ISSN: 2710-0588 DOI: 10.29556/FSE.202107_1(4).0010

The Reverse Wetting Agent Adaptability Analysis and Technology Design of the Tight Sandstone Gas Reservoir

Rui Chen[1], Shuangfeng Kou[1], Bin Li[1], Jinpeng Liu[1], Xing Liu[2,*]

[1]CNPC Chuanqing Drilling Engineering Company Limited, Downhole Operation Company, Sichuan, 610051, China;

[2]Southwest Petroleum University, Sichuan, 610500, China.

*Corresponding Author

Abstract

Under the influence of tight reservoir lithology and reservoir physical properties, the wettability is strong hydrophilic, the bound water has high saturation and the gaseous phase permeability declines sharply as the water saturation increases, which seriously affects the output of tight gas reservoir. Therefore, improving the core surface wettability with reverse wetting agent to adjust the relative permeability curve is helpful to improve the single well output and the ultimate recovery factor. However, the effect of reverse wetting agent is limited by the reservoir physical properties and formation fluid properties, it is necessary to conduct the optimization experiment for reverse wetting agent and carry out the supportive technology design to meet the construction requirements. This paper takes Sulige Block A as the research object. It selects the influence factors according to the lab experiment conclusions and determines the weight of influence factors with the method of grey correlation. In addition, it selects the reverse wetting agent which matches Block A and conducts micro fracturing technology design, thus generating a set of adaptability and technology program of wettability reversal which is suitable for this block.

Keywords

Tight Sandstone Gas Reservoir; Fracturing Technology; Reverse Wetting Agent; Wettability; Relative Permeability Curve.

1. Introduction

The favorable exploration area of tight gas on land of China is $32.46\times10^4 km^2$, and the resource quantity is $21.85\times10^{12} m^3$ [1-2]. The tight gas is mainly distributed in Erdos, Bohai Bay, Sichuan and other basins. The quantity of tight sandstone gas resource in Erdos Basin exceeds $12\times10^{12} m^3$ which accounts for about 83% of the total quantity of natural gas resources in Erdos Basin and is mainly distributed in Sulige region. [1]

Compared with the gaseous phase of conventional oil, the tight gas is closer to the source rock, the oil gas is concentrated on a large scale continuously with no obvious trap boundary, and it is less influenced by the stratigraphic structure. The reservoir stratum has poor physical properties, strong heterogeneity, low reserve density ratio (the oil gas reserve per rock volume) and low grade resource. It is difficult to predict the optimized and effective reservoir stratum of enrichment region. It has poor filtration capacity, low single well output, high declining rate, low recovery efficiency of oil gas field, difficult stable production and poor economic performance [1].

Currently, ZHUANG Yan [4], WU Meng [5] et al have studied the core surface influence factors of the tight sandstone gas reservoir. The research shows that the wettability is mainly affected

ISSN: 2710-0588 DOI: 10.29556/FSE.202107_1(4).0010

by the reservoir physical properties and mineral composition, and the reservoir wettability has a significant influence on the bound water saturation, gaseous phase permeability, etc. The nature of reservoir organic material, the mineralization of ground water and the valence state of positive ion are the key factors to determine the relative permeability curve of sandstone reservoir, and they have a great influence on the single well output and the ultimate recovery factor.

Therefore, lots of people tried to improve the core surface wettability with reverse wetting agent, water block removal agent, etc. JIANG Yun et al [6], WU Yang [7], WANG Jie et al [8] have established a systematic evaluation method used to improve the wettability of tight sandstone gas reservoir through injection experiment, wetting angle experiment, gas-water relative permeability experiment, etc. SHI Juntai [10] et al have studied the rules and influence factors of static imbibition of tight reservoir through static imbibition experiment. The lower the fracturing fluid concentration used in fracturing is, the imbibition effect of reservoir is better.

WANG Bin [11] et al have discovered that the gas reverse wetting agent of gas is helpful to remove the water block damage of tight sandstone reservoir and can further remove the fluid block damage of prop fracture formed after simulated fracturing with sand-filled model through the prop fracture formed after simulated fracturing with sand-filled pipe model and matrix core displacement experiment.

The above lab experiments show that the reverse wetting agent, the water block removal agent, etc can change the core surface wettability and adjust the relative permeability curve. The improvement effect of the reverse wetting agent and the water block removal agent is limited by the movable pore volume inside the reservoir. The reverse wetting agent is attached to the core surface to form a layer of hydrophobic film which can improve the wettability. Currently, LIU Xuefen [12] et al have used the interfacial wettability modified treating agent FW-134 to improve the core surface wettability.

WANG Jie [8] et al have compared the wetting angle improvement effect, core surface μ adsorption performance, etc of the nonionic surfactant, fluoride cationic surfactant, fluorocarbon surfactant and ethers surfactant with above evaluation methods. They believe that the ethers surfactant is superior to other surfactants, and it can be used as a measure of removing the water block damage in the immediate vicinity of wellbore.

For the reverse wetting agent, the researchers mainly conducted lab experiment evaluation to analyze the micro adsorption performance, the wetting angle improvement performance and imbibition performance under conditions of different concentrations and mineralization degrees. But there is less corresponding technology research. Therefore, this paper clarifies the main controlling factors of gas well productivity with grey correlation degree by analyzing the percolation characteristic of reservoir core, selects the reverse wetting agent, and completes the fracturing construction design and effect evaluation.

2. Research of core gaseous and aqueous phase relative permeability curve

When the multi-phase fluid penetrates and flows in porous medium, the relative permeability of each phase changes constantly as the fluid saturation of each phase changes, therefore, analyzing the change rules of fluid phase relative permeability in porous medium through lab experiment has an important significance for stimulation. This research has conducted gaseous and aqueous phase relative permeability experiment and discussed the distribution characteristics of two-phase fluid in porous medium and the change of relative permeability in the process of displacement of aqueous phase by gaseous phase.

ISSN: 2710-0588 DOI: 10.29556/FSE.202107_1(4).0010

2.1. Steps of gaseous and aqueous phase relative permeability curve experiment

There are two methods of stable and non stable for testing of gaseous and aqueous phase percolation experiment. Because the viscosity of gaseous phase is far less than the viscosity of aqueous phase and the viscosity difference between gaseous and aqueous phase is quite large, it is difficult to realize the stable percolation of gaseous and aqueous phase in the process of displacement of aqueous phase by gaseous phase. For this reason, this research used the non stable method in gaseous and aqueous phase percolation experiment.

The non stable method is to determine the relative permeability of rock sample according to the process of displacement of aqueous phase by gaseous phase. The detailed experiment steps are as follows:

(1) Prepare and clean the core;

(2) Test the absolute permeability: put the core with saturated water into the holder, apply the confining pressure, heat the core to the formation temperature, and use water to test the absolute permeability K of the core with 100% saturated water;

(3) Saturated gas and prepare the bound water: conduct the test of displacement of aqueous phase by gaseous phase at constant speed to obtain the relative permeability curve of aqueous and gaseous phase in the displacement process. Inject gas of volume which is 10 times of the pore volume, the destination is just the bound water saturation, and test the gaseous phase permeability of the bound water;

(4) According to the absolute permeability, aqueous phase permeability and the effective permeability of oil under condition of bound water, select suitable displacement differential pressure. The initial differential pressure shall not only overcome the end effect but also not generate turbulent flow. The initial displacement output speed is in the range of 7 mL/min~30 mL/min.

(5) Under the state of irreducible water by displacement, test the effective permeability of gaseous phase and then finish the experiment.

2.2. Analysis of experimental data

This paper has tested 40 groups of relative permeability curves based on the non stable method in *GB/T 28912-2012 Test Method for Two-phase Relative Permeability in Rock*, and conducted classified research for the relative permeability curve characteristics of three classes of pores distribution according to the porosity degree. Class II and Class III account for an obvious high proportion.

Table 1. Classification of relative permeability curve in Sulige block

Permeability range	Class of permeability	Quantity
>0.41 mD	I	9
0.19 mD -0.41 mD	II	14
0.02 mD -0.19 mD	III	17

It conducted normalization processing for three classes of relative permeability curve accordingly, and obtained the following relative permeability curves of different porosity degrees.

The co-permeation area of Class I relative permeability curve is 55.90%-68.2% which is significantly greater than the co-permeation area of Class II and III. It means the gaseous phase permeability of Class II and III in case of high water saturation is extremely low, which leads to sharp decline of single well output. The same-permeation point of Class I relative permeability curve is 0.06 and the same-permeation points of Class II and III are close to 0, which indicates that the single gas output declines very rapidly in case of high water saturation, meanwhile, in

ISSN: 2710-0588 **DOI: 10.29556/FSE.202107_1(4).0010**

the event of fluid accumulation at the bottom of well, it will increase the risk of watered gas well.

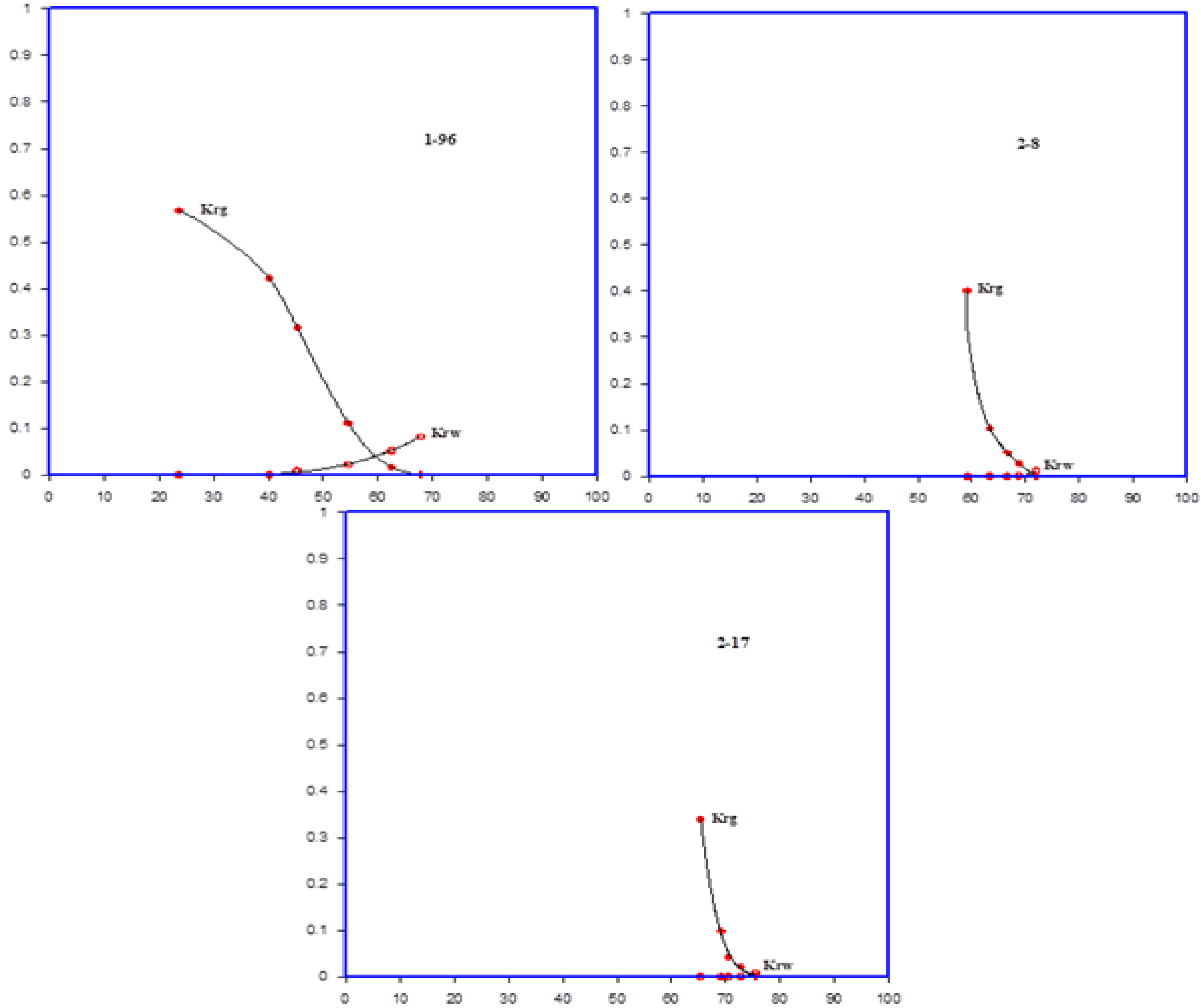

Figure 1. The normalization relative permeability curves of Class I, II and III

3. Identification of main controlling factors for productivity

3.1. Physical model of single well productivity

3.1.1. Basic assumptions

① It is two phases of gaseous and aqueous in the reservoir, and there is no interphase mass transfer between gas and water;
② The percolation is an isothermal percolation process;
③ The physical properties of gaseous phase (e.g. viscosity, compressibility factor, compressibility coefficient, etc.) change as the pressure changes;
④ The slippage effect of gaseous phase percolation is ignored;
⑤ The reservoir has stress sensibility of absolute permeability;
⑥ Consider the starting pressure gradient of gaseous phase and aqueous phase;
⑦ The well in the reservoir is a fractured straight well with a vertical fracture, and the fracture has infinite flow conductivity. Assume the gas well has no well storage phenomenon or mechanical skin.
⑧ Ignore the influence of capillary force and gravity.

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3.1.2. Mathematical model of gaseous and aqueous percolation

The two-phase percolation of gaseous and aqueous is written as

$$\overrightarrow{v_g} = -\frac{Kk_{rg}}{\mu_g}(\nabla p_g - TPG_g) \tag{1}$$

$$\overrightarrow{v_w} = -\frac{Kk_{rw}}{\mu_w}(\nabla p_w - TPG_w) \tag{2}$$

Where:

K is the absolute permeability of rock, k_{rp} is the relative permeability of p phase, TPG_p is the starting pressure gradient of p phase. In the cylindrical coordinate, the continuity equation is written as:

$$-\frac{1}{r}\frac{\partial(rJ_r)}{\partial r} - \frac{1}{r}\frac{\partial(rJ_\theta)}{\partial \theta} - \frac{\partial J_h}{\partial h} - \boldsymbol{q} = \frac{\partial C}{\partial t} \tag{3}$$

Where: J is the fluid mass velocity, and it is defined as the mass flow rate per unit cross sectional area at the flow direction. C is defined as the total mass of gaseous phase or aqueous phase in the whole gas reservoir block divided by block volume.

The mass velocity at a given direction can be written as the product of velocity and material density at this direction. The mass velocity of gas and water is as follows:

$$\overrightarrow{J_g} = -\frac{\rho_{gsc}}{B_g}\overrightarrow{V_g} \tag{4}$$

$$\overrightarrow{J_w} = -\frac{\rho_{wsc}}{B_w}\overrightarrow{V_w} \tag{5}$$

λ_p is the phase fluidity, and it is defined as the ratio of relative permeability of mobile phase and viscosity of this phase:

$$\overrightarrow{\lambda_p} = -\frac{k_{rp}}{\mu_p} \tag{6}$$

In combination with the definition of mass velocity, fluidity and density and the expression method of concentration and pressure potential, we can get the complete mathematical model of gaseous and aqueous phase percolation:

Gaseous phase:

$$\nabla\left(\frac{K\lambda_g \nabla \Phi_g}{B_g}\right) - \frac{q_g}{\rho_{gsc}} = \frac{\partial}{\partial t}\left(\frac{\emptyset S_g}{B_g}\right) \tag{7}$$

Aqueous phase:

$$\nabla\left(\frac{K\lambda_w \nabla \Phi_w}{B_w}\right) - \frac{q_w}{\rho_{wsc}} = \frac{\partial}{\partial t}\left(\frac{\emptyset S_w}{B_w}\right) \tag{8}$$

Auxiliary equation:

$$S_w + S_g = 1 \tag{9}$$

Boundary condition:

Internal boundary condition:

$$p_{wf}\Big|_{r_m} = \text{const} \tag{10}$$

External boundary condition:

$$v = \frac{dp}{dr} = 0 \tag{11}$$

Initial condition:

$$P_g(x,y,z,t) = f_1(x,y,z,t) \tag{12}$$

$$S_w(x,y,z,t) = f_2(x,y,z,t) \tag{13}$$

3.2. Analysis of productivity influence factors

In combination with the static reservoir classification of Sulige block, this paper established corresponding productivity models respectively and studied the influence of effective thickness, absolute permeability, effective porosity degree and relative permeability for productivity.

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Table 2. Static reservoir classification of Sulige block

Effective thickness (m)	Average porosity degree (%)	Average permeability (md)
≧8	>10	≥ 0.41
5~8	7~10	≥ 0.19- < 0.41
< 5	5~7	≥ 0.02- < 0.19

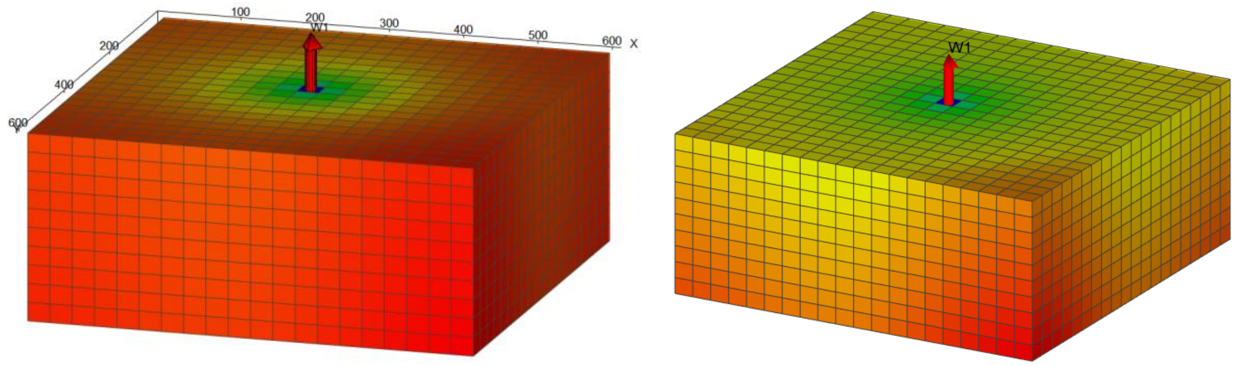

Figure 2. Pressure change after single well production for 10 years

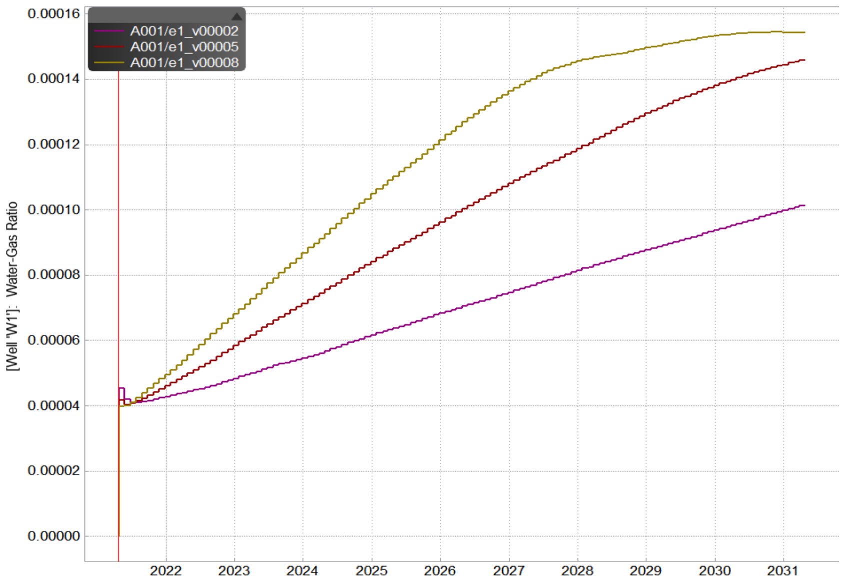

Figure 3. Change over time of permeability and water-gas ratio

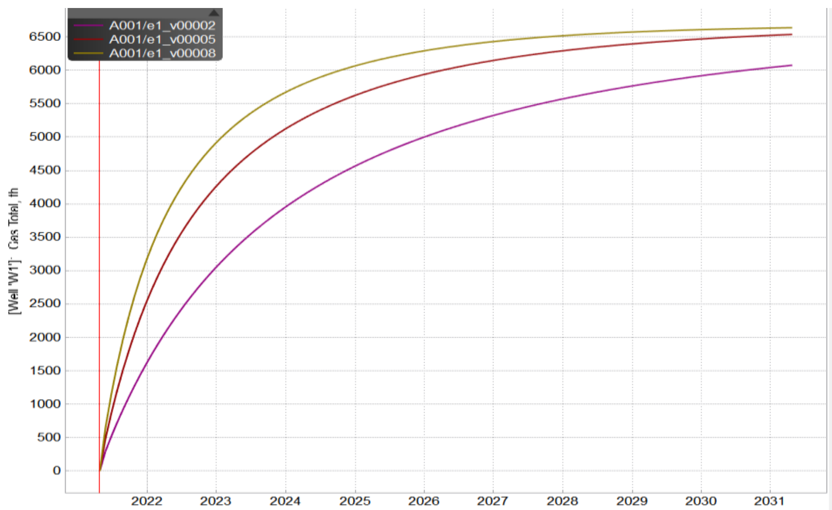

Figure 4. Change over time of permeability and cumulative gas output

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The water-gas ratio and cumulative gas output increase as the permeability increases in the early stage of production. When permeability is 0.05md, the water-gas ratio increases gradually and the cumulative gas output tends to be stable, which means the larger the permeability is, the water-gas ratio is higher and the cumulative gas output is larger.

3.3. Analysis of the main controlling factors

Grey correlation analysis is an analysis method based on the similarity degree of development trends between each factors in system to determine the correlation between each factor in system and the master variables through quantitative analysis. if the change trends of two factors are basically the same or similar to each other, then the correlation degree between the two is large, or it's small [13].

Grey correlation analysis is mainly divided into two calculation processes: (1) calculate the correlation coefficient. If the parent sequence of data change is {x0(n)} and the subsequence is {xi(n)}, then the parent sequence is the average gas output of each gas well and the subsequence is various influence parameters extracted from corresponding well point, such as buried depth of coal seam, thickness of coal seam, original reservoir pressure, proposed gas content, proposed temporary storage ratio, flowing bottom hole pressure of first gas, time of first gas, cumulative water output of first gas and formation pressure-desorption pressure difference. When n=k, the correlation coefficient ε0i(k)of {x0(k)} and {xi(k)} is calculated with the following formula:

$$\varepsilon_{0i}(k) = \frac{\Delta_{min} + \rho\Delta_{max}}{\Delta_{0i}(k)+\rho\Delta_{max}} \tag{14}$$

Where, △max and △min are respectively the maximum and minimum value among the sequence absolute differences, because the comparative sequences intersect with each other after data conversion, △min is 0 generally; p is the identification coefficient; $\triangle_{0i}(k)$is the absolute difference of two sequences at the time of h:

$$\Delta_{0i}(k) = |x_0(k) - x_i(k)| \tag{15}$$

(2) Calculate the correlation degrees. The correlation degrees of two sequences can be expressed by the average value of correlation coefficients at each time of the comparative sequences (correlation degree reflecting the process):

$$r_{0i} = \frac{1}{N}\sum_{k=1}^{N} \varepsilon_{0i}(k) \tag{16}$$

Where, r_{0i} is the correlation degree of the subsequence i and parent sequence 0; N is the length of sequence which means the number of data.

Table 3. Weight of influence factors

Class	Effective thickness	Absolute permeability	Effective porosity degree	Relative permeability
65% gas saturation of Class I	0.8319	0.6502	0.8008	0.5949
55% gas saturation of Class I	0.8341	0.6489	0.8030	0.5955
45% gas saturation of Class I	0.8316	0.6486	0.8008	0.5944
55% gas saturation of Class II	0.7290	0.6814	0.6803	0.6067
45% gas saturation of Class II	0.7282	0.6815	0.6800	0.6048
35% gas saturation of Class II	0.7240	0.6826	0.6790	0.5996
35% gas saturation of Class III	0.6990	0.6346	0.6466	0.5884
25% gas saturation of Class III	0.6813	0.6588	0.6282	0.5898
15% gas saturation of Class III	0.6489	0.6913	0.5972	0.5789

The gas saturation and effective thickness of Class I, II and III are both the main controlling factors. The normalization influence factor results show that as the production enters the later stage, the influence of relative permeability curve on cumulative gas output increases gradually,

ISSN: 2710-0588 DOI: 10.29556/FSE.202107_1(4).0010

which indicates that improvement of phase permeability is capable of effectively improving the cumulative gas output.

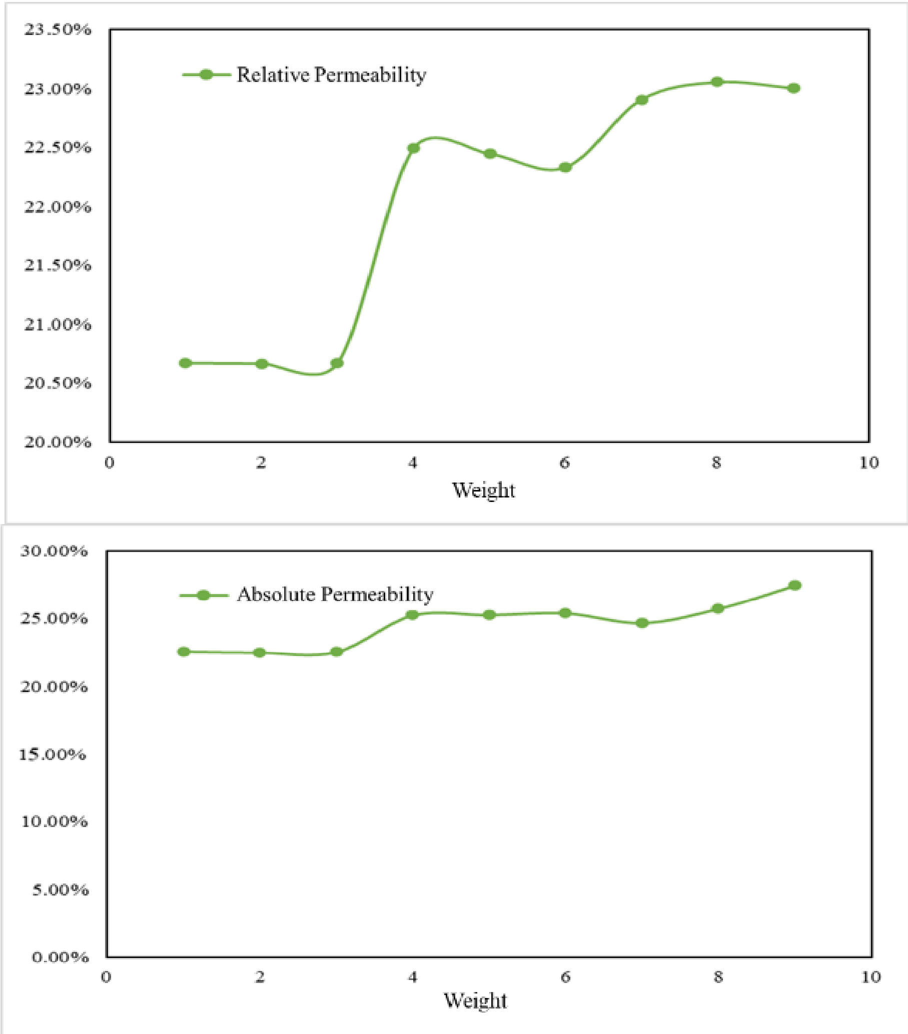


Figure 5. Weight distribution of relative permeability and absolute permeability of different reservoir classes

4. Optimization of reverse wetting agent

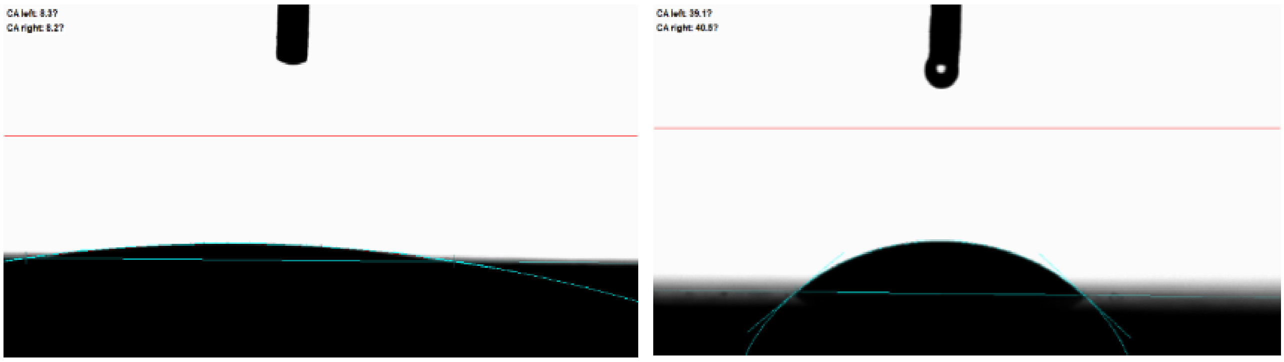
In combination with the Ping'aji program of reverse wetting agent system of WANG Jie et al, this paper preferred the reverse wetting agents of different concentrations and types with the methods of wetting angle, compatibility and residual resistance factor.

4.1. Wetting angle

Table 4. Effect of reverse wetting agents of different concentrations

Core No.	Reverse wetting agent	Concentration (%)	Contact angle (°)	
			Before improvement	After improvement
1	Agent A	0.1	7.37	16.4
2		0.2	8.45	40.5
3		0.5	8.55	38.2
4	Agent B	0.1	6.46	7.13
5		0.2	8.13	9.12
6		0.5	4.12	5.45

ISSN: 2710-0588 DOI: 10.29556/FSE.202107_1(4).0010



(a) Before improvement (b) After improvement

Figure 6. The core surface wetting angle before and after improvement with 0.2% reverse wetting agent A

Table 4 and Figure 6 show that the core wetting angle before treatment is 4.12°-8.55°which is strong hydrophilic. The reverse wetting agent B of different concentrations cannot effectively adjust the core surface wetting angle, while the 0.2% and 0.5% reverse wetting agent A can both effectively adjust the core surface wetting angle. In consideration of economy, this paper plans to use 0.2% reverse wetting agent A.

4.2. Compatibility

Compatibility experiment is conduced for the selected 0.2% reverse wetting agent A with formation water and fracturing fluid.

(a) Compatibility of formation water (b) Compatibility of fracturing fluid

Figure 7. Compatibility of 0.2% reverse wetting agent A with formation water and fracturing fluid

Figure 7 shows that there is no obvious sediment in the compatibility experiments of 0.2% reverse wetting agent A with formation water and fracturing fluid with concentration ratio of 1:1, 1:2 and 2:1, which indicates that 0.2% reverse wetting agent A can satisfy the requirements of compatibility.

4.3. Judgment of residual resistance factor

Before the displacement experiment, the core was dried in 65℃ dryer for 24 hours or until the weight stability is achieved. Then the porosity degree and permeability of the core were tested, and the aqueous phase permeability and gaseous phase permeability of different water saturations were obtained at multiple displacement speeds with the simulated formation water. It displaced 10 times of the pore volume with 0.2% reverse wetting agent A, and the aqueous phase permeability and gaseous phase permeability of different water saturations at multiple displacement speeds were tested again.

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Table 5. Parameters of the core

Length (mm)	Diameter (mm)	Porosity degree (%)	Permeability(mD)
67.66	25.21	9.49	0.095

According to the calculation method of residual resistance factor in Al-shajalee [16], that is the ratio of phase permeability before and after treatment under a certain water saturation. If $\frac{Frr_w}{Frr_g} \geq 1$, it proves that the reverse wetting agent is effective.

$$Frr_w = \frac{K_{wbefore}{}_{(sw)}}{K_{wafter}{}_{(sw)}} \tag{17}$$

$$Frr_g = \frac{K_{gbefore}{}_{(sg)}}{K_{gafter}{}_{(sg)}} \tag{18}$$

Table 6. The residual resistance factors before and after being improved by reverse wetting agent

Water saturation (%)	Gaseous phase residual resistance factor		Aqueous phase residual resistance factor	
	Before improvement	After improvement	Before improvement	After improvement
60	4.3	4.12	13.23	10.24
70	5.5	2.34	11.48	4.27
80	6.2	1.04	9.45	2.45

Figure 6 shows that the reverse wetting agent A is able to effectively improve the relative permeability curve at different saturations, $\frac{Frr_w}{Frr_g} \geq 1$, so the application of the reverse wetting agent A in reservoir producing both gas and water will effectively improve the gas output and reduce the water-gas ratio.

5. Hydraulic fracturing technology design

In combination with well logs and sedimentary facies distribution, this paper conducted fracturing design with FrachPT and reached Figure 8 and Table 7. It determined the fracture length of 130-160m and fracturing construction technology parameters including flow rate of 0.5m^3/min-0.8 m^3/min and net fluid amount of 225.6 m^3. Based on the aforementioned single well productivity model, it analyzed with 0.2% reverse wetting agent A. The ultimate cumulative gas output after 10 years increased by 24.7% from 6153×10^{4}m^3 to 7673×10^{4}m^3.

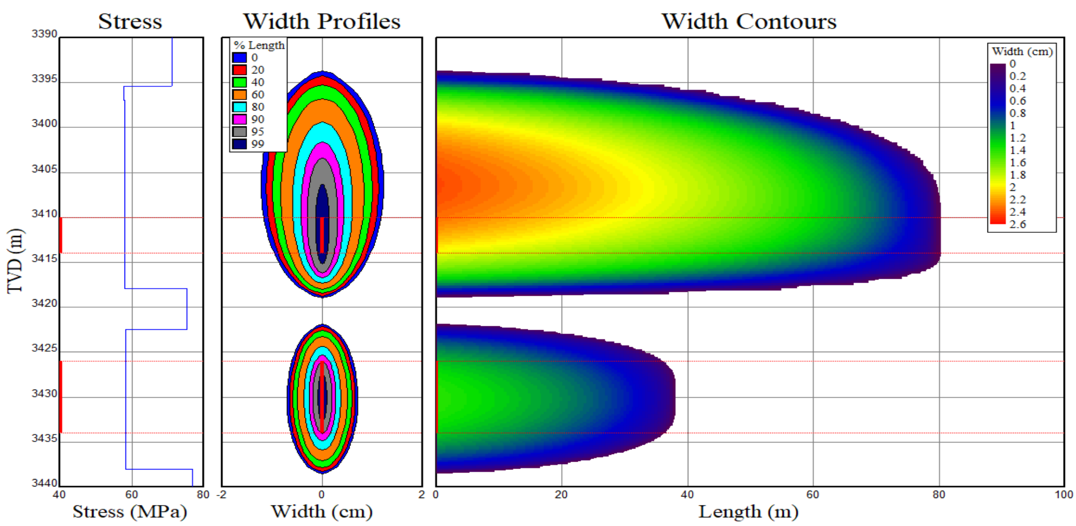

Figure 8. Fracturing design

ISSN: 2710-0588 DOI: 10.29556/FSE.202107_1(4).0010

Table 7. Fracture design parameters of stimulated formation

Well No.	Position	Number of sections	Length of prop fracture	Reservoir thickness	Porosity degree
Well A	Box 8	3426~3434m	160	8	7.2
	Box 8	3410~3414m	130	4	10.6

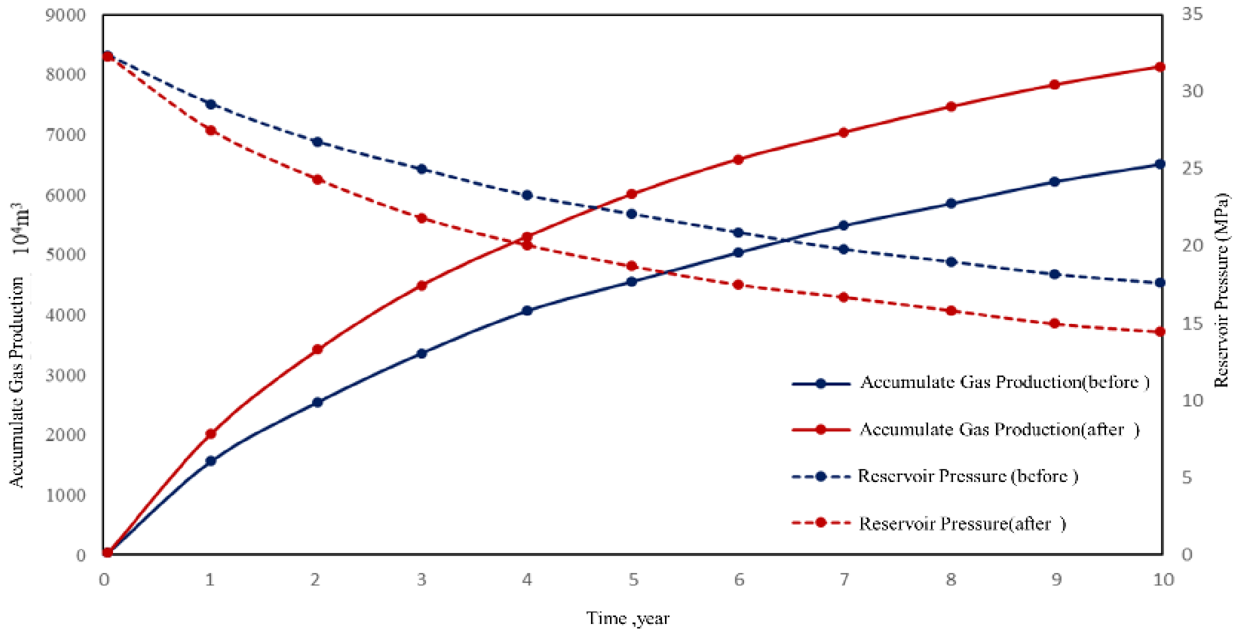

Figure 9. The cumulative gas output comparison before and after treatment

6. Conclusion

(1) In combination with the static reservoir classification of Sulige block, as the physical properties of reservoir become worse, the co-permeation area and same-permeation point of relative permeability curve both decrease, and the gaseous phase permeability in the relative permeability curve of Class II and III declines sharply as the water saturation increases.

(2) This paper studied the influence of reservoir physical properties and gaseous and aqueous phase relative permeability curve for productivity with the productivity numerical model and determined the main controlling factors of single well productivity with the method of grey correlation. The gaseous and aqueous phase relative permeability curve is helpful to improve the cumulative gas output and ultimate recovery factor.

(3) Through the experiments of wetting angle, compatibility, residual resistance factor, etc, this paper selected the agent A with concentration of 0.2% which can be used to improve the single well productivity.

(4) Through the micro fracturing technology design, this paper determined the displacement and net amount of fluid when using the reverse wetting agent. Through the research of productivity simulation, the ultimate gas output increased by 24.7%.

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