Proven Completion Efficiency Improvement with Deeprop®

Executive Summary

- The stress cage around a horizontal wellbore can lead to severe tortuosity and high treating pressures.
- Proppant erosion abrades enough rock from the near wellbore fracture face to:
    - remove any tortuosity
    - provide near wellbore conductivity
    - reduce convergent flow effects during production.
- Advancements in downhole imaging tools have allowed improved diagnostic methods for determining casing, perforation and frac plug effectiveness.
- The use of two to four thousand pounds of a very hard, small, * in the pad enhances near wellbore proppant abrasion which improves both completion efficiency and effectiveness.
- The use of a microproppant in the pad has led to:
    - Significant production uplift
    - A reduction in the decline rate
    - A reduction in the cost of over capitalization
    - Overall improvement in the capital efficiency

To support the above summary recent studies outlined below have shown that in a recent Delaware Basin well study the extra value provided by the uplift from microproppant was $8,000,000 after 575 days of production. A study in the Eagle ford also outlined below showed that the microproppant improved capital efficiency by $900,000 to 1,200,000 by improving completion effectiveness.

Near-wellbore complexity

It is well known that the stress cage or hoop stress that is left around a horizontal well after it is drilled can cause severe complexity in the geometry of hydraulic fractures that are created in horizontal wells. This complexity becomes more severe as the delta between the three stress regimes (σ_v, σ_{Hmax} and σ_{Hmin}) becomes larger. This complexity is shown visually in Figure 1 which was taken from some modeling work that was completed by Lawrence Livermore National Laboratory and presented in SPE 199689. Initially when the well is broken down the stress cage causes a longitudinal fracture to be created that is parallel to the well bore. Once the fracture propagates to a point where it is no longer influenced by the hoop stress the fracture will reorient so that the fracture is propagating in the direction of σ_{Hmax}. If the intent is to create a transverse fracture, then the fracture will reorient normal

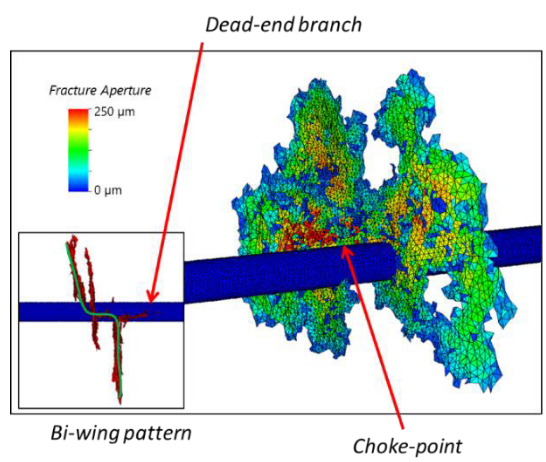


Figure 1 - Numerical model of near wellbore tortuosity causing a chokepoint[1].

to the wellbore which will cause a chokepoint or kink to form as the fracture reorients. The severity of this kink is a function of the delta between the two horizontal stresses. This "Kink" is called tortuosity and can cause severe placement problems associated with excess treating pressures and near wellbore premature screen outs. In addition, if this "kink" persists it can limit the production of the well because of low near wellbore fracture conductivity and convergent flow excess pressure drop.

Under flushing vs over flushing

The general paradigm for the design of hydraulic fractures is to under flush the treatment to ensure that proppant is left in the near wellbore fracture to prevent the fracture from pinching off and restricting flow (See Figure 2). There have been many slot flow studies completed which show that when a low viscosity frac fluid is used to place proppant a dune is formed which has a large void area near the wellbore where the velocity of the fluid exiting the perforation is high which sweeps the proppant away from the near wellbore area. Figure 3 is a photo of some recent work completed at the Colorado School of Mines that shows this void area near the point of injection. The engineering practice that is normally followed to reduce this void area is to reduce the pump rate at the end of the job to allow proppant to settle into this void.

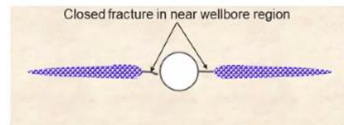


Figure 2- Perceived consequence of over flushing[2].

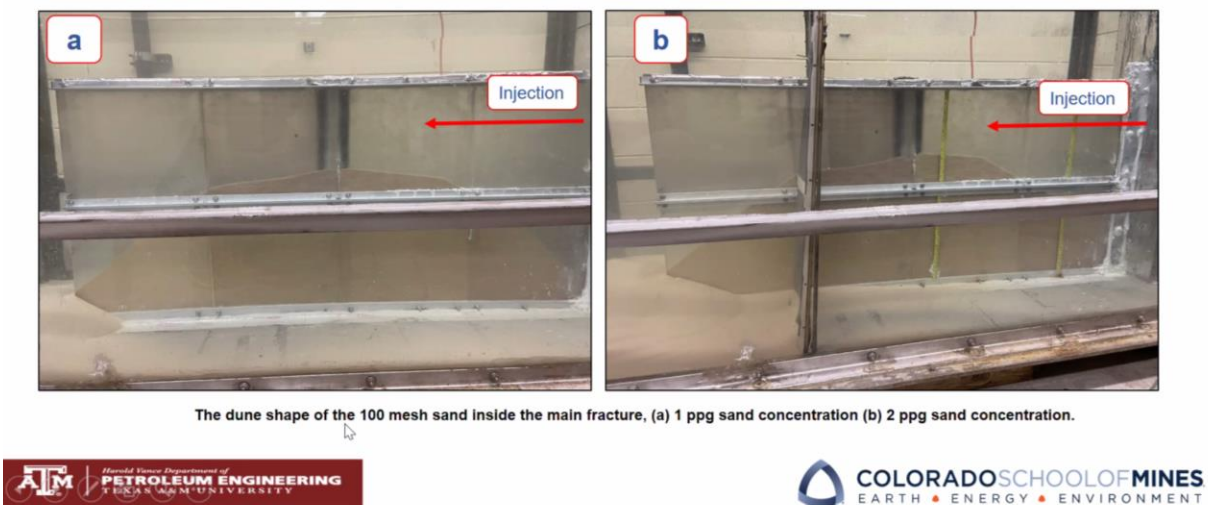


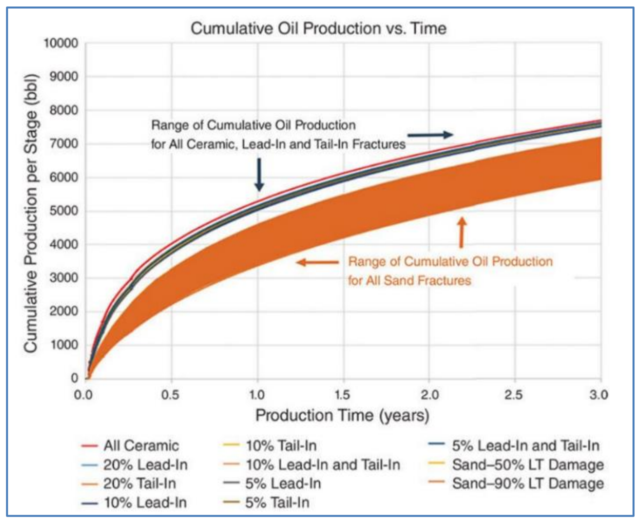
Figure 3 - Slot flow study showing a large area void of proppant near the pint of injection[3].

Interestingly in a paper recently published by Shell (SPE 201666) in which the fracturing treatments were intentional over flushed downhole video photos (See Figure 4) showed that the fractures were wide open even though no proppant was detected. The paper states that it is believed that "the strong force of proppant erosion during the treatment etched enough rock material from the fracture face to prevent it from sealing back up after fracture closure". Post product data showed that the over flushed wells dominated the top 50% of performers. To support their conclusion, they reference the shale revolution which has delivered hundreds of thousands of wells using the over flushing technique. In this paper Shell and Salym Petroleum also point out that "over flushing is not only widely considered by the shale community to be of no risk to conductivity, but it has also been linked to stronger well performance."

Figure 4 - Downhole video camera showing over flushed hydraulic fractures with no visible proppant. [2]

Importance of near wellbore conductivity

Figure 5 taken from SPE 201641[4] summarizes the results of an extensive test conducted in the Bakken by Liberty Resources using various hydraulic fracture treatment designs with both ceramic and conventional silica-based proppants. As the figure shows there is a clear production benefit from including even 5% ceramic in the treatment. In this paper the benefit is attributed to the highly conductivity ceramic proppant being deposited near the wellbore propping open the near wellbore area. Several large-scale physical model slot flow tests demonstrate this benefit.



5 - Three-year cumulative oil for various middle Bakken fracture design using ceramic as a lead-in to tail-in or for the whole job compared to using only silica sand. [4]

Given the over flushing results described above from the Shell paper[2] it may be possible that the enhanced production in the wells treated with ceramic may be the result of near wellbore abrasion. A combination of abrasion plus the added benefit of near wellbore conductivity should be additive.

Imaging the perforations

There have been several advancements in downhole imaging tools which is advancing the understanding of what is happening to the downhole hardware (casing, plugs and perforations) during the placement of hydraulic fractures. The above Figure 4 from the Shell paper[2] is an example from a tool which uses an optical camera to provide downhole images. To offset the problem of having to have a clear fluid to create an image, a tool based on ultrasonic sound was developed by Dark Vision (https://darkvisiontech.com/). Figure 6 shows several images of perforations and a photo of the tool used to create the images. Several papers[5, 6, 7] have recently been written about the tool and the results of the images provided by the tool. As shown in the upper right corner of Figure 6 not only does the tool image the feature but the associated software calculates the surface area of the feature.

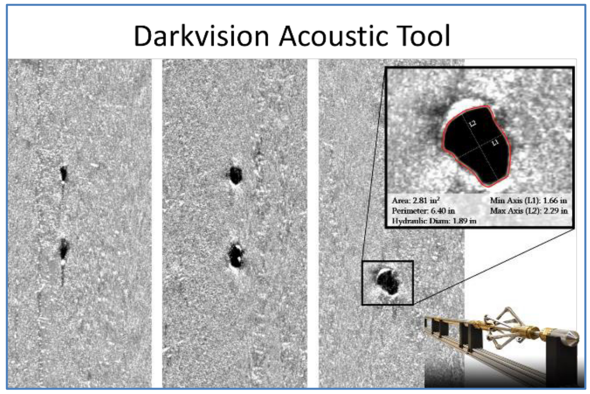


Figure 6 - Darkvision Acoustic Tool images.

Using Microproppant to Improve Competition Efficiency

A major E&P company recently completed a test to determine if a ceramic microproppant would improve the completion efficiency of their frac treatments. The study consisted of a four well study in which 18 stages out of a total of 87 stages in two wells were treated with the microproppant. One of the microproppant wells used a 10 cluster/stage perforation design where each cluster received three 0.42" EHD, 25 gm charges for a total of 30 perforations and was treated with 420K # of 100 mesh sand. In this well in addition to the 100-mesh sand 9 of the stages included 10,604# of microproppant which was pumped at a concentration of 0.25 and 0.5 lb/gal in the pad. The second microproppant well used a 14 cluster/stage perforation design with the same perforation design and was treated with 588K # of 100 mesh sand.

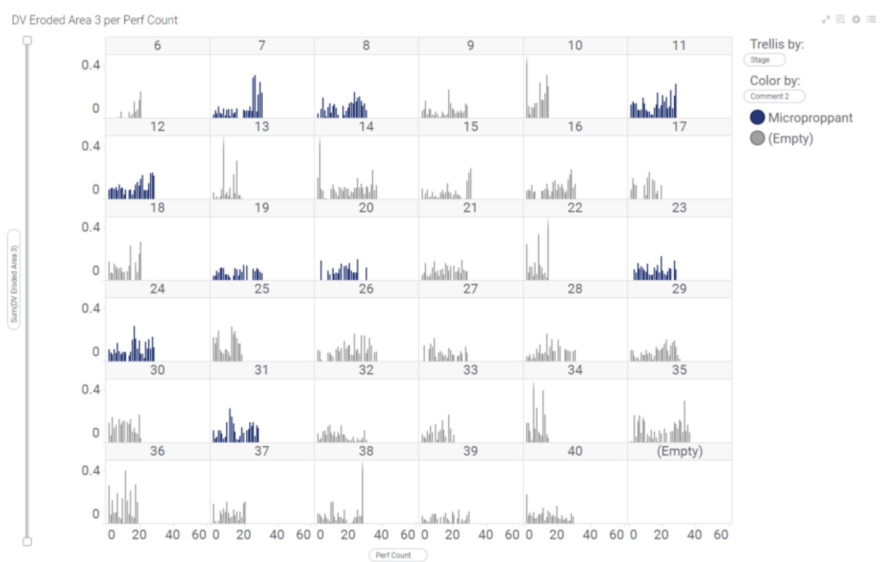


Figure 7 - Darkvision perforation eroded area for the 10 cluster, 30 perforation/cluster design.

The stages that included the microproppant were treated with 14,750# of microproppant pumped at a concentration of 0.25 and 0.5 lb/gal in the pad. After clean-up a Dark Vision tool was run to evaluate which stages had a more consistent perforation uniformity. The results from the 10-cluster design are shown in Figure 7. To understand what the plot represents, Figure 8 shows the results for the two adjacent stages 12 and 13. The vertical axis represents the eroded area of the perforation. The initial perforation size was 0.42" which is the 0 point on the vertical axis. The 0.4 on the vertical axis represents an eroded area of 0.4 square inches above the base line of 0.42". The area of a 0.42"diameter perforation is 0.14" ($A = \pi r^2 = \pi \cdot 0.21 \approx 0.13854$) so the total area of a perforation at a point on the vertical axis of 0.4 would be 0.4 + 0.14 =0.54 square inches. Stage 12 is a microproppant stage and each vertical blue line represents 1 perforation. This stage was a 10-cluster design with 3 perforations for each cluster for a total of 30 perforations. If one counts the blue lines, there are 28 of the 30 perforations or 98% that received proppant. On stage 13 which also was perforated with 30 perforations there were 17 of the 30 perforation or 57% that received proppant. Stages 13 also shows that perforation 7 was a "runaway" perforation which is taking a large portion of the treatment.

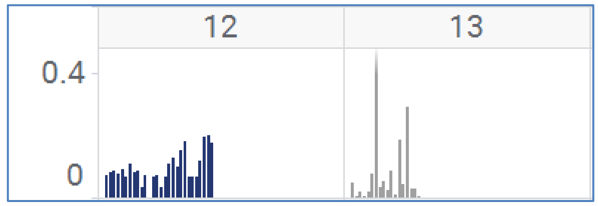
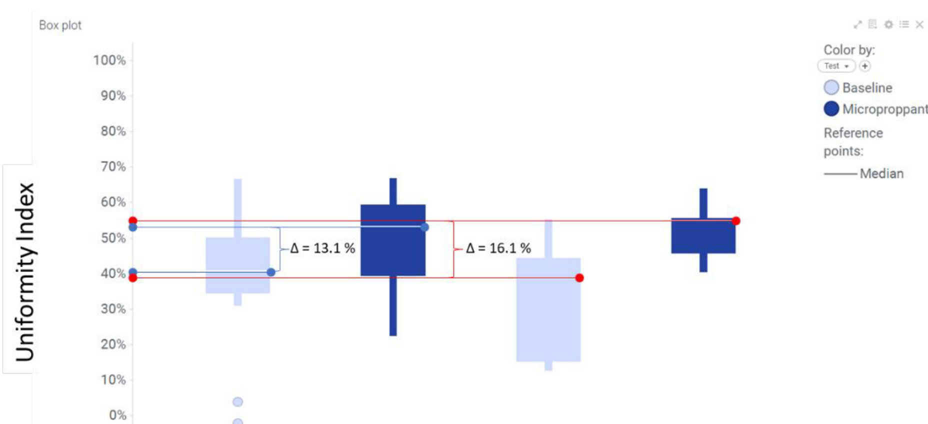


Figure 8 - Stages 12 and 13 of the 10-cluster design

A statical analysis composite of all the stages is shown in Figure 9. The light blue boxes represent the non microproppant baseline stages and the dark blue boxes represent the microproppant stages. The white line running through the boxes is the median value for all the tests. The results indicate that in the 10 cluster well the median value for the number of perforations that received proppant increased by 13.1% while in the 14 cluster well it increased by 16.1%. In general, the completion efficiency of the stages treated with the ceramic microproppant was increased by 15% to an overall competition effectiveness of 54%.



	10		14	
	0.42			
	Baseline	Microproppant	Baseline	Microproppant
Count	24	6	10	9
Median	0.40627	0.532104	0.386152	0.54762
Avg	0.357844	0.485678	-0.340223	0.522938
Outliers	4	0	2	0

Clusters Target Hole Size Test

Figure 9 - Statistical analysis comparing the effectiveness of proppant placement in microproppant vs no microproppant stages.

Proposed Mechanism

Figure 10 modified from the Shell paper[2] shows that the expected impingement velocity of proppant entering the fracture is in the range of 50 to 90 mph. Using the 10-cluster case and the pump rate shown in Figure 11 (10 clusters, 3 perf/cluster, 48% efficiency, 60 bpm = 4 bpm/perf = 7000 ft/sec) the particle velocity as it exits the perforation is about 80 mph. The ability of proppant to increase perforation hole size by eroding steel is well known. In the case of microproppant it is believed that the microproppant is probably not affecting the perforation geometry but because it is abrading the near wellbore rock it improves the distribution of the following frac treatment and the 100 mesh in the following stages is abrading the perforation. The microproppant is added into the fluid at a concentration of 0.25 to 0.5 lbs/gal and because of the Bernoulli effect is concentrated in the center of the flow stream. The mass of microproppant and sand is close (2.5 gm/cm^3 vs 2.65 gm/cm^3) but the microproppant is so small (0.032 mm) compared to even 100 mesh sand (0.149 mm) the momentum of the microproppant particle as it turns the corner thru the perforation is not sufficient to impact the edge of the perforation. Momentum is a measurement of force per second, or mass times velocity so it is a vector which has both magnitude and direction. The difference in momentum between the microproppant particle and 100 mesh at 80 mph is a factor of about 100. The inertial forces place on the microproppant as it turns the corner are focused against the cement and rock in the first few feet near wellbore area before the velocity of the fluid stream drops to the much lower velocity the fluid stream experiences in the fracture. The distance or geometry of this eroded channel is not known but it is likely to be in the order of a few feet and since it is an open channel will have infinite conductivity.

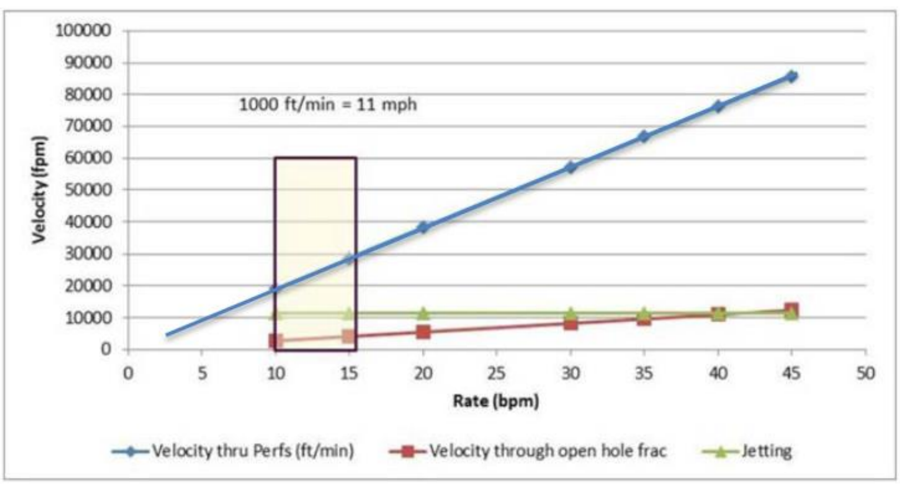


Figure 10 Proppant velocity as it exits the perforation for a 6.5" wellbore.[2]

How much does it take?

Figure 10 is a treating plot from Stage 12 of the 10-cluster design in which 10,000# of microproppant was pumped. The bottomhole concentration of microproppant is shown on the gray line, the surface treating pressure is shown on the red line and the pump rate is the green line. If the pump rate is held constant a treating pressure decrease is an indication that any near wellbore restriction is being removed. It appears that most of the pressure reduction that is being caused by the microproppant occurs very quickly. Because the pump rate is being increased initially it is difficult to determine the response but after about 8 minutes the rate is held constant and the effect of the microproppant can be clearly seen. After 6000# of microproppant no additional pressure improvement can be seen.

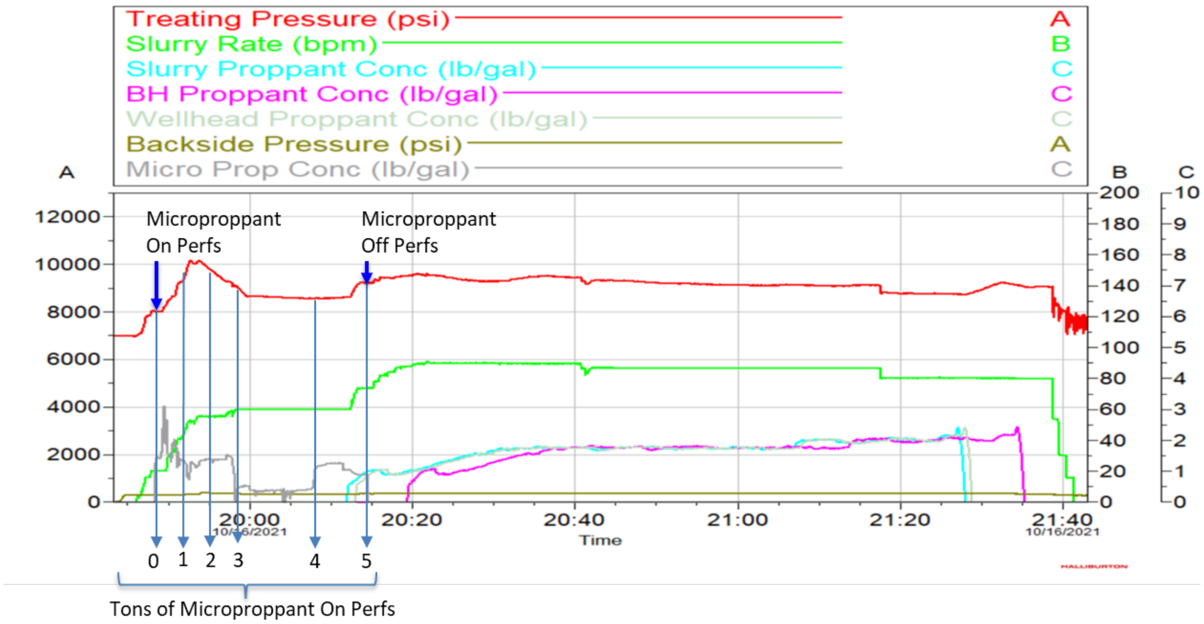


Figure 11 - Stage 12 treating plot showing microproppant induced pressure reduction.

This reduction in pressure response when the microproppant hits the formation has been noted many times. Figure 11 shows examples from the Barnett and Baaken. The red lines are again the treating pressure. In both these cases the pressure reduction was quite rapid with about 4000# of microproppant being sufficient to open any restrictions.

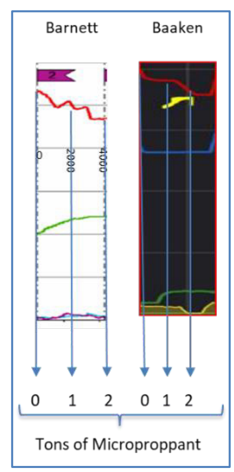


Figure 12 – Treating pressure response when the formation is exposed to microproppant.

There are several benefits from this reduction in treating pressure. In addition to opening more perforations and eroding or abrading out any near wellbore rock this reduction in pressure allows the pump rate to be increased. If the pump rate is increased, then there is less time for the treating fluid to leak off which improves the fluid efficiency. This means that the treatment will contact more rock with the same amount of fluid which again will improve the treatment effectiveness. If the pump rate is not increased, then the lower treating pressure will result in a lower horsepower requirement which is a treatment cost savings.

Economics

There are several examples of the dramatic production improvement provided by the use of a microproppant in reference 8. Figure 12, which is not included in reference 8, is from a recently conducted test in the Delaware Basin Wolfcamp formation of West Texas. Using a value of \$50/boe the extra value provided by the microproppant is \$8,000,000.

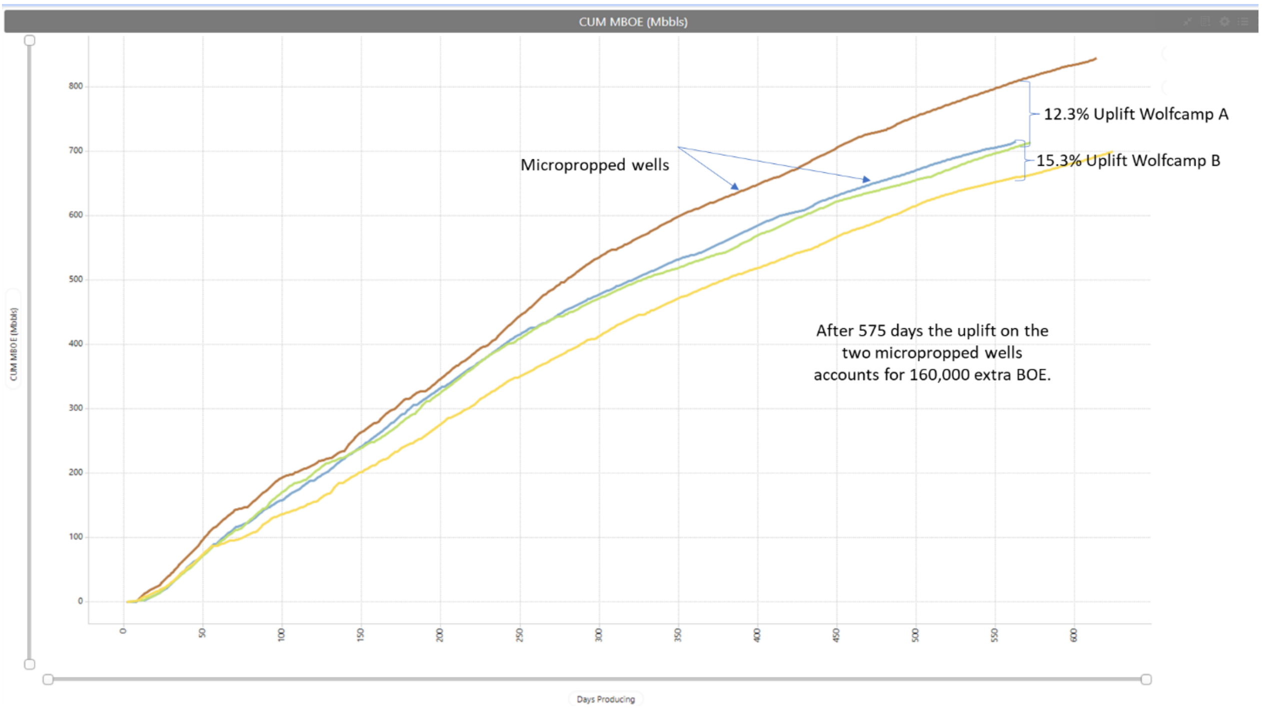


Figure 13 - A 575-day comparison of two micro propped wells vs two adjacent wells without microproppant.

In addition to the dramatic improvement in production the improved completion effectiveness represents an improvement in capital efficiency. For example, the average capital expense for a forty-stage hydraulic fractured horizontal well in the US is \$6 to \$8 million dollars. A completion efficiency of 40% as shown in Figure 9 represents a \$0.9 to \$3.2 million cost in over capitalization. In addition to improving the effectiveness of the treatment the 15% improvement in completion efficiency (see Figure 9) provided by using the microproppant represents a \$0.9 to \$1.2 MM improvement in capital efficiency.

References

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