FIELD DATA DEMONSTRATE BENEFITS OF COMBINING GAS LIFT WITH FLOW IMPROVER

Lucas McKernan and David Gilmore

ChampionX

ABSTRACT

As gas lift utilization increases as a form of artificial lift for many assets in the Permian Basin, optimization through gas allocation remains a challenging problem. Operators are often limited on the amount of gas that can be injected downhole due to infrastructure capabilities and added operational cost. In addition to how these constraints impact production, wells may have a higher tendency for slugging behavior. This regime can also be exasperated by high water cuts, steep natural declines, compression issues/inefficiencies, and sub-optimal gas lift injection depth and volume.

BACKGROUND

The Permian well operator experienced production decline in gas condensate wells due to a natural decline in well production. The operator was limited on the volume of lift gas that could be injected downhole due to infrastructure capabilities and added operational cost, both factors exacerbating a decline in production. The affected asset is located onshore in Permian basin Texas. Total fluid production is between 100 to 800 bbd with light oil (API ≥ 35), and high water cut ranging from 50 to 80%.

Gas Lift flow improvers (GLFI) possess a unique chemical composition which generates stable foam in the presences of oil in gas/condensate wells. GLFI reduces the produced fluid density and surface tension, contributing to a decreases in the bottom-hole pressure. As such, introduction of GLFI can lower the critical velocity needed for gas/condensate flow out of the wellbore. Production rates increase as improved flow in a wellbore is achieved through the synergistic application of a GLFI in combination with a lift gas system. As Foam is formed, the Gas-Liquid interface increases resulting in an increased effective gas lifting force as illustrated below in (**Figure 1**).

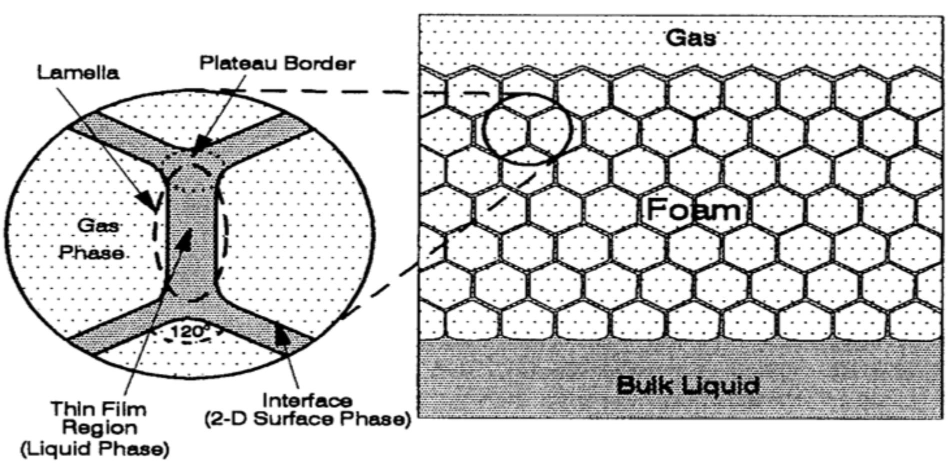


Figure 1. Gas-Liquid interface with Lamella illustration

To establish an analytical basis for implementing changes effecting well performance, the following KPIs were used:

- Reduced or maintained the lift gas injection.
- Increased Production.
- Reduced slugging.
- No negative impact on water quality.
- Generated no tight emulsion.

SOLUTION

Fluid samples were collected from the selected Permian wells (18 wells) and were tested using foam height test and emulsion tendency test. These tests confirmed the efficacy of GLFI FLOW43343A and it showed no adversary impact of emulsion and water quality on the produced fluid.

FLOW43343A was then put to the field trial test on selected wells. The chemical was introduced to downhole wellbore through an atomizer into the gas-lift system. Results showed a significant increase in production observed on most of the trial wells. Decrease in production slugging on wells where the bottom hole pressure exceeded bubble point pressure was an added benefit to the customer.

Daily collaborations with Operations and the production engineer were instrumental to optimize the chemical injection rate. Using tank level monitoring (TLM) and automated pump technology, the results were adjusted remotely. By utilizing this remote technology, the customer was able to optimize the rate quickly which decreased costs during the trial. This also allowed the operator and ChampionX to correlate daily well tests to daily chemical usage to validate the results. Description of the physical properties of FLOW43343A can be seen below in (**Figure 2**).

Physical properties of FLOW43343A						
Cap-string certified	Gas-lift certified	28 days - MCT	Pour point (C)	Flash point (C)	Specific gravity @ 15.6 C	Viscosity @ 40 C (mm2/s)
Yes	Yes	Yes	-25	>110	1.08	9

Figure 2. Physical properties of FLOW43343A

RESULTS

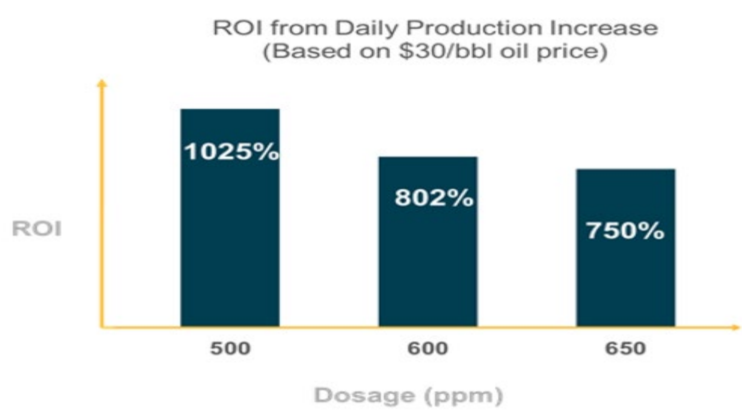
FLOW43343A was trialed on twelve high-water wells experiencing uplift challenges in the Permian basin. Wells selected for trial ranged from 50 – 80% water cut with 100 – 800 barrels of fluid per day.

The *Production Summary* for the primary well studied during the field trial shows the increase in production based on the estimated production decline curve provided by the customer. The data shows a 28 – 36 % production increase with the application of FLOW43343A at 500 – 650 ppm as shown in (**Figure 3**).

Figure 3. Production Summary

The financial benefits or the return on investment (ROI)* to the customer was calculated based on the chemical cost and the monetary gain from the increased fluid production of the primary well. This calculation is a non-GAAP financial measure and was based on a low end/ conservative $30/bbl fluid price. For example, the application of FLOW43343A at 500 ppm was found to be optimum resulting 1025% ROI to the customer based on the chemical cost and the increased fluid production. This ROI calculation does not include the increased revenue from gas sales, but an increase in gas production was also observed.

Production Summary FLOW43343A vs *Untreated* shows the production summary for the primary well. During this trial the rate of lift gas injection and all other process variables were held constant. A significant increase in total fluid production was observed when this well was treated with FLOW43343A compared to untreated. On average, a 20% increase in fluid production was observed.



The chemical was turned off to confirm that it was responsible for the increase in production. This can be seen by the sharp decrease in production when the chemical was turned off. The production returned to the estimated decline curve which supported the accuracy of the model. The chemical was then turned back on which led to an increase in production above the decline curve. (**Figure 5**).

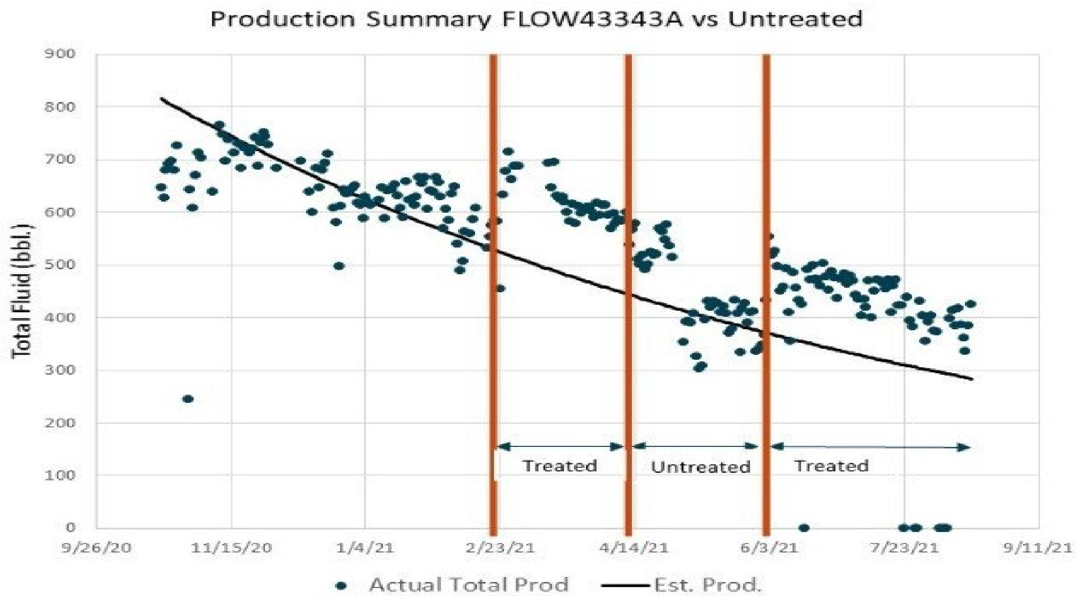


Figure 5. Field trial Summary data

The table below summarizes the FLOW43343A field trial results for seven wells in the Permian basin. Twelve wells were selected for field trial; the data presented here shows wells in which data was obtained from the customer. The application of FLOW43343A resulted in a 30% average increase in barrels of fluid produced, ranging from a 25 – 137 barrel per day increase.

Well	Initial BTFD	Average Increase BTFD	Average Uplift (%)
1	606	254	42
2	550	193	35
3	769	200	26
4	810	129	16
5	1126	135	12
6	581	41	7
7	1279	76	6

SUMMARY

Total fluid production rates increased by 10-40% as improved flow in the wellbore was achieved through the synergistic application of a GLFI in combination with a lift gas system. The increased fluid production alone presented a 300-1800% return of investment (ROI) for the customers based on their chemical cost.