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Research Article

Alkali-surfactant-polymer flooding experiment in GT block of Daqing oil field

Zhao Yang[1], Liya Wang[2], Xingang Wang[3]
[1, 2]Northeast Petroleum University in China
[3]No.1 Oil production Company of Daqing Oilfield in China

***Corresponding author**
Xingang Wang
Email: wly1234569@sina.com

Abstract: GT block at present, injection-production well pattern and water injection mode has basically met the needs of oil field development. In order to study the suitable surfactant flooding system of domestic carboxylate for ASP flooding in Daqing oil field, for the first time, in GT block we carry out domestic oleic acid carboxylate surfactant applied to field experiment of asp flooding. The indoor experiment and field test show that, test obtained the effect that oil is increased and water precipitation is reduced. In addition, great changes have taken place in ion of produced fluid. And emulsification happened, but emulsification extent without added. This experiment is the first time to apply oleic acid surfactant in Daqing oil field. Therefore the result and analysis produce a positive effect on alkali-surfactant-polymer flooding in Daqing oil field.

Keywords: GT block, Daqing oil field, surfactant

INTRODUCTION

General situation of GT block

Basic situation of the test block

MI2, the test block, is located in the eastern of GT block. Total area is 0.225 km^2. Average injector producer distance is 170 m. Average sandstone thickness is 5.3 m. Average effective permeability is 0.46μm^2. Reservoir pore volume is $23.42\times10^4 m^3$.Original oil in place is 11.8×10^4t. Original saturation pressure is 7.5Mpa. Reservoir temperature is 45˚C. Formation oil viscosity is 8.4mPa·s. Original formation salinity is 700mg/L. Primeval silicon ion concentration is 19.23mg/L. Primeval calcium ion concentration is 39mg/L.

MI2, the test block, is plain depositional facies of Delta distributaries, and distributary channel sand sedimentary mainly. Reservoir sedimentary type is compound rhythm in the majority, positive rhythm a few.

Centered on well M11-2,the wells of the test block constitute the five-spot pattern with four injection wells and nine producing wells. The experiment layer is formation MI2, including well M11-2、well M11-3 and well M12-2. The other six wells is commingled production MI2 with between formation C and M（Fig. 1）.

Development profiles of the test block

Over November 1995 to June 1998, in the test block, the cumulative water injection is $6\times10^4 m^3$, equal to 0.252PV. At the end of the water flooding, the injection pressure is 5.7MPa. The daily water injection is 240m^3. Apparent water injectivity index is 2.31m^3/d·m·MPa. At the end of water flooding slug, for the whole block, daily oil production is 37t, blanket water cut is 94%, staged cumulative oil production is 1.6725×10^4t, recovery percent is 45.2%. For the central well, daily oil production is 3t, blanket water cut is 98.2%, staged cumulative oil production is 1051t, and recovery percent is 44.5%.

SLUG INJECTION PARAMETERS

Core displacement experiment

We carry out the core displacement experiment indoors. Prescription for the displacement system is NaOH of 0.9wt%. Concentration of polymer is 2000mg/L. Concentration of carboxylate is 0.25wt%. And we inject 0.3PV. Subsequent slug polymer concentration for protection is 1200mg/L, and we inject 0.3PV. The result is improved recovery efficiency of more than 20% (Table-1).

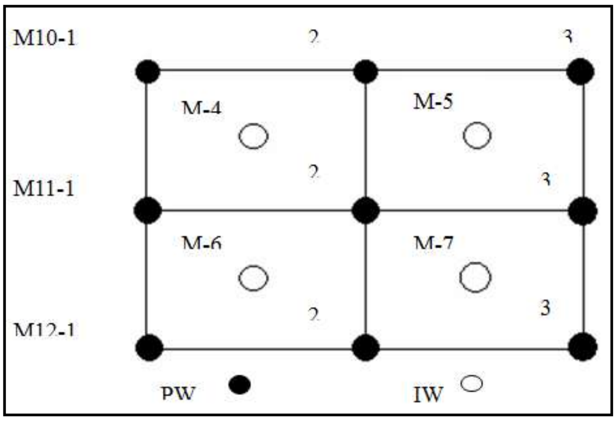

Fig-1: well position map in the test block

Table -1: Comprehensive data of core displacement experiment

No.	Core No.	Permeability(× 10μm2)	Original oil bearing saturation (%)	water flooding recovery (%)	Combination flooding recovery(%)	Ultimate recovery(%)
1	Man-made 1	1050	70	41	21	62
2	Man-made 2	1105	78.5	43.37	20.5	63.87
3	Man-made 3	1191	82.02	41.28	21.1	62.38
4	Man-made 4	1233	82.75	41.41	20.43	61.84
5	Natural A	1668	74.29	54	21.2	75.2

Note: 1. Prescription: 0.3PV(0.3%909—9A+1.0%NaOH+2200mg/LP)+0.2PV(1200mg/LP);
2. Temperature of experiment is 45˚C.

The process of injection

The work of experiment injection is divided into three stages. There are Pre-slug of ASP flooding[1], ternary complex slug and subsequent polymer protection slug (Table-2).

Pre-slug of ASP flooding

Early on the Pre-slug of ASP flooding, concentration of injection polymer is 800mg/L. Solution viscosity near the wellhead is 40mPa·s. Then Well M12-2 found the polymer first. Cumulative injection of polymer solution is $1.0729\times10^4 m^3$, equal to 0.0451PV. At the end of Pre-slug of ASP flooding, injection pressure is more 2.1MPa than that of water flooding. Daily injection rate declined $90m^3$. For the whole block, cumulative oil production is 1.9615×10^4t , and recovery percent is 45.66%.

ASP system slug

During the experiment, we strengthen the dynamic analysis, adjust the pressure distribution timely. It requires that the injection quality of ASP system is important. It sticks to principles that detection firstly, injection lately; no eligibility, no injection. Then the index of different stages of injection system such as viscosity achieves the design requirements. The concentration of injection alkali is about 1.0%. The concentration of surfactant is 0.29%-0.33%. Interfacial tension is 4.0×10-3-8.0×10-3mN/m.We adjust injection profile; improve the polymer concentration in the ternary system. At the end of ASP slug, for the whole block, the capacity of produced fluid and water cut declined. Cumulative oil production is 3.2807×104t. Recovery percent is 49.66%.

Subsequent polymer protection slug

In order to make the wellhead viscosity of injection in Subsequent polymer protection slug is not lower than that in ternary system;[2] we raised the first polymer, the second polymer protection slug concentration. Then the wellhead viscosity is more than 50mPa·s. The cumulative injection of polymer solution is $5.1017\times10^4 m^3$, equal to 0.2158PV. At the end of Subsequent polymer protection slug, for the whole block, the capacity of produced fluid declined, and the capacity of water cut remain stable. Cumulative oil production is 10.2222×104t. Recovery percent is 52.61%.

Table-2: single well injection of each stage

Well No.	Pre-slug of ASP flooding		ASP system slug				Subsequent polymer protection slug	
	Polymer injection of single well(×104m3)	Polymer dosage(t)	Single well injection of ternary system(×104m3)	Surfactant dosage (t)	Polymer dosage (t)	Alkali dosage (t)	Polymer injection of single well(×104m3)	Polymer dosage (t)
M4-1	2409	2.31	19579	57.1	35.7	188.9	9891	13.5
M4-2	2762	2,61	13713	43.5	25.0	132.1	13976	19.0
M4-3	2350	2.27	14807	44.5	27.0	142.8	10633	14.6
M4-4	3205	3.07	23276	70.8	42.5	225.1	16515	23.4
Total	10726	10.26	71375	215.9	130.2	688.9	51015	70.5

PRODUCTION PATTERN

Injection pressure rises, the injection capacity decreased

During the period of injection of pre-polymer slug, as the injection viscosity reaches 40mPa·s.The increase rate of injection pressure is as high as 46.4MPa/PV. Due to the viscosity decline of injection ternary liquid, the pressure shows a slow rise. If the injection volume is 0.3016PV, the pressure will rise to 10.4MPa, and increase rate is 8.6MPa/PV. After the injection of subsequent polymer protection slug, the pressure rise to 11.9MPa. Though the addition of injection pressure range was wide, injection pressure was still below the fracture pressure (13.4MPa) (Fig.-2).

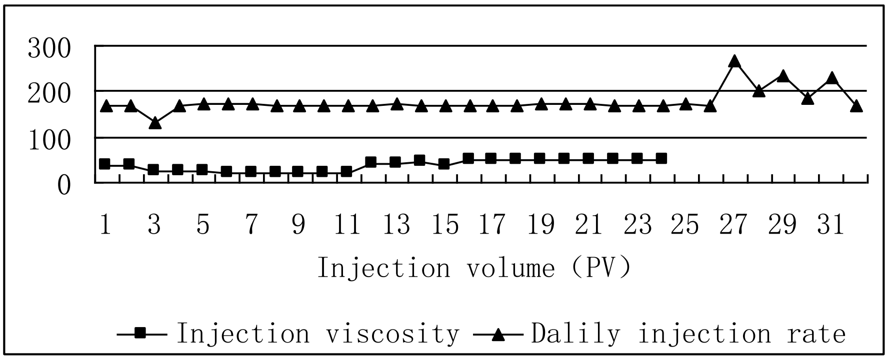

Fig-2: Injectability changing curves of ASP

Liquid production decrease, liquid producing capacity decrease

After the injection of ternary liquid, as the viscosity of injection liquid rises and the absorption of polymer, the permeability decreases, with the filtration capacity, production and production index decreasing (Table 3).

Table-3: Liquid-producing capacity changing of central wells

Block	Injector producer distance (m)	Liquid production capacity			Produced fluid index (m3/d·m·MPa)		
		Water flooding (m^3/d)	Combination flooding (m^3/d)	Descend range (%)	Water flooding (m^3/d)	Combination flooding (m^3/d)	Descend range (%)
GT1	105	35	30	14.3	0.92	0.395	58.5
GT2	200	133	40	69.5	10.32	2.4	95.5
GT3	170	152	63	59.2	15.14	1.62	89.2
GT4	240	198	78	60	10.2	1.5	91.2

Because the stable time of carboxylate viscosity of ASP system is short, it is adverse to expanding swept volume of ASP system.

We contrast the viscosity stability of carboxylate (PBH-808E) ternary system and sulfonate (ORS - 41) ternary system in door, In 20 days, the initial viscosity of carboxylate (PBH-808E) ternary system is from 46 MPa·s down to 19 MPa·s. The decrease amplitude is 58.7%; While the initial viscosity of sulfonate (ORS - 41) ternary system is from 57MPa·S down to 38.7 MPa·s. The decrease amplitude is 32.9%.The experiment shows that, after adding the carboxylate (PBH-808E) to the polymer solution, the viscosity decreased with the increase of surfactant concentration.

The ternary system compounded with PBH-808E's stable phase is shorter than sulfonate, which is not conducive to play a role of ternary system mobility control. Because it is the first time vegetable oil carboxylate ASP flooding pilot test on domestic and overseas, through the experiment, continuously strengthen the related technology research, sum up experience, a set of systematic and comprehensive of surface active agent, receive and ternary system performance evaluation standard can be presented. Promote the surface active agent of Daqing oil field development and the technical development of asp flooding, and provide reference basis of ASP flooding for further researches.

CONCLUSION

- According to the test results of produced fluid, its output rule is: Found polymer firstly, alkali lately. After the production well has effect, Ion of produced liquid has obvious changed, phenomena of oil well scaling and polish rod corrosion appeared.
- Though water cut decline of the experiment block is lagging, the time of water content remaining less than 89% is more. At present, integrated water cut remains stable.
- Analysis of that the produced fluid appear emulsification phenomenon, but the time is short, only 3 months, no further aggravate the degree of emulsification and mainly for the: The produced fluid viscosity small increase compared with water flooding; produced liquid demulsification difficulty did not increase.

Physical simulation flooding experiment results show recovery values in 19 ~ 22% between the emulsifying raise appear core outlet end effluent and does not appear recovery value in 14 ~ 16% between the emulsion to improve, they have difference of 5 ~ 6 percentage points. The test produced fluid emulsification degree is smaller, test results will affect.

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