Research on Waterless Fracturing technology in Tight Gas Formation in China

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Abstract

As typical tight sandstone gas reservoir with “low porosity, low permeability, and low production”, the tight gas reservoirs in the Ordos Basin of China have 68% of cores with pressure permeability of less than 0.03mD, and pressure coefficient of 0.85-0.95, 30-50%lower than domestic and foreign typical tight gas reservoirs. The reservoirs have fairly strong heterogeneity, higher mud content and fine pore throats, so wells have generally low production after fracturing, which seriously jeopardizes the economic benefit of this area. Based on the analysis of difficulties in reservoir stimulation of this block, new design idea of fracturing scheme has been put forward, and tested in tight gas reservoirs of this block, achieving remarkable production increase effect.

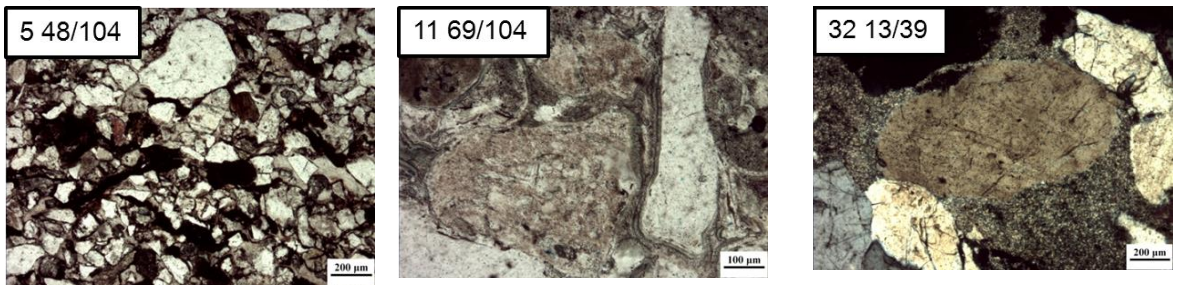
Keywords

Fracturing technology in Tight Gas.

1. Reservoir characteristics and difficulties

1.1 Lithological characteristics

The reservoir rocks in the study area are dominated by medium-fine sandstone, with a small amount of coarse sandstone, of medium-poor sorting, and angular-sub rounded roundness; with quartz being the dominant component, the reservoirs have high content of rock debris, including flint, phyllite, and quartzite debris, and low content of feldspar; the fine sandstone often contains richer biotite fragments, showing strong alteration (Fig.1).



a. Medium sorting of grain, and strong compaction

b. Chlorite coating around grains

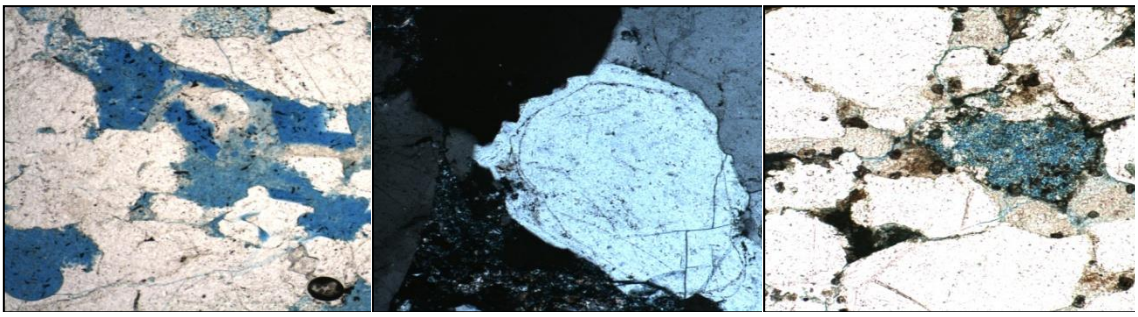
c. Strongly deformed plastic rock debris filling pores

Fig.1 Microscopic characteristics of reservoir rock

From the quantitative analysis of whole rock, it can be seen that the reservoir rock has higher clay content, higher percentage of montmorillonite and mixed clay with expansion effect, and a certain amount of kaolinite with migration effect.

1.2 Pore types

The reservoirs mainly contain intergranular dissolved pore, intragranular dissolved pore and kaolinite intercrystal pore, of which the intergranular dissolved pore accounts for 88%, the kaolinite intercrystal pore 10%, and intragranular dissolved pore 2%. Clearly, intergranular dissolved pore is the primary pore type (Fig. 2).



a. Intergranular dissolved pore

b. Intragranular dissolved pore, secondary growth of quartz

c. Kaolinite intercrystal pore

Fig.2 Microscopic features of major pore types shown by thin sections

1.3 Pore structure

In terms of pore-throat structure, reservoirs different in permeability are obviously different in pore-throat structure too, and this difference consequently results in different seepage capacity of water and gas and production mechanism of reservoirs. According to the different levels of permeability, the reservoir pore-throat structures have been divided into five types (Table 1). Class I pore-throat structure has a permeability of more than 10mD, displacement pressure of 1.68MPa, median radius of pore throat of 1.68um, and ultra-capillary pore accounting for nearly 50%. Class II pore-throat structure has a permeability of 1-10mD, displacement pressure of 0.3MPa, median radius of 0.39um, and capillary pore-throat in majority (accounting for 41.5%). Class III pore-throat structure dominated by micro-capillary pore throat, has a permeability of 0.1-1mD, displacement pressure of 0.88MPa, and median radius of 0.06um. Dominated by micro-capillary and a no-pore-throat, Class IV pore-throat structure has a permeability of less than 0.1mD, high displacement pressure and small median radius.

Table 1 Pore-throat types and relevant parameters

Class	Permeability Range mD	(mercury porosimetry curve, n=42) Pore-throat type and ratio							Evaluation result
		Core proportion %	Supercapillary pore (>1um)	Capillary pore-throat (1-0.1um)	Micro-capillary pore-throat (0.1-0.01um)	Nano-pore-throat (<0.01um)	Displacement pressure MPa	Medium radiusum	
I	>10	10	49.1	25.7	17.2	7.9	0.14	1.68	Good
II	1-10	10	19.3	41.5	26.2	12.9	0.3	0.39	Medium
III	0.1-1	50	3.6	31.5	44.2	20.7	0.88	0.06	Poor
IV	0.01-0.1	17.5	4.4	17.2	34.4	44	1.43	0.016	
IV	<0.01	12.5	4.2	14.5	45.8	35.5	2.83	0.017	worse

1.4 Distribution of reservoir physical properties

According to the analysis of physical properties of cores, it is found in the study area that samples with conventional permeability of less than 0.1mD account for about 80%, and in terms of the distribution of pressure permeability, the samples with permeability of less than 0.1mD are87.2%, indicating the reservoirs are typical tight reservoir.

1.5 Distribution of reservoir physical properties

In conclusion, the sandstone reservoirs in Block Dong2 of the Sulige gas field are tight and high in clay content, moreover, the clay particles in intergranular pores and around pore-throats are highly likely to swell and migrate, plugging pore-throats and causing damage to the reservoir. Meanwhile, with fairly poor physical properties, low pressure coefficient, small pore-throat radius, and higher displacement pressure, the reservoir is more susceptible to the damage of fracturing fluid.

2. Damage from reservoir stimulation

Reservoir damages caused by fracturing mainly include the damage of matrix permeability by filtrate fluid and the damage of fracturing fluid residues and filter cake to the flow capacity of hydraulic fracture. The main factors affecting the two kinds of damages are the properties of fracturing fluid system and choice of fracturing mode.

Since the reservoirs in Sulige Gasfield are tight and contain clay minerals, the main damages caused by filtrating of fracturing fluid into the reservoir matrix include: (1)swell of clay, the most common expansive clay minerals are montmorillonite and montmorillonite mixture, the montmorillonites wells up to 6 times of its original volume by absorbing water, severely reducing reservoir permeability; (2) water locking, due to the capillary force, the formation pressure can't drive external fluid out completely, resulting in increase of water saturation and sharp drop of gas phase permeability of reservoir, this is especially serious in low ultra-low permeability gas reservoir. In general, the two kinds of damages work together to impair gas production, so to find out their effects on production, first, the effect of filtrate on reservoir permeability was examined, the distance of filtration into the reservoir matrix during the whole fracturing process was calculated, that is the immersion zone distance of fracturing fluid.

There are many ways to test the core damage (reference), for Block Dong2 in the Sulige Gasfield, it takes more than 100 hours averagely from the start of fracturing to the end of flowback. The damage of filtrate fluid on core was tested by using cores with different permeabilities and a kind of clean fracturing fluid, the test method: (1) drying the core, the gas phase permeability was measured; (2) the gel breaker of fracturing fluid was injected into the core (at the confining pressure of 5MPa, and displacement pressure of 10 MPa); (3) the cores with gel breaker injected were respectively set aside for 24 hours, 48 hours, and 72 hours, after drying, their gas phase permeability was measured. This method was employed to test the damage of fracturing fluid to the reservoir, and the results are shown in Table2.

Table 2 Results of damage rate to core permeability at different soaking time

Original permeability, md	2.13	1.56	0.82	0.75	0.52	Immersion time (t)
	20.4	26.3	31.4	38.9	42.5	24
Permeability damage ratio, %	25.3	29.8	35.2	40.1	46.5	48
	38.1	45.7	49.3	55.8	59.1	72

The experimental results show that with the increase of infiltration time of the gel breaker, the matrix permeability decreases obviously, the lower the original permeability of the matrix, the more obvious the damage. As no-residue cleaning fracturing fluid was used in this experiment, conventional fracturing fluid damage rate should be higher. To lower the damage to matrix during fracturing, the amount of filtrate into formation must be reduced, that means the invasion time of filtrate into matrix must be shortened, therefore, for the low pressure tight gas reservoirs in eastern Sulige Gasfield, fracturing fluid should be quickly flowed back after the closure of fractures, which can be achieved by increasing liquid nitrogen amount and using coiled tubing gas lift. In the actual fracturing before, natural flow was tried in some of the wells after fracturing, significantly extending the flowback time,

some wells with Class II, III physical properties had an average flowback time of more than 150 hours, although saving some cost, this kind of fracturing mode had strongly negative effect on post-fracture gas yield, not conducive to improving economic benefit.

3. Carbon dioxide foam fracturing

3.1 Rheological properties of CO2 foam fracturing fluid

CO2 foam fracturing fluid is a mixture composed of liquid CO2 and fracturing fluid, in the process of down hole injection, when the temperature rises to the critical temperature of 31°C,the liquid CO2 begins to gasify, forming a gas and liquid two-phase dispersion system [3]with CO2 as the internal phase and the water-based fracturing fluid containing polymer as the external phase. Due to the occurrence of two-phase foam system, the viscosity of the fluid significantly increases. Meanwhile, foaming agent and macromolecule polymer greatly enhance the stability of the foam fluid. Increasing the stability of the foam is an effective way to improve the rheological properties of the foam.

For the Upper Paleozoic low foam mass fraction fracturing fluid system in the Changqing Oilfield,

Measures to improve foam stability are as follows:

(1) Using appropriate foaming agent to reduce the liquid surface tension, which is conducive to the formation of foam, increasing the strength and elasticity of the liquid film.

(2) Making use of the synergistic effect of a variety of surfactants and adding foam stabilizer.

(3) Increasing the viscosity of the fluid and using cross-linking technology to form a jelly surface, increasing the viscoelastic properties of liquid film.

The CO2 fracturing fluid formula: 0.45% thickener + 0.5% FL-100 + 0.5% acid-resistant foaming agent.

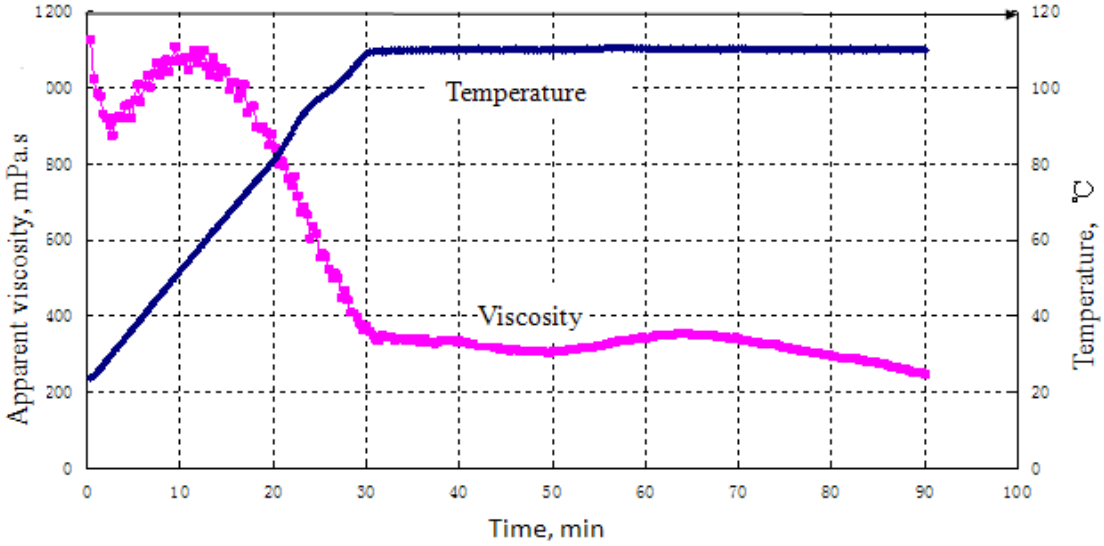


Fig. 3 Viscosity vs. temperature of carbon dioxide fracturing fluid (50% carbon dioxide foam, in weight)

3.2 Reservoir parameters and fracturing scale

The specific physical properties of tight gas reservoir in a well in the Sulige gas field are shown in Table 3

Table 3 Physical properties of a well in Sulige Gasfield

Formation	Interpreted layer No.	Parameters of interpreted gas layers from well logging				
		Mud content (%)	Permeability ($10^{-3}\mu m^2$)	Total porosity (%)	Effective porosity (%)	Gas saturation(%)
He 8	20	6	1.19	8.6	6.8	58.8
	19	13.4	0.543	8.9	4.6	34.5

Table 4 Designed dosage of fracturing fluid

Liquid type	Liquid CO_2	Acid clean fracturing fluid	Total
Pad volume (m^3)	100	110	210
Sand carrying fluid volume (m^3)	90	110	200
Displacement fluid volume (m^3)		18	18
Total	190	238	428

The Upper Paleozoic gas reservoir in Changqing Oilfield is 3500 - 3600m deep, and the main gas reservoirs are the Shihezi Formation and the Shanxi Formation. The fracturing interval in this well was the eighth member of Shihezi Formation. With a porosity of 8.7% and a permeability of (0.543 - 1.19) × 10-3μm2, a formation pressure coefficient of 0.88MPa/100m, and a gas reservoir temperature of 118 °C, the reservoir represents low porosity, low permeability and low pressure gas reservoir. The fracturing had a sand dosage of 49.8m3, sand ratio of26.1% in general and 29.2% at maximum, and was done at the injection rate of 4.5m3/min, and foam volume fraction of up to 0.527. After fracturing, the tested production was5.8 × 103m3/d, compared with conventional fracturing wells, the output increased by over 50%, achieving good effect of yield increasing.

4. Conclusion

(1) The Sulige gas reservoir is tight and contains fine pore-throat, high content of clay, so conventional fracturing works poorly in increasing its production, restricting the economic development of this block.

(2) Carbon dioxide foam fracturing fluid can reduce filtration of fracturing fluid, significantly reducing the amount of fluid filtrating into the reservoir, and thus lowering the damage to the reservoir.

(3) Carbon dioxide speeds up the flowback, reducing the treatment time and lowering operating costs.

(4) The field application results in the Sulige Gasfield show that carbon dioxide foam fracturing can effectively improve the production of tight gas reservoir after fracturing, and thus has fairly high economic benefit.

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