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Industry-First Hydrocarbon-Foam EOR Pilot In An Unconventional Reservoir: Design, Implementation And Performance Analysis

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Abstract

An immiscible hydrocarbon foam (HC-Foam) enhanced oil recovery (EOR) pilot has been designed and implemented in a hydraulically fractured tight reservoir in the Woodbine field, Texas. Although gas injection is being considered as the main EOR technology for unconventional tight fractured reservoirs, gaseous foams of this type have not been previously considered as an effective conformance solution. This paper presents experimental evaluation of the surfactant, field pilot design and implementation and performance analysis of the pilot towards developing an unconventional HC-Foam EOR conformance solution. Several surfactants were screened through a bulk foam test for the harsh reservoir conditions (120 ˚C, 3.23% salinity and ~27% clay). The selected surfactant was further evaluated for static adsorption on reservoir rocks at room temperature to ensure an economic field pilot. The surfactant was also evaluated for oil-brine emulsion tendency to mitigate any field implementation issues. A single horizontal injector and two surrounding horizontal producers pad was developed for an IOR/EOR pilot implementation in Woodbine field. Water and produced hydrocarbon gases were injected alternately as well as in co-injection mode, however no consistent incremental oil was observed. Injected gas and water broke through on the order of hours and days respectively. The injector showed more connectivity with one of the producers, suggesting a strong areal conformance problem. A steady baseline operation was established by co-injecting gas and water at a constant gas fraction and total constant rate that resulted in steady production baseline. The baseline injection was continued with surfactant injection in brine for in-situ foam generation. During five weeks of surfactant injection, foam generation and mobility reduction were confirmed with the increase in the measured bottom-hole pressure. Mobility control resulted in out of zone injection elimination for both gas and water and gas diversion to bypassed areas. With conformance corrected at the injector and deeper in the reservoir, oil production rates more than doubled, gas utilization was improved, and a low gas-to-oil ratio and improved volumetric sweep were confirmed. The increased oil production continued for at least 6 weeks after completing surfactant injection. More than 2000 bbl. of incremental oil was recovered in 11 weeks of pilot operation. Current work confirms the technical efficacy and potential of the gaseous foam conformance solution for incremental oil production in unconventional plays.

Introduction

There has been overwhelming growth in the U.S. oil production from tight unconventional hydraulically fractured formations in recent years ((EIA) 2015, Todd and Evans 2016). However the steep decline in oil production rates in these wells has resulted in less than 10% of primary recovery during their average 10 year economic production life. This has generated a need for secondary and tertiary phases of oil recovery for unconventional reservoirs (Todd and Evans 2016). Miscible gas injection is one the most effective tertiary recovery methods for conventional light oil reservoirs. To improve oil recovery from declining unconventional reservoirs, a number of field pilot tests have been conducted in the last few years with water flood, gas flood and water-alternate-gas flood in the Bakken formation and elsewhere (Todd and Evans 2016). These field pilots in general show little to no additional oil recovery with quick breakthrough and poor sweep efficiency, despite positive laboratory and simulation studies (Zuloaga-Molero et al. 2016, Jia and Sheng 2018, Dong and Hoffman 2013).

Gas EOR in ultra-tight formations is a slower process in comparison to conventional reservoirs with, at least partial, dependence on gas diffusion into tight pores (Hawthorne et al. 2014, Li and Luo 2017). However in such formations, there potentially exists direct connectivity between injector and producer wells due to hydraulic and secondary fracture networks. The permeability of these connected fracture networks could be orders of magnitude higher than the surrounding matrix, resulting in quick breakthrough without allowing gas to make contact with the oil deeper in the matrix. In addition, due to complex fracture connectivity in these reservoirs, the injected gas may not be kept contained in the target pay zone resulting in significant out of zone (OOZ) injection loss and poor volumetric sweep of the pay zone. Like a few other unconventional field operators, MD America Energy (MDAE) has also implemented water flood and immiscible hydrocarbon gas flood EOR tests in an effort to increase oil recovery above primary production in their Woodbine field in Madison County, TX. The water and gas floods were implemented in a three well pad consisting of parallel horizontal wells in the same formation at a spacing of 500 ft. between wells. In this pattern the center well was converted to an injector for the purposes of testing gas flood, water flood, and ultimately foam conformance. The initial attempts of gas and water flooding showed similar observations of quick fluids breakthrough (gas on orders of hours and water on orders of days) and significant OOZ fluid injection loss. Water injection provided mobility control to gas injection but was ineffective for increasing oil production from the pad.

In-situ generation of foam or emulsion between injected gas and brine using surfactants has been applied to correct conformance issues and improve volumetric sweep of gas and steam floods in conventional reservoirs by reducing the mobility of injected gas and steam and diverting flow to otherwise uncontacted oil (Hirasaki and Lawson 1985, Blaker et al. 2002, Brownlee and Sugg 1987, Patil et al. 2018, Sanders, Jones, Linroth, et al. 2012). Foam has been shown to demonstrate yield-stress behavior, requiring a minimum mobilization pressure gradient to transport due to the resistance of individual lamellae to stretching. When the pressure gradient is below the minimum mobilization pressure gradient, gas is immobilized. Experimental work has shown gas trapping in the presence of foam to range from 50% to 99% of the total gas saturation. Gas trapping in the presence of foam reduces the saturation of flowing gas and thus reduces its relative permeability. However the foam conformance solution has not always been considered highly effective for reservoirs with fractures (Ransohoff and Radke 1988, Falls et al. 1988, Jonas et al. 1990). Therefore, an unconventional immiscible hydrocarbon foam conformance correction field test was planned in partnership between MDAE and The Dow Chemical Company (Dow).

The targeted MDAE operated reservoir presented a much bigger challenge in foam generation due to high temperature (120 ˚C), high clay content (~27%), and flow occurring mainly in the connected fracture networks between the injector and the producers. The foam generation in such hydraulically fractured reservoirs is highly challenging due to following reasons. Fracture aperture could be sufficiently large where gas bubbles cannot be split small enough to generate large bubble density−controlling foam strength−that can be achieved in millidarcy scale porous rocks. Further, relatively high shear in such open fractures can shear-thin any foam generated by mixing of gas and surfactant solution. With such understanding, foam EOR conformance solution was assessed to be fairly risky and uncertain for a strongly positive outcome. However, there were a few strong positives identified and discussed below in applying foam conformance technique in this hydraulically fractured reservoir which encouraged us to take the risk.

The operator established the co-injection mode of injecting gas and surfactant-in-water in the reservoir. This co-injection mode provides an ideal mode of mixing gas and surfactant solution and in turn results in stronger foam generation in comparison to the water-alternate-gas (WAG) mode of injection. In most of conventional gas EOR field operations, gas and water are injected in the WAG mode. When a gas foam conformance solution is implemented in the WAG mode, foam strength remains dependent on the extent of mixing of injected gas and surfactant solution and their mixing ratio which is hard to control relative to when operating in co-injection mode. Secondly, the hydraulic fracture networks do propagate deeper in the reservoir with gradually smaller aperture, including their interaction with smaller aperture natural fractures. Thus generating foam near wellbore is still a challenge, however these foam forming constituents (gas, water and surfactant) on travelling deeper in smaller apertures can generate strong foam and lower shear to limit shear thinning resulting in deeper conformance control.

In this paper, we first provide the reservoir and the EOR pad background followed by the laboratory work on foaming surfactant screening involving bulk foam testing, static adsorption and oil-brine emulsion tendency test. In the subsequent sections, we discuss the pad operations and performance in different stages; early evaluations of gas and water injection before baseline operation, baseline operation for foam EOR implementation, foam pilot implementation with surfactant injection and post surfactant injection period.

Reservoir and pad background information

Figure 1 shows the pilot pad with 3 horizontal wells in purple color, 3H, 4H and 5H in the Woodbine field. The middle well 4H is made injector and the two surrounding wells are made produces for this pilot. The other relevant pad background information is given below:

- Field Name -Madisonville West – Woodbine A
- State/Providence/Country – TX, USA
- Geologic Basin-Brazos Basin
- Formation Name - Woodbine Sand
- Depth ~8,500'TVD
- Discovery Date – 1970's
- Flood Pad - Parallel 3 horizontal wells pad with center well injecting
- Well length and spacing – 5000 ft. long and 500 ft. apart

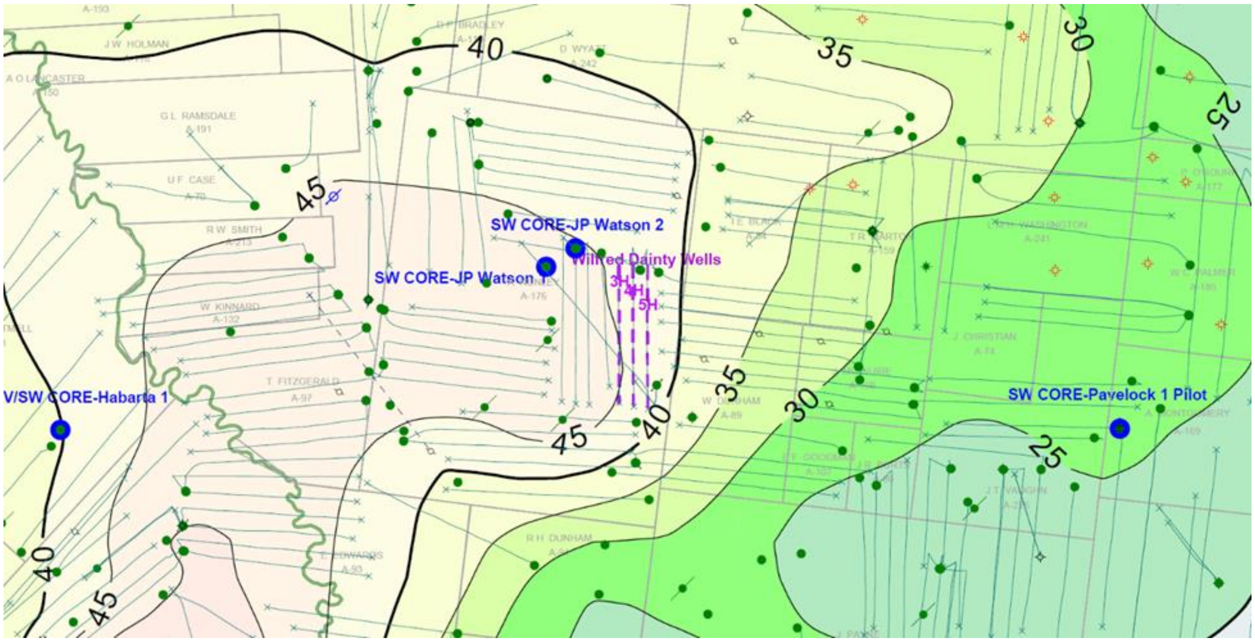

Figure 1: Wilfred Dainty horizontal wells 3H, 4H and 5H in the Woodbine field

Reservoir properties

- Average Pay Thickness ~50ft
- Average Porosity ~13%
- Low permeability ~100µD
- High permeability~15mD
- Reservoir temperature ~ 120 ˚C
- Original reservoir pressure ~3800psi
- Fracture Gradient ~0.7 psi/ft.

Oil Properties

- Original Gravity ~39 deg API
- Original solution gas to oil ratio – 600 scf/bbl
- Formation volume factor ~1.25
- Minimum miscibility pressure ~3850psi MMP with Rich field gas
- Current gas to oil ratio ~3,050 scf/bbl

Reservoir performance

- Original oil in place (OOIP) ~138MM bbl.
- Cumulative Oil Production ~18.5MM bbl.
- Cumulative Water Production ~10.5MM bbl.
- Primary Producing Mechanism – Solution gas drive

Surfactant Screening

Given the need of implementing the foam conformance solution in Woodbine field in the shortest possible time, following key surfactant screening and risk mitigation experiments were performed.

1) Bulk foam screening
2) Static adsorption of surfactant on reservoir rock, and
3) Emulsion tendency test.

Bulk foam screening experiment

The initial bulk foam screening experiments with the synthetic brine (Table 1) werewas first performed at 80 ˚C, lower than the reservoir temperature of 120 ˚C. In order to understand foaming characteristics of a large group of surfactants, it was decided to first perform initial screening at a lower temperature. For this test, the cell was filled with 5000 ppm active foaming formulation to a fixed height through which Nitrogen gas (surrogate to injection gas) was bubbled at constant temperature and pressure to generate foam. The gas was injected for a fixed time at a fixed rate and the foam height reached was recorded. After this, gas injection was stopped and the entry to cell was closed, at which point the foam started to collapse as there was no flow to continue foam generation. Foam height and the time for foam to decay to half of its original height were recorded to infer the stability of the generated foam. A stronger foaming surfactant would show higher foam column and a longer half-life time ($t_{1/2}$). The variation in foam volume with time for several foaming formulations is plotted in Figure 2. For the chosen rate and time, there is no significant difference in foamability of the screened formulations, all of them reached to ~50-60 mL of foam volume during gas injection. However once the gas injection was stopped to monitor foam decay, clearly Formulation-1 showed distinctly better performance over the rest with largest half-life time shown in Figure 2. Formulation-1 was further tested at 5000 ppm active in synthetic reservoir brine at the reservoir temperature of 120 ˚C. This test was performed in a different bulk foam set up following a separate experiential protocol; however the half-life was not compromised at this higher temperature. Thus Formulation-1 was considered as a final candidate to perform the rest of the laboratory evaluation experiments.

Table 1: Composition and the recipe of the Woodbine field brine

Ions	(ppm)	**Brine composition**	
Na+	12146	$CaCl_2 \cdot 2H_2O$ (g)	1.5
Ca++	401	$MgCl_2 \cdot 6H_2O$ (g)	0.5
Mg++	59	Na2SO4 (g)	0.0
K+	55	NaCl (g)	30.9
Cl-	19660	KCl (g)	0.1
SO4-	0	Water (g)	967.1
Total TDS	32320	Total (g)	**1000.0**

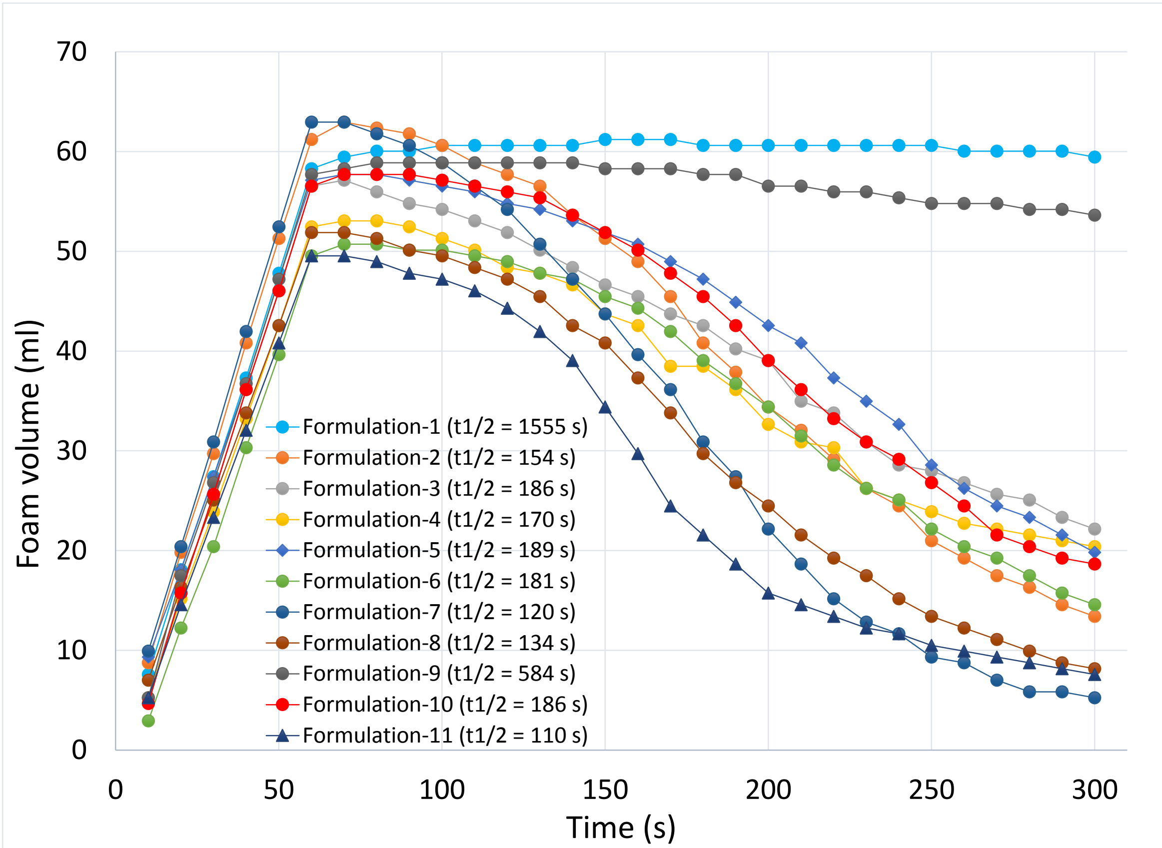

Figure 2: Variation in foam volume with time and half-life ($t_{1/2}$) for screened foaming formulations

Static adsorption of Formulation-1 surfactant on reservoir rock

A well-known issue with injection of surfactants in a reservoir is their propensity to adsorb to the reservoir rock, particularly clay species. The loss of surfactant to adsorption can severely limit the economic feasibility of a trial. Therefore a static adsorption test was performed with Formulation-1 to determine the worst case (maximum) loss of surfactant to the rock.

Static adsorption test was performed with Formulation-1 to determine its economic applicability for pilot implementation. In the static adsorption test, a surfactant solution of known concentration is contacted with a known mass of crushed reservoir core materials. The concentration of the equilibrated surfactant solution is determined and adsorption is computed by material balance. The concentration of the surfactant solution should be within a range where loss from adsorption to rock can be detected. To determine the value of static adsorption, the following equation is used:

$$Surfactant\ adsorption\left(\frac{mg}{g_{rock}}\right) = \frac{\left(W_{Surf\ Solution}*(C_i - C_f)\right)}{1000*W_{Rock}} \tag{1}$$

where:

C_i= initial surfactant solution concentration (ppm)
C_f= final surfactant solution concentration (ppm)
$W_{Surf\ Solution}$ = weight of the surfactant solution in contact with the rock (g)
W_{Rock} = weight of the crushed rock in contact with surfactant solution (g)

HPLC was used for the quantification of active surfactant concentration in Formulation-1 in reservoir brine. All samples were run in duplicates to validate reproducibility of the surfactant concentration measurements. A calibration curve was obtained to quantify concentration (Figure 3). The near perfect linearity in the variation of surfactant concentration with the area count in the HPLC spectrum strongly supports the validity of the HPLC method.

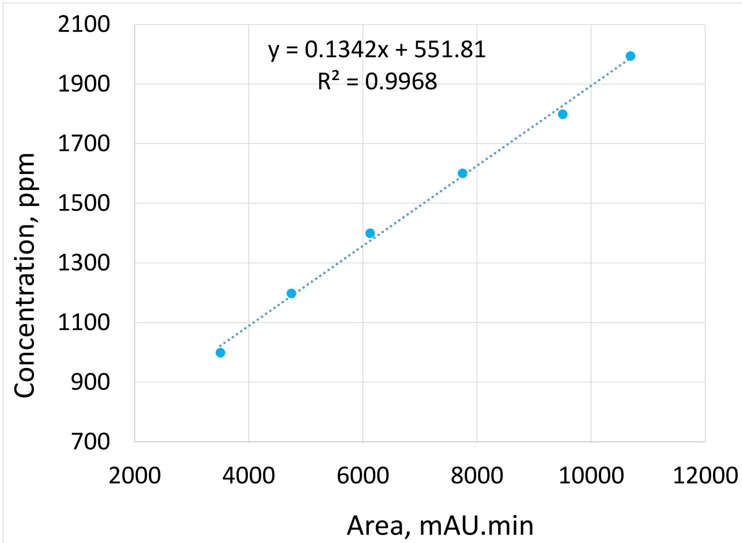

Figure 3: Calibration curve for Formulation-1 surfactant concentration quantification using HPLC

For the static adsorption experiment, two reservoir cores (1-9 and 1-13) were selected. The mineralogical composition of these cores are listed in Table 2. Core 1-13 has 29% total clays which is very close to the field average of 27% while core 1-9 has lower clay content of 9%. The remaining minerals in the two cores are mainly based on Quartz. For the static adsorption test, 3 g of relatively homogeneous crushed/sieved rock grains in the size range 300 µm – 600 µm were contacted with 10 g of 2000 ppm active Formulation-1 in Woodbine field synthetic brine. The test bottles were gently shaken and stored at room temperature and 1 g aliquots were withdrawn at 48 hr. and 240 hr. These samples were filtered through a 0.45 micron Nylon filter and injected into HPLC for surfactant concentration determination. Based on the quantified Formulation-1 concentrations in the blank and collected samples, the static adsorption of Formulation-1 at room temperature was quantified to 1.27 mg/g of rock and 0.58 mg/g of rock on cores 1-9 and 1-13 respectively. Note that the adsorption test was done at room temperature and the adsorption at elevated reservoir temperature and in dynamic conditions is expected to be lower. An adsorption of less than 0.5 mg/g of rock is generally considered economic for field implementation of a surfactant in gas foam EOR. However given that in fractured reservoirs, fluids mostly travel through the fractures where the surface area is negligible compared to actual matrix pore surface area, the obtained room temperature static adsorption (maximum) close to 1 mg/g of rock was not limiting for field implementation.

Table 2: Mineralogical composition (wt. %) of cores used in static adsorption test

Core	Sample Depth (ft)	CLAYS				CARBONATES				OTHER MINERALS							TOTALS		
Number	Top	Chlorite	Kaolinite	Illite/Mica	Mx I/S*	Calcite	Dolomite[1]	Dolomite(Fe/Ca^{+})[2]	Siderite	Quartz	K-spar	Plag.	Pyrite	Marcasite	Apatite	Barite**	Clays	Carb.	Other
1-9	8075.00	5	1	Tr	3	2	Tr	1	Tr	78	4	5	1	0	Tr	0	9	3	88
1-13	8079.05	9	5	3	12	2	Tr	Tr	Tr	57	4	6	2	0	0	0	29	2	69
Field	**AVERAGE**	7	4	4	12	2	Tr	Tr	Tr	59	4	6	2	Tr	Tr	Tr	27	2	71

Oil-brine emulsion tendency test

Surfactants are known to lower interfacial tension between oil and water and sometimes to an ultra-low level that causes a micro-emulsion phase. Formation of stable emulsion is not desirable either in-situ or at surface facilities for this production enhancement mode. Therefore an emulsion tendency test was conducted to characterize the interaction between surfactant containing brine and dead oil. A good foaming formulation should readily separate into brine and oil layers within few minutes. The emulsion tendency test was conducted with Formulation-1 at different concentrations prepared using field produced brine as well as synthetic brine prepared in the lab (Table 1). Emulsion test was done in 6 oz. bottles at 60 ˚C using filtered and non-filtered dead oil from producer 5H (30 % by volume) and the Formulation-1 solution (70% by volume). Experimental limitations did not allow performing this test at reservoir temperature of 120 ˚C. The surfactant solution was added in the bottles, filling to the 70 mark on the glass. The crude oil was then carefully added to the 100 mark by pipetting down the side of the glass to minimize mixing at the oil/water interface. A blank sample (brine and crude oil, no surfactant) was included for each brine. The initial ratio of the oil and the brine was noted in each bottle and then the bottles were placed in a water bath for at least 1 hour at 60 ˚C. After equilibration in the bath, the bottles were removed and shaken on an Eberbach shaker at 236 rpm for 2 minutes, followed by an immediate reading of the water, oil and emulsion interfaces and a photo. The bottles were returned to the water bath, then removed again at 15 min, 30 min and 24 hr. for additional interface readings and photos (Figure 4).

In Figure 4, samples 1A to 6A contain the synthetic brine and samples 7A to 13A contain the produced field brine. With each brine, concentration variation and oil filtration effects were investigated. In all of these samples, only the unfiltered oil blank showed oil droplets in brine even after 24 hr. The pictures clearly suggest no stable emulsion formation, de-risking the use of Formulation-1 relative to emulsion formation for pilot implementation.

Sample ID	Active formulation/Blank
In synthetic brine	
1A, filtered oil	Synthetic Brine (Blank)
2A, filtered oil	Formulation-1 (1000 ppm)
3A, filtered oil	Formulation-1 (2000 ppm)
4A, filtered oil	Formulation-1 (5000 ppm)
5A, unfiltered oil	Synthetic Brine (Blank)
6A, unfiltered oil	Formulation-1 (2000 ppm)
In production brine	
7A, filtered oil	Production Brine (Blank)
8A, filtered oil	Formulation-1 (25 ppm)
9A, filtered oil	Formulation-1 (50 ppm)
10A, filtered oil	Formulation-1 (100 ppm)
11A, filtered oil	Formulation-1 (500 ppm)
12A, unfiltered oil	Production Brine (Blank)
13A, unfiltered oil	Formulation-1 (100 ppm)

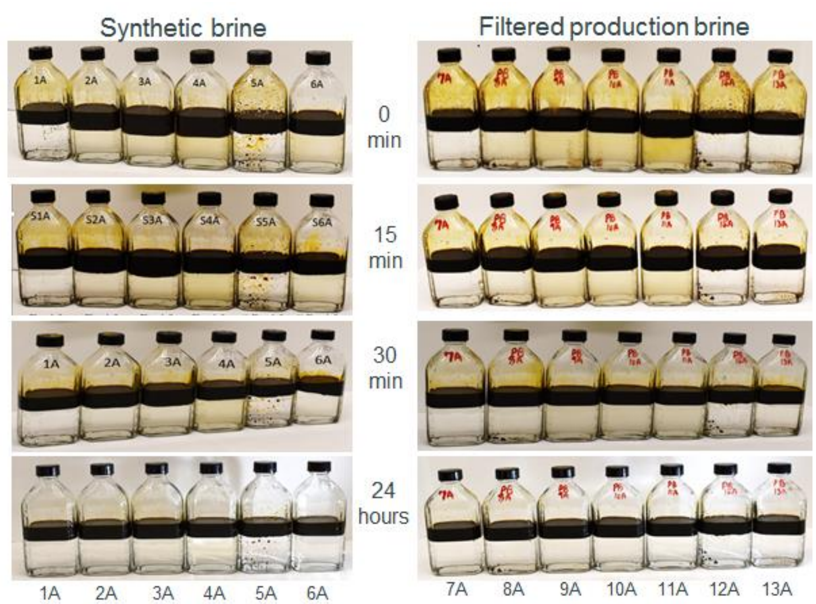

Figure 4: Emulsion test results

Pilot pad operation and performance

The operation and performance of the three well pad converted to evaluate water and gas injection based IOR/EOR methods was reviewed in the following four phases from November 2017 to August 2018.

1) Early evaluations of gas and water injection before baseline operation
    - To help in characterizing conformance problem
2) Identification of baseline operation for gaseous foam EOR implementation
    - To establish steady baseline injection and production operation
3) Gaseous foam pilot implementation with surfactant injection
    - To evaluate the conformance correction and resulting production enhancement
4) Post surfactant injection period
    - To evaluate how long the effects of gaseous foam lasts

Early evaluations of gas and water injection before baseline operation

In November 2017, gas injection started in well 4H for about three weeks with no water injected (Table 3). Gas injection was held steady above 4500 mscfpd (Figure 6) which resulted in steady gas production of ~ 3200 mscfpd from two neighboring producers 3H and 5H (Figure 7) suggesting about 1300 mscfpd (30%) of injected gas was not being recovered (Table 3). Figure 7 reports fluid production rates from the two producers in the pad. There is a high likelihood that the lost gas may have been injected out of the pay zone due to significant conformance issues. Bottom-hole pressure (BHP) in this period was ~1000 psi and the total injectivity (total injection rate in reservoir barrels – RB/BHP) fluctuated between 10 – 20 RB/psi (Figure 5). Figure 5 also reports the injection foam quality (% gas in total injection at reservoir condition). Such an anomalously high injectivity index for the injector 4H in a micro Darcy formation is a clear sign of flow in the fracture networks at least near wellbore. In addition, the high gas production within a few days after the onset of gas injection (Figure 6, Figure 7) also indicates that the majority of the injection gas was moving through highly permeable fracture networks and other high permeability streaks (thief zones).

Table 3: Average injection/production data in different pilot periods before surfactant injection

			Average injection rates				Average Production rates								
Time			Gas	Water	Total	BHP-Calc	Gas	Oil	Water	Gas lost	Water lost	Oil Cut	GOR	GLR	GUR
Starts date	End date	Process	mscfpd	bpd	RB/day	psi	mscfpd	bpd	bpd	mscfpd	bpd		mscf/bbl	mscf/bbl	mscf/bbl
11/3/2017	11/21/2017	Gas flood	3900	0	11200	1000	2645	28	54	1255		35%	109	38	164
11/22/2017	1/13/2018	Coinjection	3650	1290	6300	2300	2122	9	280	1528	1010	6%	373	11	661
1/14/2018	1/30/2018	Water injection	0	1050	1025	3000	7	5	110	0	940	6%			
1/31/2018	4/20/2018	Dry coinjection	3150	200	4634	2065	2330	30	200	820	0	12%	108	13	176
4/21/2018	5/18/2018	Coinjection	3100	1050	4000	3020	2100	17	360	1000	690	5%	306	6	480
5/19/2018	5/31/2018	Baseline	2526	629	3206	2822	1875	33	340	651	289	9%	58	5	78

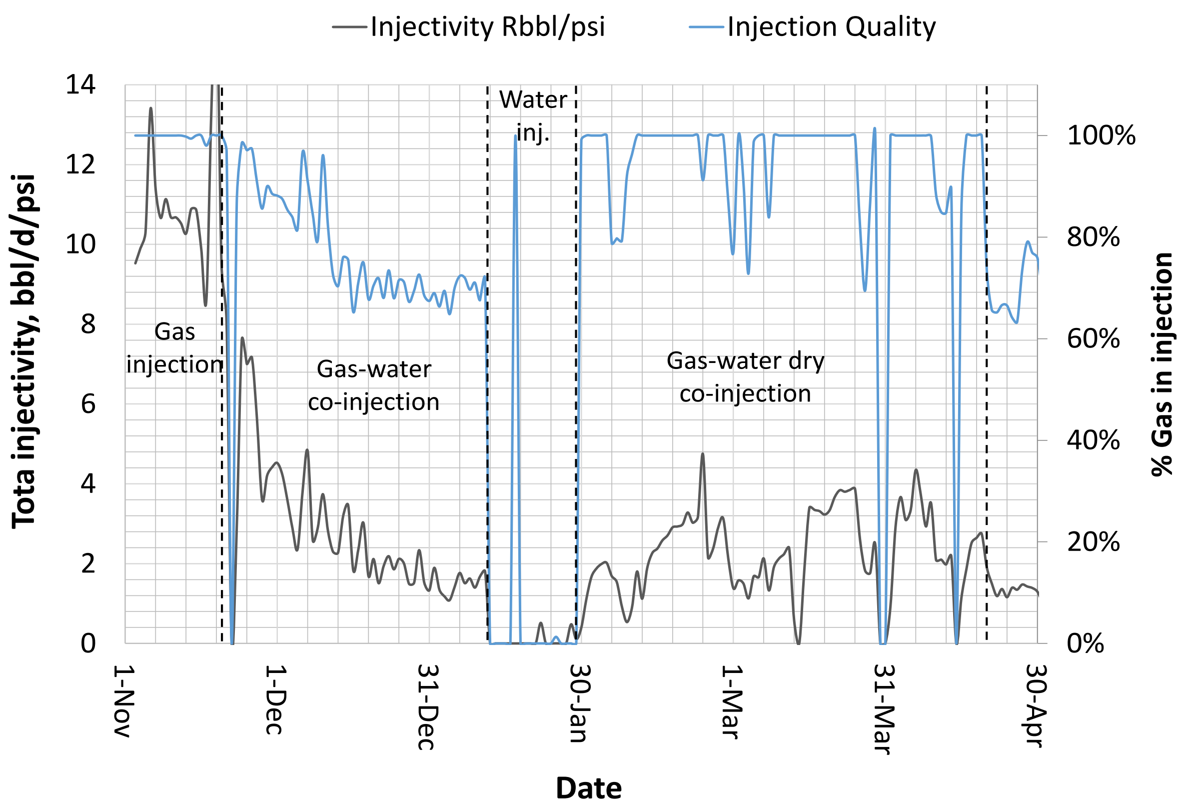

Figure 5: Total injectivity and injection quality (% gas in injection) with time

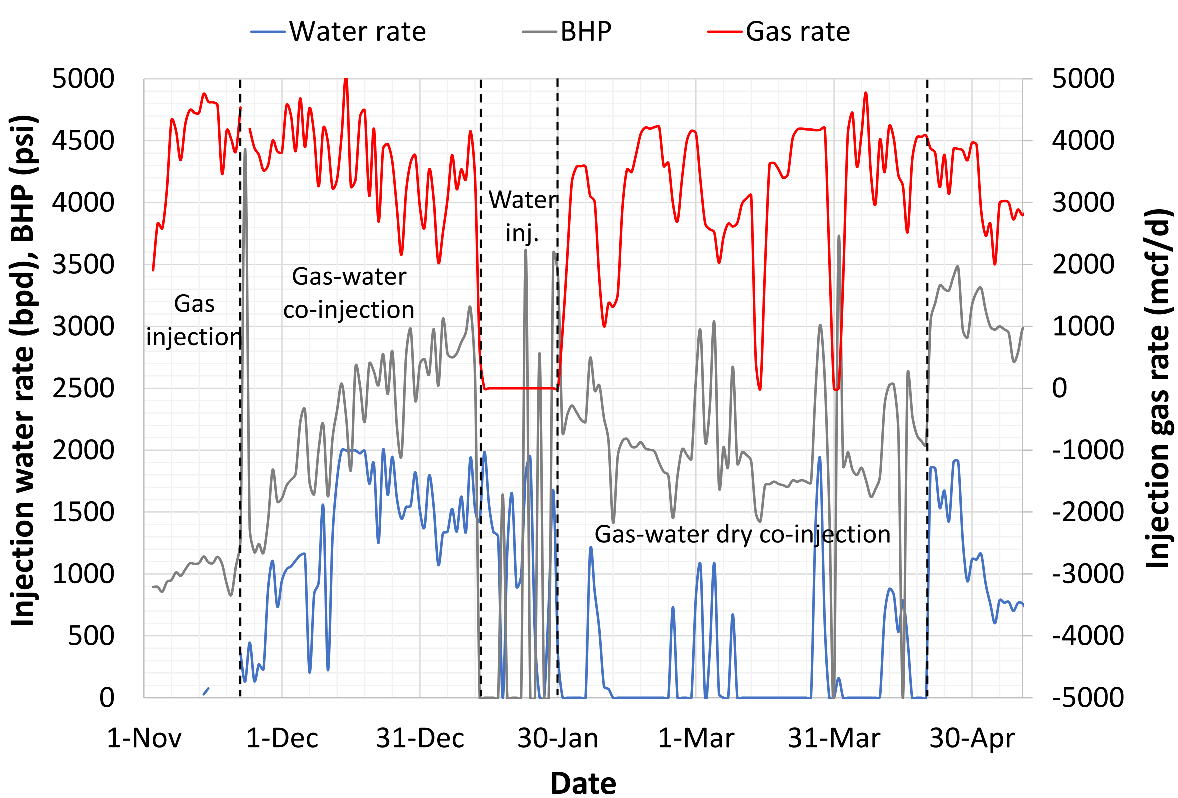

Figure 6: Gas and water injection rates and bottom-hole pressure before baseline operation

Total oil production from the pad increased quickly to ~50 bpd but declined steeply at ~3% daily to ~20 bpd, suggesting that gas injection alone is not a viable option to sustain economic oil production from this pad. As a result, the initial gas utilization ratio, GUR (i.e. the volume of injected gas to produce a barrel of oil) was very high (~ 160 Mscf/bbl) for both 3H and 5H (Table 3). From Figure 7, it can be inferred that the produced gas responds to variation in injected gas very quickly (connectivity time ~ hrs.) suggesting a very strong connection between 500 ft. apart injector and producer via hydraulic/induced fracture networks.

To lower the mobility of injected gas and increase its residence time in the formation, co-injection of gas and water was performed. In the next phase from November 22 to January 12 (Figure 7, Table 3), water was simultaneously injected with gas but at a relatively high rate. Water injection climbed to ~2000 bbls/day (bpd) which later settled to ~ 1600 bpd while injecting gas at ~3500 mscfpd (Figure 6). The observed response time for water production rate was longer than that of gas but still unexpectedly short (less than 14 days) for the well spacing of 500 ft. During this co-injection period at average injection gas quality of ~75%, BHP steadily increased to ~3000 psi from 1000 psi (Figure 6) and total injectivity decreased to 2 RB/psi (Figure 5). The increase in BHP and lower injectivity suggests that water was able to control gas mobility, which is critical to push the gas into the tight matrix to recover more oil.

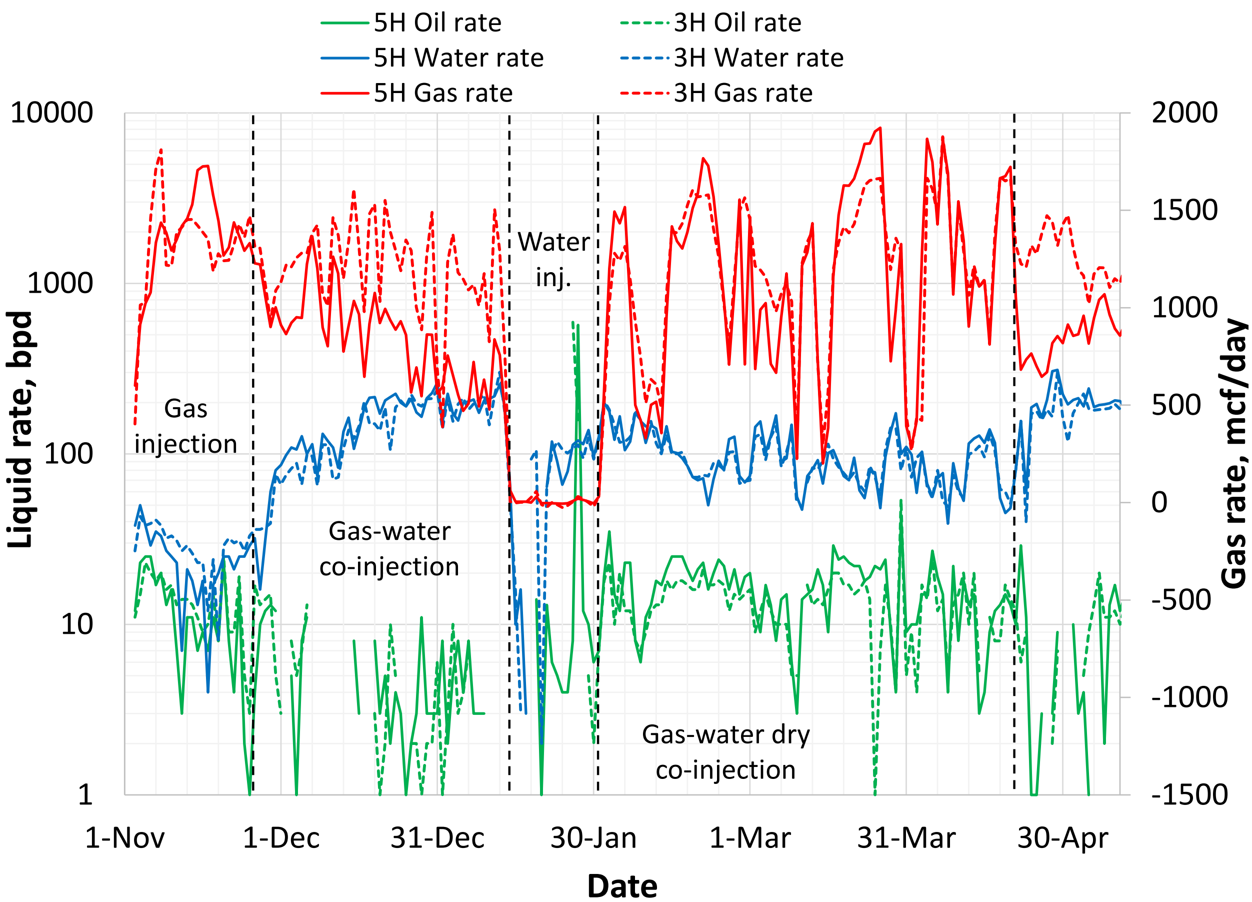

Figure 7: Production from producer 3H and 5H before baseline operation

During this co-injection period at total 6300 RB/day with mobility control and lower produced gas-liquid ratio (GLR) (Table 3), the oil production rate was less than 10 bpd, making it even less effective than just gas flood (Figure 7). The oil production rate at times approached zero at the highest water injection rate of ~2000 bpd. With almost no oil production, the GUR, GLR and GOR became worse than the gas only injection phase (Table 3). One hypothesis for such poor oil recovery is a very high water injection rate which would impact the contact and transport of gas and oil and increase the amount of gas needed to sustain oil displacement. In addition, the conformance control provided by water was not enough to divert the injected gas into higher oil saturation zone hence no improvement in oil recovery was observed.

It appeared that more water was injected towards the producer 5H at an elevated water injection rate, which diverted more injection gas towards the producer 3H, resulting in a significant decrease of produced GLR and oil production from the pattern area produced by 5H (Figure 7). Looking at the gas and water production from the two producers, 3H and 5H (Figure 7), clearly more gas was produced from 3H. This suggests that the injector is more connected with 3H, making it the preferred path for injected gas to channel. This clearly supports that there is fluid segregation and conformance issue in the reservoir, which gives rise to poor areal sweep efficiency. Based on the production response to water injection, it can be concluded that the use of water to reduce gas mobility in thief zones for better sweep efficiency was not very effective for this specific pad, and that the amount of water used for gas conformance control should be lowered to mitigate the adverse effect on gas miscible displacement. During this period, ~1500 mscfpd of gas and 1000 bpd of water was being lost out of the injection zone (Table 3) suggesting that co-injection of gas and water (at a very high rate) could not sufficiently correct the out of the zone injection problem. The production characteristics of the wells 3H and 5H in this phase clearly indicate a severe conformance issue in the current pilot area.

The next phase of injection from January 15 to January 30 involved only water injection and averaged ~1050 bpd (Table 3). From the previous phase of co-injection, when the injector was switched to only water, the oil production did not improve and stayed to almost zero (Figure 7). This result supports the hypothesis reported earlier that water injection at a higher rate and alone cannot improve oil production due to high capillary pressure in an oil-wet matrix. During this water flood, the OOZ water loss continued to ~800 bpd (Table 3) suggesting the need for conformance correction to eliminate OOZ injection loss. Based on the data collected to date, various gas and water injection methods did not result in stable oil production from this pad. Gas injection recovered initial oil, but did not sustain it more than a couple of weeks. Co-injection of gas with large amount of water did hold the fluids in the reservoir increasing BHP and reducing gas injectivity, but did not improve oil recovery. Water flood alone did not result in any oil recovery.

Since water injection alone did not improve oil recovery (From January 30 to April 20, mainly gas injection was implemented at an average of 3150 mscfpd while water was injected only intermittently at an average of 200 bpd (Table 3). During this period, a total of 4634 RB/day was injected. The BHP remained steady around 2065 psi, which is lower than the BHP during the previous co-injection phase. This would be expected as highly mobile gas cannot alone pressurize a well-connected hydraulically fractured reservoir. The total injectivity averaged 3 RB/psi in this phase (Figure 5). Nonetheless, the gas injection in this phase with higher BHP of >2000 psi in comparison to 1000 psi of first gas injection in November, the oil production increased and averaged ~30 bpd. This suggests that the oil response to gas injection is significant as long as BHP can be maintained high enough and gas permeates into the matrix from fractures because flow is not affected due to large water injection.

As gas is driving the oil recovery, maintaining gas in the pay zone will increase the oil recovery efficiency. During this period of operation, water production averaged 200 bpd and gas production averaged 2330 mscfpd. The out of zone injection gas loss was ~ 820 mscfpd and no water loss was observed as not enough water was injected. With respect to production response, this phase of mainly gas injection is quite similar to the first gas-only injection phase in terms of oil production rate, GOR, GUR, and gas loss. It further suggests that gas injection can recover oil from this pad, however a conformance solution will be needed to limit higher GOR and GUR and OOZ injection (Table 3).

Baseline design

For the foam pilot implementation it was recommended to utilize co-injection of gas and water. Dow's previous conventional core flood foaming experiments for CO_2-foam EOR field pilots, as well as the literature data (Abbaszadeh et al. 2014, Farajzadeh et al. 2013, Ma et al. 2013, Harpole et al. 1994), report 70−85% of the injected gas fraction in RB as optimum for generating strong foam. These optimum conditions allow minimum surfactant consumption, while achieving maximum foam strength. Therefore, a baseline operation of 80% quality at constant total injection rate in RB/day was implemented to better understand the impact of foam on the pilot over the baseline operations.

In such foam pilots, injectivity is monitored to assess the foam generation and gas mobility control. Typically in conventional reservoirs, injectivity drops the most within the first couple of days when surfactant, water and gas get mixed and are forced to pass through the porous medium. As the foam gains mobility over time, injectivity is slowly regained (Sanders, Jones, Linroth, et al. 2012). Since the injection rate is being kept constant for the pilot operation, on foam generation, increase in BHP and accordingly an increase in tubing head pressure (THP) was anticipated. Given that the surface pumping facility had a safety limit of 2100 psi, the total daily injection rate was controlled such that the THP is under 1900 psi and that there is about 200 psi of pressure available to increase during foam generation.

Pad operation and performance during baseline period

From April 20 to May 31, a baseline operation was approached in which water injection was initiated simultaneously with gas injection. From April 20 to April 30, water was injected at a higher rate of ~1800 bpd while maintaining the gas injection ~3500 mscfpd from the previous phase (Table 3). At this high water rate, the production declined very steeply (Figure 12). This result confirmed that water injection at a higher rate, where it becomes water drive, is not effective in oil production in this fractured pad. With an effort to achieve 80% injection gas quality, the water injection was dropped to ~700 bpd and gas injection was maintained at 3000 mscfpd in the first week of May (Figure 8). With this operation, oil production was again revived to 30 bpd (Figure 7).

From May 19 to May 31, a very steady 80% injection gas quality baseline operation was established (Figure 8) ensuring that THP was under 1900 psi. During this period, the healthiest baseline operation of this pad was achieved as explained below. The gas injection averaged 2526 mscfpd, and water injection averaged 629 bpd, giving total injection rate of ~3200 RBpd (Table 3). In terms of total production from both 3H and 5H wells, oil production averaged 32.5 bpd, gas production averaged 1875 mscfpd, and water production averaged 340 bpd (Table 3). The baseline production response confirmed that an optimal foam design should involve relatively high foam qualities (~ 80%) to minimize the adverse water blocking effect on gas miscible displacement and maximize gas throughput. It was observed that the OOZ injection of gas averaged 650 mscfpd and water averaged 289 bpd. The GOR averaged 58 mscf/bbl, GLR averaged 5 mscf/bbl, and GUR averaged 78 mscf/bbl (Table 3).

Looking at the gas produced from the two producers in Figure 12, clearly more gas was produced from 3H as observed in early pad operations. As highlighted before, this clearly suggests non-uniform fluid distribution in the pad and on conformance correction with foam, a uniform fluid distribution and increased oil production were expected. A simple tracer test was conducted to estimate the thief zone volume using salinity as a tracer. A slug of brine (about 100 bbls) that had a higher salinity than the regular injection brine (22,800 ppm TDS) was injected at an average rate of 650 bpd and the salinity of the produced water was monitored. The breakthrough of high salinity water was observed after 11 days of slug injection, indicating a relatively small total thief zone volume.

Foam pilot design and optimization

A very stable baseline operation was set and the respective data shown in Table 3. The average THP was set at 1850 psi, 250 psi under the safe operation limit, giving enough room for THP and BHP to increase on surfactant injection and in situ foam generation. The baseline operation was followed by a foam slug strong enough to provide mobility control, and more importantly fluid diversion and mitigation of OOZ injection as they were the main conformance issues of this pad. Once a strong foam plug was placed in the reservoir (characterized by increased BHP), a chase fluid could be injected to process the bypassed areas faster to recover more oil per day. There were three important process design parameters to be considered for this particular pilot: (1) surfactant concentration (lbs. of surfactant injected daily), (2) foam slug size, and (3) chase fluid slug size.

Surfactant concentration is a critical optimization variable as the pilot economics depends on it. Based on the prior experience with this formulation in core flood foaming experiments and field implementation, and given that the current reservoir has relatively high temperature and clay content, we chose higher Formulation-1 concentration of 1% (3200 ppm active). This resulted in 2100 lbs. of formulation injection daily in ~700 bbl. of brine at baseline rate and injection gas quality. At the specified formulation injection rate, the supplied formulation quantity for the pilot could last for 24 days. Under any operation issues causing deviation from the baseline rates and quality, the daily formulation injection rate was to be adjusted to maintain the bulk formulation concentration, lbs. of formulation injected per lb. of total gas and water injected.

Regarding the slug size for foam and the chase period without surfactant, in absence of any reservoir modeling and simulation work, we relied on field injection and production response to control the injection strategy. Given the 24 days of surfactant supply, the foam slug could be maximum 24 days long. During this period, if the THP stayed under the safe operation limit, it would allow as much processing of thief zone as possible to be followed by a chase fluid. However, if the THP approached safe operation limit within 24 days, surfactant injection would be stopped to follow up with a chase fluid injection to bring the THP lower towards the baseline THP to be followed up with a foam slug again. Based on this understanding we decided to monitor the surfactant injection and switch to chase fluid based on THP. The chase fluid was suggested as 80% gas fraction injection at lower water rates as neither 100% foam quality nor 75% foam quality at a high water rate was able to sustain oil production.

Foam pilot implementation with surfactant injection

After establishing the injectivity and production baselines, on June 1, 2018, Formulation-1 was injected at 1% (3200 ppm active) in brine, keeping the water and gas injection rates at the baseline operation. The individual fluid and surfactant injection rate are plotted in Figure 8 and resulting BHP (calculated and measured), gas injectivity, and total injectivity are plotted in Figure 9. For the first 2 days, due to pump operational issues, surfactant was injected only a few hours in the day limiting the total surfactant injected to less than 1000 lbs., as opposed to set 2100 lbs. daily. Due to this, the surfactant concentration in brine was under the threshold for strong foam generation. From June 3, the injection operation continued as designed at ~2100 lbs. of total surfactant per day. From June 3 to June 11, a very steady operation of the foam pilot was maintained. This is the period identified as high performance foam period (HPF) in Figure 8 to Figure 11.

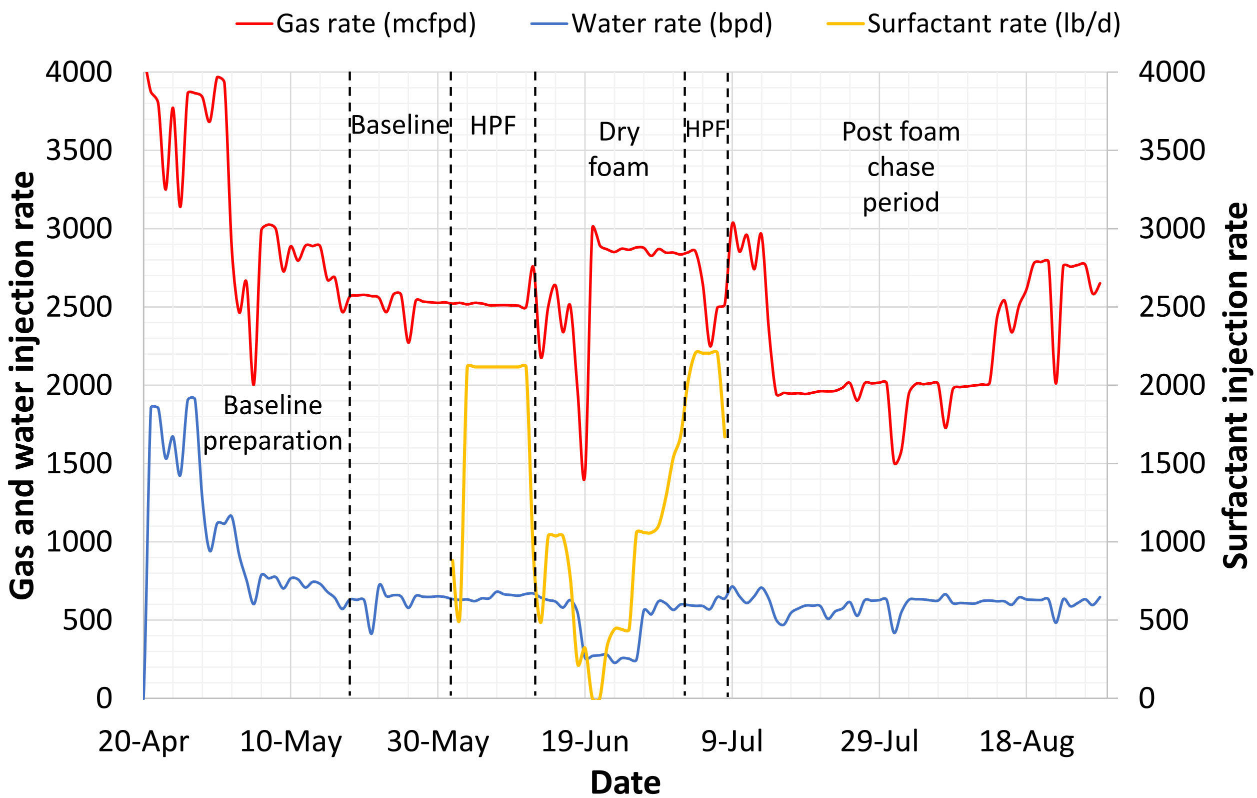

Figure 8: Gas, water and surfactant injection rates before, during and after surfactant injection

During this HPF period, BHP increased from 3100 psi to 3400 psi. The injectivity drop during this period was not more than 10%. Most previous conventional foam field pilots reported a significant injectivity loss (20% to 50%) during WAG mode surfactant injection (Sanders, Jones, Rabie, et al. 2012, Harpole et al. 1994). Injectivity loss is more enhanced with gas-water-surfactant co-injection (Harpole et al. 1994). From this reference, one may assess that a weak foam was generated near wellbore and/or the generated foam transported with higher mobility to not reduce injectivity more than 10%. Given the possibility of open and connected fracture networks around the wellbores in the pad, both of these scenarios are highly likely limiting early injectivity loss. In addition, unlike vertical wells, horizontal wells are much longer with bigger zone for injectivity redistribution with foam. This would also limit injectivity to reduce sharply with foam as often seen in vertical conventional wells (Sanders, Jones, Linroth, et al. 2012). However, the limited mobility control or injectivity loss near wellbore should not be inferred as poor foam performance. In this case, the injectivity is expected to gradually decrease as foam propagates deeper and gets stronger in the thief zones. This is clearly shown by the gradual decrease in transient injectivity index and increase in BHP of the 4H injector throughout the surfactant injection and post surfactant injection period (Figure 9).

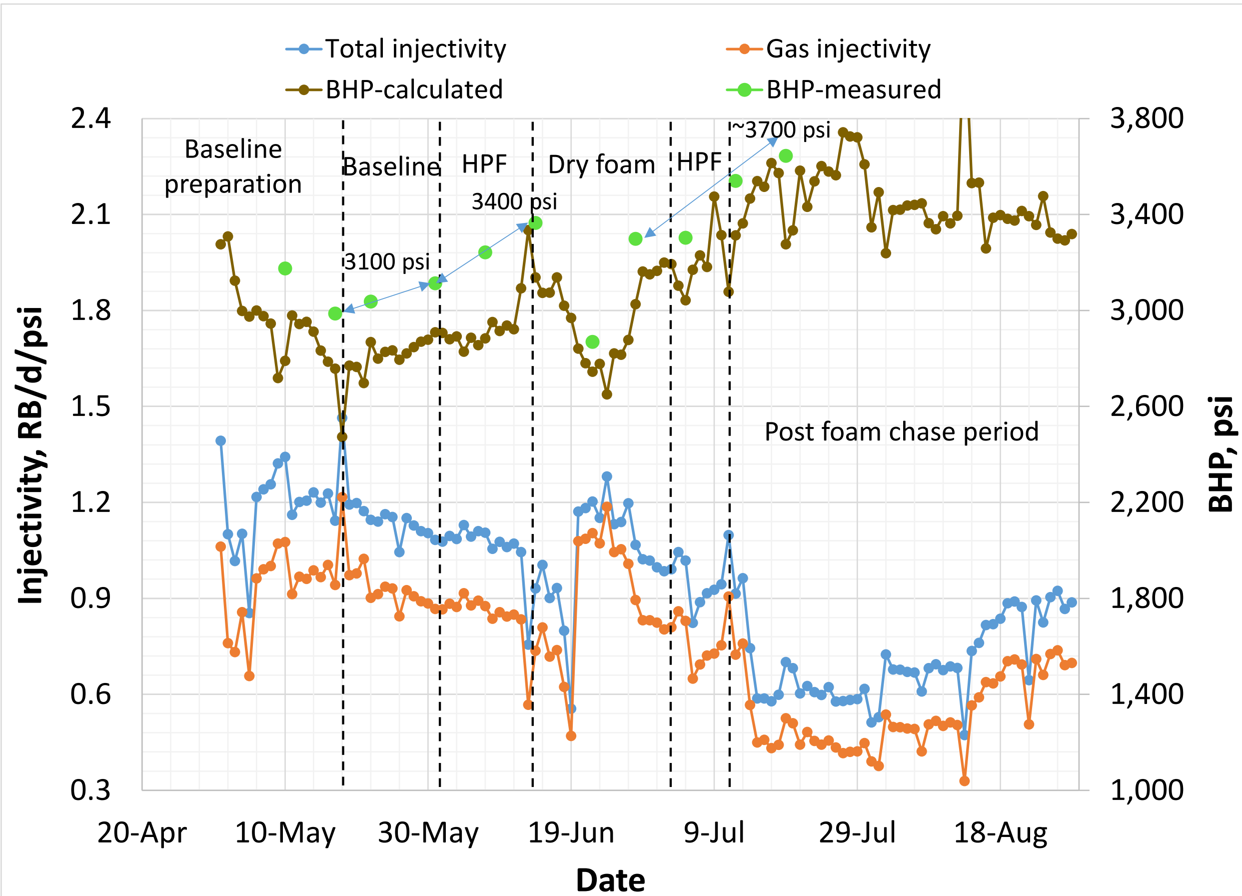

Figure 9: Gas and, total injectivity, and BHP before, during, and after surfactant injection

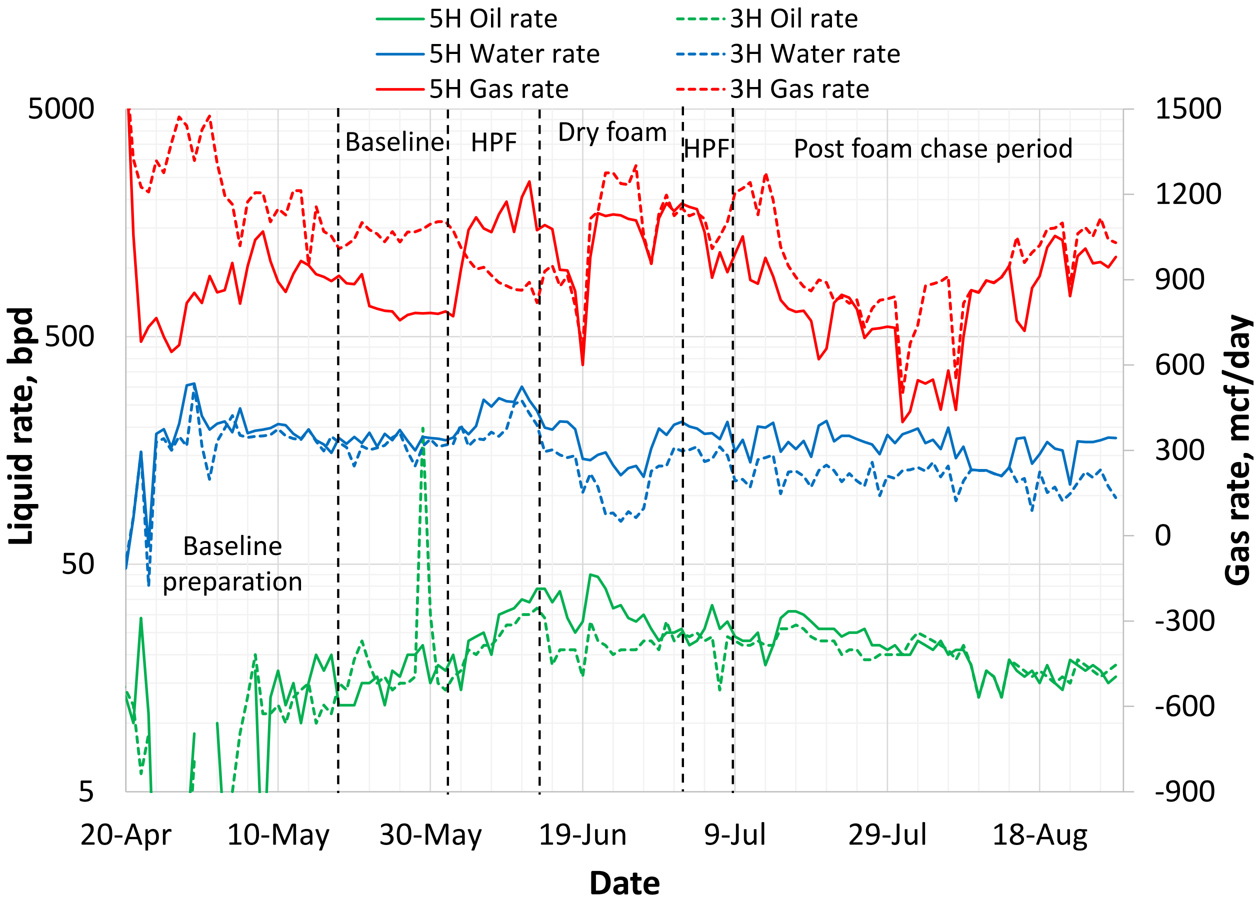

Figure 10: Individual well production rates before, during and after surfactant injection

Individual produced fluid rates from the two producers 3H and 5H from baseline, surfactant injection and post surfactant injection are reported in Figure 10. It can be seen here that at the point of surfactant injection during the 1st week of June, the gas production at 5H increased from 780 mcfpd to 1245 mcfpd, an increase of 465 mcfpd. During the same time the gas production decreased at 3H from 1104 mcfpd to 819 mcfpd, a drop of 285 mcfpd. This data clearly shows that a strong foam was generated in the preferred path of gas transport in the direction of producer 3H that resulted in diversion of injected gas from 3H to 5H. This fluid diversion towards bypassed zones in the direction of producer 5H resulted in increased oil production at 5H from 16 bpd (baseline) to 45 bpd on June 20. Additionally, foam generated towards 3H also improved the volumetric sweep with conformance correction towards 3H resulting in improvement in oil production at 3H from 16 bpd (baseline) to 32 bpd on June 13.

Another variable monitored to infer reservoir sweep improvement is the oil production/1000 RB injected daily. In a severe conformance issue, this value will be smaller and any conformance correction resulting in improved volumetric sweep will result in an increased value. Oil production/1000 RB injected daily and the total oil production rate from the pad are plotted in Figure 11. It can be seen that oil produced (bbl.)/1000 RB injected daily during baseline was < 10, but the pilot implementation pushed it to 28 almost tripling the volumetric sweep efficiency. To investigate the effect of foam on OOZ injection loss, the difference between injected and produced gas and water before and during the foam pilot was monitored. From Table 3, it can be seen that before pilot implementation, >1000 mcfpd of gas and >1000 bpd of water were lost to the formation. These rates highlight an OOZ injection issue and represents one of the conformance problems that can be corrected by foam. During the peak production response period on June 11, almost all of the injected water was recovered while gas OOZ loss dropped from 650 mcfpd during baseline to ~300 mcfpd. This rate decrease was a key technical success for the pilot where OOZ injection loss was eliminated while recovering most of the injected gas and water. During the first 10 days of formulation injection, water production climbed from 372 bpd to 563 bpd, this additional recovered water was accompanied by recovered oil. A recovery mechanism with water being responsible for the increase oil rate is not suggested. Gas is recovering additional oil and the water/foam is driving oil out of formation more efficiently.

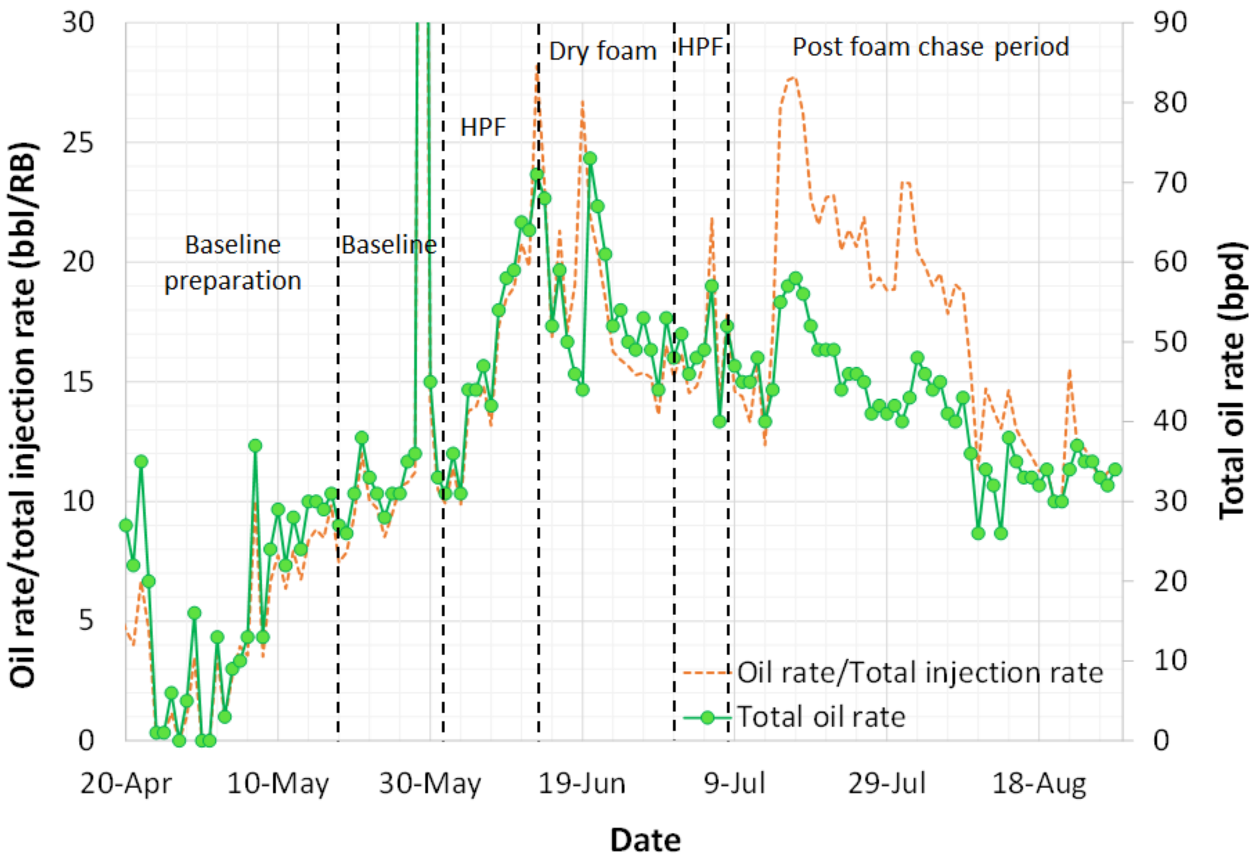

Figure 11: Oil recovery efficiency and total oil production rate during baseline and foam pilot.

During this consistent operation, total oil production climbed to 71 bpd from 32.5 bpd improving GUR from 78 to 31 mscf/bbl. GOR also reduced significantly from 58 to 32 mcf/bbl and GLR improved from 5 mcf/bbl to 3.3 mcf/bbl. In addition to the oil production response, the water production rate also increased sharply after foam injection (Figure 2) and the additional gas diverted into the area produced by 5H (signified by a cross-over of gas production rates) occurred after the onset of surfactant injection, which indicated an improvement of sweep efficiency as well as a relatively high oil saturation in the bypassed oil-rich zones.

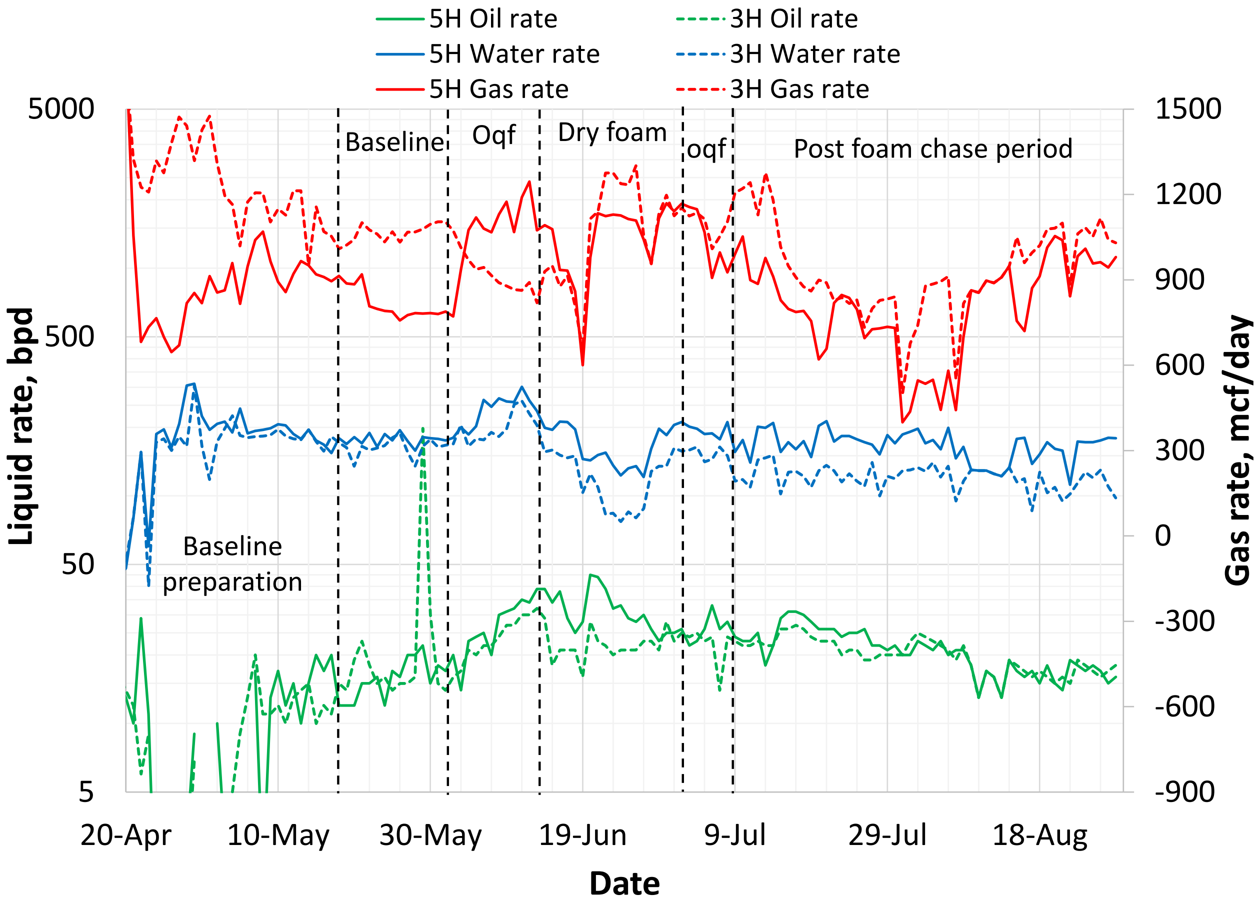

Figure 12: Individual well production rates during foam pilot

While a strong foam was produced in the reservoir during the first 10 days of operation, the following in-field experiments were conducted using the limited on-site available formulation:

1) Lowering surfactant concentration for sustained and economic conformance correction
2) Identifying the existence of a better injection gas fraction (foam quality) for maximum production response.

Regarding surfactant concentration, due to the relatively higher reservoir temperature and higher formulation adsorption, a concentration of ~1 wt% (~3200 ppm active) was considered sufficient to make stronger foam. However, it was yet to be determined whether a lower concentration could also be efficient to sustain conformance correction made by injecting higher concentration of 1%. At the same time, it was also inferred from previous pad operations that water injection could be detrimental to the production performance of this pad. Therefore, from June 12 to July 1, operational changes were made to implement 90% injection gas quality at half the surfactant concentration in brine, with this phase indicated as the dry foam period in Figure 8 to Figure 11.

Although the change of 80% to 90% injection foam quality does not seem to be large however for foam generation in a porous medium, right after 80% foam quality, foam strength drops steeply. During this period a few operational issues appeared to affect pilot control and outcome. From June 12 to June 19, due to operational issues, the injection volume dropped significantly resulting in a steep drop in all produced fluids as well as the BHP. During this period, we suspect the generated foam stability was compromised resulting in a redistribution of the injected fluids similar to baseline operations with conformance issues (Figure 10). On June 20, with operation returned to normal, 90% foam quality was implemented. During this period gas injection increased from 2500 mscfpd to ~2850 mscfpd and water was reduced from 650 bpd to 250 bpd. The injection gas spike resulted in an accompanying increase in the oil rate (76 bpd) (Figure 11), but the rate declined to 50 bpd within a couple of days. During this dry foam generation at lower concentration (1000 ppm – 1500 ppm) , production response confirmed that incremental oil can be produced at a much lower decline than early attempts of dry co-injection without foam but this operation did not reach the larger incremental oil rates seen during the first 10 days of HPF period. On June 27, foam quality was returned to 80% and the surfactant flow rate was reduced to half of the designed surfactant quantity in order to understand the influence on surfactant concentration on performance. In early July, operations returned to the original foam pilot implementation strategy, however only 5 days of foam injection occurred due to available surfactant. As the oil production rate continued to increase to 60 bpd until surfactant injection was stopped on July 9th, we do not believe that the full benefit of the foam was realized during the trial period. This did bring the oil rate/1000 RB injected to as high as the previous peak of 28 (Figure 11). The upward trend started to decline a few days after surfactant was stopped. The pilot was continued with the chase fluid maintaining a total injection at 80% gas quality.

Post surfactant injection period

Once the surfactant injection was stopped, the pilot was reverted to baseline 80% quality co-injection operation. The BHP continued to be above baseline during this period. The oil production increase above baseline was sustained for 42 days before declining to 32 bpd (Figure 11). Sweep efficiency still remained 30% higher than at the start of the pilot. In 75 days of pilot operation including the foam slug and the post surfactant injection chase period about 2000 – 3000 bbl. of incremental oil was recovered. The range of 2000 – 3000 bpd comes from the uncertainty in the baseline decline. The baseline operation was not monitored sufficiently long enough to truly capture the decline. From the oil production rate data collected from June 24 to August 6, the oil production declined only at 0.35% per day (Figure 10) which is ~10 times lower than the decline rate before the baseline operations. This data suggests that the effect of foam injection can last for a significant amount of time after surfactant injection is stopped, (e.g. here at least 6 weeks). Due to multiple changes in operating conditions during the foam pilot, we estimate that a strong foam was generated for 2 weeks only (9 days in the beginning and 5 days in the end) out of the 5 weeks of surfactant injection. The 2 weeks of strong foam strength could hold the oil production above the baseline for at least 6 weeks.

Surfactant Breakthrough

Brine samples were collected in order to measure produced surfactant concentration at the two producer well heads, in the frac-tank, where produced water is collected before being mixed with fresh water and re-injected, and at the injection well head. Figure 13 shows active surfactant concentration in ppm both at the injector and the producers. HPLC was used for surfactant concentration quantification.

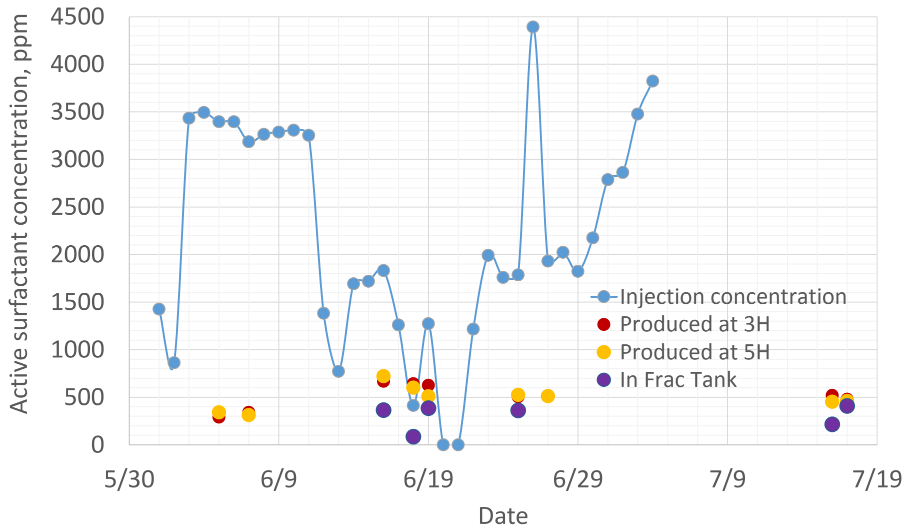

Figure 13: Surfactant concentration at different locations during foam pilot

Surfactant injection started on June 1 and the first collected brine sample on June 5 showed ~300 ppm of surfactant. On June 16, the surfactant concentration at the two producers was ~700 ppm. The change in produced surfactant concentration from 300 ppm to 700 ppm correlates well with the increase in injection concentration from 1300 ppm for the first 2 days to 3200 ppm from June 3 to June 11. The frac tank concentrations were around 50% less than the well head concentrations given produced water is mixed with fresh water before being injected. For a quick assessment of surfactant breakthrough in the produced brine at the pilot site, brine samples were collected and shaken to determine the time for foam to completely decay. The produced brine contained a significant amount of surfactant with the ability to stabilize bulk foams over 60 min. This indicated good surfactant transport (i.e. low surfactant adsorption to the rock surfaces, thermally stable molecular architecture, and insignificant partitioning of the surfactant into the oil phase) in the reservoir and the potential for recycling of the surfactant through the reuse of produced water. A stable oil-water emulsion was not observed in the produced water throughout the foam pilot, indicating a good compatibility of surfactant and the crude oil.

Conclusions

An unconventional immiscible hydrocarbon foam pilot has been designed and implemented in Woodbine field in partnership between MDAE and Dow within 6 months of time. The objective of the pilot was to correct the conformance issues identified as out of zone injection loss and non-uniform areal sweep from several months of injection operation with gas and water floods. The extent of the conformance issue was severe to record hours and days of breakthrough time for gas and water respectively. A foaming formulation was identified that showed distinct performance in bulk foam test performed at 80 ^oC and reservoir temperature of 120 ^oC. During this pilot, the surfactant formulation was injected at different concentrations and injection gas fractions for 5 weeks, out of which a strong foaming was observed for 2 weeks. The pilot met all of the success criteria: mobility and injectivity control, out of zone injection elimination, fluid diversion to bypassed areas, increased oil production rates, increased gas utilization ratio, better volumetric sweep, and sustained production after stopping of surfactant injection. The production sustained for at least for 6 weeks after the surfactant injection period. The learnings from this breakthrough pilot may be leveraged to a vast number of other hydraulically fractured tight/ultra-tight reservoirs.

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