

Review Article

Review on Mechanism, Prediction, and Remediation of Salt Deposition in Gas Production Wells

Duocai Wang, Zhongxin Ren^{ORCID}, Haichuan Li, Ping Jiang, Jian Wang, Yanwei Zhu, and Ziheng Zhu

PipeChina West-East Gas Pipeline Company, Beijing 100728, China

Correspondence should be addressed to Zhongxin Ren; renzx01@pipechina.com.cn

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During the gas production process, the evaporation of formation water leads to an increase in the water content of the gas and increases the salinity of the remaining formation water. Salt deposition generally occurs near the wellbore and in the wellbore. When the wellbore is clogged with salt deposition, it will lead to a rapid decrease in gas well pressure and production. This work analyzes the effects of formation water evaporation, temperature, and pressure on salt deposition in gas wellbore. And the salt deposition mechanism in the wellbore was summarized. This work presented a technical review on the salt deposition prediction in the gas wellbore. Finally, this work summarizes three different techniques for salt deposition remediation in gas wells, including cold-water removal, hot-water washing, and chemical salt prevention. This work can provide a reference for salt deposition prevention and remediation in the underground gas storage.

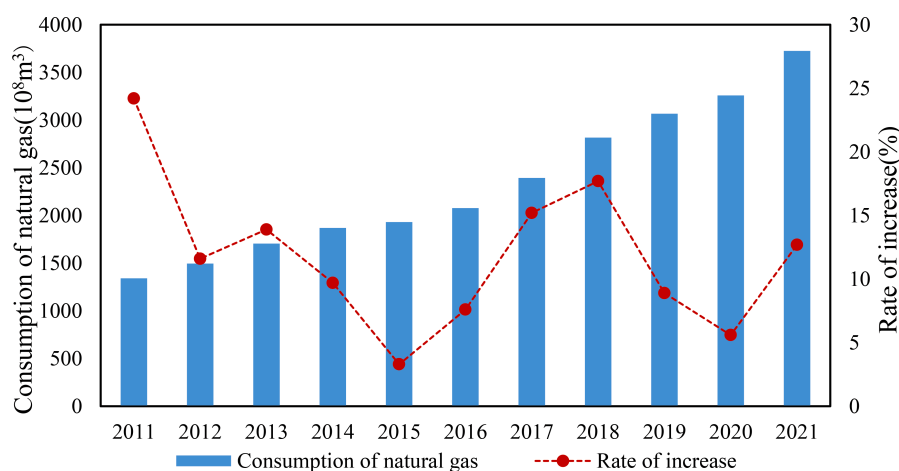
1. Introduction

The exploitation and use of natural gas are beneficial to the adjustment of the energy structure and economic improvement. China's natural gas consumption has grown rapidly in recent years. In 2021, natural gas consumption in China was 372.6 billion m³, 46.67 billion m³ higher than that in 2020 (with an annual growth rate of 12.7%), as shown in Figure 1(a). In December 2021, China's apparent consumption of natural gas was 39 billion m³, with an annual growth rate increase of 15.1% (Figure 1(b)).

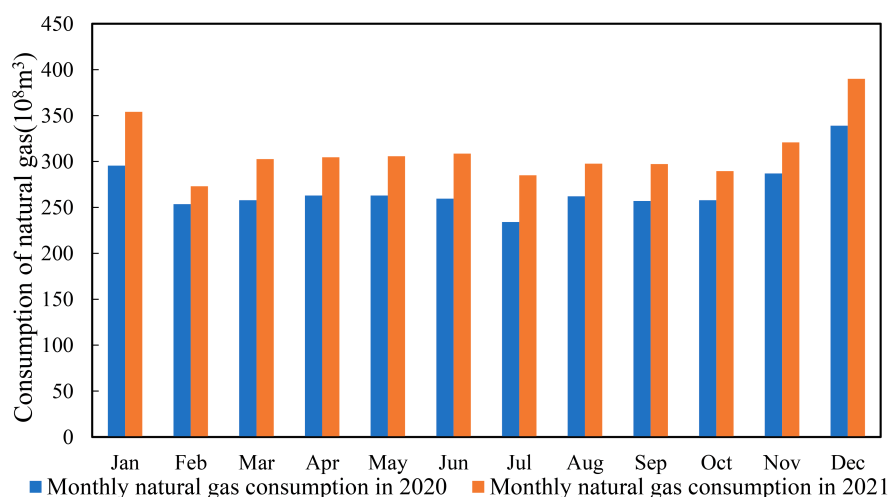
Unconventional natural gas reservoirs have become an important source of natural gas production since conventional natural gas production has rapidly declined [1–3]. Natural gas has the advantage of low carbon content compared with other fossil fuels (e.g., coal and oil). It also has the advantage of being a low-cost and huge source compared with renewable energy [4–8]. However, the gas production is still unable to meet consumption demand [9, 10]. In the face of such huge natural gas consumption, the contradiction between supply and demand of natural

gas will be intensified if there is no emergent natural gas supply system, which may lead to serious consequences. The experience of natural gas development shows that underground gas storage (UGS) is the most economical and effective means to guarantee the supply of natural gas. Depleted oil and gas reservoirs are the first choice for UGS due to their good sealing, storage properties, and construction conditions. About 75% of the UGS in the world is built on depleted oil and gas reservoirs, and China's depleted oil and gas reservoir UGS account for more than 90%. Most of them are reconstructed from depleted gas reservoirs, and the subsequent construction of UGS is still dominated by depleted gas reservoirs.

Gas reservoir usually contains a large amount of saline water in the form of formation water [11]. When the salty formation water flows into the wellbore during gas production, water is vaporized into the gas phase, and salt precipitation happens in the gas reservoirs near the wellbore [12] and even in the wellbore [13, 14]. Furthermore, due to a long-term drying formation during gas production, the salinity of the formation water could reach and even



(a) China's natural gas consumption from 2011 to 2021



(b) Monthly consumption of natural gas in China from 2020 to 2021

FIGURE 1: China's natural gas consumption in recent years (<https://www.in-en.com/search.php?q=%E5%A4%A9%E7%84%B6%E6%B0%94%E8%A1%A8%E8%A7%82%E6%B6%88%E8%B4%B9%E9%87%8F>).

exceed the solubility of halite in the aqueous solution at the later development period of gas reservoirs. As for the UGS, salt deposition may occur after multiple injection-production cycles as the formation water is evaporated by dry natural gas [15–17]. In particular, salt deposition can clog the wellbore when the initial salinity of the formation water in the reservoir is high (Wen23 and Wen96 UGS), which increases the risk of the UGS. Moreover, salt deposition also occurs in the process of CO_2 geological storage [18–20]. In natural gas production, salt deposition in the wellbore will significantly reduce the productivity of the gas well, and the wellbore will be blocked and abandoned in serious cases [21]. Salt scale and salt deposition are often removed by water flushing, mechanical salt cleaning, or chemical salt suppression. The purpose of all these measures is to maintain or restore the original gas flow channels in the wellbore.

China's dependence on natural gas is 43%, while the working gas of China's UGS only accounts for 4% of annual consumption, lower than the average ratio of UGS working gas over the world (i.e., 12%) and much lower than the average ratio of UGS working gas in the United States (i.e., 17%) and the average ratio of UGS working gas in the European Union (i.e., 25%). Therefore, it is necessary to further increase the working gas of the UGS. In addition to adding new UGS facilities, the built UGS also needs to be improved in order to reduce the risk of UGS capacity loss, eliminate the potential safety hazard, prolong the working time of the UGS, and increase the working gas volume of the UGS. During multi-cycle production for the UGS with limited formation water, salt deposits may occur in the UGS after multiple injection-production cycles as the formation water is evaporated by dry natural gas. Firstly, this work introduces the factors that affect the salt deposition in the gas

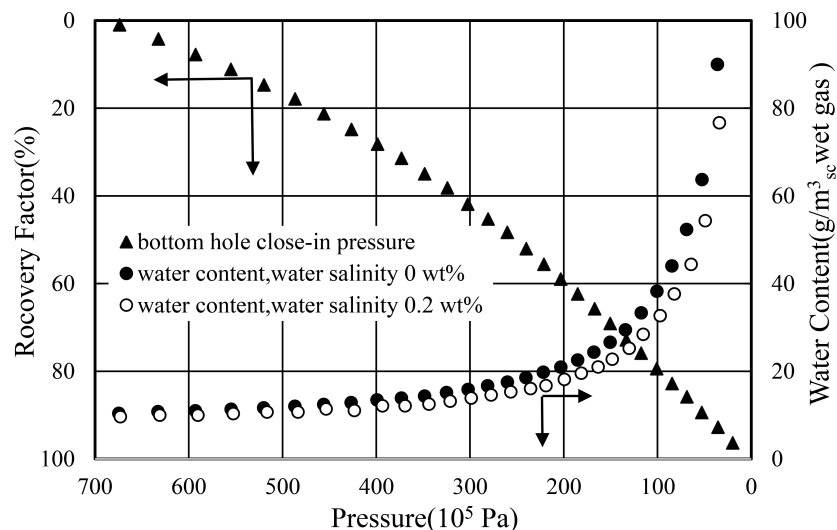


FIGURE 2: Water content in methane and recovery factor as a function of pressure and water salinity ($T_{res} = 145^{\circ}\text{C}$) [26].

production wellbore of UGS. The salt deposition mechanism is described by analyzing these factors. Then, this work introduces the prediction technique of salt deposition. At the end of the work, remediation technology in the wellbore is introduced by combining with field cases.

2. Mechanism of Wellbore Salt Deposition

There are two main mechanisms leading to salt deposition in the wellbore. First, water solubility in the gas increases with the decrease in pressure when the formation water flows through the wellbore. The salinity of the remaining formation water will increase when the fresh water is dissolved into the gas during production [22]. When the salinity of the formation water reaches the saturation salinity under the formation temperature and pressure, salt deposition will occur in the wellbore [23]. Second, the flow of formation water through the wellbore is often accompanied by a decrease in temperature and pressure, which leads to a decrease in salt solubility of the formation water [24]. The two conditions directly impact the salt deposition in the wellbore. The first one is that the produced water in the wellbore is formation water rather than condensate water from the reservoirs. The formation water has a much higher salinity than the condensate water. Second, salt deposition in the wellbore generally occurs when the salinity of the formation water is high. High-salinity formation water is the basis and source of wellbore salt deposition in gas fields. The salt deposition occurs earlier in wellbore and causes more serious blockage in the wellbore because of the higher salinity of the formation water. It is observed that the salt is deposited from the perforations up into the tubing [25].

2.1. Water Evaporation in Wellbore. During the flow of natural gas and formation water in the wellbore of UGS, the change in pressure or temperature is not enough to make the fluid reach saturation. After the formation water evaporates in the wellbore, the salt concentration in the water phase will be close to saturation. The ability of the gas phase to absorb

the water phase increases with the decrease in pressure and increase in temperature in the wellbore, which improves the evaporation capacity of the water phase in the wellbore. The concentration of salts will be higher because the gas will evaporate fresh water from the water phase.

Kleinitz et al. [26] found that the degree of salt precipitation in the formation water was increased during the production progress in the natural gas reservoirs located in Northern Germany. The salt deposition resulted in a significant decrease in production, which eventually blocked the flow channel and led to well abandonment. Figure 2 illustrates the causes of salt deposition in gas wells in Northern Germany. The maximum water content of methane is a function of pressure and water salinity. On the other hand, the water solubility in the gas increases when the reservoir pressure decreases during the production process. As pressure decreases, the salt concentration in the remaining formation water increases until salt deposition occurs to block the wellbore.

Tang et al. [27] found that water evaporation and gas geological storage in the rock will lead to salt deposition after multiple injection-production cycles of UGS, resulting in a rapid loss of gas well production. The water vaporization and salt deposition during gas production were numerically simulated by using compositional simulation software. The simulation results show that there is a dry zone with a radius of 78 m around the wellbore, and the gas production is affected by salt deposition. Salt deposition will shorten the duration of the stable production stage of the UGS, which is 230 days shorter than that without salt deposition, and the gas production will decrease by 34.42%. The simulation results for the influence of salt deposition on gas production are shown in Figure 3. The production shows similar trends over time before salt deposition. However, production is obviously influenced by both increased gas saturation and salt deposition after salt deposition.

2.2. Variation of Wellbore Temperature and Pressure. The influence of temperature and pressure on salt deposition in the wellbore is analyzed. First, the decrease in pressure will

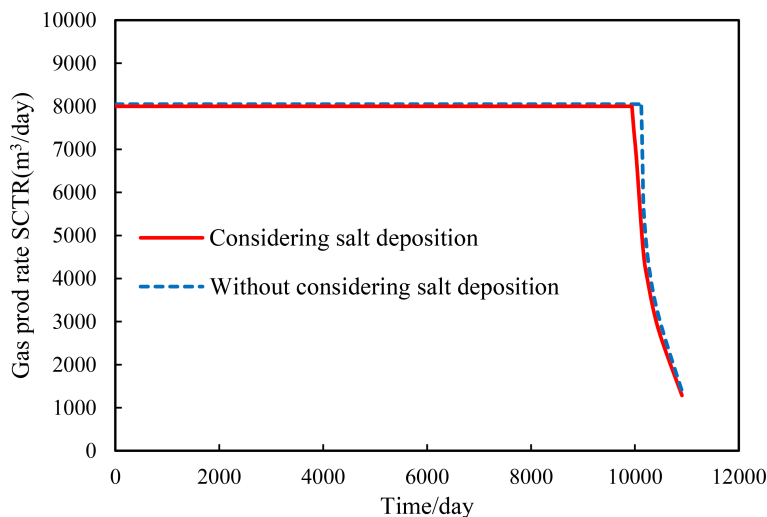


FIGURE 3: Effect of salt precipitation on gas production [27].

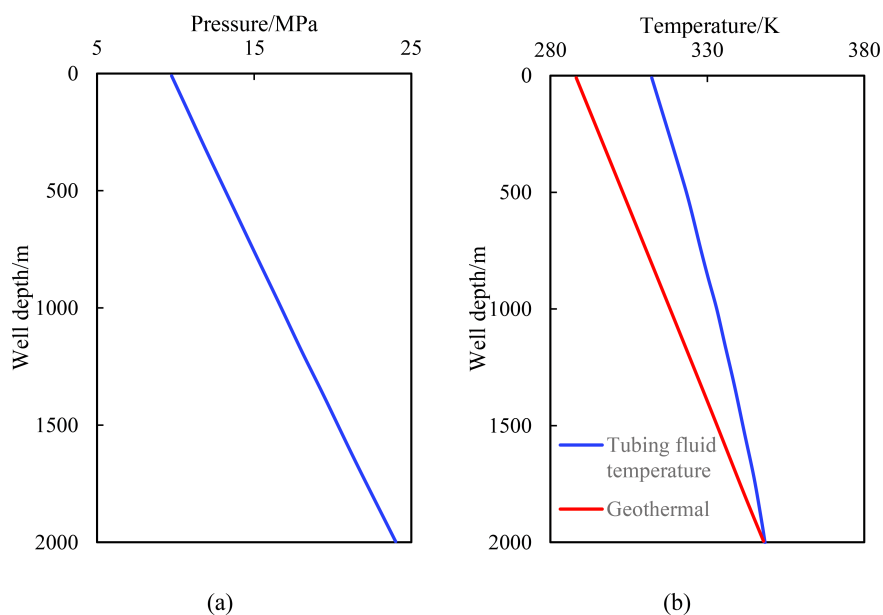


FIGURE 4: (a) Wellbore pressure profile. (b) Wellbore temperature profile [28].

intensify the gas evaporation in the wellbore. The gas flow in the wellbore is accompanied by pressure loss. The water vapor carried in the gas increases and the salt content of the remaining liquid increases as the pressure in the wellbore gradually decreases. Second, the salt solubility is related to temperature, and the influence of pressure can be ignored. In the process of fluid flow in the wellbore, heat loss leads to a continuous decrease in fluid temperature, which causes a decrease in salt solubility in the produced water in the wellbore. The salt begins to deposit in the wellbore when the solubility of salt ions reaches the saturation solubility under the temperature and pressure.

Guo et al. [28] studied the changes of temperature and pressure in the wellbore based on the Span-Wagner CO_2 gas state equation and the Fenghour gas migration equation by combining with the classical wellbore flow

and heat transfer model. The results show a downward trend of pressure and temperature in the wellbore from bottomhole to wellhead, similar to the oil and gas production process. The low-flow rate has little influence on the wellbore pressure but has an obvious influence on the wellbore temperature. Under high-flow-rate conditions, changes in flow rates affect both pressure and temperature. As the flow rate increases, the wellbore temperature decreases. This is due to a gradual decrease in pressure from bottom to wellhead, and carbon dioxide expands and absorbs heat, causing a drop in temperature. The temperature and pressure inside the wellbore change with depth, as shown in Figure 4.

At present, the fully coupled process of wellbore fluid phase state, pressure, and temperature has become a major research trend at home and abroad [29]. Since

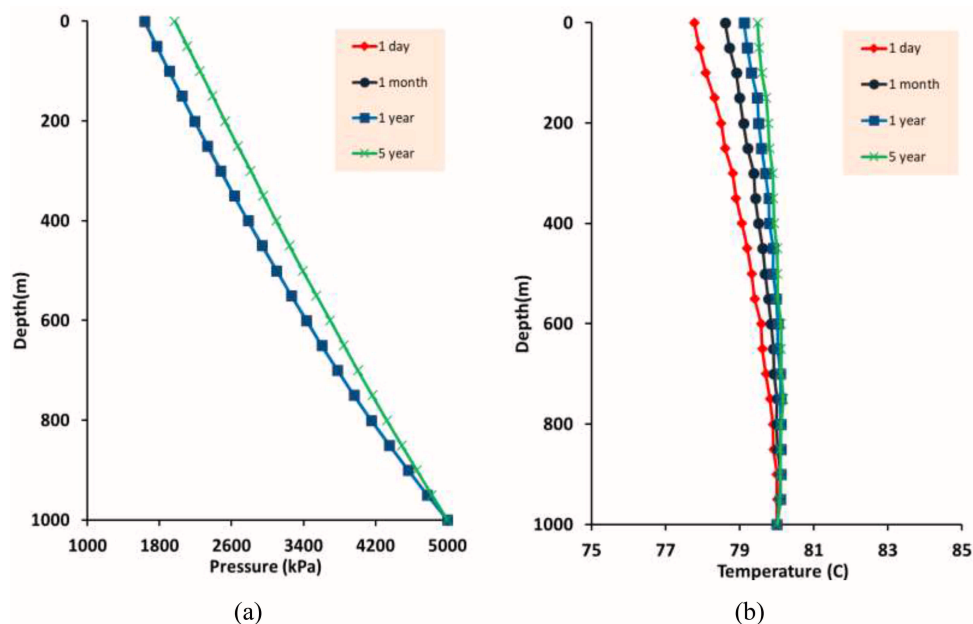


FIGURE 5: (a) Pressure along the wellbore at different times. (b) Temperature along the wellbore at different times [34].

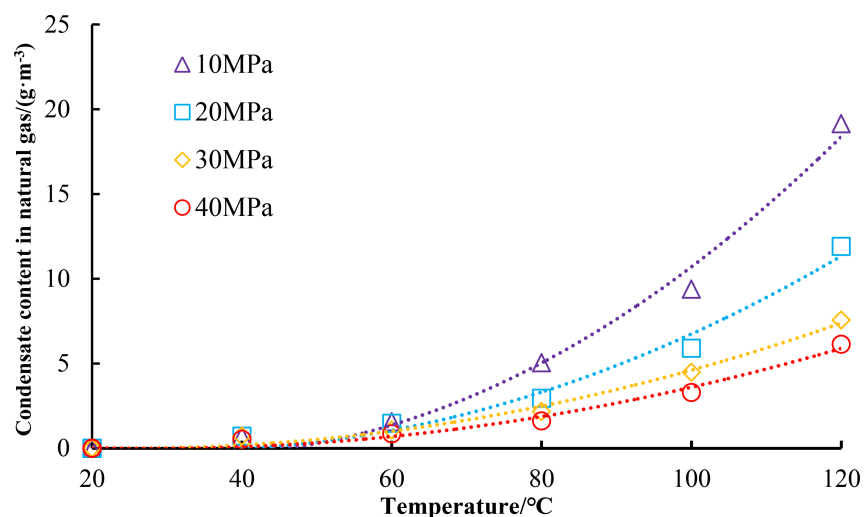


FIGURE 6: Variation of condensate content in natural gas with temperature and pressure [35].

the diameter of salt crystal particles after salting out from supersaturated brine is only a few microns, it is difficult to directly observe and measure the location of salt deposition in the wellbore and flow velocity field by conventional optical equipment. Most of the measuring tools and methods are noncontact testing systems, including Laser velocimeter, particle image velocimeter, Phase Doppler velocimeter, CT scanning, and local particle concentration measurement technology [30–33].

Xiong [34] calculated the temperature-pressure variation along the wellbore at different times from 1 day to 5 years (Figure 5). When gas production time is longer, it significantly increases the chance of salt deposition along the wellbore. Long gas production time usually leads to a higher gas flow temperature and lower pressure, which causes more liquid water to evaporate into the gas

phase. As more water evaporates into the gas phase, the remaining liquid phase has a higher salinity and begins to precipitate salt once the solubility of salt at a specific temperature is exceeded.

Shen et al. [35] tested the water evaporation features of formation water under different pressure and temperature conditions and determined the salt deposition conditions of the formation water. The results show that with the increase in temperature and decrease in pressure, the evaporation rate of formation water increases exponentially, and the critical salinity of salt deposition in the formation water is 35×10^4 ppm. The main mechanism of salt deposition in the wellbore is that the evaporation of formation water is intensified from the bottomhole to the wellhead due to the hydrocarbon-water balance under the wellbore tempera-

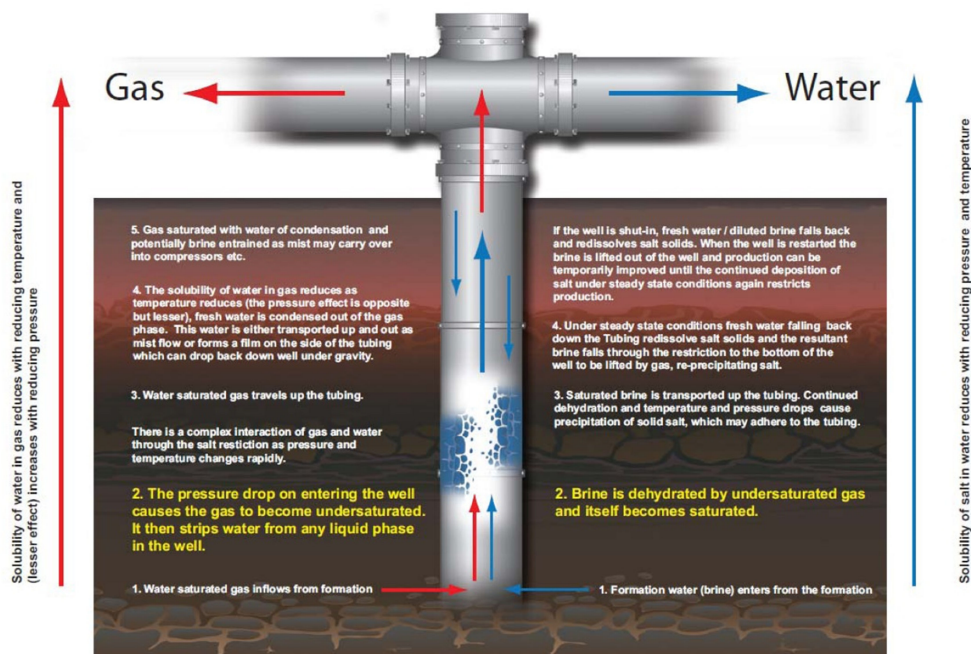


FIGURE 7: Diagrammatic summary of salting mechanisms [36].

ture and pressure conditions, and the salinity of the formation water reaches the critical salinity for salt deposition. The experimental test results of condensate content in natural gas under different temperature and pressure conditions are shown in Figure 6.

The theoretical prediction model for salt deposition within the wellbore in the UGS was established by coupling wellbore fluid mass conservation, energy conservation, momentum conservation, wellbore fluid heat transfer, fluid phase equilibrium, and salt deposition critical conditions of the formation water. The effect of formation water salinity and water-gas ratio on salt deposition within the wellbore is calculated based on the proposed model. The results show that with the increase in temperature and decrease in pressure, the evaporation rate of formation water increases exponentially.

2.3. Summary of Salt Deposition Mechanisms. Figure 7 summarizes the main salting mechanisms found in the wellbore [36]. There are mechanisms associated with both the water phase and the gas phase, and they are interrelated. The effect of changing salt solubility in moving up the wellbore is reported as being small compared with the dehydration mechanism. However, severe salting can result. The most widely reported mechanism is that of low water-gas ratio (WGR) gas wells becoming blocked by salt. The mechanism here is that of low volumes of produced water becoming dehydrated at the sand face as the sudden pressure reduction allows the gas to dissolve more water, dehydrating and causing the produced water to become saturated, precipitating salt in the wellbore. The reservoir pressure decreases as recovery

progresses. The solubility of water in the gas increases with decreasing reservoir pressure [26]. The flow of the formation brine may cause salt deposition with the development of reservoir production [17].

3. Prediction of Wellbore Salt Deposition

In order to understand the status of salt deposition in the wellbore as early as possible and take preventive measures against salt deposition, it is very necessary to measure salt deposition in the early stages of wellbore salt deposition. Early detection of salt settling based on simple criteria is a prerequisite for timely stimulation. Experience has shown that consideration of gas well productivity indicators alone is not sufficient to detect initial salt deposition in the wellbore, and subsequent stimulation is often too late to restore the original flow state. A feasible method for early prediction of wellbore salt deposition is to determine the ionic composition of formation water during production. In the production process, the water sample is collected and analyzed, then the ion concentration and density of the corresponding salt water are recorded, and finally, the ratio of various cations and anions is calculated. This method can be used to study whether there is inorganic scale in the well.

The ion ratios observed at brine density of 1.235 g/cm^3 are shown in Table 1 [26]. The ratio of ions before ($\rho = 1.100$ and 1.235 g/cm^3) and after ($\rho = 1.25$ and 1.30 g/cm^3) salt deposition is compared.

Experimental results show that for formation water with NaCl deposition, the concentration of sodium ions decreases after salt crystallization. The ratio of sodium to lithium (Figure 8) is used as an indicator for the

TABLE 1: Ionic quotients before and after NaCl deposition [26].

Quotient	Reservoir water	Critical density	Salt deposition	
	$\rho_{\text{brine}} = 1.10$	$\rho_{\text{brine}} = 1.235$	$\rho_{\text{brine}} = 1.25$	$\rho_{\text{brine}} = 1.30$
Na/Li	480	460	400	100
Na/K	17	16.5	14	2
Na/Mg	45	42	40	10
Na/Ca	1.3	1.25	1.2	0.2
Na/Cl	0.3	0.3	0.3	0.1
K/Mg	2.7	2.6	2.5	2.8
K/Cl	0.022	0.024	0.025	0.035
Mg/Cl	0.0065	0.007	0.008	0.012
Ca/Mg	34	34	34	33
Ca/Cl	0.23	0.23	0.25	0.4
Na/(Ca+Cl)	0.24	0.25	0.25	0.07
(Na+K)/Cl	0.33	0.33	0.33	0.13
(Ca+Mg)/Cl	0.25	0.23	0.25	0.4

early detection of salt deposition. The ratio of Na/Li before salt deposition is about 460, and the ratio of Na/Li after salt deposition is significantly less than 400.

CaCO_3 is an insoluble salt compared with MgCO_3 and is preferentially deposited because the solubility of MgCO_3 in water (0.223 g/L) is almost four times that of CaCO_3 in water (0.053 g/L). This situation also leads to a corresponding decrease in the concentration of CO_3^{2-} ions in water, resulting in a decrease in the deposition trend of MgCO_3 . Therefore, CaCO_3 deposition is first precipitated. The deposition trend of CaSO_4 was also lower than that of CaCO_3 . The principle of predicting salting out is various for reservoirs with different formation water types and different salt depositions. There are many methods for predicting CaCO_3 deposition, one of which is the saturation ratio method based on Ramstad et al. [37]. The definition of saturation ratio is as follows:

$$\text{SR} = \frac{a(\text{Ca}^{2+})a(\text{CO}_3^{2-})}{K_{\text{sp}}(\text{CaCO}_3)} \quad (1)$$

where SR is the saturation ratio, “ a ” is the ion activity, and K_{sp} is the solubility product.

If $\text{SR} < 1$, the system is not saturated, so there is no deposition.

If $\text{SR} = 1$, the system is saturated.

If $\text{SR} > 1$, the system is oversaturated and deposition may occur.

Langelier et al. [38] proposed the concept of saturation index, which is the earliest scale prediction model available in current literature in order to solve the scaling phenomenon in the industrial circulating water treatment system. The calculation equation is as follows.

$$\text{SI} = \text{pH} - \text{pH}_s \quad (2)$$

where SI is the saturation index, pH is the potential of hydrogen, and pH_s is the pH at saturation.

When $\text{SI} > 0$, the solution is supersaturated and tends to scale.

When $\text{SI} = 0$, the solution keeps phase equilibrium with inorganic salt scale, which is a critical state.

When $\text{SI} < 0$, the solution is not saturated and has no scaling tendency.

The assumed conditions for the laboratory test process were proposed, and the scope of application was also defined. It is suitable for the temperature (0–100°C), pH (5.5–8.5), and ion concentration (<6%). This method only considers the related factors of thermodynamics and does not consider the influence of salt content, temperature, pressure, concentration multiple, and total alkalinity, so it will cause a large error in practical application.

Stiff and Davis [39] improved pH_s calculation method in Langelier formula for scale formation of produced water in oil field, and the scaling trend calculation formula is as follows:

$$\text{SI} = \text{pH} - K - p_{\text{Ca}} - p_{\text{AlK}} \quad (3)$$

$$p_{\text{AlK}} = \lg \frac{1}{2[\text{CO}_3^{2-}] + [\text{HCO}_3^-]} \quad (4)$$

$$\mu = \frac{1}{2}(c_1 z_1^2 + c_2 z_2^2 + \dots + c_i z_i^2) \quad (5)$$

Ryznar et al. [40] proposed the concept of stability index based on the correlation of the Davis-Stiff saturation index method according to the relevant characteristics of water supply system. The formula for calculating the scaling trend is as follows:

$$\text{SAI} = 2(K + p_{\text{Ca}} + p_{\text{AlK}}) - \text{pH} \quad (6)$$

If $\text{SAI} \geq 6$, no scaling trend.

If $\text{SAI} < 6$, scaling trend.

If $\text{SAI} < 5$, the scaling trend is more serious.

Each oil field can adjust the determination value according to its own water quality characteristics. For example, when $\text{SAI} > 7$, there is no scaling trend in Zhongyuan oil field; when $6.5 < \text{SAI} \leq 7$, it is in a critical state; when $4.5 \leq \text{SAI} \leq 6.5$, the scaling trend is slight; when $\text{SAI} < 4.5$, the scaling trend is serious [41]. Compared with the Davis-Stiff saturation index method, the advantage of this method is that it can reflect the scaling trend and scale degree qualitatively with numerical values. Considering the influence factors such as thermodynamics and salinity, it is more accurate to predict the water quality with high salinity and high alkalinity and can also be used to predict the scaling trend of produced water in gas reservoirs. But when the solution pH value is higher (8–9), the model prediction and site condition will appear as inconsistent phenomena. The method does not consider the crystallization kinetics

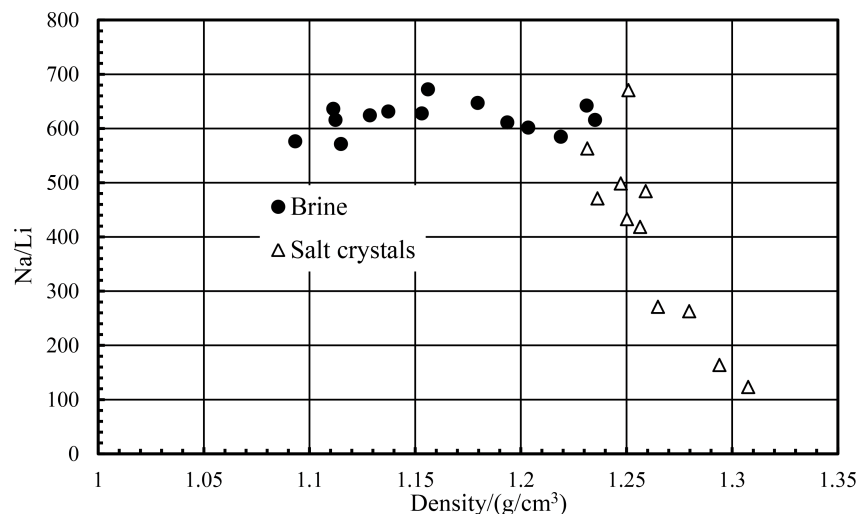


FIGURE 8: Na/Li-quotient versus brine density [26].

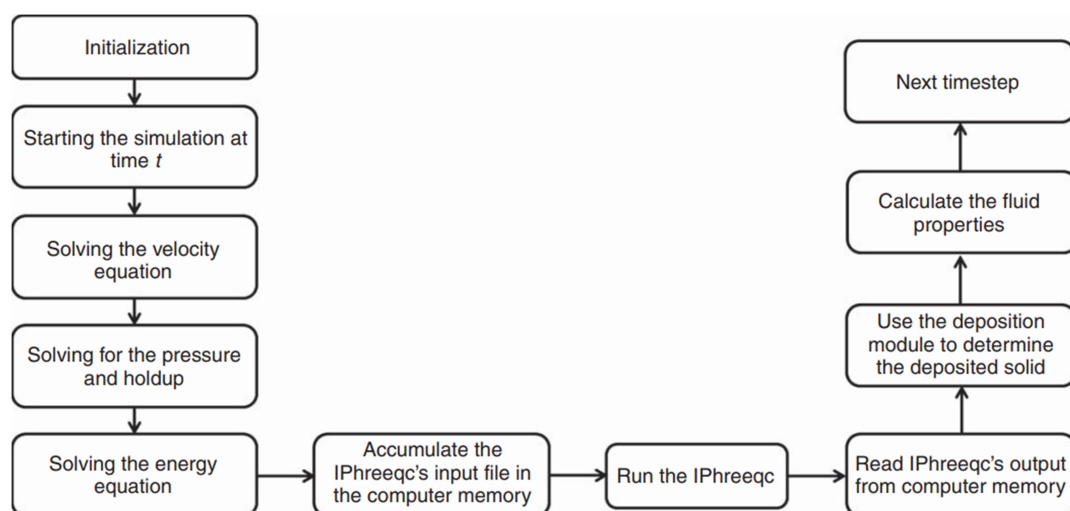


FIGURE 9: Schematic flow chart of coupled UTWELL-IPhreeqc [11].

and hydrodynamics of the influence of the scaling trend and also ignores the fluid shear stress on the scale of flushing action. Therefore, there is a deviation in the actual application.

Luo et al. [42, 43] improved the Davis-Stiff saturation index method and provided carbonate and sulfate scaling trend calculations suitable for domestic onshore oil field produced water. Luo set up a new kind of horizontal well numerical simulation model based on the vertical well black-oil simulation model. It considers the influences of four kinds of pressure losses when the fluid flows in the horizontal wellbore (including well friction loss, acceleration pressure loss, mixture pressure loss, and weight loss). The numerical simulation program based on the model can also deal with the anisotropic formation. Based on the classical solution theory, solubility product theory, and ion association theory, the influence of temperature and pressure on the scaling trend under reservoir conditions is considered by analyzing water samples from Daqing, Jilin, and Tuha oil fields.

A composite wellbore simulator (UTWELL) is developed by using different numerical methods and flow regime-detection methods to accurately model multiple phase flowing in the wellbore [11]. Besides, several precipitation mechanisms are contained for the transportation, entrapment, and deposition of solid particles in the wellbore. Subsequently, a geochemical module, IPhreeqc, is integrated into the wellbore model to handle homogeneous and heterogeneous, reversible and irreversible, and ion-exchange reactions under either local-equilibrium or kinetic conditions. Figure 9 presents the coupling scheme of IPhreeqc with UTWELL.

Kamari et al. [44] proposed a reliable prediction model, the least squares support vector machine (LSSVM) optimized with a simulated annealing optimization strategy, for estimating the potential deposition of the equilibrium calcium carbonate aqueous phase. The model has been developed and tested using the correction factor K reported in the 200 series of literature as a function of temperature and total ionic strength data. The model results, shown in

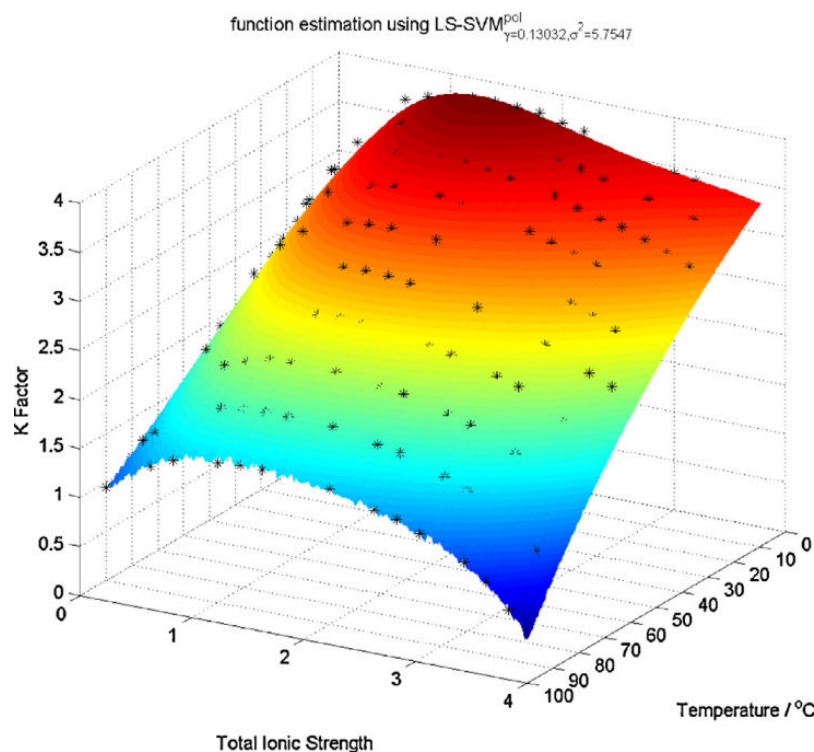


FIGURE 10: The modeling results versus the literature-reported data [44].

the figure, are in good agreement with the literature data (Figure 10).

Shen et al. [35] established a theoretical prediction model for salt deposition within the wellbore in the UGS by coupling with wellbore fluid mass conservation, energy conservation, momentum conservation, wellbore fluid heat transfer, fluid phase equilibrium, and salt deposition critical conditions of formation water. The effect of formation water salinity and water-gas ratio on salt deposition within the wellbore is calculated based on the proposed model. The results show that with the increase in temperature and decrease in pressure, the evaporation rate of the formation water increases exponentially. The effect of different formation water salinity on salt deposition is shown in Figure 11.

Engineers can predict salt deposition in gas wells mainly by monitoring the ion concentration of the produced water or by directly observing the well through downhole television. Salt deposition can be determined by the increase in ion content in gas well-produced water. Downhole television is a new logging technology that visually monitors the condition of downhole tubing.

4. Remediation Technology of Wellbore Salt Deposition

There are three main methods for salt removal and salt prevention in gas wells, including cold-water removal, hot washing, and chemical salt prevention. Salt accumulation has been indicated by mechanical wireline surveys and by a video-camera survey (Figure 12). Most salts were found in the upper perforations [36].

4.1. Cold-Water Removal. For the cold-water removal, the water can be injected into the wellbore to reduce the salinity, but too much water will cause liquid accumulation. When water is added, well shut-in will affect gas production. Figure 13 shows the effects of cold-water washing on the North Sea well in the Netherlands sector. It can be seen that there is a slow decline in flow rate and flowing wellhead pressure, both of which are restored after the cold-water wash [36].

4.2. Hot-Water Washing. The aim of this method is to pump hot water above 80°C to dissolve salt particles and achieve the purpose of salt removal, but the cost of large operation equipment is high [45].

4.3. Chemical Salt Prevention. The inhibitor molecules were dissolved in salt water at a certain concentration and adsorbed around Na⁺, Cl⁻, or NaCl crystal nuclei. The dissociated charged groups adsorbed Cl⁻ with a positive charge and Na⁺ with a negative charge, thus preventing or delaying the generation of NaCl crystal nuclei, inhibiting the growth rate of specific crystal planes, and changing crystal morphology. The crystallization is not easy to precipitate and is easy to be carried out by water flow.

The effects of [Fe(CN)₆]⁴⁻ ions on the crystallization of NaCl in an aqueous solution have been studied [46], particularly in the situation where the saline fluid percolates through and evaporates from a saturated porous body (i.e., an ornamental porous limestone). At concentrations ranging from 2.48×10^{-4} to 2.85×10^{-3} M, the additive was able to increase the critical supersaturation of the solution by up to 8%, resulting in a significant

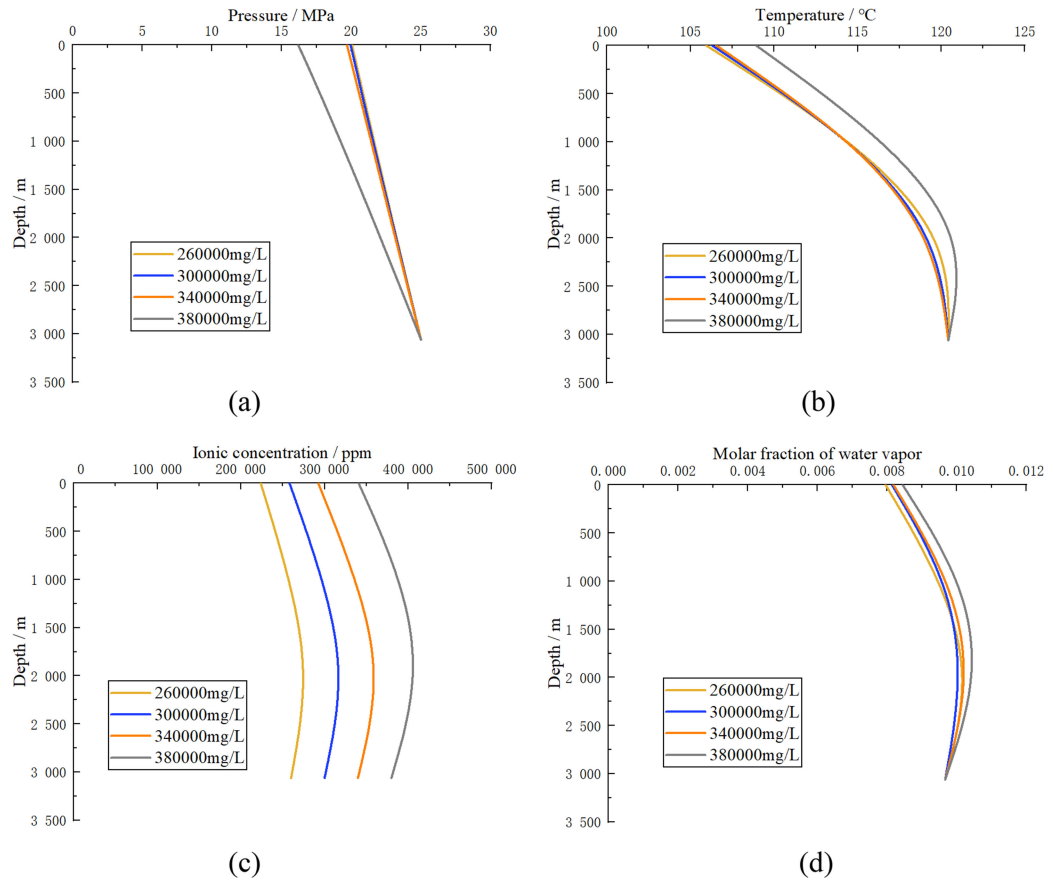


FIGURE 11: The effect of different formation water salinity on salt deposition. (a) Pressure along wellbore with respect to water salinity. (b) Temperature along wellbore with respect to water salinity. (c) Ionic concentration along wellbore with respect to water salinity. (d) Molar fraction of water vapor along wellbore with respect to water salinity [35].

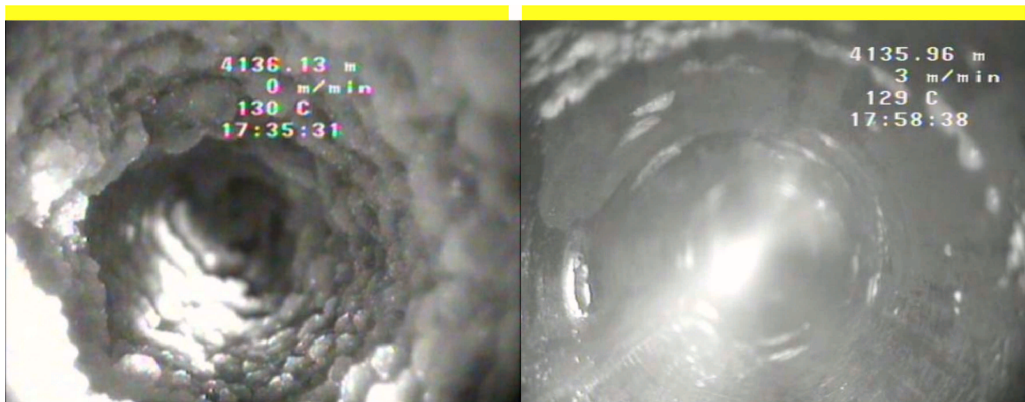


FIGURE 12: (a) Salt deposition within wellbore over a perforated interval. (b) The same wellbore location after cleaning [36].

crystallization inhibition effect. Figure 14 shows the NaCl formed on the stone surface. It should be noted that in the control sample, most of the solution was still in the beaker following 48 hours, while a very small amount of solution remained in the sample with the additive Figure 4(a). The solution in the control was completely evaporated after 1 wk when limited efflorescence growth was observed Figure 4(b).

The salt resistance of the mortar has been tested by means of a crystallization test [47]. The crystallization test results show that the salt resistance of mortar is significantly improved by the addition of a corrosion inhibitor. SEM observation of the cross-section surface of the sample showed that the inhibitor changed the habit of salt crystals while inhibiting the development of specific crystal planes.

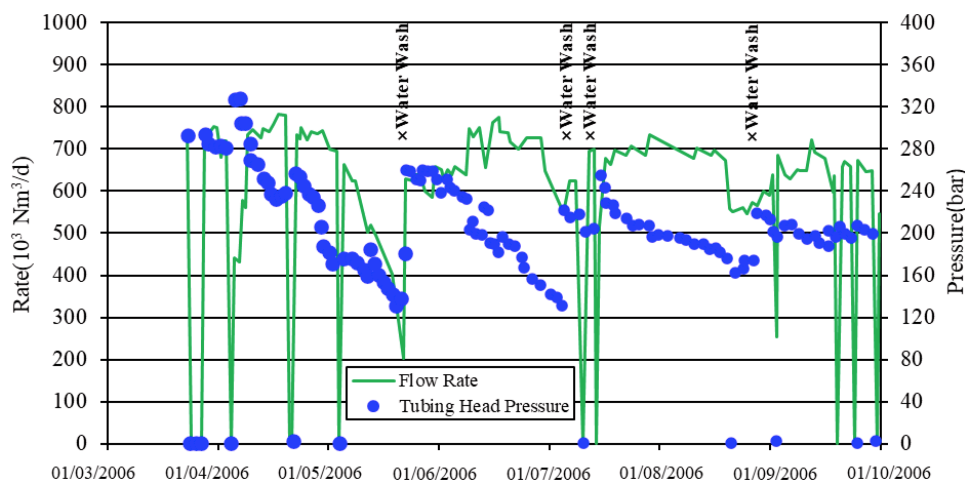


FIGURE 13: An example of the effectiveness of cold-water washing [36].

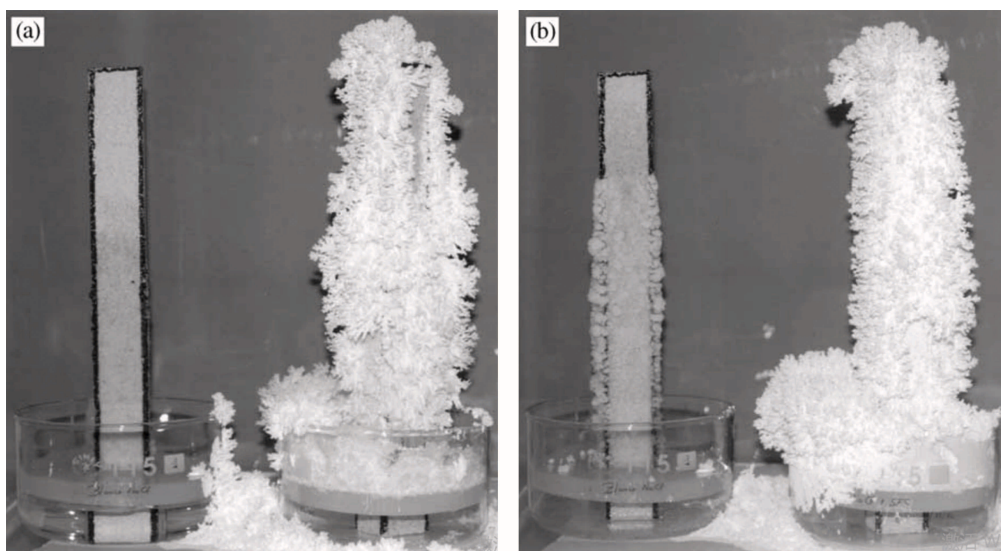


FIGURE 14: Photographs of porous calcareous stone slabs following 48 hours (a) and 7 days (b) NaCl saturated solution flow through and evaporation/crystallization [46].

Cold-water removal is adopted when salt deposition is relatively light in gas wells. Hot-water washing is adopted in the case of a large amount of salt in the well. Chemical salt prevention can be adopted when the salt is not formed in the salt well, which can effectively slow down the formation of salt in the gas well. These methods remove salt deposits by cleaning the wellbore or dissolving salt to increase gas flow capacity.

In gas reservoirs in Northern Germany, the deposition of salt from the reservoir water is observed to an increasing extent as recovery progresses [26]. The result of salt scale can lead to a significant decrease in production until the flow path is completely blocked, and eventually, the well is abandoned. In order to remove salt deposits and prevent salt deposition in the area around the well, freshwater treatment is performed regularly during production operations.

5. Conclusions

- (1) There are two main mechanisms leading to salt deposition in the wellbore. First, the water solubility in gas is increased due to pressure drop during the formation water flow in the wellbore. The salinity of the remaining formation water will increase after fresh water is dissolved in the gas during production. When the salinity of the local formation water reaches the saturation salinity, the phenomenon of salt deposition will occur in the wellbore. Second, the flow of formation water through the wellbore is often accompanied by a decrease in temperature and pressure, which leads to a decrease in salt solubility in the formation water, resulting in salt deposition in the wellbore.

- (2) Early prediction models of salt deposition in gas wells are simple and mostly based on empirical formulas. The modeling of fluid flow and salt deposition in the wellbore could provide better insight and help to tackle serious flow assurance challenges in the production strings and keep UGS working stable and reliable. Abouie et al. and Kamari et al.'s model can better predict salt deposition in the wellbore compared with the literature-reported data.
- (3) At present, there are three main methods for salt removal and salt prevention in tight sandstone gas wells, including cold-water removal, hot washing, and chemical salt prevention. The method of cold-water removal requires a high amount of water. Hot-washing salt removal requires large operating equipment and a high cost. In contrast, chemical salt prevention is the most promising method.
- (4) It is very difficult to remedy wells where salt depositions have occurred. The remediation technology of wellbore salt deposition can cause damage to the reservoir if not properly performed. In order to understand the status of salt deposition in the wellbore as early as possible and take preventive measures against salt deposition, the prediction of wellbore salt deposition will be the key direction of future development. However, the model that can estimate salt deposition locations along the wellbore and its timescale is not reported. This model can provide valuable guides to salt mitigation strategies and management of gas well production.

Conflicts of Interest

There are no conflicts of interest to declare.

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