Scaling tendency prediction in water injection well of K2 formation of C68 block

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Abstract. The K2 formation of C68 block is explored by injecting water to maintain formation pressure, but the continuous decrease of injection rate significantly reduces oil production. Therefore, it is important to predict scaling tendency of injected water in the formation. Firstly, ion composition of formation water and injected water was tested according to recommended practices in petroleum industry. Then, wellbottom temperature distribution of injection wells was simulated under injection water rate requirement of oilfield development. Furthermore, based on the "Oddo-Tomson" prediction model of inorganic scale, the scaling trend of water flooding in K2 formation is predicted according to the possible temperature and pressure. The research indicates that sulfate scale cannot be formed in C68 block and there is a slight possibility of carbonate scaling, which provides a basis to select the correct stimulation technology for increasing production.
Keywords: Injection water; Scaling tendency; Prediction; Temperature.

1 Introduction

A series of prediction models of scaling tendency has formed since Langelier saturation index was proposed. Davis & Stiff [1] improved Langlier's method considering the comprehensive influence of temperature, pressure, ionic strength and total alkalinity on scaling trend. Ryznar [2] improves the accuracy of scaling prediction of high-salinity and high-alkalinity water considering thermodynamics, salinity and other factors on the basis of Davis-Stiff's theory.Oddo-Tomson[3,4] further improved the saturation index model comprehensively considering activity product theory, solubility product theory and ion association combined with thermodynamics theories and proposed the calculation method of scaling trend whether there is gas liberation.

Luo and Pu [5.6] analysed typical water samples of oilfields in China, improved Davis-Stiff's saturation index calculation model taking into account the influence of reservoir temperature and pressure on scaling trend, and came up with the saturation index formula for calculating carbonate and sulfate scaling suitable for produced water of Chinese onshore oilfields. Zhu [7] obtained the mix solubility product of injected water and formation water at different temperatures, pressures, and salinities by experiments, developed a scaling

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prediction software applying Pitzer's electrolyte activity coefficient equation to deal with the related data of solid -liquid-gas phases. Yan [8] simulated the scaling trend of formation water and injected water mixed in different proportions under the conditions of reservoir temperature and pressure, and applied the simulation results to improve the quality of injected water, thus the compatibility of different water quality can be improved.

Yang [9] predicted the scaling trend of calcium carbonate deposition of injection wells in XH high-pressure and low-permeability reservoir by Stiff-Davis' and Ryznar's methods. Hu [10] predicted the scaling trend of both calcium carbonate and calcium sulfate during injection development of C8 formation in Xifeng oilfield according to Davis-Stiff's and Oddo-Tomson's saturation index method, Ryznar stability index method and thermodynamic solubility method. You [11] predicted the scaling trend of formation water and injected water in Huabei Oilfield and its influencing factors comprehensively applying Davis-Stiff's saturation index method and Odd-Tomson's saturation index method.

The K2 formation of C68 block is explored by injecting fresh water and mixed water (fresh water mixed with produced water), but it is difficult to inject water into formation under limited wellhead pressure, which significantly reduces oil production. It is necessary to research the scaling tendency of injected water in the formation.

2 Temperature distribution of injection wellbore

Scaling trend is closely related to temperature. Wellhole temperature distribution during water injection process were calculated by simulator from Southwest Petroleum University. The curve of bottomhole temperature with injection rate and time is illustrated in Figure 1.

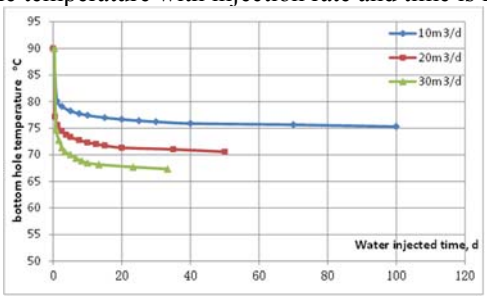

Fig. 1. Influence of injection rate on bottomhole temperature of K2 formation.

The simulation results in Fig.1indicate that: (1) Bottomhole temperature was affected by injecting rate under the same injected water volume. (2) Wellbore temperature of water injection wells always decreases with the increase of injected water volume. (3) bottom temperature approximates a constant after injected water reaches 150m^3. At this time, the bottom hole temperature is still higher than 67°C even if injecting rate reaches 30m^3/d.

3 Scaling prediction and simulation of injection wells

Scaling tendency usually includes sulfate scaling and carbonate scaling. They can be predicted by Oddo-Tomson's saturation index method[3-4].

3.1 Prediction of sulfate scaling

(1) Sulfate scaling

Sulfate scale is mainly composed with sulfate insoluble compound such as $CaSO_4$, $BaSO_4$, $SrSO_4$ which is formed when Ca^{2+}, Ba^{2+}, Sr^{2+} mixed with SO_4^{2-}. Ca^{2+} may form

different $CaSO_4$ hydrate with SO_4^{2-} at different temperature, that is, gypsum ($CaSO_4 \cdot 2H_2O$), hemihydrate($CaSO_4 \cdot ½H_2O$) and anhydrite($CaSO_4$).

1) Ionic activity of Ca^{2+}, Mg^{2+}, Ba^{2+}, Sr^{2+}, SO_4^{2-}

The stability constant K_{st} of $MgSO_4$ and $CaSO_4$ and the concentration of free sulfate and metal ions can be calculated by following formula.

$$\lg(K_{st}) = 1.86 + 0.0045T - 0.0012T^2 + 0.0155p - 2.38I_i^{1/2} + 0.58I - 0.0013 \times I^{1/2}T$$

$$[SO_4^{2-}] = \left\{-\left[1 + K_{st}\left(C_m - C_{SO_4^{2-}}\right)\right] + \left[1 + K_{st}\left(C_m - C_{SO_4^{2-}}\right)\right]^2 + 4K_{st}C_{SO_4^{2-}}^{0.5}\right\} / (2K_{st})$$

$$[Mg^{2+}] = C_{Mg^{2+}}\{1 + K_{st}[SO_4^{2-}]\} \quad [Ca^{2+}] = C_{Ca^{2+}}\{1 + K_{st}[SO_4^{2-}]\}$$

$$[Sr^{2+}] = C_{Sr^{2+}}\{1 + K_{st}[SO_4^{2-}]\} \quad [Ba^{2+}] = C_{Ba^{2+}}\{1 + K_{st}[SO_4^{2-}]\}$$

$$C_m = C_{Mg^{2+}} + C_{Ca^{2+}}C_{Sr^{2+}}C_{Ba^{2+}}$$

2) Saturation index and scale discrimination of different types of sulfate scale

$$\mathrm{SI} = \log\{[Ca^{2+}][Mg^{2+}]\} + A + BT + CT^2 + Dp + ES_i^{1/2} + FS_i + GS_i^{1/2}T$$

Where the types and parameter values of different types of sulfate scale determined based on environment temperature are shown in Table 1.

Table 1. Values of coefficients in scaling trend prediction model.

		A	B	C	D	E	F	G
Calcium sulfate	*Gypsum	3.47	1.8E-3	2.5E-6	-855.5E-5	1.13	0.37	-2.0E-3
	#Hemihydrate	4.04	-1.9E-3	11.9E-6	-1000.5E-5	-1.66	0.49	-0.66E-3
	**Anhydrate	2.52	9.98E-3	-0.97E-6	-445.5E-5	-1.09	0.50	-3.3E-3
Strontium sulfate (celestite)		6.11	2.0E-3	6.4E-6	-667E-5	-1.89	0.67	-1.9E-3
Barium sulfate(barite)		10.03	-4.8E-3	11.4E-6	-696E-5	-2.62	0.89	-2.0E-3
Carbonate scale		-2.76	9.88E-3	0.61E-6	-439.35E-5	-2.348	0.77	
Remarks: *gypsum (<80°C) #hemihydrate (80°C-l21°C) **anhydrate (>121°C)								

(2) Prediction of carbonate scaling

Oddo-Tomosn's saturation indices is calculated as the following formula, where the parameter values are shown in Table 1.

$$\mathrm{SI} = \log\{[Ca^{2+}][HCO_3^-]\} + pH + A + BT + CT^2 + Dp + EI^{1/2} + FI$$

3.2 Scaling discrimination criteria

The criteria for determining the scaling trend by saturation index are as follows:

- When SI<0, sulfate is under saturation and does not scale;
- When SI=0, sulfate is at solid-liquid equilibrium with no scaling tendency;
- When SI>0, sulfate is over saturation and tends to scale.

4 Analyses of scaling in injection wells of K2 formation

The buried depth of the K2 formation is 2500m. The freezing point of crude oil is 33.5°C. Reservoir pressure coefficient is between 0.76-1.01, and temperature is approximately 90°C.

4.1 Analysis of ions in water samples

The injected water is mainly fresh water from source well, mix water of fresh water and produced water. According to SY/T5523-2006 (Oilfield Water Analysis Method), the ion concentrations of different water samples from 3 wells in K2 formation were tested and displayed in Table 2.

Table 2. Analysis results of formation water properties (ions) in C68 block.

		Formation water	Injected water	Detection method
pH		6.52	8.1	Water quality tester
Na^++K^+	mg/L	12940	92.74	ICP
Ca^{2+}	mg/L	1433	100.71	ICP
Mg^{2+}	mg/L	196.8	20.54	ICP
Cl^-	mg/L	22810	368.78	Titration
SO_4^{2-}	mg/L	298.1	167.81	Titration
HCO^{3-}	mg/L	248.8	248	Titration
Total salinity	mg/L	37877	998.58	Water quality tester

4.2 Prediction results of scaling in injection well

Based on the injection rate, well hole temperature changes from 20°C to 90°C and pressure from 10MPa to 30MPa in injection wells. Scaling tendency prediction results of fresh water, formation water and mixed water are illustrated in Figure 2 to Figure 3.

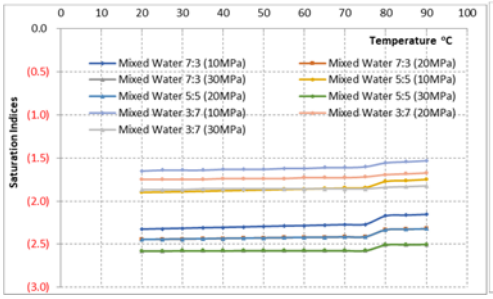

Fig. 2. Prediction of sulfate saturation index.

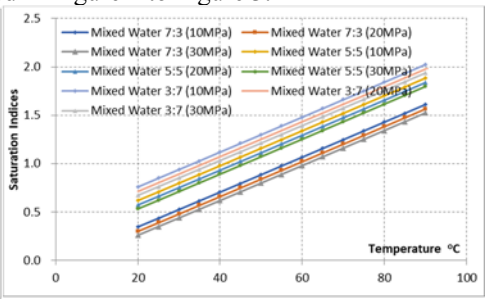

Fig. 3. Prediction of carbonate saturation index.

These results show that:

• There is no barium or strontium scaling whether clear water or formation water. Because there is no barium or strontium ions in injecting water.

• There is almost no possibility of sulfate scaling, because sulfate saturation index of insoluble sulfate (including gypsum, hemihydrate and anhydrous sulfate) is far less than zero for both formation water and fresh water.

• There is a slight possibility of carbonate scaling, because carbonate saturation index always is slightly greater than 0 for no matter formation water and fresh water.

• The slight carbonate scale in K2 formation can be dissolved by acidizing.

5 Conclusions

The following conclusions can be obtained from the simulation of wellbore temperature distribution and scaling of injection wells in K2 formation of C68 block:

(1) The wellbore temperature of water injection wells always decreases with the increase of injection volume and the decrement decreases under the same water injection volume.

(2) The bottom temperature tends to be stable after injected water reaches 150m^3. At this time, the bottom hole temperature is still higher than 65°C even if injecting speed reaches 30m^3/d.

(3) Neither formation water nor injecting water contains barium or strontium ions, therefore there will be no barium or strontium scaling.

(4) There will be no sulfate scaling when injecting mixed water.

Nomenclature

C = total amount of ionic species in solution, *M*
I—ionic strength, M. I=TDS(mg/L) /53,470 or CI -(mg/L) /32460
Kst = complex stability constant, *M-I*
p,T = pressure (psi) and temperature (^{O}F)
$\Sigma M = C_{Ca} + C_{Mg} + C_{Sr} + C_{Ba}$, *M*
C_j —Total sulfate concentration ($_j = {}_{SO4}{}^{2-}$, $_{Mg}$, $_{Ca}$, $_{Sr}$, $_{Ba}$), mol/L

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