Study of fluid system for pressure reduction and injection of long-term injection wells in sensitive reservoirs

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Abstract. Due to the sensitivity of the reservoir itself and the aggravation of reservoir damage caused by long-term water injection in a sensitive reservoir of a block in northwest China, the phenomenon of high wellhead pressure and water injection difficulty of new injection Wells is presented in different degrees. Based on the analysis of the effect of increasing injection measures in each stage, combined with the analysis of the cause of reservoir scaling and the sensitivity of long-term water injection volume flow, a new composite treatment liquid system was developed. The system integrates the secondary precipitation inhibition technology, anti-expansion and shrinkage composite technology, deep acidification technology and foam composite acidification technology, and achieves the dissolution rate of the main treatment solution of 22.5%, can maintain a low pH for a long time, and meet the long-term scale inhibition rate of 84.89%. In the evaluation of the core flow experiment, the core permeability recovered and increased after the treatment of the working fluid system, and achieved a good effect of plugging removal and injection increase in the field practical application.

Keywords: Reducing pressure and increasing injection; Plugging and adding fluid; Reservoir damage.

1. Introduction

The sensitive reservoirs in A area of northwest China were transferred to the water injection development stage in 1982. Among them, the A^1-A^3 reservoirs are all strongly water-sensitive and salt-sensitive, and the A^4-A^6 reservoirs are strongly water-sensitive and quick-sensitive. During the past thirty years of production and development, the block has been studied and tested in various aspects such as reservoir characteristics, anti-expansion water injection process, acidification and unblocking to increase injection, and has achieved certain results. However, in recent years, the water injection pressure has remained high, the effect of increasing injection has become increasingly poor, and the phenomenon of under-injection of injection wells is very serious, which makes it difficult to meet the requirements of injection distribution[1].

2. Basic information of the re-injection well and the reason of blockage

There are 227 injection wells in the block, 123 open wells and 60 under-injection wells, all of which have high wellhead pressure and difficulties in water injection. 15 new injection wells were added in 2018, and some of the new injection wells have been under-injected (Table 1), making it difficult to meet the block's injection requirements overall.

Table 1. Undernote statistics

Blocks	Total wells	Number of wells opened	Under-injected wells	Under-injection volume(cube/month)
A^1	57	27	21	11986
A^2	49	29	12	3892
A^3	17	4	2	14
A^4	26	9	3	4075
A^5	32	21	8	7252
A^6	12	9	3	6884
A^7	34	24	11	3150
Total	227	123	60	37253

The mineral composition of the reservoir in block A is dominated by quartz, sodium feldspar and potassium feldspar, and the clay mineral content is between 10% and 20%, among which kaolinite is predominant and imonite is above (Table 2), which is prone to quick-sensitive and water-sensitive, with wide distribution of reservoir porosity and permeability, strong non-homogeneity, and overall concentrated performance of low permeability-ultra-low permeability, small throat channel, and easy to occur quick-sensitive blockage[2]-[3] (Figure 1).

Table 2. Statistical table of average clay content of each small layer

Layer	Eamonn mixed layer	Emmonds mixed layer ratio	Elysium	Kaolin	Chlorite
S_3	15.50	20.00	7.00	60.00	17.50
S_4	17.40	20.00	6.80	65.00	10.80
S_5	31.25	20.00	6.50	53.00	9.25

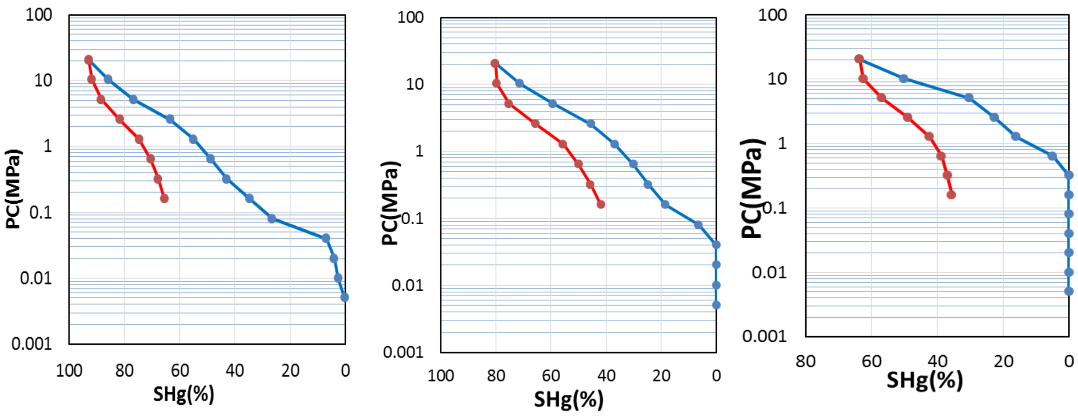

Figure 1. Core capillary pressure curve of block A[4]

After analysis, the formation water type in block A is $CaCl_2$ type, the total mineralization is 13,240.66mg/L on average, and the chloride ion content is 7,481.66mg/L. According to SY/T0600 analysis of potential damage to reservoir fluid, the formation water has a serious calcium carbonate scaling trend (Table 3).

Table 3. Prediction of scaling trend

Analytical Projects	Calculation results	Conclusion
$CaCO_3$	SI>0，SAI=4.26	Severe scale
$CaSO_4$	S<C	Tendency to scaling
$BaSO_4$	0	No scaling
$SrSO_4$	0	No scaling

Simulating the effect of long-term water injection in an injection well in Block A on the reservoir core, the evacuated core was soaked in the injection water and then dried, followed by a long-time formation water repulsion experiment, and the experimental results showed that despite the sensitivity damage that had occurred in the core, there was still a significant decrease in permeability with the increase in water injection (Figure 2). This decrease in permeability was due to multiple factors, i.e., there was some volumetric flow sensitivity due to long-term water injection.

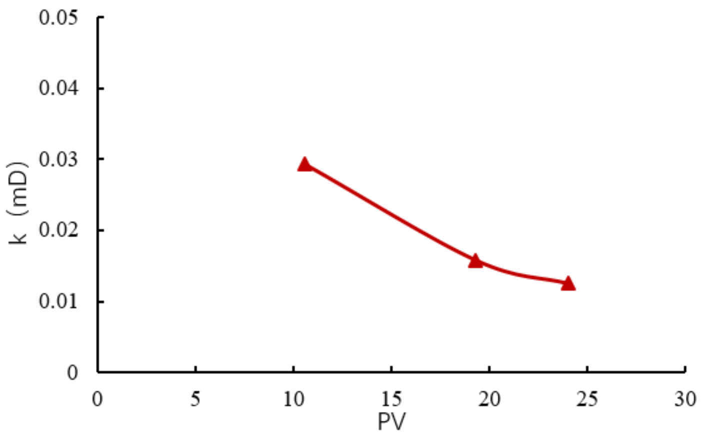

Figure 2. Permeability varies with water injection volume

In addition to the reservoir mineral composition, pore throat characteristics, formation water scaling trend and volumetric flow sensitivity of this block, considering the scaling risk of injection water quality, the injection water in this block has severe calcium carbonate scaling and the generated calcium carbonate precipitation causes blockage of injection wells [4]. In summary, the causes of block A transfer injection well blockage are mainly: 1) water-sensitive and salt-sensitive risks caused by the high specific gravity of the reservoir's own sensitive components; 2) velocity-sensitive risks caused by the uneven distribution of reservoir pore throats and small throat channels; 3) CaCO3 scaling risks of formation water quality; 4) volumetric flow sensitivity risks of long-term water injection in sensitive reservoirs; and 5) $CaCO_3$ scaling risks of injection water quality.

3. Pressure reduction and injection decongestion ideas

The block currently mainly relies on acidizing combined with surface pumping for additional injection, but there is a general phenomenon of deteriorating acidizing effect and rising pumping pressure. Take A2 area S1 well as an example, this well betting time is early, in 1996 the water absorption index 1.62 t/(d-MPa), then after fracturing rose 3.12 t/(d-MPa), during the transfer of injection through several times after acidification in a higher injection amount to maintain a longer time; 2006 booster pump, achieved a better The booster pump was installed in 2006 and achieved a good injection effect; with the extension of the injection time, the injection effect became significantly worse after the pump pressure was raised to 13.6 MPa; meanwhile, the acidizing effect gradually became worse under the influence of long-term injection volume flow sensitivity, etc., and the validity period lasted only 5 months at a lower injection volume after acidizing in 2017 (Table 4).

Table 4. Water injection parameters of block A

Time for additional measures	Type of measure	Valid period (months)	Dispense volume (m^3)	Cumulative increase(m^3)
1996.9	Acidification	10	60	3166
1997.8	Acidification	30	60	24267
2000.11	Acidification	53	60-80	66551
2006.12	Booster pumps		80	18634
2017.6	Acidification	8	40	7183
2017.9	Acidification	5	50	1784

At present, the existing conventional acidizing and ground booster pump injection measures can no longer meet the block's demand for additional injection volume Combined with the analysis of blockage causes, it is recommended to use "compound decongestion" combined with "long-lasting scale inhibition" to solve the current problems [5]-[6]

4. Novel bucketing and booster fluid system preferences

Through the identification of reservoir acidification controllable factors, the basic ideas of "descaling + scale inhibition", "anti-expansion + shrinkage", "hole passage + throat expansion" and "cleaning + dissolution" are clarified, and the secondary precipitation inhibition technology, anti-expansion and shrinkage compound technology, deep acidification technology and foam compound acidification technology are preferably selected to form a new unblocking and injection fluid system of "compound unblocking" + "long-lasting scale inhibition" (Table 5).

Table 5. New interpretation of the formula of liquid injection system

Composition	Role
Glacial acetic acid + citric acid	Deep acidification
Hydrochloric acid	detergent
Organic clay stabilizer NW-7#	Anti-expansion and expansion reduction of montmorillonite and illite
Composition	Role
Imidazoline-1#	Corrosion mitigation and equipment protection
TW-4# organic carboxylate ion-containing stabilizer	Prevention of iron ion precipitation
ZP-2# composite surfactant	Anti-emulsion breaking, reduce surface tension, help backdraft
4# Inorganic phosphate	Prevents the formation of nuclei or critical nuclei, prevents crystal growth and disperses crystals

4.1. Dissolution properties

Due to the serious calcium carbonate fouling in the block formation, after comprehensive consideration, the combination of HCL+HF was recommended for the test. 2h of dissolution test was conducted on the rock powder (80 mesh) of the target block reservoir at a constant temperature of 50℃ using the loss of weight method. The dissolution rate was calculated by calculating the difference between the mass before reflecting and the mass of rock powder after drying, and 1.5% HF was finally selected to make the dissolution rate reach 21.92% considering that it would not cause reservoir collapse and secondary damage to the formation due to excessive acid concentration.

Figure 3. Acid rock reaction experiment

Figure 4. Dried rock powder

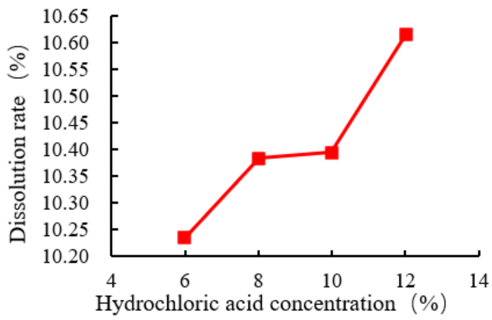

Figure 5. Hydrochloric acid dissolution rate curve

4.2. Deep acidification performance

The temperature of the target formation exceeded 50°C[7], and the acid would react sharply near the wellbore during construction and be consumed before entering the deep part of the formation, so the effective penetration degree was low, so the deep acidizing process was selected. The retardation performance of the two acids was analyzed by comparing the acidity curves of the formulated acid system (HCL+HF+glacial acetic acid+citric acid-5#) with that of the earth acid system (HCL+HF) (Figure 7). The formulation acid has a longer reaction time compared to the earth acid and can maintain a low pH for a longer period of time.

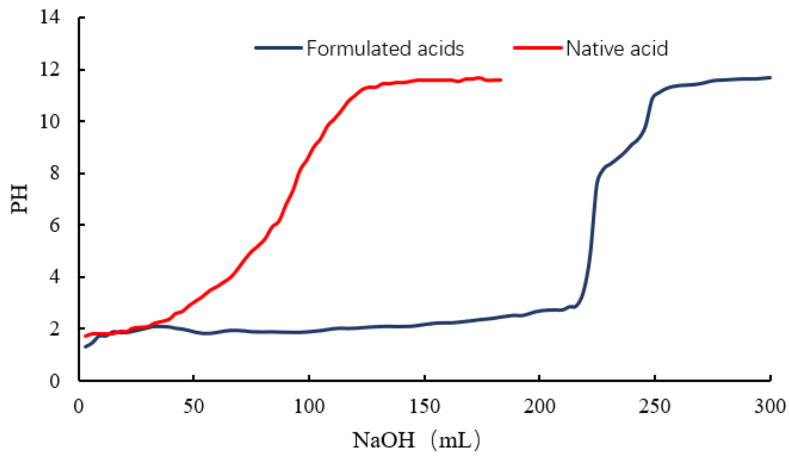

Figure 6. Comparison of retarding performance of acid solution

4.3. Long-lasting scale inhibition performance

According to the results of water sample and scale sample analysis, five different types of scale inhibitors were selected to evaluate their scale inhibition ability using static scale prevention performance measurement method. Finally, the scale inhibition rate reached 84.89% when 4# scale inhibitor of 2.5mg/L was preferably selected (Figure 8 and 9).

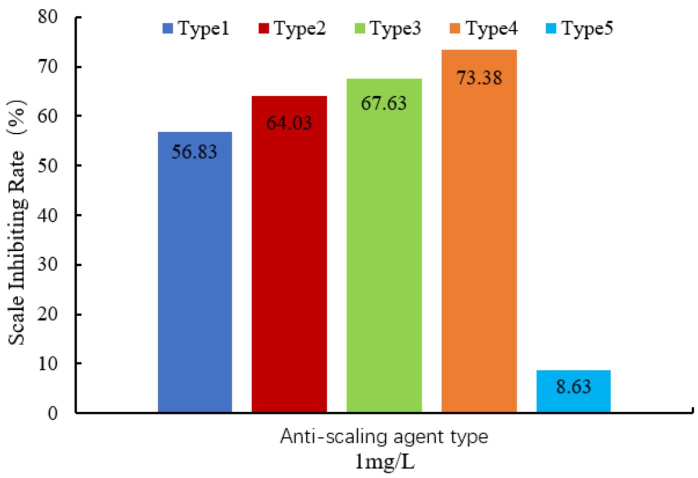

Figure 7. Anti-scaling effect of different scale inhibitor with concentration of 1 mg/L on carbonate

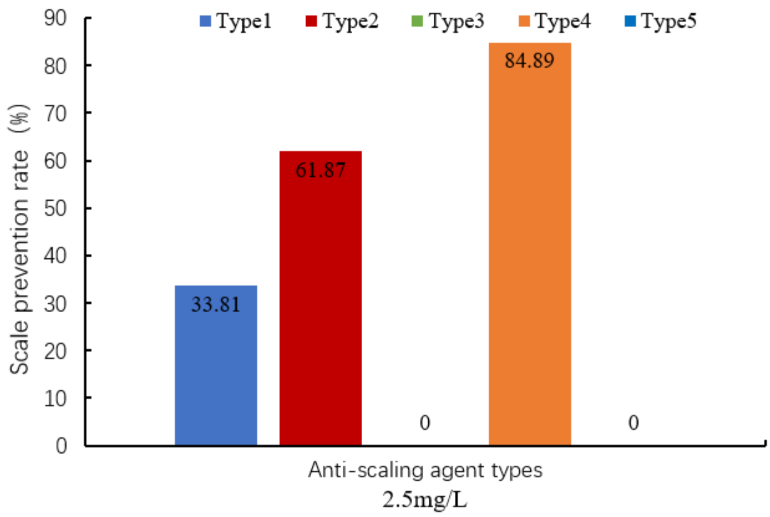

Figure 8. Anti-scaling effect of different scale inhibitors with concentration of 2.5 mg/L on carbonate

4.4. Compatibility

The acidification corrosion inhibitor, high-temperature drainage aid, high-temperature iron ion stabilizer and high-temperature clay stabilizer screened above were added into the pre-treatment solution and the main treatment solution in turn, and left to stand for 2 h at room temperature and 50 ℃[8], respectively, to observe the compatibility. The additives were mixed with the pre-treatment solution and main treatment solution at room temperature and 50℃, respectively, and no precipitation was produced, so the compatibility was good (Table 6).

Table 6. The situation of precipitate produced by the newly deplugging and injecting liquid system

Acid type	Main Agent	Additive Type						Temp. (℃)	Transparency	Sedimentation
Pre-liquid	HCl + glacial acetic acid + Citric acid	1% Imidazoline -1	2% ZP -2	2% NW -8	2% TW -4	8% Seepage enhancer	5% Foam	Room temperature	Opaque	None
								50	Opaque	
Main treatment fluid	HCl +HF							Room temperature	Opaque	
								50	Opaque	
Post-liquid	glacial acetic acid + citric acid-5#							Room temperature	Opaque	
								50	Opaque	
Long-term effective scale inhibiting liquid	2.5mg/L of 4# inorganic / Phosphate							Room temperature	Opaque	
								50	Opaque	

4.5. Experimental evaluation of core flow

The core flow experimental device was used to evaluate the unblocking performance of the working fluid system[9]-[11], and there was a significant decrease in the reservoir permeability after the water injection injury. After the treatment of the working fluid system, the core permeability finally recovered and increased to a certain extent, indicating that the working fluid system is effective in decongesting (Figure 10).

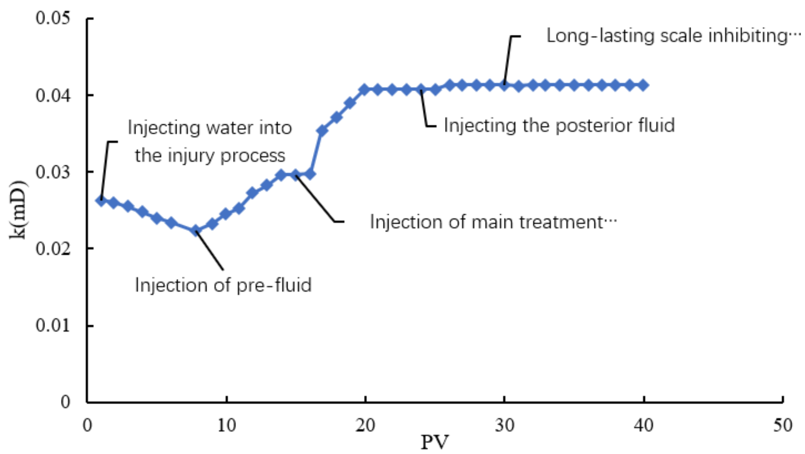

Figure 9. Core permeability varies with water injection volume after plugging of working fluid

5. Construction effect evaluation

Through the evaluation of the construction of four wells in the field, the new unblocking and injection fluid system of "compound unblocking" + "long-lasting scale inhibition" has achieved a daily injection increase of 30 m3 and a significant decrease in oil pressure, with an average decrease of about 3 MPa. From November 2020 to November 2021, the cumulative injection volume has reached 6000 m3, which exceeds the technical expectation of 3000 m3 and is still in the effective period of injection (Figure 11).

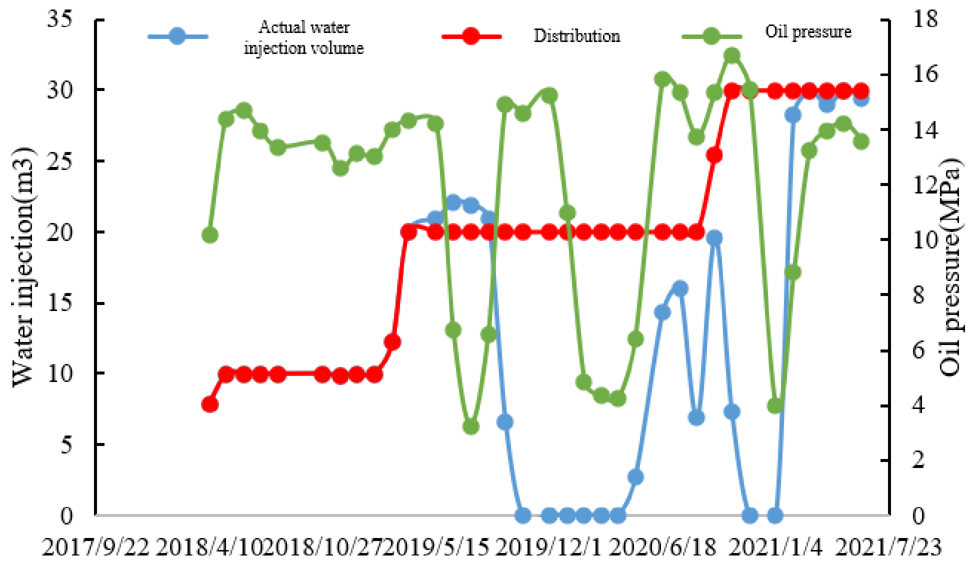

Figure 10. Daily water injection and oil pressure change curve of well A

6. Conclusion

(1) A sensitive reservoir in area A is currently under high oil pressure and inability to inject due to long term water injection transfer wells, after analysis, the block has obvious speed-sensitive and water-sensitive characteristics, the reservoir has a serious calcium carbonate scaling trend, and poor water quality, and there is a certain volume flow sensitivity.

(2) Based on the analysis of blockage causes in area A, combined with the identification of reservoir acidification controllable factors, a new unblocking and injection fluid system of "compound unblocking" + "long-lasting scale inhibition" was formed. The core experiment after declogging shows that the recovery of permeability exceeds 100%.

(3) The oil pressure has dropped significantly after the field unblock construction, and the 12-month incremental injection volume has far exceeded the expectation of 3,000m3, and is still in the incremental injection validity period, which is a significant increase compared with the original acid system of 5-month incremental injection validity period.

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