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Surfactant-Alternate-Gas (SAG) Injection Process as a Novel EOR Technique-- A Laboratory Investigation.

Category: Reservoir Modeling and Characterisation

Abstract

The ultimate oil recovery after primary and secondary recovery is less than 40% of the Original Oil in Place (OOIP) in most reservoirs. Suitable EOR methods needs to be chosen to improve oil recovery by injecting fluid materials that are absent in the reservoir. Nowadays, each EOR method has been modified to suit the requirements of specific reservoir condition. A study was carried out to evaluate the feasibility of immiscible Surfactant-Alternate-Gas (SAG) injection at laboratory scale for Limbodara field of Ahmedabad Asset, ONGC, Ahmedabad.

Surfactant alternate gas (SAG) is an immiscible gas injection process using a method for mobility control to improve sweep efficiency. The main factors which contribute towards incremental displacement efficiency are entrapment of gas due to hysteresis and the effect of the 3 phase flow further contribute to increase recovery by injecting immiscible gas in SAG manner. SAG injection can thus lead to improved oil recovery through combination of factors such as mobility control, contact of unswept zones, improved microscopic displacement efficiency and oil vaporization due to mass transfer between reservoir oil and injected gas due to vaporization process.

The concept of SAG process as an enhanced oil recovery technique is relatively new, with very little experimental and theoretical work available on the subject. Displacement efficiency from SAG experiments are comparable to ASP core flood experiments carried out under similar conditions. Experimental data show a strong synergic effect of alkali-surfactant and ultra-low oil-water IFT on oil recovery. It is observed that, on immiscible single cycle & two cycle SAG process an incremental displacement efficiency of 27.79% & 29.01 % were achieved over and above water flooding. Indicating feasibility of additional oil recovery by SAG process in areas in the field where early breakthrough of the ongoing injection water occurs.

Introduction:

Limbodra field was discovered in 1985 by drilling of Limbodra # 1 which produced oil from Limbodra Pay – III of Tarapur formation. Chhatral sands are the main pay zones of interest in Limbodra Field. The Chhatral Unit-II has been further subdivided into CH-IIA, IIB and IIC on the basis of sand packages. It comprises of around 45 % of total OIIP and it contributes around 75% of the total production from the field. Till date, about 175 wells have been drilled. As per approved estimates (01-04-2009), it holds OIIP of 27.89 MMT and currently produces about 593 TPD (as on 01.08.2009) from various pay zones of the field.

Water injection scheme has been implemented for pressure maintenance in Chhatral sands. Selected blocks of Chhatral I, II and III are under water injection. Cumulative water injection of 1.609 Mm^3 has taken place as on 01/02/2009. Chhatral Pay sand of Limbodra field has porosity between 18 to 35 %, permeability 40 to 1000 md and oil viscosity at reservoir temperature of 80°C is between 2.0 to 5.0 cp. Keeping these points in view, Limbodara field is selected for laboratory investigation of SAG process. As the use of surfactant can reduce gas mobility and the effect of heterogeneity and therefore increase sweep efficiency in a heterogeneous reservoirs.

Details of Samples Collected / Used:

Formation water	:	LM # 132
Process water	:	Tube well water
Oil Sample	:	LM # 98
Alkali	:	Sodium Carbonate
Surfactants	:	L – 46, AOS
Polymer	:	Pusher – 1000
Barea Core	:	Permeability 100md.

Laboratory Studies:

Details of screening studies and core flood displacement studies carried out are as follows:

A. Solubility Measurement:

Alkali and Surfactants are found to be soluble in process water. The test indicates that the chemicals are completely soluble in the process water. Visual observation confirmed the readily solubility of both the surfactant and alkali samples in process water, without any precipitation.

B. IFT Measurements:

IFT measurements for crude oil vs process water, crude oil vs different Alkali / Surfactant in varying concentrations and alkali-surfactant blends were carried out. Significant IFT reduction is observed in many combinations of alkali – surfactant & salt. Minimum IFT value of 12.6 millidyne/cm was measured with crude oil vs alkali (0.1 %) + AOS (1.4 %).

C. Thermal Stability Study:

Thermal stability of alkali, surfactant and polymer in ASP containing the surfactants (namely L-46 and AOS) has been studied at reservoir temperature of 80°C. The study carried out for about one & half month showed thermal stability of more than 95 % for both the surfactants.

D. Emulsion Formation Studies:

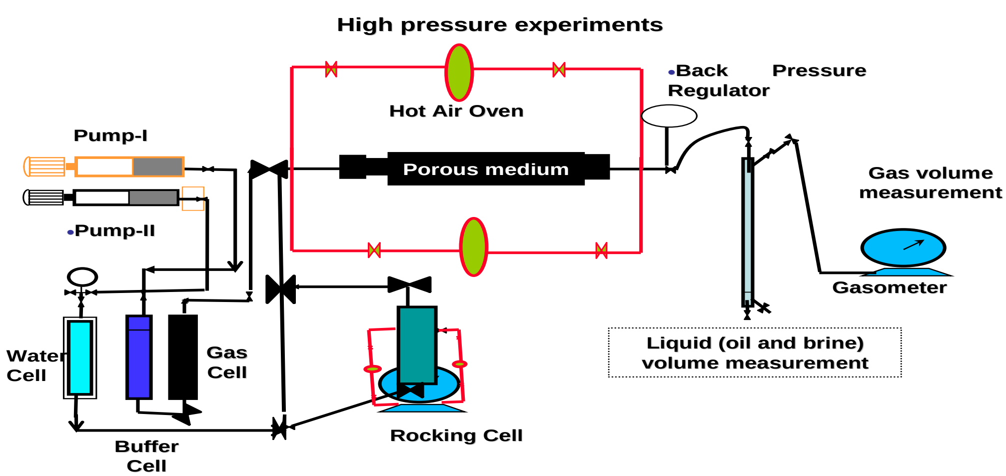
Emulsion formation test were carried out between crude oil and ASP slug at reservoir temperature. Very good emulsion in Oil: Aqueous ratio 70:30 & 60:40 , moderate emulsion in ratio 50:50 and slight emulsion in 30:70 & 20:80 were observed both static and dynamic

Core Flood Displacement Studies

A detailed micro plan for the experiment to be performed on a Berea sand stone core having 100 md permeability at actual reservoir conditions using live oil from Limbodara well No. 98 completed in Chattral main pay sand was drawn with following steps:

- Saturation with formation water
- Determination of pore volume and absolute permeability
- Oil flood to connate water saturation
- Water flood to water flood residual oil saturation and tertiary immiscible single/ two cycle SAG followed by chase water & ASP followed by polymer buffer & chase water.

EXPERIMENTAL SET-UP FOR DISPLACEMENT EFFICIENCY STUDIES



Experimental Results and Interpretation

In all the experiments, after the core pack was properly saturated with live oil at connate water saturation, water injection was started at the rate of 10cc/hr in the horizontal condition.

Experiment – 1

Primary water Injection:

The break through of water occurred after injecting 0.478 PV of water. The displacement efficiency at water breakthrough was 47.47% of Hydro Carbon Pore Volume (HCPV). The displacement efficiency after injecting 0.651 PV of water was found to be 52.11% of HCPV. However, the water injection was continued till injection of 0.943 PV but no improvement in recovery was observed as oil ceased to flow.

Tertiary Surfactant alternate Gas injection:

After injecting about 0.943 PV of water when no more oil recovery was there the water injection was stopped. The injection of 0.5HCPV of AS followed by 0.5 HCPV of CO_2 gas was carried out at the rate of 10 cc/hr followed by chase water. The displacement efficiency at 1.644 PV injection was 27.79% of HCPV. However, injection of chase water was continued upto 1.962 PV but no improvement in recovery was observed as oil ceased to flow. Thus incremental displacement efficiency with SAG process over primary water injection is 27.79 % of HCPV.

Experiment –2

Primary water Injection:

The break through of water occurred after injecting 0.479 PV of water. The displacement efficiency at water breakthrough was 45.16% of Hydro Carbon Pore Volume (HCPV). The displacement efficiency after injecting 0.769 PV of water was found to be 55.58% of HCPV. However, the water injection was continued till injection of 1.9 PV but no improvement in recovery was observed as oil ceased to flow.

Tertiary ASP:

After injecting about 1.9 PV of water, when no more oil recovery was there, the water injection was stopped. Injection of ASP solution followed by three polymer buffers of graded concentration and chase water was started at the rate of 10 cc/hr. The displacement efficiency at 1.2 PV injection was 12.74% of HCPV. However injection of chase water was continued upto 1.508 PV & displacement efficiency was 14.36 % of HCPV and the oil flow stopped. Thus incremental displacement efficiency with ASP process over primary water injection is 14.36 % of HCPV.

Experiment –3

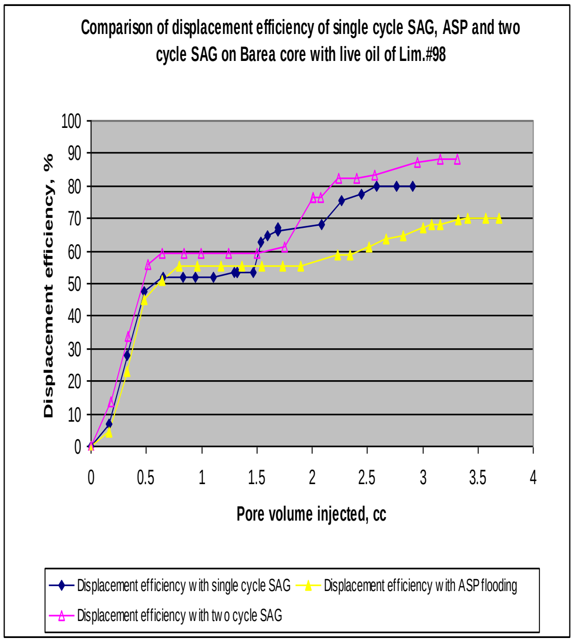
Primary water Injection:

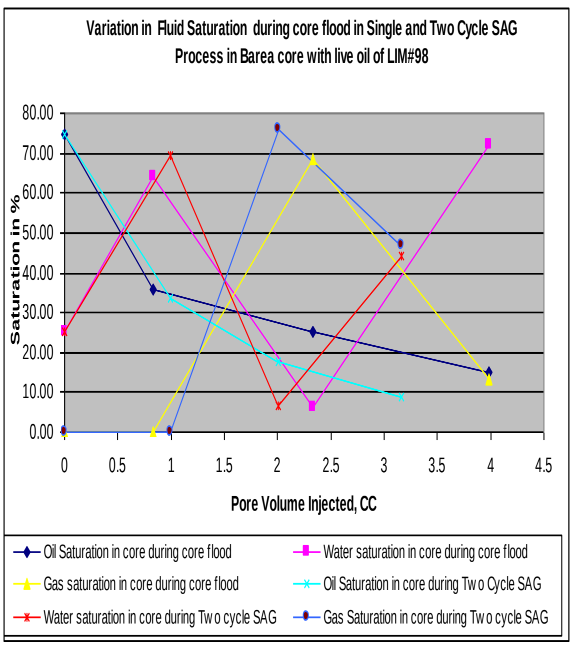
The break-through of water occurred after injecting 0.516 PV of water. The displacement efficiency at water breakthrough was 55.70% of Hydro Carbon Pore Volume (HCPV). The displacement efficiency after injecting 0.648 PV of water was found to be 59.18% of HCPV. However the water injection was continued till injection of 0.997 PV but no improvement in recovery was observed as oil ceased to flow.

Tertiary Surfactant alternate Gas injection:

After injecting about 0.997 PV of water, when no more oil recovery was there, the water injection was stopped. The injection of 0.25 PV AS, 0.25 PV CO_2 Gas, 0.25 PV AS, & 0.25 PV CO_2 gas was started at the rate of 10 cc/hr followed by chase water. The displacement efficiency at 1.157 PV injection was 29.01% of HCPV. However, injection of chase water was continued upto 1.309 PV and no improvement in displacement efficiency was observed and the oil flow stopped. Thus, incremental displacement efficiency with two cycle SAG process over primary water injection is 29.01 % of HCPV.

Comparative results of displacement efficiency & variation in fluid saturation during single cycle SAG, two cycle SAG, and ASP process under simulated reservoir condition are given below.





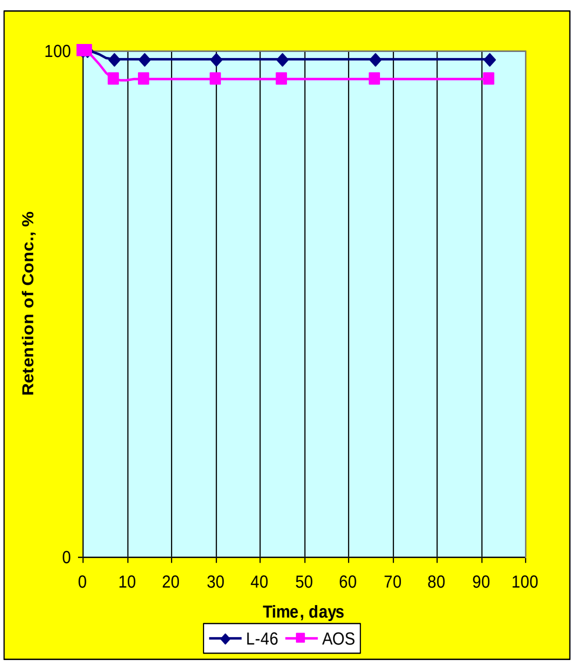
Conclusion

Higher water flood recoveries, a sharp breakthrough with negligible oil production after breakthrough (Seen in the plot of oil recovery vs PV injected) all are characteristic of water wet rock.

On single cycle and two cycle SAG process over and above water flooding, an incremental displacement efficiency of 27.79 and 29.01 % are achieved respectively indicating feasibility of additional oil recovery by immiscible SAG process in areas in the field where early breakthrough of the ongoing injection water occurs.

Higher displacement efficiency in SAG process may be due to entrapment of gas due to hysteresis and the effect of the 3 phase flow further contribute to increase recovery by injecting immiscible gas in SAG manner, SAG injection can thus lead to improved oil recovery through combination of factors such as mobility control, contact of unswept zones, improved microscopic displacement efficiency and oil vaporization due to mass transfer between reservoir oil and injected gas due to vaporization process.

Thermal Stability of Chemicals (in Tube well water) at 80^{0}C



Chemical:	Surfactants: Conc.3000 ppm in Limbodra Process water	
Time, days	% Conc. Retention	
	L-46	AOS
0	100	100
1	100	100
7	98.2	94.4
14	98.2	94.4
30	98.2	94.4
45	98.2	94.4
66	98.2	94.4
92	98.2	94.4

A. SARA Analysis of Residue Oil

B. Density and Acid Number of Oil

Sl. No.	Parameter	LM #98	LM # 138		Sl. No.	Parameter	LM #98	LM # 138	
1	Saturates (w/w) %	65.75	62.46		1	Density (g/cc)at 80°C	0.804	0.82	
2	Aromatics (w/w) %	23.03	25.54		2	Acid No. (mg KOH/g Oil)	1.35	1.35	
3	Resin (w/w) %	7.01	9.22						
4	Asphaltene (w/w) %	4.21	2.78						