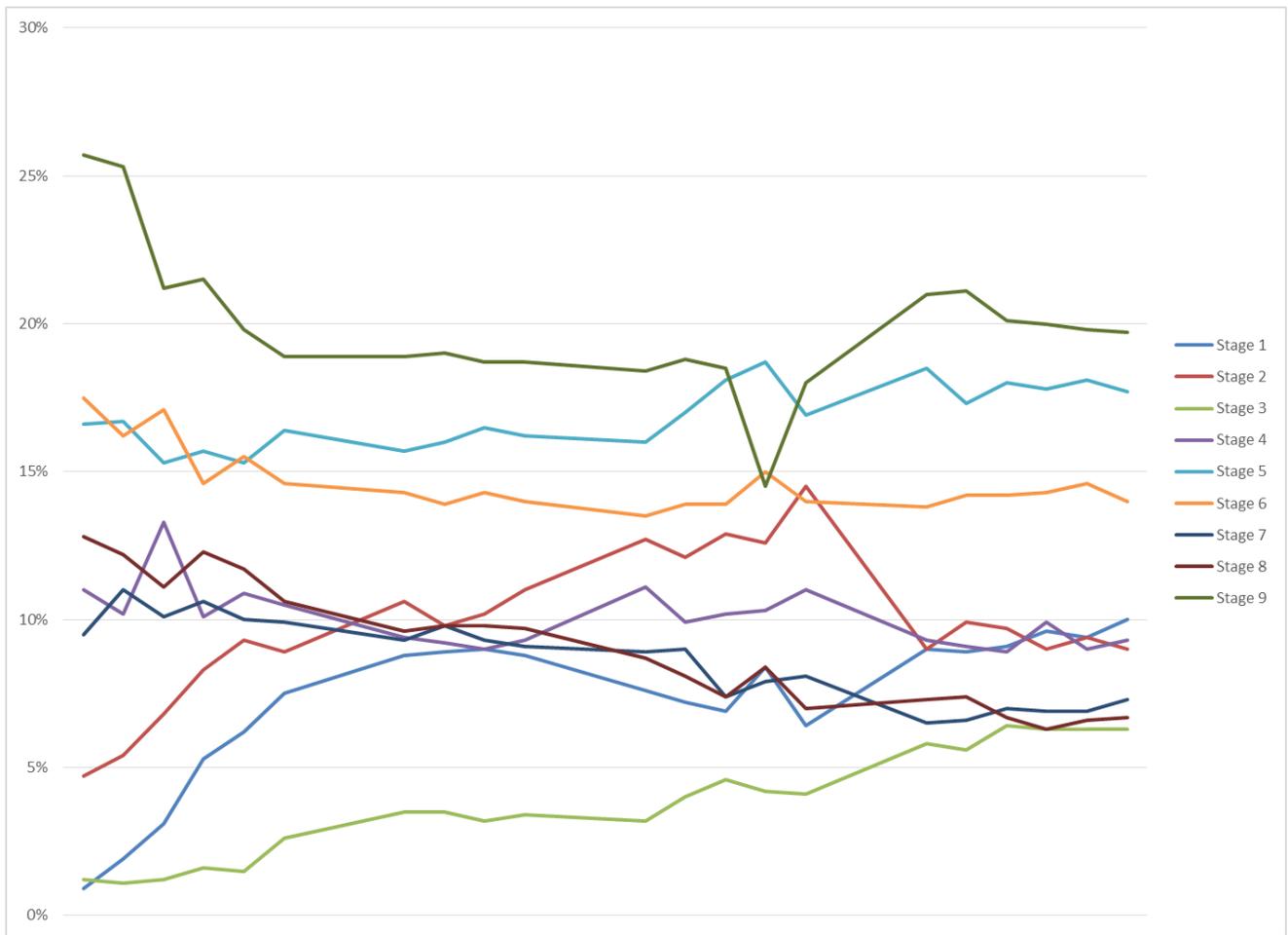


Figure 7 - F-4H Percentage of Oil Soluble Tracer Present by Stage over Time

R-1H

The second well in the study to be traced was the R-1H. The nearest offset well to the R-1H was over 3,000 feet away, and this distance exceeded the distance between the B-2H in the F-4H study well. The decision was made to not use WSTs in conjunction with oil soluble tracers in the R-1H as data as the F-4H showed no communication with the B-2H well.

The R-1H is also a Lower Marmaton "A" well with the "B" sand present in log interpretation. The lateral was landed in the shale in error, and the effort to turn the heel up to get back into the "A" sand was successful. Steering difficulties occurred throughout the drilling of the lateral of the R-1H resulting in parts of the wellpath lying outside of the "A" sand, and in the bounding shale layers. The R-1H was successfully drilled and cased to planned total depth.

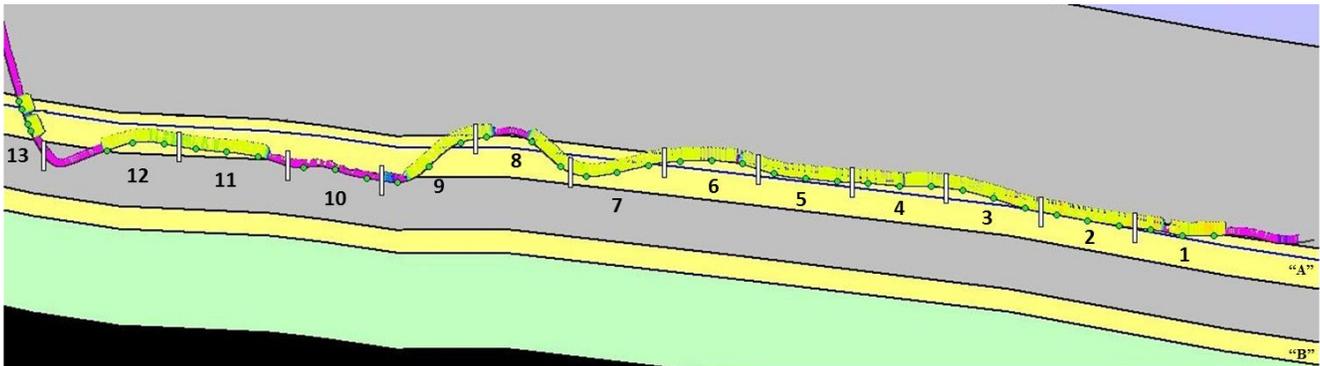


Figure 8 - R-1H Wellbore Interpretation with Plug and Perforation Locations

The R-1H was designed as a 13 stage plug and perforation hydraulic fracture stimulation. The plug and perforation locations for the R-1H may be seen in Figure 8. Stages 9, 10 and 13 were of particular interest for OST recoveries given their somewhat unique geometry and locations. Stages 9 and 10 were of interest due to the perforations being located in the shale bed between the "A" and "B" sands. Stage 13 was of special interest for two reasons; 1. the wellbore lay at a sixty degree angle, and 2. the hydraulic fracture stimulation design was half the size of the first 12 stages.

The availability of unique solid OSTs at the time this well was completed was limited to ten tracers. This numerical limitation required 6 stages to be paired and use the same OST. The decision of which stages to pair was made by evaluating and choosing adjacent stages exhibiting similar reservoir properties of the "A" sand. The stages paired were 1 & 2, 7 & 8, and 11 & 12. Given the unique characteristics of stages 9, 10, and 13, a conscious decision was made to not pair these stages with any other stage.

The fracture design was a 3 cluster perforation scheme utilizing a 25 pound cross-linked borate gel fluid system transporting 20/40 white sand, with a tail-in of 20/40 light weight ceramic proppant. All 13 stages were pumped as designed and the fracture gradients averaged 0.96 psi/ft. The fracture gradient of the R-1H was significantly higher than the F-4H and the M-2H wells. Stage 13 had an unusually high fracture gradient; over 1.0 psi/ft. This is likely attributed to the more acute angle of the wellbore in this stage. The R-1H was brought on production immediately after all plugs were drilled out. Daily oil samples were taken from the R-1H for a period of 60 days.

R-1H Results

Figure 9 shows the percent of OSTs present in oil samples taken from the R-1H well. The figure shows the lateral did not have any production blockage, and all stages contributed to oil production. The highest contributing stages at the beginning of sampling were the stages closest to the heel. Stages 1 through 6 did not start to contribute significantly until the well had been on production for some time. Figure 9 shows that percent contribution flips between the heel and toe stages halfway through sampling time frame. This was thought to be a function of the water oil ratio changing with time, but further investigation needs to be done to verify. The stages of particular interest in proximity to the shale showed good production contribution at the beginning of sampling. Stages 10 and 13 were average performers with around 5-6% OSTs recovered, but stage 9 was the single best stage for percent OST recovered, although its overall percentage declined in time.

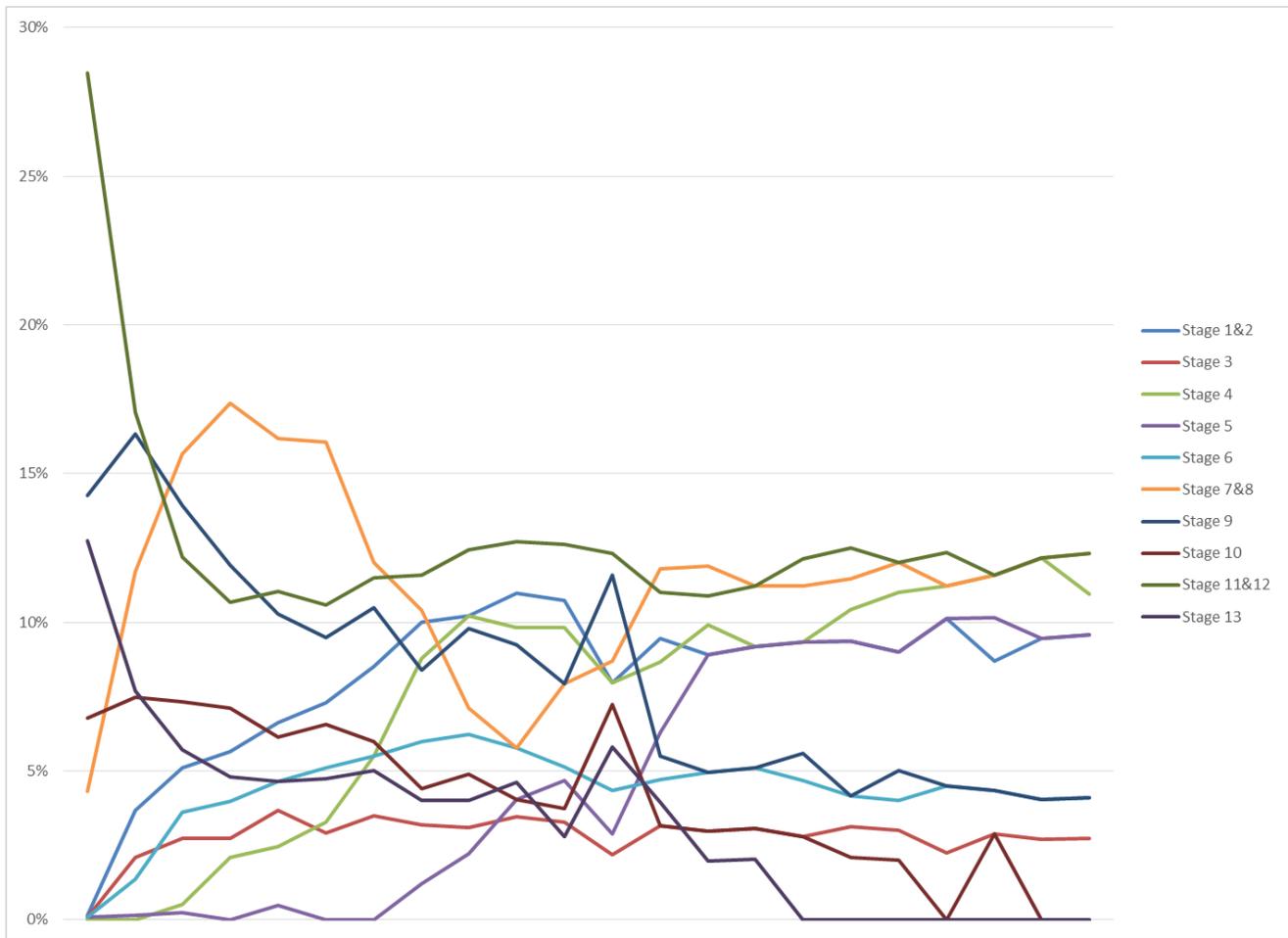


Figure 9 - R-1H Percentage of Oil Soluble Tracer Present by Stage over Time

M-2H

The third and final well of the study was the M-2H. The well was traced only with particulate OSTs as both direct offset wells were non-producing due to casing collapse. This well had difficulties drilling, with loss circulation being the main culprit. The result was another short set lateral.

The M-2H is a Lower Marmaton “A” well, and no “B” sand was present according to log interpretation. The wellbore stayed mostly in the center of the “A” sand, except towards the middle where it dips down into the shale bed below as shown in Figure 10.

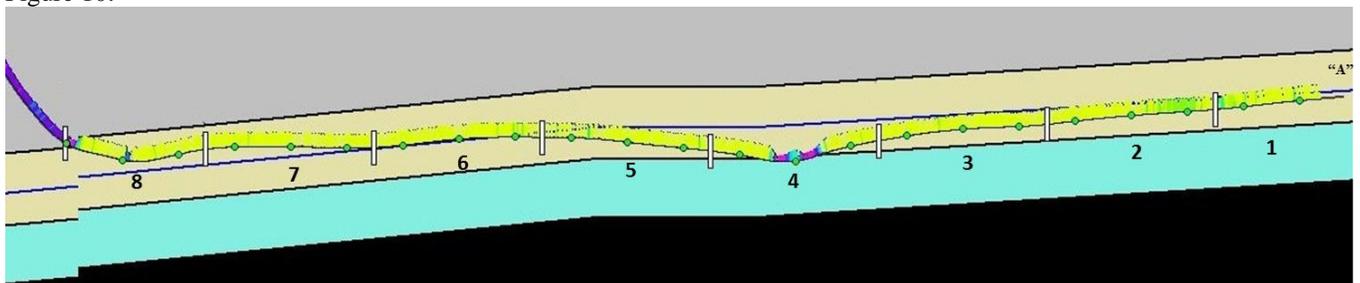


Figure 10 - M-2H Wellbore Interpretation with Plug and Perforation Locations

The M-2H was designed as an 8 stage plug and perforation hydraulic fracture stimulation. The plug and perforation locations for the M-2H are included in Figure 10. Stage 4 was of particular interest since the wellbore dipped into the shale bed below the “A” sand. A perforation was placed directly in the shale for this stage.

The fracture design was a three cluster perforation scheme utilizing a 25 pound cross-linked borate gel fluid system transporting 20/40 white sand and a tail-in of 20/40 light weight ceramic proppant. All stages were pumped as designed and all proppant and OSTs were successfully placed in the reservoir. The average fracture gradient was 0.84 psi/ft; significantly

lower than the other two wells in the study. The treating pressures for this well were also lower than any previous Lower Marmaton hydraulic fracture stimulation in the study wells. The M-2H was brought on production immediately after all plugs were drilled out. The sampling procedure and schedule was the same as that of the M-2H and R-1H wells.

M-2H Results

Figure 11 shows the percent of OSTs present in oil samples taken from the M-2H well over time. The figure shows all stages recovered at least 5% of OSTs except stage 2. The highest contributing stages at the beginning of sampling were the stages closest to the heel. This recovery pattern is similar to the R-1H well. Stage 4 had perforations directly in the shale, and showed good OST production contribution at the beginning of sampling; however, OST recovery was quite reduced in later sampling efforts. This well was the poorest performer of the wells in the study, and sampling was discontinued after 30 days as the concentration of recovered OSTs and oil became *de minimis*.

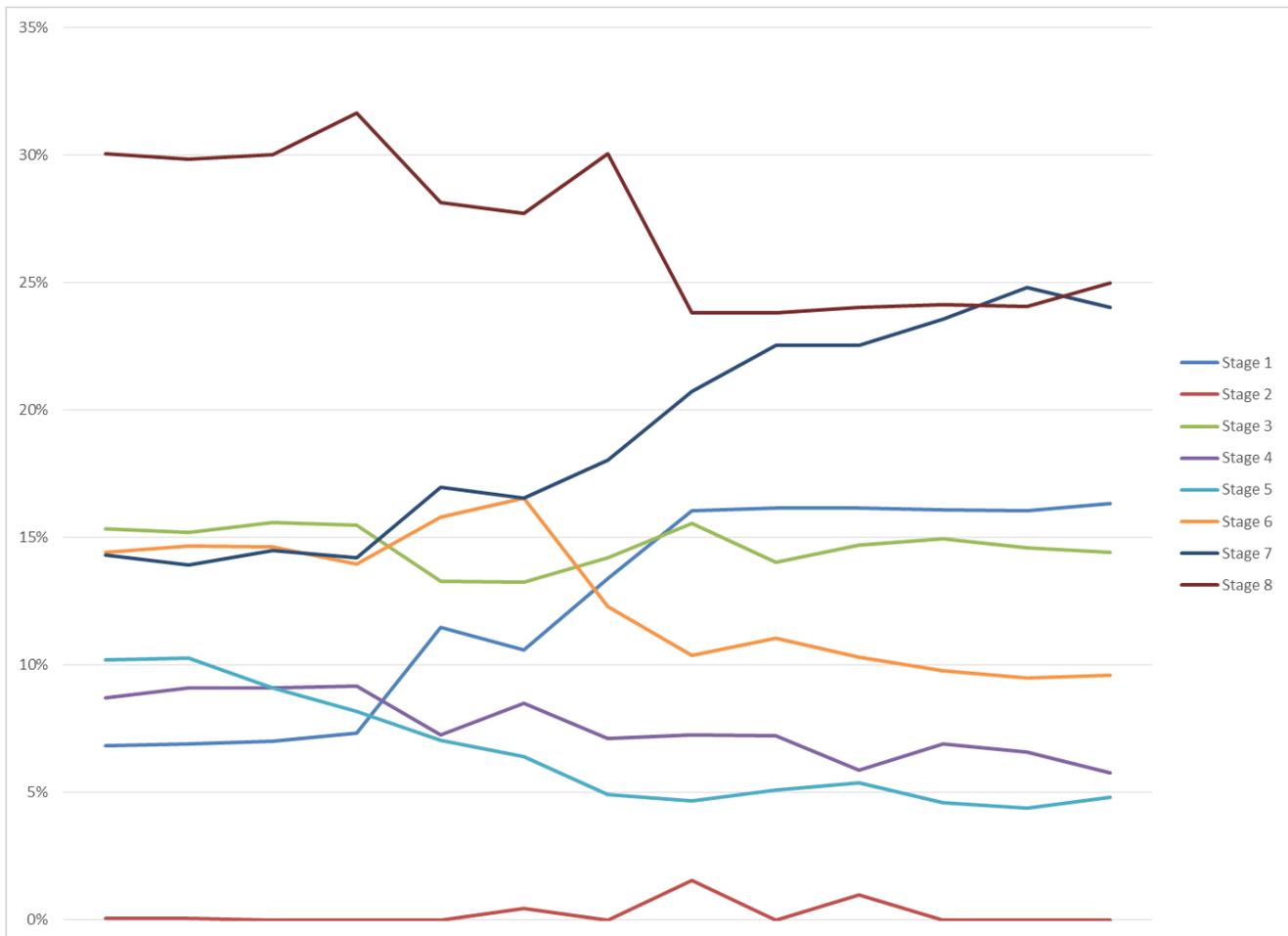


Figure 11 - Figure 9: M-2H Percentage of Oil Soluble Tracer Present by Stage over Time

Conclusions

The goal of this study was to observe and understand individual stimulation stage water and oil contribution in a three well pilot study. A reviewed of the data discussed clearly indicates the goal was achieved. Knowledge was also gained on hydraulic fracture stimulation communication in offset wells in the Lower Marmaton. This fact has important implications for future well spacing and stimulation design. Key takeaways from the pilot study include:

1. Every stage in each of the study wells contributed to each wells' oil production.
2. The poorer performing stages (i.e. less overall percent recovered OSTs) of F-4H well were also the stages in which WST were recovered in offset wells. This clearly confirmed reservoir communication with offset wells, and shows the benefit of pumping OSTs and WSTs together.
3. Hydraulic Fracture stimulation stages placed in wellbore sections with high gamma ray rock did contribute significantly to oil production.
4. The F-4H well did not show any WST recovery at sampling day 180; however, the offset wells were still recovering WSTs at this time. This suggests the stimulation volume used in the treatment of the F-4H well was perhaps larger than it needed to be to effectively stimulate the well.
5. Placing solid OST particulate within a stimulation proppant pack proved to be an effective new methodology to indicate oil production.
6. Tracer data indicates the heel stage, and the adjacent stages closest to the vertical wellbore, dominated flowback and early well life production.
7. Toe stage tracer recovery indicated no lateral wellbore blockage or plugging had occurred in any of the study wells.

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