EXPERIMENTAL INVESTIGATING OF THE PERFORAMNCE OF CYCLIC GAS INJECTON (CGI) ON ACID STIMULATED SHALE OIL CORES

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ABSTRACT

The combination of two technologies- horizontal drilling and hydraulic fracturing- made it possible to produce shale oil reservoirs economically. Although the massive stimulation treatment is the primary solution to recover efficient amount of oil from shale oil reservoirs, the recovery factors of these reservoirs are expected to be around 5-10%.The enormous remaining oil volumes stimulate our efforts to investigate the application of enhanced oil recovery methods in shale oil reservoirs. In unconventional reservoirs, cyclic gas injection using various gases could be an effective technique. Since it is a single-well process, well-to-well connectivity is not required. The hydraulic fracturing provides a large contact area for the injected gas to penetrate and diffuse into the low-permeability matrix swelling the volume of oil and increasing the near wellbore pressure which helps increasing the oil recovery in the production stage of this technique. Experimental and numerical studies by Gamadi et al, 2013 and 2014, and Tovar et al 2014, have shown that there is a great potential of increasing the recovery factor from shale oil formation. Since the hydraulic fracturing provides a large contact area for the injected gas to penetrate and diffuse into the low-permeability matrix, we investigated the performance of Cyclic Gas Injection on acid stimulated shale oil cores. The aim of the acid stimulation treatment was to improve the low-permeability matrix of the shale cores. The results showed that the acid treatment cores resulted in improving the porosity and permeability, this improvement led to better recovery factors comparing to unstimulated cores. In the conclusion, the combination of acid stimulation treatment followed by cyclic gas injection led to improving the recovery factors of the shale cores to about 30 % comparing to the unstimulated shale oil cores used in previous studies by Talal 2013 and 2014.

MATERIALS

The oil properties used in this study are shown in Table 1
Three different outcrops shale core`s types were used in our study, Barnett, Engle Ford, and Mancos. Cores properties are presented in Table 2.

CORE SATURATION PROCESS

The conventional method of saturating the cores in the lab is not a practical technique to saturate shale cores because of their ultra-low permeabilities. In this study, a new technique, developed by us, was used. Figure1 shows the set-up used in the saturation process. This process is done in general as following; a shale core is put in high pressure vessel then vacuumed for certain time. The vacuum pump is stopped and the valve is turned off, after that, the oil is injected from the top of the vessel using syringe pump. After the core is completely soaked in the oil, high pressure is maintained during the whole period of the saturation process for certain period of time.
Prior to conducting the main experiment, cores from Barnett, Eagle Ford, and Mancos were named and dry weighed. The dry weights of the cores were recoded. The cores were vacuumed for 3 days then The cores were put in the vessel and saturated with oil under different pressures, , 500, 1500, 2000, 2500 psig. The pressure on these cores was increase steadily. At each pressure, saturated oil volume in each core was calculated using the difference between the saturated weight and dry weight divided by the density of the used oil. Figure 2 shows the effect of the soaking pressure on the saturated oil volume. The oil volume is increasing with the increase of the pressure but kept constant after using 2000 psig. The key factor of this process is the pressure release. It is highly recommended to release the pressure on the core gradually to prevent cause damage to the core samples. After the cores were saturated, the wet weight was recorded. The saturated cores were put in the core holders and the huff-n-puff procedures were started.

MANCOS CORES

In Figure 3, at pressure near to miscible conditions 3000 psig, the peak of oil production was at the first five cycles and begins to increase slightly by 2 % or less after the 3^{th} cycle till it stabilized after the 6^{th} cycle at average of 32.15 as shown in Table 3, second row. At 4500 psig, Figure 4, more oil recovery compare to the use of 3500 psig. The peak of oil production was Also at the first five cycles and begins to increase slightly by 2% or less after the 3^{th} cycle till it stabilized after the 6^{th} cycle at average of 37.15 % as shown in Table 4, second row.

BARNETT CORES

In Figure 3, at pressure near to miscible conditions 3000 psig, the peak of oil production was at the first , second, and third cycle and begins to increase slightly by 2 % or less after the 3th cycle till it stabilized after the 6th cycle at average of 32.15 as shown in Table 3, third row. At 4500 psig, Figure 4, more oil recovery compare to the use of 3500 psig. The peak of oil production was at the first three cycles and begins to increase slightly by 2% or less after the 6th cycle till it stabilized after the 6th cycle at average of 37.15 % as shown in Table 4, third row.

EAGLE FORD CORES

The performance of N_2 cyclic process was the highest in Eagle Ford shale cores. In Figure 3, at pressure near to miscible conditions 3000 psig, the peak of oil production was at the first , second, and third cycles and begins to increase slightly by 2 % or less after the 3th cycle till it stabilized after the 6th cycle at average of 71.15 as shown in Table 3, fourth row. At 4500 psig, Figure 4, more oil recovery compare to the use of 3500 psig. The peak of oil production was at the first three cycles and begins to increase slightly by 2% or less after the 6th cycle till it stabilized after the 6th cycle at average of 75.5 % as shown in Table 4, fourth row. Comparing the performance of N_2 cyclic processes on the three core samples, when operating pressure was changed from 2000 to 4500 psig, show again the effect of injection pressure on the cyclic N_2 process.

CONCLUSION

Injection pressures have a significant effect on the performance of cyclic gas injection. The performance of Cyclic Nitrogen Injection (CNI) is high dependent on the soaking time and pressure because of the N_2 low solubility.

PART TWO ACIDIZING TREATMENT (STIMULATED CORES)

The main goal of the work was to investigate the effect of acid on shale rock sample. Previous investigations have been carried out by other researchers but none under the same operation procedures. Morsy et. al. (2014) investigated the impact of acid on shale rock samples by submerging the samples in dilute HCl acid solution over time intervals ranging from 30minutes to 180 minutes. The dilute acid solutions had concentrations of 0.8%, 3% and 5%. It was recommended that in order for rock to maintain its integrity no greater than 1% HCl be used. Under reservoir conditions, the rocks will be under confining stresses from all a directions apart from the area exposed to the fracture, hence, the attempt to tailor the experiments to these conditions. To replicate these conditions, it was proposed that the acid be pumped to the rock as will be the case in actual operation conditions at a pressure below the rocks strength. The cores used were dried outcrop samples obtained from the Eagle Ford shale play in South Texas. The Core plugs used were cut in both orientations of beddings, Sample labeled A, parallel to the length of the core plug, and the other with beddings perpendicular to the length of the core plug, labeled B.

Sample Preparation

The samples were inspected, weighed dry, and scanned using a computer tomography scanner (CereTom CT scanner). Both samples had similar diameters of 3.7cm, while the lengths were 5.08cm and 2.27cm for A and B respectively. To avoid contamination of the acid solution by hydrocarbon solvent, the initial porosity calculations were not done using the CT scanner, as it would require the core to be fully saturated with the oil sample. According to Walls and Sinclair (2011), the eagle ford has porosity ranging from 2% to over 15% percent. Therefore, we assumed the cores to have porosity in the range of a helium porosimeter was used to measure the porosity of the smaller sample, B, to see if the samples fell within the assumed range of 2 to 7% of interconnected porosity. The porosity of sample B was calculated using the Helium porosity 9.6%.

Acid Treatment

Sample A was treated using 5% dilute HCl acid solution as well. The sample was placed in a triaxial core holder with confining pressure just over 2500psi. The setup was supposed to mimic actual reservoir conditions as flooding process would represent the application of acid to the formation through hydraulic fractures. Acid was pumped to the core holder at a constant injection pressure of 1500psi and held at constant temperature of 65 degrees Celsius for 20 hours. Sample B was treated using 5% dilute HCl acid solution. The sample was treated by soaking it in a pressure vessel containing the dilute 5% HCl solution and keeping a constant pressure of 1000psi and temperature of 65 degrees Celsius 24 hours.

Observations and Discussions

For Sample A, which had beddings parallel to the direction of flow, was stopped after 10hrs of injection. The key observation for sample B was the fact that the pressure at the inlet of the core sample was observed to have increased to about 2100psi, hence, stopping the pump from operating. The pressure was allowed to deplete gradually. Though break through was observed, it was at a very low rate with barely less than 20cc of breakthrough fluid observed at the outlet. Some precipitate was also observed in the breakthrough fluid. It is suspected that the fluid may have actually etched the rock and flowed through it to the outlet. CT images generated showed density changes in the portion of the core closer to the inlet.

Sample B which was placed in a pressurized vessel was observed to have a similar buildup in pressure as the vessel temperature went up. The CT images generated showed changes in the density of the outer portions of the core sample. This density change is observed to be evenly distributed throughout the periphery of the rock sample. It is believed that the increase in pressures seen to occur in both samples' setup, may be due to the reaction of the HCl acid solution with the rock resulting in the generation of CO_2 gas under confined conditions and high temperatures thus, resulting in buildup in pressure.

Post Acid Treatment

After the samples were taken out of their setup, the samples were cleaned using Dean Stark distillation process. The solvent used was toluene and distillation process was run for two days. Samples were then dried at temperatures between 50 and 60 degrees Celsius for 36 hours. It was assumed that being outcrop core samples, there was no organic matter in the cores, no significant changes in porosity would be due to Dean Stark process. CT scans of the dried samples were then taken. Both samples were then vacuumed for 24hrs and then saturated with Soltrol 130 synthetic oil. Saturation process was carried out by placing core in a pressurized vessel filled with Soltrol 130 and gradually increasing the pressure at intervals of 500psi from 500psi to 2000psi over a period of at least 12hours at ever pressure interval. At 2000psi the vessel was held at constant pressure for 48hrs before being depressurized gradually. After saturation, the samples were weighed and scanned using the CT scanner. The post acid treatment Porosity was calculated using:

$$\varphi = \frac{CTN_{sat} - CTN_{dry}}{CTN_o - CTN_a}$$

Where, ϕ is the porosity and CTN is the mean Hounsfield Number. The subscripts, "*sat*" represents the saturated sample, "*dry*" represents the sample empty and dry, "*o*" represents Soltrol 130, and "*a*" represents air. The Porosity values obtained for slices of sample A ranged between 1.2% and 37%, with an average core plug porosity of 9%. For sample B, porosity of the CT slices ranged from13.3% to 37.6%, with a core plug average porosity of 19.6%. Comparing the result obtained with the typical values, it can be affirmed that there was improvement in the porosity of the rock samples due to the acid treatment.

Huff and Puff

The saturated samples were placed in a pressure vessel and connected to a Nitrogen gas supply. Nitrogen gas was then pumped into the sealed vessel to a pressure of 3000psi and held at this pressure for 24hrs. After the soaking period, the gas vessel was bleed and the samples were weighed. The recovery factor was calculated using

$$R.F = \frac{Wet\ Weight - Weight\ After\ Soaking\ Period}{Wet\ Weight - Dry\ Weight}$$

Comparing the results of unstimulated core with the stimulated cores showed that recovery factor increased by 30%. This might be related to the improvement of porosity and permeability of acid stimulated shale cores.

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Table 1: Oil Properties

Component 100%	Relative density	Viscosity cp
C10-C13 Isoalkanes	0.76	1.5

Table 2: the unstimulated cores properties

Cores	Diameter (in)	Length (in)	Ave Porosity %
Barnett	2	2	6.0
Mancos	1.5	2	5.0
Eagle ford	1.5	2	7.7

Table 3: Recovery factor at operating pressure near miscible conditions 3000 Psig

No. of cycles	1	2	3	4	5	6	7	8	9
R.F of Marcos Core	15%	22%	25%	27%	29%	31%	32%	33%	33%
R.F of Barnett Core	16%	30%	37%	43%	48%	53%	56%	58%	58%
R.F of Eagle Ford core	23%	31%	35%	51%	66%	70%	72%	72%	72%

Table 4: Recovery factor at operating pressure near miscible conditions 4500 Psig

No. of cycles	1	2	3	4	5	6	7
R.F of Marcos Cores	22.01	25.78	30.12	33.86	35.92	36.99	38.87
R.F of Barnett Cores	23.21	35.73	42.96	48.18	52.18	54.18	56.18
R.F of Eagle Ford cores	32.01	38.00	48.00	58.00	70.12	75.12	76.00

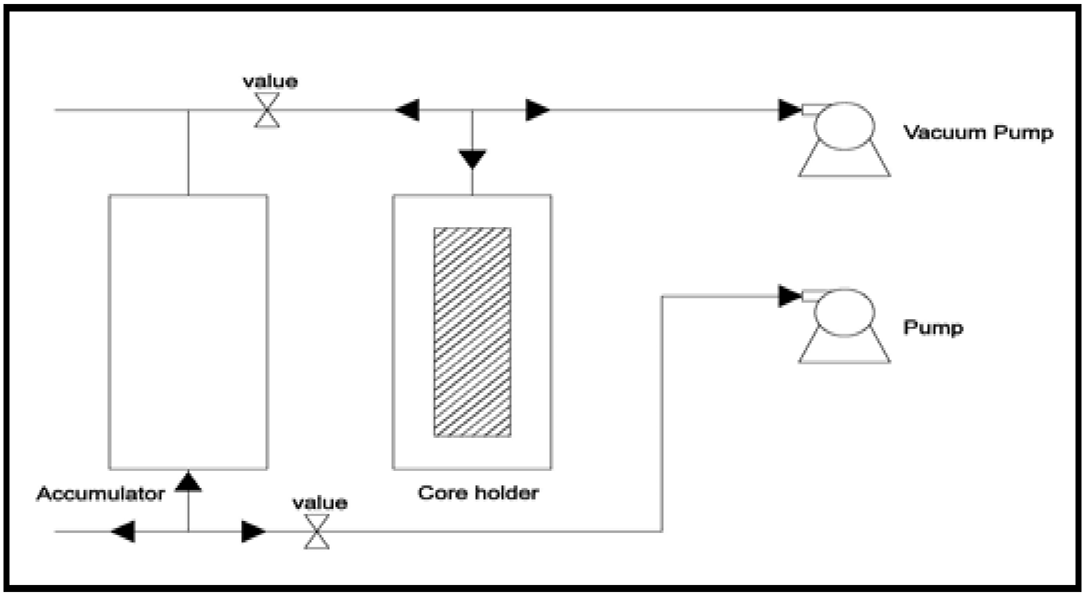

Figure1 - Diagram of the Set up Used in the Saturation Process

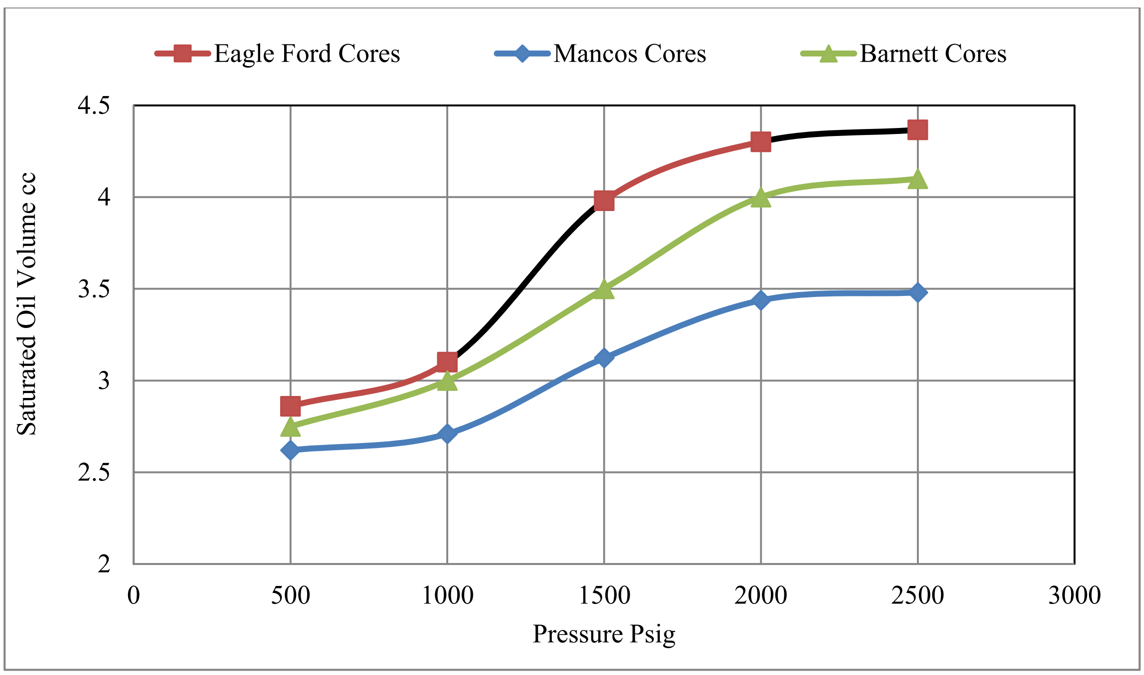

Figure 2 - shows the effect of the soaking pressure on the saturated oil volume.

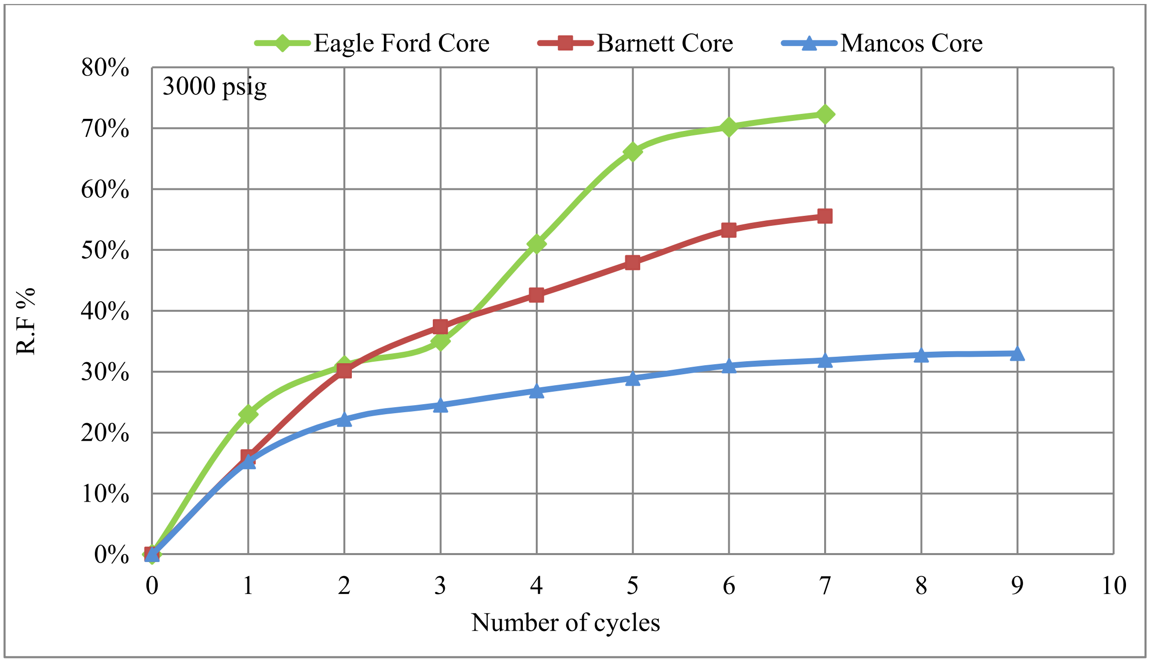

Figure 3 - Performance of Nitrogen Huff-n-Puff at near miscible conditions as function of number of cycles

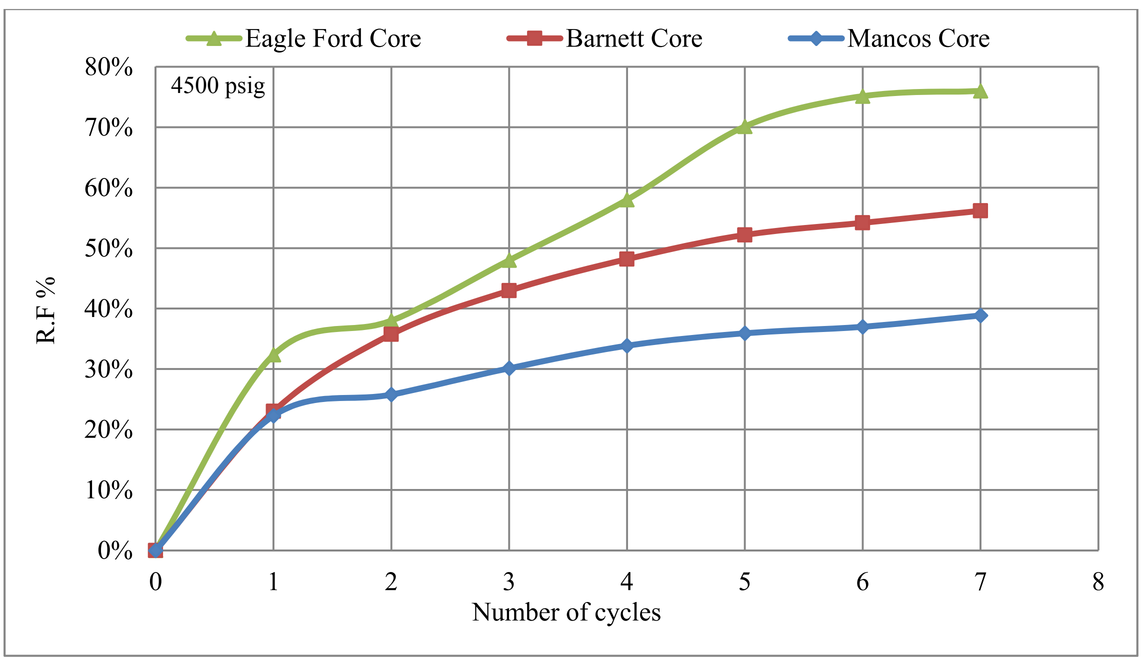

Figure 4- Performance of Nitrogen Huff-n-Puff at near miscible conditions as function of number of cycles