The successful application of a new high temperature resistant movable gel system in HBU fault block

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Abstract. The HBU fault block is a sandstone reservoir with the temperature as high as 118°C, multiple longitudinal layers, severe heterogeneity, and the development of interflowing channels. After years of development, the reservoir has a high recovery rate (33.6%) and a high comprehensive water cut (93.6%). In order to improve the effect of water flooding development block, on the basis of geological research, we developed a new type of high temperature resistant movable gel displacement system, optimizing injection technology at the same time. In July 2018, deep adjustments and flooding were carried out on five oil well groups, and by May 2020, 16 Wells had increased oil by 13,000t. It was predicted that the production decline would reverse to -2.1%, which was a technical and economic success.

1. HBU fault blocks overview
HBU fault block is a complex sandstone reservoir with multilayer system and high temperature in North China. It is a flattened nasal structural reservoir. The main oil-bearing layer of the fault block is on Ed3 ~ Es1, which is subdivided into 46 layers in 5 oil groups and 23 layers in 4 oil groups. The main pay zones are Ed3-IV, Ed3-V and Es1s-III. Longitudinally, the oil layers are thick and dispersed. The distribution of the oil layers on the plane is controlled by both tectonic and sedimentary factors, and the heterogeneity between the plane and the layer is strong, as Figure 1 shows. The HBU fault block was fully put into water injection development in November 1995, with water cut rising rapidly and production decreasing rapidly. In 2006, the oilfield development entered the stage of high water cut and high production. With the long-term erosion of a large amount of injected water in the formation and the formation of water channeling large pores, the stable production situation of the oilfield is severe.

Figure 1 Water injection profile of Wells U46 and U27 in 2017
2. Study on distribution of remaining oil

In recent years, the development effect of HBU fault block has been improved after injection and production pattern adjustment and single well group displacement adjustment test. However, at present, the fault block as a whole is in the stage of high-water-cut development, the distribution of remaining oil is more scattered and complex, and the routine adjustment is more and more difficult.

The production dynamics of fault blocks were comprehensively analyzed, and the reservoir engineering formula (1) was used to calculate the geological reserves of each oil group. The results were shown in Table 1. Data show that on the vertical, the remaining reserves are mainly concentrated in Ed3-IV, the Ed3-V, Es1s-Ⅱ, a total of three main groups. Although the recovery degree of the main oil group is relatively high (21.8%~33.0%), the original geological reserves of the oil group are high (46.0~70.0) ×10^4 t, and the proportion of the remaining reserves is still as high as 77.8%, which is the main distribution area of the remaining oil of the fault block and the target layer of diversion-flooding.

\[ N=100 \times A \times h \times \Phi \times S_o \times \rho / B_{oi} \] (1)

Table 1 Cleavage production table of each oil group of HBU fault block

| Oil group | Geological reserves ($10^4$ t) | The cumulative oil production ($10^4$ t) | Recovery degree (%) | Remaining reserves ($10^4$ t) |
|-----------|-------------------------------|------------------------------------------|---------------------|-------------------------------|
| Ed3-III   | 11.1                          | 1.5                                      | 13.5                | 9.6                           |
| Ed3-IV    | 68.9                          | 15.0                                     | 21.8                | 53.9                          |
| Ed3-V     | 70.0                          | 20.1                                     | 28.7                | 49.9                          |
| Es1s-Ⅱ   | 46.0                          | 15.2                                     | 33.0                | 30.8                          |
| Es1s-Ⅲ   | 20.1                          | 12.2                                     | 60.7                | 7.9                           |

To further subdivide the geological reserves of each well group in the fault block, combined with the data of water injection profiles, production dynamic response and tracer monitoring, the dominant channel of water flow in the main layer is studied. Using the method of comprehensive identification and description of the superior channel, the superior channel of water flow in the waterflooding well group is judged and classified\(^{[1-3]}\). Taking the U46 well group as an example, the accumulative water absorption capacity of the main suction layer of the well group was calculated to reach 250,000 cubic meters. Tracer monitoring results showed that the slowest plane water flooding speed between Wells was only 0.93 m/d, and the fastest plane water flooding speed reached 7.01 m/d. Based on the normalized values of data such as physical difference, liquid yield strength and water cut of the well group, it was concluded that there was a dominant channel of strong and high seepage flow between Wells U46, U26 and U75, and a second dominant channel of high seepage flow between Wells U36, U56 and U66, while no water flow channel developed between Wells U16.

The purpose of diversion-flooding is to block the dominant channel of water flow to enhance the capacity of non-dominant channel. Therefore, it is necessary to design the injection volume by determining the physical parameters of the dominant channel. Using numerical simulation technology, taking the U46 well group as an example, 98% water-phase fractional flow was set, corresponding to 0.77 water saturation. Through calculation and analysis, it was found that the water saturation of the dominant channel with water flow in reservoir pore development should be greater than 0.77. The pore volume calculation of the dominant channel with water flooding is shown in Table 2\(^{[4]}\).

Table 2 Statistical table of pore volume of water flow dominant channel of well groups U46

| Layer no. | Mean porosity (%) | Mean water saturation (%) | Mean effective thickness (m) | Model mesh number | Water flooding dominant channel pore volume ($m^3$) |
|-----------|-------------------|--------------------------|----------------------------|------------------|------------------------------------------|

2
3. Research and development of new high-temperature crosslinking system

The formation water salinity of HBU fault block is 12000 mg/L. Through laboratory tests, clean water (with a salinity of 800 mg/L) and backwater injection (with a salinity of 9,000 ~ 25,000 mg/L) were used to prepare polymer solution and movable gel respectively at the same concentration of solution. By comparing the viscosity of polymer solution and gel when clean water and backwater injection were mixed, as shown in Table 3, the viscosity of polymer solution prepared by backwater injection was 48% ~ 98% lower than that of clear water, and the viscosity of gel was 30% ~ 65% lower than that of clear water. It can be seen that backwater injection has a great influence on the viscosity of the polymer and its gelation. Different water quality of backwater injection has different influence degree. The higher salinity of backwater injection is, the more viscosity of polymer and gel decreases.

### Table 3 Effect of water preparation on polymer viscosity and gel viscosity

|        | With liquid water | Polymer solution viscosity (mPa·s) | Gel viscosity (mPa·s) |
|--------|-------------------|-----------------------------------|----------------------|
|        |                   | HPAM 0.1% HPAM 0.15% HPAM 0.2% HPAM 0.25% HPAM 0.3% |                      |
| Clear water (800 mg/L) | 95 162 225 280 345 |                      | 1930                  |
| Reinjection water 1 (10,011 mg/L) | 29 48 70 108 141 |                      | 1321                  |
| Reinjection water 2 (24,119 mg/L) | 12 14 20 30 46 |                      | 1109                  |
| Reinjection water 3 (19,648 mg/L) | 15 23 38 58 90 |                      | 704                   |

The traditional movable gel system is obviously affected by temperature and salinity of water quality. The phenolic resin crosslinking system is suitable for reservoir profile control and flooding above 70 °C. Phenolic resin was cross-linked with amide group of polymer molecule to form uniform and elastic gel with network structure. However, when the reservoir temperature is higher than 90 °C, the amide group is completely hydrolyzed into sodium carboxyl group, and the cross-linking bond is gradually dissociated, and the gel is broken and dehydrated. The higher the temperature is, the higher the degree of hydrolysis is. According to previous experiments, the stability of the movable gel of HBU fault block with formation temperature as high as 118 °C is less than 15 days when a single cross-linking agent is used and the concentration of polyacrylamide is 2,000 mg/L or below, and the application effect is poor.

In order to improve the temperature stability of movable gel, the traditional work focuses on polymer research. Our review of relevant literature, reference to optimize the molecular structure to improve the stability of the gel. We use the clear water liquor, independent research and development of a new type of high temperature resistant composite crosslinking agent, play I type and II type 2 kind of synergistic effect of crosslinking system, and polyacrylamide composite crosslinking, achieve the goal of significantly increasing gel strength and stability. The viscosity retention rate of the gel reached 63% ~ 78% at 90 d, while that of the traditional high-temperature cross-linking agent at this temperature was only 14% at 90 d. The experimental results are shown in Table 4. Therefore, the high-temperature composite crosslinking agent developed can improve the viscosity retention rate of the gel up to 60%, and soak the gel in the formation water for 90 days to conduct stability investigation, so that the viscosity of the gel does not change and its appearance is not damaged.
Table 4 The thermal stability of gels was investigated by using traditional and new crosslinking agents

| Inspection time | Traditional crosslinking agent | Formulation 1 | Formulation 2 | Formulation 3 | Formulation 4 |
|-----------------|--------------------------------|---------------|---------------|---------------|---------------|
| 2d              | 1220                           | 2132          | 1889          | 1710          | 880           |
| 15d             | 905                            | 2205          | 2023          | 1694          | 566           |
| 30d             | 622                            | 1902          | 1652          | 1301          | 352           |
| 60d             | 315                            | 1655          | 1403          | 1025          | 155           |
| 90d             | 169                            | 1635          | 1201          | 945.00        | 68            |

Through composite crosslinking agent formula optimization experiment, at 120 °C, polymer concentration of 1,600 mg/L, new crosslinking agent concentration under the condition of 2, 100 mg/L, determine I type and II crosslinking agent optimal mix proportion of 1:1 ~ 1:2. Through the formula optimization experiment, the new compound cross-linking system is adopted, the concentration of polyacrylamide is recommended to be 1,500 ~ 2,000 mg/L, and the concentration of compound cross-linking agent is 1,250 ~ 2,000 mg/L.

4. Injection parameter optimization
The development of fault block is analyzed, and 5 well groups are selected to implement profile control and flooding overall synchronization, classification and grading\(^{[10]}\). In order to ensure the sealing strength, the concentration optimization design of gel formula mainly considers the remaining oil distribution of each well group, the level of water flowing dominant channel, and the pore volume of water driving dominant channel, as shown in Table 5.

Table 5 Optimize gel formulation design

| Water flooding (m/d) | Water flooding dominant channel pore volume (m\(^3\)) | HPAM (mg/L) | Gel viscosity (mPa•s) |
|----------------------|--------------------------------------------------------|-------------|----------------------|
| x < 1                | y < 9000                                               | 1200        | 1400                 |
| 1 ≤ x ≤ 3            | 9000 ≤ y < 15000                                       | 1600        | 1800                 |
| x ≥ 3                | y ≥ 15000                                              | 2000        | 2400                 |

The relationship between the injection amount and the injection amount of the formula was calculated by numerical simulation technology. PV number was the proportion of the volume injected by the flooding agent to the pore volume of the water flooding dominant channel, and the oil increase amount of the formula was the ratio of the total oil increase amount of the well group to the injection amount of the flooding agent. The calculation results are as follows: when the injection volume of the flooding agent reaches 0.3 times the pore volume, the best input-output ratio can be achieved. Therefore, the five well groups of HBU fault block were designed to inject a total of 45,000 m\(^3\) profile control agent.

5. Technical results
At the peak of effect, daily oil production increased from 35.1 t to 67.8 t, daily oil production increased to 32 t, and comprehensive water content decreased from 90.2% to 80.2%, decreasing by 10%. By May 2020, the accumulative oil increase has reached 13,000t, which is still effective at present. According to the forecast of current production trend, the oil increase of 20,000 t can be accumulated during the project validity period. The decline rate slowed from 10.2% in 2017 to 2.5% in 2018, reversed to -2.2% in 2019, and is projected to be -2.1% in 2020, as Figure 2 shows. The overall development situation of oilfield has been improved.

Based on the annual actual oil price, by May 2020, the project will have achieved a cumulative
economic benefit of 4,163.04 KUSD, with an input-output ratio of 1:8. Assuming the low oil price of 30 USD/B, the economic benefit of the project can still be 450.8 KUSD with an input-output ratio of 1:4. Therefore, the project has a good economic profitability.

Figure 2 Annual production decline rate curve of HBU yield

6. Lessons Learned and Conclusions
The successful independent research and development of high temperature resistant composite crosslinking system adapted to HBU fault block is the basis for the overall profile control and flooding to achieve significant results. The mutual verification of reservoir engineering method and numerical simulation method and the quantitative description of the spatial distribution of remaining oil are the foundation of the success of the project. The successful independent research and development of high temperature resistant composite crosslinking system, adapted to HBU fault block, is the basis for the overall profile control and flooding to achieve significant results. The perfect combination of engineering technology and geological research and the design and implementation of "differentiated" and "characteristic" schemes are the premise of achieving significant economic benefits.

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