Research Article

Comprehensive Research of Scaling Prediction for Gas Reservoir Fluid considering Phase State

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During the exploitation of a gas reservoir containing water, the scaling problem is usually affecting the gas production in gas wells [1, 2]. Due to the change of production conditions, such as the chemical reactions in the electrolyte solution and phase changing between oil, gas, and water [3, 4], the scaling formation of gas reservoir fluid is very complicated. Not only will the scaling conditions of inorganic salts themselves change with the change of temperature and pressure but also the dissolution, precipitation, and evaporation of oil and gas components will severely affect the scaling trend of inorganic salts. The current scaling prediction method includes the saturation index method, thermodynamic solubility method, saturation coefficient method, and sulfate compound scaling prediction method. Based on the principle of a chemical equilibrium of solution, these methods only consider the change of solubility of acidic gas with a chemical reaction and do not consider the comprehensive effect of phase change on fluid scaling. Therefore, they cannot truly reflect the process of inorganic salt scaling of gas reservoir fluids.

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1. Introduction

In the exploration of gas reservoirs containing water, a scaling problem is usually created which severely affects the production of gas wells [1, 2]. Due to the change of production conditions, such as the chemical reactions in the electrolyte solution and phase changing between oil, gas, and water [3, 4], the scaling formation of gas reservoir fluid is very complicated. Not only will the scaling conditions of inorganic salts themselves change with the change of temperature and pressure but also the dissolution, precipitation, and evaporation of oil and gas components will severely affect the scaling trend of inorganic salts. The current scaling prediction method includes the saturation index method, thermodynamic solubility method, saturation coefficient method, and sulfate compound scaling prediction method. Based on the principle of a chemical equilibrium of solution, these methods only consider the change of solubility of acidic gas with a chemical reaction and do not consider the comprehensive effect of phase change on fluid scaling. Therefore, they cannot truly reflect the process of inorganic salt scaling of gas reservoir fluids.

The alteration in temperature and pressure is not the only factor governing the scaling, but the dissolution and
precipitation of oil and gas components and the evaporation of water can also severely influence the inorganic scale formation. Due to the involvement of mass transfer and energy conversation (Peyghambarzadeh et al. [5]), there are many factors, such as temperature [6–8], pressure (Fu et al. [9]), and water composition [10], that affect the scaling in a gas reservoir. Under this complex scenario, it is a challenge to accurately predict the extent of scaling. The most common scaling prediction techniques are the saturation index method, thermodynamic solubility method, and sulfate solubility product constant method [11–13]. Therefore, it is a challenge to predict scaling accurately. Among these methods, Ryznar and Langelier [14, 15] predicted the scaling of carbonate by the calculating saturation index. Zhang et al. [16, 17] predicted the scaling of carbonate by the thermodynamic solubility method. Bourland predicted [18] the scaling tendency by calculating the sulfate solubility product constant. In these prediction models, the influence of temperature and pressure and the composition of the formation water on scaling were taken into consideration, but the phase changes were ignored in the models; thus, they cannot truly reflect the process of the inorganic salt scaling in the gas reservoir fluid. At the same time, it was difficult to measure the amount of formation fluid scaling under a high-temperature and high-pressure condition because the experimental equipment has not yet been developed. It was necessary to establish a model which takes the phase change into account to predict the scaling under a high-temperature and high-pressure condition.

In this research, a set of experimental devices which has taken the phase change of oil, gas, and water into account was developed to understand the scaling law of the fluid in the actual gas reservoir. Based on thermodynamics, a multi-phase equilibrium scaling prediction model of gas (natural gas)-liquid (hydrocarbon)-liquid (formation water)-solid (inorganic salt) was proposed that takes into account the change of fluid phase state and the reaction of inorganic salt scaling, and the fluid phase state transformation and scaling law of the actual gas reservoir were investigated.

2. Experiment Description

2.1. Experimental Equipment and Samples. In this research, a set of experimental devices was developed that was able to simultaneously test the phase change of fluid in gas reservoirs under high-temperature and high-pressure conditions and the amount of formation water ion and scaling. The schematic diagram of the device is shown in Figure 1. The whole system included a liquid supply system, sampling unit, PVT constant temperature and pressure system, separator, fluid property detection system, formation water ion analyzer, and temperature and pressure collection control system. The maximum working pressure of the system was up to 70 MPa, and the temperature range was from -50 to 200°C. The main equipment was a PVT analyzer, conventional formation water ion analyzer, and relevant physical property testing devices produced by the Canadian DBR Company. The pressure and temperature measurement accuracy of the device were 0.01 MPa and 0.1°C, respectively. The PID control system was used to adjust the temperature and pressure during the whole experimental process. The temperature control system used the electric heating system to carry out heating and temperature control on the PVT test room. 8 heating rods were used to heat the PVT test chamber to...
When the temperature of the test room dropped by 0.1 °C, the system would turn off. When the pressure reached the experimental set point, the control system would turn on, thus reducing the pressure of the test room. When the experimental setting value, the electric motor would pull the piston up and down, so as to realize the change of the volume of the PVT test room and the pressure of the PVT test room. When the pressure of the PVT test room was higher than the pressure of the PVT test room and the pressure of the PVT test room, the electric heating system would reconnect the power supply to ensure uniform heating. In the heating process, when the temperature of the test room reached the set temperature of the experiment, the control system would turn off the power; when the temperature of the test room dropped by 0.1 °C, the electric heating system would reconnect the power supply and reheat the test room. The pressure of the PVT test chamber was controlled by piston movement. In the experiment, the electric motor under the piston would drive the piston up and down, so as to realize the change of the volume of the PVT test room and the pressure of the PVT test room. When the pressure of the PVT test room was higher than the experimental setting value, the electric motor would pull the piston down and increase the volume of the PVT test room, thus reducing the pressure of the test room. When the pressure reached the experimental set point, the control system would turn off the power. When the pressure of the PVT test room was lower than the set value of the experimental system, the electric motor would pull the piston upward and compress the volume of the PVT test room, thus increasing the pressure of the test room.

The gas, oil, and water samples obtained from the BS8 well in the Qianmiqiao gas reservoir were used in the experiment. The sample composition was shown in Tables 1–3. The initial formation pressure of the well was 43.57 MPa, the formation temperature was 171.4 °C, the production water and gas ratio was 4.33 m³/10⁴ m³, and the gas-oil ratio was 11,507 m³/m³.

2.2. Experimental Procedures. In the experiment, the formation fluid was first compounded according to the production data and pumped to the intermediate container by an automatic pump. Then, the fluid was heated and pressurized under constant temperature and pressure in a cylinder to restore the formation conditions. It was then held for 24 hours to ensure that the phase changes of the oil, gas, and water in the formation fluid and the scaling reaction proceeded sufficiently and achieved equilibrium. The volume of natural gas saturated with water at the top of the PVT cylinder and the volume of formation water that the gas dissolved were then obtained. Finally, the condensate gas of a small amount of saturated water at the upper part of the PVT tube was discharged, and the natural gas and the saturated water content were flashed to the standard condition and measured. The PVT cylinder was set for half an hour; then, the formation water of natural gas dissolved in the lower part was discharged and measured. The ion detection analyzer was used to measure the concentration of each ion in the formation water. According to the change of ionic concentration and formation water physical property before and after the experiment, the scaling amount of the formation fluid was determined.

2.3. Experimental Data Analysis. Beginning from the initial formation conditions, the high-temperature and high-pressure phase analysis and scaling test of the BS8 well fluid were carried out under five pressure and three temperature conditions, respectively. The results of the experiment are shown in Figures 2–5. It is indicated in Figure 2 that the content of dissolved gas in formation water (GWR) increased as the pressure increased under the same temperature. When the pressure is raised from 5 MPa to 20 MPa, the content of dissolved gas ascended dramatically. When the pressure was over 20 MPa, the rise gradually slowed down. Under the same pressure, the content of dissolved gas went up with the increase of temperature. When the pressure was 5 MPa, the content difference of dissolved gas was smaller under the three different temperatures. When the pressure increased to 20 MPa, an obvious difference appeared. When the pressure went up to 45 MPa, the content difference of dissolved gas enlarged continuously. However, the content of saturated water in natural gas (WGR) decreased when the pressure increased under the same temperature. As demonstrated in Figure 2, the WGR increased with the rise of the temperature under the same pressure. With the increase of pressure, the content difference of saturated water between different temperatures in natural gas gradually decreased. From the WGR curve, the WGR curve experienced a dramatic decrease from 5 MPa to 12 MPa, and a huge content difference appeared when the pressure was 5 MPa. When the pressure was 20 MPa, the WGR became stable, and the content difference decreased greatly compared when the pressure was 5 MPa. The experimental data showed that these ions had the same concentration change ratio. At high pressure, the changing of the ion content such as Ca²⁺, HCO₃⁻, and Sr²⁺ was similar to Na⁺, but it decreased suddenly and had a trend of decreasing with decreasing pressure when the pressure decreased further. The content of SO₄²⁻ increased with the decrease of pressure. The experimental results demonstrated that some ions participated in the scaling reaction under certain conditions, and inorganic salt scales were formed in the formation fluid.

Under the experimental condition, the ions such as Na⁺ and K⁺ were not involved in the scaling reaction, and the concentration change was mainly due to the change of water physical properties caused by high temperature and high pressure. Taking the concentration of Na⁺ as a standard,
the change of scale ions in formation water before and after the experiment can be calculated by the test data as follows:

\[ C = \frac{C_{\text{Na}^+}}{C_{\text{Na}^+}^0} \times C_n - C_n^* \]  

where \( C \) is the change of the molar concentration of the scale ions; \( C_{\text{Na}^+} \) is the current molar concentration of sodium ions; \( C_{\text{Na}^+}^0 \) is the initial sodium ion molar concentration; \( C_n \) is the initial scale ion molar concentration; and \( C_n^* \) is the current scale ion molar concentration.

According to the change of ion concentration, the type of scaling and the amount of scaling of the inorganic salt in the formation fluid under the standard condition were determined. The amount of scaling under the experimental conditions was also obtained according to the change of the volume coefficient and density of the formation water. As shown in Figure 4, two kinds of inorganic scales, CaCO\textsubscript{3} and SrSO\textsubscript{4}, were generated in the formation water of BS8 in the experimental condition, while the amount of scales was zero under the initial formation pressure. When the pressure was lower than 20 MPa, the CaCO\textsubscript{3} scale occurred. When the pressure was lower than 30 MPa, the SrSO\textsubscript{4} scale appeared.

At present, as the formation pressure was 11.5 MPa and the formation temperature was 117.4°C, more CaCO\textsubscript{3} scales and a small amount of SrSO\textsubscript{4} scales appeared in the formation fluid. In addition, the amount of fouling increased with the decrease of experimental pressure and increased with the rise of temperature.

In order to study the influence of fluid phase change on the scaling of inorganic salts, scaling tests were carried out under the same conditions using BS8 degassed formation water. As indicated in Figure 5, it can be concluded that the inorganic scale was generated in the whole experiment. Although the amount of inorganic salt scale in degassed formation water also increased with the decrease of pressure and increased with the rise of the temperature, the change trend was not obvious compared with the formation fluid. This was mainly because the oil and gas components in the actual fluid were more easily dissolved in the formation water under the conditions of high temperature and high pressure. The dissolution of the acid gas CO\textsubscript{2} promoted the reaction of CaCO\textsubscript{3} to be dissolved, which led to the low scale of the inorganic salt scaling in the formation fluid. However, with the decrease of pressure, the solubility of the gas components in water decreased, while the evaporation of water into natural gas obviously increased.

### 3. Scaling Prediction Model

#### 3.1. Model Description

The inorganic salt scaling in a gas reservoir was a complex multiphase system consisting of natural gas, liquid hydrocarbons, formation water, and various solid inorganic salt scales with chemical reactions. Under equilibrium conditions, the system should meet the conditions of material conservation and thermodynamic equilibrium. The system consists of \( N \) components and \( P \) phases, and the chemical reaction balance and phase equilibrium existed simultaneously and follow the law of element conservation:

\[ \sum_{i=1}^{N} \sum_{j=1}^{P} n_{ij} \omega_{ik} = b_k. \]  

Only the phase equilibrium exists, and the total molar conservation of the components is observed:

\[ \sum_{j=1}^{P} n_{ij} = n_i^{\text{total}}. \]
For the electrolyte solution with ions, the charge conservation condition should also be satisfied.

\[ \sum_{i=1}^{N} n_{iw}Z_i = 0. \]  \hspace{1cm} (4)

For a given temperature and pressure, the system should meet the minimum thermodynamic equilibrium condition of Gibbs free energy.

\[ \min G(n) = \sum_{i=1}^{N} \sum_{j=1}^{P} n_{ij} \mu_{ij}, \]  \hspace{1cm} (5)

where \( n_{ij} \) is the number of moles of component \( i \) in phase \( j \), \( \omega_k \) is the mole number of the element \( k \) in component \( i \); \( b_k \) is the total mole number of the element \( k \); \( Z_i \) is the number of charges in component \( i \) in the solution; \( n_{iw} \) is the number of moles of \( i \) in the formation water electrolyte solution; and \( \mu_{ij} \) is the chemical energy of component \( i \) in phase \( j \).

3.2. Model Analysis. The entire gas reservoir multiphase system with inorganic salt scaling was divided into two interactive processes: the first process is the natural gas and liquid hydrocarbon phase change between formation water electrolyte solutions and the other process is the chemical reaction of each ion and inorganic salt in formation water. Further analysis was made on the representation method of the composition of the multiphase system and the calculation method of the thermodynamic equilibrium of the two processes.

3.2.1. Composition Representation Method. In order to clearly express the composition of the phases in the system, the material representation method of phase equilibrium was adopted. Under certain equilibrium conditions,

\[ V + L + W + \sum_{j=1}^{mm} M_j = 1, \]  \hspace{1cm} (6)

\[ V y_j + L x_j + W w_i + \sum_{j=1}^{mm} M_j m_i = z_j, \]

where \( V, L, W, \) and \( M_j \) are the molar components of natural gas, liquid hydrocarbon, electrolyte solution, and each solid inorganic scaling, respectively; \( y_j, x_j, w_i, \) and \( m_i \) are the molar compositions of component \( i \) in gas phase, liquid hydrocarbon, aqueous phase, and solid inorganic salt, respectively; and \( z_j \) is the molar composition of the components in the total system under a certain condition.
3.2.2. Phase Equilibrium. The fugacity of each component in each phase should be equal when the equilibrium of gas, liquid, and liquid was achieved:

\[ f_i^V = f_i^L = f_i^W, \quad (8) \]

where

\[ f_i^V = x_i \phi_i^VP, \]
\[ f_i^L = y_i \phi_i^LP, \]
\[ f_i^W = \omega_i r_i f_i^0. \]

In the formula, \( f_i^V \), \( f_i^L \), and \( f_i^W \) are the fugacities of component \( i \) in the gas phase, liquid hydrocarbon phase, and water phase, respectively; \( \phi_i^V \) and \( \phi_i^L \) are the fugacity coefficients of components in the gas phase and liquid hydrocarbon phase; \( f_i^0 \) is the standard fugacity of pure component \( i \); and \( r_i \) is the activity coefficient of component \( i \) in the electrolyte solution. Among them, PR state equations can be used to calculate the related thermodynamic parameters of components in gas phase and liquid hydrocarbons; the Pitzer method is used to solve the activity coefficients and standard fugacity of components in formation water.

3.2.3. Chemical Equilibrium in Electrolyte Solution. According to the Gibbs free energy minimum principle and the calculation method of the chemical potential of the solution components, the equilibrium condition in the chemical reaction is as follows:

\[ \prod_{i=1}^{N} (r_i C_i)^{\nu_i} = K_{sp}, \quad (10) \]

where \( \nu_i \) is the stoichiometric number of component \( i \) in the chemical reaction; \( C_i \) is the concentration of component \( i \) in the solution; moles/l; and \( K_{sp} \) is the reaction equilibrium constant.

\[ \begin{align*}
\text{Ca}^{2+} + \text{SO}_4^{2-} & \rightleftharpoons \text{CaSO}_4 \downarrow \quad (11) \\
\text{Ba}^{2+} + \text{SO}_4^{2-} & \rightleftharpoons \text{BaSO}_4 \downarrow \quad (12) \\
\text{Sr}^{2+} + \text{SO}_4^{2-} & \rightleftharpoons \text{SrSO}_4 \downarrow \quad (13) \\
\text{Ca}^{2+} + 2\text{HCO}_3^- & \rightleftharpoons \text{CaCO}_3 + \text{H}_2\text{O} + \text{CO}_2 \quad (14)
\end{align*} \]

In the field practice, the Oddo-Tomson Saturation Index was commonly used to obtain the equilibrium conditions for inorganic salt scaling:

\[ I_s = \lg \left( \frac{C_{A}^{n^+} \cdot C_{B}^{m^-}}{K_{sp}^{c} (P, T, S_i)} \right) - \lg K_{sp}^{c} (P, T, S_i) = 0, \]
\[ -\lg K_{sp}^{c} = a + bT + cT^2 + dp - eS_{i}^{1/2} + fS_{i} - gS_{i}^{1/2}T, \quad (15) \]

where \( A^{n^+} \) and \( B^{m^-} \) are the positive and negative ions in the inorganic reaction; \( K_{sp}^{c} \) is a quasiequilibrium constant taking into the activity coefficient; \( I_s \) is the saturation index of the inorganic salt; \( T \) is the temperature in °C; \( P \) is the pressure in psi; \( S_i \) is the solution’s ion intensity in moles/l; and \( a-g \) is a regression coefficient for various salts.

The condition of scaling was judged by the saturation index of the inorganic salt \( I_s \) of each inorganic salt in the solution. When the \( I_s < 0 \), the solution is undersaturated.
and no scale appeared in the solution; when the \( I_z = 0 \), the solution is in a state of saturation but no scaling; when \( I_z > 0 \), the solution is in a supersaturated state and the scale appeared in the solution.

According to the balance of materials and the equilibrium conditions, the scaling prediction method considering multiphase equilibria in electrolyte solution was deduced. Under equilibrium conditions, the relationship between the amount of inorganic salt scale and solution ion concentration is as follows:

\[
\begin{align*}
\left( C_{\text{SO}_4^{2-}}^0 - M_{\text{CaSO}_4} - M_{\text{BaSO}_4} - M_{\text{SrSO}_4} \right) \\
\cdot \left( C_{\text{Ca}^{2+}}^0 - M_{\text{CaCO}_3} - M_{\text{CaSO}_4} \right) = K_{\text{SPCaSO}_4}^\prime,
\end{align*}
\]

\[
\begin{align*}
\left( C_{\text{SO}_4^{2-}}^0 - M_{\text{CaSO}_4} - M_{\text{BaSO}_4} - M_{\text{SrSO}_4} \right) \\
\cdot \left( C_{\text{Sr}^{2+}}^0 - M_{\text{SrSO}_4} \right) = K_{\text{SPsSO}_4}^\prime,
\end{align*}
\]

\[
\begin{align*}
\left( C_{\text{SO}_4^{2-}}^0 - M_{\text{CaSO}_4} - M_{\text{BaSO}_4} - M_{\text{SrSO}_4} \right) \\
\cdot \left( C_{\text{Ba}^{2+}}^0 - M_{\text{BaSO}_4} - M_{\text{BaCO}_3} \right) = K_{\text{SPBaSO}_4}^\prime,
\end{align*}
\]

\[
\begin{align*}
\left( C_{\text{CO}_2}^p \right)^2 \left( C_{\text{Ca}^{2+}}^0 - M_{\text{CaCO}_3} - M_{\text{CaSO}_4} \right) \\
\cdot \left( C_{\text{CO}_2}^p \right) = K_{\text{SPCaCO}_3}^\prime,
\end{align*}
\]

where \( M \) is the amount of scale in each inorganic salt solution in moles/l; \( C_{\text{Ca}^{2+}}^p \) represents the concentration of the components under equilibrium conditions in moles/l; \( C_{\text{Ca}^{2+}}^0 \) is the initial concentration of the components in moles/l; \( K_H \) is Henry’s constant of \( \text{CO}_2 \) dissolution; \( K_1 \) and \( K_2 \) are the primary and secondary ionization constants of carbonic acid; \( \text{const} \) represents the total initial concentration of \( \text{CO}_2^\prime \), \( \text{HCO}_3^- \), and \( \text{CO}_2 \) in the solution in moles/l; and \( \gamma_{\text{CO}_2} \) and \( f_{\text{CO}_2} \) are the molar contents and fugacity of \( \text{CO}_2 \) in the gas phase, respectively. For its formula or equation of state calculation, this paper uses the PR equation of state. Meanwhile, the ratio of gas and water in a gas reservoir was very large, and the molar content of ionic components in the whole system was relatively small. The change of the electrolyte solution concentration caused by the phase state change between gas, oil, and water has a greater influence on the scaling of inorganic salt, while the physical property change caused by inorganic salt scaling on the gas, liquid, and liquid phase states is relatively weaker. Therefore, the phase equilibrium of gas, liquid, and liquid in the entire multiphase system is solved firstly, then the chemical equilibrium in the formation water is calculated under the condition of phase equilibrium. Finally, the final condition based on the conservation of materials and the unity of physical properties is determined. The specific solution steps are as follows (Figure 6):

**Step 1.** We input the pressure \( (P) \), temperature \( (T) \), and the initial composition \( z_i^0 \). Assuming that there is no scaling in the formation water, the Michelsen discriminant method is used to determine the three-phase stability of gas, liquid, and liquid. The PR equation is used for flash calculation to determine the molar composition for each of phases \( V^0, L^0, W^0 \), the composition of the reactions \( y_i, x_i, w_i \), and the corresponding thermodynamic parameters.

**Step 2.** The composition of formation water determined by flash calculation is used to predict the tendency of inorganic salt scaling. If \( I_z \leq 0 \), it means that there is no scaling in the fluid under the current condition. The calculation result of Step 1 can describe the composition of the entire multiphase equilibrium system, and no further calculation is required. If \( I_z > 0 \), the solution is in the state of supersaturation. The following calculations need to be continued to determine the equilibrium scale of inorganic salts.

**Step 3.** If the formation water is not at the natural equilibrium state, the initial scale of each inorganic salt and the composition of formation water are calculated by equations (11)–(16). If the scale of an inorganic salt accounts for the molar content of the aqueous solution of the formation, the molar content of the inorganic scale in the entire multiphase system is as follows:

\[
M_j^f = W^0 X_{M_j},
\]

**Step 4.** After eliminating the inorganic salt scale, the three-phase flash evaporation was used to determine the molar content \( (V^0, L^0, W^0) \) of each phase in the new gas, liquid, and liquid three-phase fluid, composition \( (y_i^0, x_i^0, w_i^0) \), and corresponding thermodynamic parameters.

**Step 5.** We combine the mole content of each phase in the gas, liquid, and liquid three-phase fluid calculated by Step 4 with the inorganic salt scales calculated in Step 3 to preliminarily determine the gas, liquid, liquid,
and solid phase contents and the composition of the entire multiphase system:

\[
\begin{align*}
V'' &= V' \left( 1 - \sum_{j=1}^{n_m} M'_j \right), \\
L'' &= L' \left( 1 - \sum_{j=1}^{n_m} M'_j \right), \\
W'' &= W' \left( 1 - \sum_{j=1}^{n_m} M'_j \right), \\
M''_j &= M'_j, \\
z''_i &= V' \left( 1 - \sum_{j=1}^{n_m} M'_j \right) y'_i + L' \left( 1 - \sum_{j=1}^{n_m} M'_j \right) x'_i \\
&+ W' \left( 1 - \sum_{j=1}^{n_m} M'_j \right) w'_i + \sum_{j=1}^{n_m} M'_j m_{ij} = V'' y'_i \\
&+ L'' x'_i + W'' w'_i + \sum_{j=1}^{n_m} M''_j m_{ij}.
\end{align*}
\]

**Figure 6:** Flow chart of gas-liquid-liquid-solid multiphase equilibrium scale prediction.

**Step 6.** We calculate the scaling tendency of the solution after flashing calculation in Step 4. If the \( I_s \) of the existing inorganic salt that has been scaled reached \( I_s = 0 \) and the \( I_s \) of the inorganic salt that has not been scaled reached \( I_s \leq 0 \), then the formation water was in a chemical equilibrium state and the entire gas-liquid-liquid-solid system has reached equilibrium, and the calculation results from Step 4 was the balanced composition of the multiphase system under the current conditions and it is not necessary to continue calculation. If \( I_s > 0 \), it means that the formation water was still in a state of supersaturation and the amount of scaling needs to be recalculated.

**Table 4:** Composition of injection water.

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<thead>
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<th>Ion</th>
<th>Content (mg/l)</th>
<th>Ion</th>
<th>Content (mg/l)</th>
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<td>K(^+)</td>
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<td>Sr(^{2+})</td>
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Table 5: Comparative analysis of scale amount in electrolyte solution.

<table>
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<tr>
<th>Mass fraction (%)</th>
<th>Experimental results</th>
<th>Prediction results under phase equilibrium</th>
<th>Prediction results without phase equilibrium</th>
<th>Model without phase equilibrium</th>
<th>Model with phase equilibrium</th>
<th>Error (%)</th>
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<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
</tr>
</tbody>
</table>
Table 6: Comparative analysis of the predicted scale amount of BS8 reservoir fluid and the experiment data.

<table>
<thead>
<tr>
<th>Temperature (°C)</th>
<th>Pressure (MPa)</th>
<th>Experimental results</th>
<th>Scale amount (mg/l)</th>
<th>Error (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Prediction results under phase equilibrium</td>
<td>Prediction results without phase equilibrium</td>
</tr>
<tr>
<td>171.4</td>
<td>43.57</td>
<td>1.36</td>
<td>1.42</td>
<td>0.85</td>
</tr>
<tr>
<td></td>
<td>30</td>
<td>8.98</td>
<td>8.83</td>
<td>7.90</td>
</tr>
<tr>
<td></td>
<td>20</td>
<td>14.52</td>
<td>13.89</td>
<td>12.71</td>
</tr>
<tr>
<td></td>
<td>11.5</td>
<td>88.59</td>
<td>90.18</td>
<td>70.49</td>
</tr>
<tr>
<td></td>
<td>5</td>
<td>281.67</td>
<td>292.98</td>
<td>216.10</td>
</tr>
<tr>
<td>155</td>
<td>30</td>
<td>1.24</td>
<td>1.22</td>
<td>0.38</td>
</tr>
<tr>
<td></td>
<td>20</td>
<td>6.70</td>
<td>6.72</td>
<td>5.67</td>
</tr>
<tr>
<td></td>
<td>11.5</td>
<td>12.36</td>
<td>11.65</td>
<td>9.91</td>
</tr>
<tr>
<td></td>
<td>5</td>
<td>144.32</td>
<td>141.93</td>
<td>95.39</td>
</tr>
<tr>
<td>135</td>
<td>5</td>
<td>8.13</td>
<td>7.71</td>
<td>2.36</td>
</tr>
</tbody>
</table>
If $I_s < 0$, the amount of inorganic salt that is calculated in Step 3 is too high and needs to be recalculated.

**Step 7.** We combine the formation water that was still in a nonchemical equilibrium state with the inorganic salt scale. Then, the formation water that was still in a nonchemical equilibrium state is combined with the inorganic salt scale. Steps 3–6 are then repeated to have the chemical balance of the formation fluid calculation, and the multiphase flash calculation of gas, liquid, and liquid until the total system is balanced.

**4. Validation and Application**

**4.1. Model Validation.** The prediction of inorganic salt scaling in an electrolyte solution is an important part of the Multiphase Equilibrium Prediction model. The accuracy of this part is of great significance to the comprehensive prediction of formation fluid. Based on the data of formation water and injected water in the Qianmiquiao reservoir, the scaling of formation water and injected water mixtures is predicted by using the model established above. Afterwards, the model outcomes were compared with the experimental data and the predicted values of the Oddo-Tomson model, respectively. In the simulation, the pressure and temperature were 10 MPa and 171.4°C, respectively, and the composition of formation water is shown in Table 1. Besides this, the composition of injection water is shown in Table 4.

By comparing the experimental value of electrolyte solution scaling, the predicted value was calculated by applying the Oddo-Tomson model as shown in Table 5. It can be concluded that the predicted values of the Oddo-Tomson model and the established model were close to the experimental value with an error of 9.2% and 3.2%, respectively. The Oddo-Tomson saturation index was a common method to predict the scale amount in an electrolyte solution. However, the new model had a higher accuracy in predicting electrolyte scaling, which indicated that it was feasible to predict inorganic salt scaling in an electrolyte solution by using this model in the Multiphase Equilibrium scaling prediction.

The proposed model for predicting multiphase equilibrium fouling and the prediction model of formation water scaling based on the Oddo-Tomson saturation index were applied to predict the scale of the fluid in the BS8 well fluid under experimental conditions, and the predicted results were compared with the experimental result to verify the reliability of the proposed model. From the results (Table 6), it is demonstrated that the predictive value of scale in the proposed multiphase equilibrium scaling model was close to the experimental results, with an average deviation of 3.5%. In comparison, the prediction results of the model based on the Oddo-Tomson saturation index was significantly lower than the experimental values, and the average error was 30%. The reliability of the proposed model was verified. The advantage of the proposed model was that the phase change of the reservoir fluid can be described accurately, which was necessary to predict the amount of scaling in a gas reservoir. In comparison, the model based on the Oddo-Tomson saturation index ignored the influence of phase change on scaling. In the simulation, the compositions of formation water, natural gas, and condensate oil are shown in Tables 1–3. When the temperature was 171.4°C, the scale amount under 5 different pressure values (43.57 MPa, 30 MPa, 20 MPa, 11.5 MPa, and 5 MPa) was predicted. When the temperature was 155°C, the scale amount under 4 different pressure values (30 MPa, 20 MPa, 11.5 MPa, and 5 MPa) was predicted. When the temperature was 135°C, the scale amount under 5 MPa was predicted.

**4.2. Application.** The multiphase equilibrium scaling model was used to predict the inorganic salt scaling and fluid phase changes in the BS8 wellbore and formation. At present, the wellhead pressure was 3 MPa and the temperature was 60°C. The other production data were described above. The prediction results are shown in Figures 7–10. As demonstrated in Figure 7, it could be seen that the pressure of BS8...
decreased continuously from the near-wellbore area, and the pressure reduction caused the formation water to evaporate into the natural gas. The closer to the wellbore, the higher the saturated water content of the natural gas was. According to the prediction, the saturated water content at the bottom of the well reached 12%. As indicated in Figure 8, much CaCO₃ and a little of SrSO₄ scale were generated in the current formation under equilibrium conditions. With the decrease of the formation pressure, the amount of scale increased from the formation to the near-wellbore area, and the total inorganic salt scale at the bottom of the well reached 133.8 mg/l. As indicated in Figure 9, the molar content of the gas phase and inorganic salt in the formation fluid increased with the decrease of pressure, and the molar content of free formation water continuously decreased. From the prediction of the scaling pressure and temperature curve of the inorganic salt in the BS8 formation fluid (Figure 10), it indicated that the temperature of the SrSO₄ scaling point was lower than that of CaCO₃ at the same pressure. When the temperature and pressure curves were above the scaling point, the corresponding inorganic salt scale would be generated in the fluid. Currently, the SrSO₄ scale was formed at the depth of 2700 m in the BS8 well, while the CaCO₃ scale was produced at a well depth of about 3000 m. With the decrease of the wellbore temperature, the amount of inorganic salt from the bottom to the wellhead continuously decreased.

5. Conclusion

(1) A set of experimental devices for testing the amount of inorganic salt scales in formation fluids under high-temperature and high-pressure conditions was developed. The high-temperature and high-pressure phase analysis and scaling test of the actual gas reservoir fluid in the BS8 well were carried out by the devices. The experimental results demonstrated that with the decrease of formation pressure, the dissolved gas volume of formation water decreased, while the saturated water content in natural gas increased. In addition, two kinds of CaCO₃ scale and SrSO₄ scale were generated in the gas reservoir fluid under experimental conditions. The amount of fouling increased with the decrease of pressure and increased with the increase of temperature. The change of scaling with the pressure and temperature in the actual gas reservoir is more obvious than the degassing formation water.

(2) A new model for predicting the scale of inorganic salts in gas-liquid-liquid-solid multiphase equilibria is established. According to the composition characteristics of gas reservoir fluid, the chemical equilibrium calculation of the inorganic salt scaling under
the condition of gas, liquid, and liquid equilibrium is put forward. The method can simplify the complicated problem of directly solving the phase equilibrium system of a chemical reaction

(3) The new multiphase equilibrium scaling model was proposed which can accurately predict the amount of inorganic salt scale in the actual gas reservoir fluid. The prediction results were close to the experimental data with an average deviation of 3%. In comparison, the prediction results of models that did not consider phase changes were significantly lower than the experimental data, and the average deviation was about 30%. To accurately predict the amount of scaling in gas reservoir fluids, it is necessary to consider the changes in the phase state of the fluid

(4) Through the prediction of the scaling in the BS8 well, much CaCO3 and a little of SrSO4 scale were generated in the current formation under equilibrium conditions. With the decrease of the formation pressure, the amount of scale increased from the formation to the near-wellbore area, and the total inorganic salt scale at the bottom of the well reached 133.8 mg/l

Abbreviation

PVT: Pressure, volume, and temperature relationship.

Data Availability

The data for the paper can be accessed through the following link: https://www.dropbox.com/s/oe9n49ss8pqssyl/data.xlsx?dl=0.

Conflicts of Interest

The authors declare that they have no conflicts of interest.

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