Research Article

Competitive Effects of Permeability and Gravity on the Drying-Out Process during CO₂ Geological Sequestration in Saline Aquifers

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Salt precipitation from the drying-out process has a profound effect on the well injectivity during the storage of carbon dioxide (CO₂) in deep saline aquifers. Both gravity and reservoir heterogeneity have a significant impact on CO₂-plume behavior and CO₂ storage capacities. The collective effect of gravity and heterogeneity on the drying-out process by site-scale numerical simulation based on the Sleipner project had been investigated. Three site-scale permeability heterogeneous models and a fracture model had been built; simulation results showed that the gravity effect significantly increased the solid saturation at the injection well in the homogeneous model; changing the position of the injection well can change the distance that gravity can act and affect the amount of salt precipitation near the injection well. A novel conclusion is gravity and heterogeneity showed a mutual resistance relationship when considering the collective effect of gravity and heterogeneity on solid saturation. Gravity effects reduced the amount of salt deposited in the fracture model; at low CO₂ injection rate, gravity force dominated CO₂ flow; increased rock heterogeneity suppressed the production of salt precipitates; at high CO₂ injection rate, viscous force dominated flow; and increased heterogeneity increased salt precipitation. This research is of important guiding significance for the design of site screening and injection schemes from the perspective of avoiding a large amount of salt precipitation and pressure build-up.

1. Introduction

It has been reported that unless there are immediate, rapid, and large-scale reductions in greenhouse gas emissions, limiting warming to close to 1.5°C or even 2°C will be beyond reach [1]. Greenhouse gases (GHG) mainly include carbon dioxide (CO₂), nitrous oxide (N₂O), methane (CH₄), perfluorocarbons (PFCs), sulphur hexafluoride (SF₆), and hydrofluorocarbons (HFCs). Among all the greenhouse gases, CO₂ stands out as the most important GHG due to its excessive amount in the atmosphere compared to others [2]. The atmospheric concentration of CO₂ as of 2021 was at about 414 ppm, growing 100 ppm compared to that of 1958 [3]. In the near term, the effect of controlling the greenhouse effect by shifting the energy mix to less carbon-intensive alternative fuels and improving energy efficiency is limited [2]. Carbon-neutral and net-zero carbon emissions are a consensus long-term goal to reduce “global warming” [4, 5]. Carbon Capture and Storage (CCS) is one of the effective technologies to mitigate the global warming effect [6, 7]. CCS involves capturing CO₂ from energy-related sources, compressing it, transporting it to a suitable storage location, and storing it in deep geological formations [8, 9]. CCS is currently the only technology that allows the continued use of fossil fuels while reducing CO₂ emissions to the atmosphere [10].

The suitable geological formations that can carry out the CCS project include deep ocean, saline aquifers, depleted oil and gas reservoirs, unmineable coal seams, oil and gas reservoirs, and carbonation [10–15]. Deep saline aquifers are the
most effective storage site due to their high storage capacity [16–18]. When CO₂ is injected into deep saline aquifers, the mutual solubility of the CO₂-brine system increases the complex drying-out (water loss due to evaporation) and salting-out (salt precipitation begins to form due to the increase in brine saturation) process, once salts precipitate, the porosity and permeability diminish [19]. Salt precipitation can influence injectivity in a geological formation; monitoring pressure build-ups is a common method to evaluate the impact of CO₂ injection on well injectivity [20]. Some site tests [21–23] demonstrated the influences of salt precipitation on well injectivity.

Several laboratory studies have been performed by many scholars on the formation drying-out and salt precipitation with CO₂ sequestration. Of these studies, the position of salt precipitation in pores and the influence law of salt precipitation in pores on rock porosity and permeability are obtained by selecting cores with similar sites, changing fluid salinity, and the CO₂ injection strategy [24–28]. On the other hand, some scholars also use microfluidic models to study the mechanism of salt precipitation, especially the effect of the structure of the pore space on the location of salt precipitation and the process of accumulating salt precipitation generation [29–32]. However, it is found that the results of these experiments are controversial. Some scholars believe that salting has a great impact on CO₂ injection [25, 27, 33], while others believe that it has little impact [34] and even improves injectivity [35]. Ott et al. [36] believe that the reason for the dispute is that experimental domains have a limited volume and mass of salt that can be transported and precipitated within the domain, most of the experiments were carried out in a single primary drainage process, and small-scale tests underestimated the effect of precipitation. What is more, due to the limitation of scale, it is difficult for laboratory tests to consider the effects of gravity and the real heterogeneity of rock on the distribution of multiphase in the CO₂-brine system [37]. In fact, according to the monitoring data of the site, when CO₂ is injected into the deep saline aquifers, the salt precipitation range can be tens of meters, and the gas migration front can reach hundreds of meters to kilometers [21, 22]. Therefore, the field-scale numerical experiment is helpful to overcome the scale defects of laboratory research.

The physical properties of the matrix and fluid and the interaction of various forces in the displacement process are the main factors controlling fluid flow in porous media [38]. In recent years, it has been widely studied to explore the influence of different parameters on the spatial distribution of CO₂ and brine [39]. The influence of different parameters on the salting-out process can be analyzed when the phase change involving the (dis)appearance of solid salt is recognized and the permeability changes from precipitation and salt dissolution [40]. These numerical simulation studies consider the sensitivity parameter including injection rate, initial brine saturation, salinity, water content, capillary pressure, relative permeability, temperature, and permeability [19, 41–46]. Recent research shows that capillary-driven backflow is considered a key mechanism that determines regimes of salt precipitation [47–49]. Norouzi et al. [50] performed a comprehensive sensitivity analysis on a wide range of parameters, including relative permeability and capillary pressure curves; injection flow rate and temperature; and initial salinity, porosity, and reservoir temperature to support the role of capillary pressure and capillary-driven backflow in salt precipitation.

The conditions for capillary-driven backflow are capillary pressure gradient larger than the viscous pressure gradient [36, 51]. Therefore, how to break the balance between capillary pressure and viscous pressure is the key point for salting out. Capillary number (Cₘ) is used to quantify the influence of capillary dispersion, and it is defined as different expressions [11, 52–54]; changing parameters in the capillary number equation (such as injection rate of nonwetting phase and fluid viscous) has been shown to affect the stability of the two-phase displacement patterns [55, 56].

The gravitational effect regulated by density difference becomes highly essential in the real porous media system since it is not flat and horizontal [57]. The pore-scale study conducted by Suekane et al. [58] finds that the effect of buoyancy on fingering growth activity in immiscible two-phase flow displacements and buoyancy stabilizes or destroys fluid motion depending on fluid characteristics, injection direction, and capillary-viscous force competition. The gravity number (N_g) is used to quantify the influence of the gravitational effect [38, 54]. In the CO₂-brine system, buoyancy-dominated flow between CO₂ and brine indicated increased vertical CO₂ migration and brine counterflow, as well as localized salt precipitation; the buoyancy effect is one of the most critical parts in affecting the distribution of both the CO₂ plume and the salt precipitation associated with it [59].

Reservoir heterogeneity has an impact on CO₂-plume migration and trapping capacity [60]. Han et al. [61] conducted numerical simulations to explore the systematic effects of permeability heterogeneity on CO₂ trapping mechanisms and found that permeability heterogeneity influences buoyancy-driven CO₂ migration. The research by Green and Ennis-King [62] finds that the heterogeneity in the reservoir rock acts to retard buoyant migration by increasing the tortuosity of the migration pathways.

In summary, gravity and formation heterogeneity have been shown to have a substantial impact on saturation in deeper regions [37]. Both gravity and reservoir heterogeneity significantly impact CO₂ injectivity and migration and need to be incorporated into reservoir simulations to provide accurate predictions of both CO₂-plume behavior and CO₂ storage capacities. This is of important guiding significance for site screening and injection scheme design from the perspective of avoiding a large amount of salt precipitation and pressure build-up. In this paper, the collective effect of gravity and heterogeneity on the drying-out process will be investigated by site-scale numerical simulation. The Sleipner site project was used as a research background for numerical simulations. In Section 2, different permeability heterogeneous models are built. In Section 3, numerical simulations are performed based on the models in Section 2. The results of the numerical simulation are given in Section 4.
2. Methodology

2.1. Model Setup. The schematic model used in this research was based on the CO₂ injection project at the Sleipner Vest field in the Norwegian sector of the North Sea [63]. The system was idealized as a symmetric two-dimensional (2D) domain perpendicular to the horizontal injection well with a screen length of 100 m (Figure 1) [40]. Two sand layers and two shale layers were chosen to do the simulation (the area enclosed by a dashed line in Figure 1), and the thickness of the formation site was idealized at 88 m.

Three different models were set to characterize the sandstone layer formation, and "sand" was used to simplify the meaning of "sandstone" (homogeneous model, fracture model, and three permeability heterogeneous models). The gas phase can rarely invade into cap rock (shale layer) due to the low permeability; the shale layer formation was kept as a homogeneous model. The homogeneous model in this research was the 52 m thick homogeneous sand formation overlaid by the 36 m thick homogeneous shale caprock. Hydrogeological parameters of sand formation and shale formation are given in Table 1. A 500 m horizontal fracture was built near the well in the sand formation to express the simple fracture model (Figure 2). In this paper, the fracture was set as a solid unit to represent the fracture characteristics by setting as large porosity as possible and certain permeability; hydrogeological parameters of the fracture are given in Table 1.

As for different heterogeneous models, the Sequential Gaussian Simulation (SGS) method was used to generate spatially correlated property fields [64]. The values generated by GSLIB (var) represent the logarithm (base 10) of the property, \( \text{var} = \log_{10}(k) \), where \( k \) means permeability [65]. The "var = 0" means that there is no modifier for the original rock permeability, a positive number means that the permeability increases, and a negative number means that the permeability decreases. In this study, three different permeability change intervals were set to characterize the strength of heterogeneity. Interval (-1.6, 1.2) indicated low heterogeneity of the sand layer, interval (-3.5, 2.5) indicated medium heterogeneity, and interval (-5, 4) indicated high heterogeneity. Permeability distributions of three models are given in Figure 3. The specific method was shown in Finsterle and Kowalsky's [66] research. In Figure 3, the homogeneous shale layer remains unchanged, the red circled area indicates a low-permeability zone near the injection well.

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**Table 1: Parameters used in the simulation: permeability \( k \), porosity \( p \), salinity \( X_{\text{NaCl}} \), temperature \( T \), injection rate \( q \), and injection time \( t \).**

| Parameters | Values                  |
|------------|-------------------------|
| \( k \)    | Shale: 10 mD, sand: 3 D, fracture: 100 D |
| \( p (-) \) | Shale: 0.1025, sand: 0.35, fracture: 0.99 |
| \( X_{\text{NaCl}} (-) \) | 0.032 |
| \( T (°C) \) | 37 |
| \( q (\text{kg/s}) \) | 0.1585 |
| \( t (s) \) | \( 3.1536 \times 10^7\) |

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**Figure 1:** Schematic representation and idealized 2D schematic representation of geometry for CO₂ injection in Sleipner Vest field formation.

**Figure 2:** Schematic representation of the fracture model.
2.2. Space Discretization. The model grid was generated with the MESHMAKER module of TOUGH2 as a horizontal (X-Z) grid [67]. The geological model had an X and Z dimension of 6,000 m × 88 m. The drying-out phenomenon is not expected to occur throughout the reservoir, but only close to the injection point. Therefore, the mesh of the model was only densified near the injection well. The space discretization for the 2D grid is presented in Figure 4. In the x-axis direction, the grid is divided into 28 units. In a 20 m region around the injection well, there are 6 units with unit sizes of 1 m, 1 m, 2 m, 4 m, 4 m, and 8 m. From 20 to 1,500 m, there are 13 units with unit sizes of 15 m, 20 m, 30 m, 40 m, 50 m, 50 m, 100 m, 150 m, 50 m, 150 m, 300 m, 50 m, and 475 m. From 1,500 to 6,000 m, the unit is the coarsest, with 500 m and 9 units in total. Along the z-axis, the grid is divided into 10 units; the unit sizes from top to bottom are 3 m, 6 m, 12 m, 6 m, 2.5 m, 1 m, 2.5 m, 6 m, 6 m, and 7 m, respectively.

3. Modeling Approach

For the boundary conditions, the right boundary was fixed at constant pressure to allow flow in and out; the other three boundaries were set as no-flow boundaries (Figure 1). For the initial conditions, the formation temperature (T) was set at 37°C to maintain the isothermal condition. The injection well was 1,020 m below the ground, so the pressure was approximately 11 MPa in the injection well. The q in the field project was approximately 10^6 tons per year, corresponding to q = 0.3170 kg/s in the simulation, and q was 0.1585 kg/s for the half space in this study [40]. The total simulation time is specified as 1 year. Other parameters used in this simulation are listed in Table 1. Relative permeability function, capillary function, and porosity-permeability relationship were three governing equations of salt transport.
Table 2: Governing equations of salt transport and flow behavior.

| Description                                      | Equation                                                                 | Parameters                  |
|--------------------------------------------------|--------------------------------------------------------------------------|----------------------------|
| Relative permeability function, van Genuchten-Mualem model [68, 69] | $k_{il} = \left\{ \begin{array}{ll} \sqrt{S_s} \left( 1 - \left( 1 - \left( S_s^{1/\lambda} \right)^{1/\lambda} \right)^2 \right) & \text{if } S_s < S_h, \ 0 \leq k_{il} \leq 1 \\ 1 & \text{if } S_i \geq S_h \\ 1 - k_{il} & \text{if } S_{gr} = 0 \\ \left( 1 - S_{gr} \right)^2 \left( 1 - S_h^{1/\lambda} \right) & \text{if } S_{gr} > 0 \end{array} \right.$ | $\lambda = 0.4, S_h = 0.2, S_i = 1.0, S_{gr} = 0.05$ |
| Capillary pressure function, van Genuchten function [69] | $P_{cap} = -P_o \left( S^{1/\lambda} - 1 \right)^{1-\lambda} - P_{max} \leq P_{cap} \leq 0$ | $\lambda = 0.4, S_h = 0.2, P_{max} = 107 \text{ Pa}$ |
| Porosity-permeability relationship for tube-in-series model [70] | $\frac{k_{il}}{k_i} = \theta^2 \frac{1 - \Gamma \left( \frac{1 - \phi_i}{\phi_i} \right)^{1/\Gamma}}{1 - \theta^{1/\Gamma} \left( \frac{1 - \phi_i}{\phi_i} \right)^{1/\Gamma}}$ | $\phi_i = 0.8, \Gamma = 0.8$ |

Table 3: Description of sensitivity scenarios: gravity $g$, distances between the injection well and cap rock $D$.

| Case       | $g$ (m/s$^2$) | $D$ (m) | Model     |
|------------|--------------|--------|-----------|
| Case 1     | —            | 30     | Homogeneous |
| Case 1-1   | 9.81         | 30     | Homogeneous |
| Case 1-2   | 9.81         | 42     | Homogeneous |
| Case 1-3   | 9.81         | 12     | Homogeneous |
| Case 1-4   | 9.81         | 8      | Homogeneous |
| Case 2     | —            | 30     | Fracture   |
| Case 2-1   | —            | 30     | Var (-1.6~1.2) |
| Case 2-2   | —            | 30     | Var (-3.5~2.5) |
| Case 2-3   | —            | 30     | Var (-5~4) |
| Case 3     | 9.81         | 30     | Fracture   |
| Case 3-1   | 9.81         | 30     | Var (-1.6~1.2) |
| Case 3-2   | 9.81         | 30     | Var (-3.5~2.5) |
| Case 3-3   | 9.81         | 30     | Var (-5~4) |

and flow behavior; the selection of equations and the selection of relevant parameters are shown in Table 2.

In Table 2, $k_{il}$ is the liquid relative permeability, $\lambda$ is the empirical parameter related to core size distribution, $S_i$ is the liquid saturation, $S_h$ is the liquid saturation when saturated, $S_{gr}$ is the residual gas saturation, $S_{gr}$ is the residual liquid saturation, $k_{ig}$ is the gas relative permeability, $P_{cap}$ is the capillary pressure, $P_0$ is the air entry pressure, $P_{max}$ is the maximum capillary pressure, $k_i$ is the initial permeability, $\Gamma$ is the fractional length of the pore bodies, and $\phi_i$ is the fraction of original porosity at which permeability is reduced to zero.

In this paper, the gravity effect and the heterogeneity effect were two main factors of sensitivity analysis (SA) during case studies; solid saturation ($S_s$) was used as the response variable for SA. Descriptions of different simulation cases are given in Table 3. Parameter $D$ means the distances between the injection well and the caprock; it is related to the gravity effect on $S_s$; the specific content is given in Section 4.1.1.

4. Simulation Results and Discussion

Numerical simulations were performed using the TOUGH2 code and the related fluid characteristic module ECO2N [40, 67]. The TOUGH2-ECO2N module was used to simulate the value of $S_s$ in the injection well when CO$_2$ was injected into deep saline aquifers. ECO2N represents a mixture of three phases: a liquid phase rich in water, a gas phase rich in CO$_2$, and a solid salt. The simulation time was 3.1536 $\times$ 10$^7$ s (1 year) and did not consider temperature changes in the system. The results of the numerical simulation are given below.

4.1. Effect of Gravity on $S_s$. Case 1 and Case 1-1 were contrasted together to research the effect of gravity. Gas saturation ($S_g$) mainly gas CO$_2$ saturation) and $S_s$ were given as contour maps after 3.1536 $\times$ 10$^7$ s simulation. The injection well was chosen as the monitoring point, the time evolution of $S_s$ and the mass of salt at the injection well were picked up from the simulation output file by [66], and the mass of salt denotes salt mass in the aqueous phase and solid phase. Figure 5 shows the simulation result of Case 1; Figure 6 shows the simulation result of Case 1-1. Due to the salt-gas phenomenon that occurs particularly in and close to the borehole [24], Figure 7 shows the comparison result of two cases at the monitoring point (injection well).

In Figure 5(a), gas phase (CO$_2$) invades into sand formation evenly in the horizontal direction while there is no gravity effect. In the vertical direction, the caprock blocks the gas invasion into the upper layer due to its low permeability. After 1-year simulation, the maximum CO$_2$ migration line is about 2,200 m from the injection well in the horizontal direction (Figure 5(a)). Salt precipitation occurred mainly near the injection well (0~6 m in the horizontal direction, -72~60 m in the vertical direction). The maximum value of $S_s$ is located in the injection well; the $S_s$ values in each element are in the range of 0 to 0.1056 (Figure 5(b)). Like the $S_s$ contour map, the $S_s$ contour map also shows symmetrical features. In Figure 6(a), the distribution of the gas phase is asymmetric when it comes to the gravity situation, and the
distribution of CO₂ presents the shape of a funnel. CO₂ is gathering at the bottom of the shale formation due to the buoyancy and low permeability of the caprock. The maximum CO₂ migration line is about 3,000 m from the injection well. The preferential flow of CO₂ and the gathering of CO₂ at the bottom of the shale formation can be attributed to the effect of gravity. The preferential flow caused by gravity leads to a higher salt accumulation near the injection well (Figure 6(b)) compared to the case without gravity (Figure 5(b)); $S_s$ values near the well are at the range of 0 to 0.1584. The contour map of $S_s$ also shows asymmetrical features; the $S_s$ distribution has an upward trend due to the gravity effect.

Specifically, the gravity effect caused additional salt precipitation in the injection well; the value of $S_s$ is increased $\Delta S_{sG}$ (+0.0529) due to the gravity effect (Figure 7(a)). In this paper, positive values are used to indicate a rising trend, and negative values indicate a decreasing trend. In Figure 7(b), the mass of salt in the injection well is increased $\Delta M_{G}$ (+22.8 kg) when considering the gravity effect. The consensus mechanism about the salt aggravating near the injection well is the brine backflow around the well caused by the capillary difference [43]. In Figure 7, the value of $S_s$ and the mass of salt are in the same trend of change; the change in the mass of salt can be observed by the change in $S_s$.

4.1.1. Changes in Distances between the Injection Well and the Caprock (D). In a certain storage formation, the scope
of buoyancy can be changed by setting injection well at different locations (Figure 8). In addition to the location of the injection wells in the project ($D = 30$ m), the location of the other three injection wells was established to perform an analogy analysis (Case 1-2, Case 1-3, and Case 1-4). Parameters used for simulation were consistent with Case 1 and Case 1-1. The simulation results are given below.

In Figure 9, the gravity effect makes a significant increase of $S_e$ at the injection well in all four case studies. $\Delta S_{eg1}$, $\Delta S_{eg2}$, $\Delta S_{eg3}$, and $\Delta S_{eg4}$ mean the $S_e$ increment caused by gravity effect in four different $D$ simulations. $S_e$ decreases with the decrease of parameter $D$ when considering the gravity effect in homogeneous simulations (red line in Figure 9). However, the location of the well has a very small effect on $S_e$ when the gravity effect is ignored (blue line in Figure 9). The increment of $S_e$ caused by the gravity effect is weakened with the decrease of $D$ (from $\Delta S_{eg1}^1 = +0.0677$ to $\Delta S_{eg1}^2 = +0.0529$, $\Delta S_{eg2}^1 = +0.0418$, and $\Delta S_{eg3}^1 = +0.0056$). Compared to Figure 6(a), the contour map of CO$_2$ is not changed obviously when the location of the injection well is changed, they all show the shape of the funnel, and the maximum migration line of CO$_2$ is about 3,000 m from the injection well (Figure 10). The above results indicate that salt precipitation can be reduced by shortening the distance from the injection well to the caprock ($D$), without affecting the CO$_2$ storage efficiency.

In the laboratory experiment, the limit size of the sample would limit the flow caused by gravity, and it would obtain a much smaller $S_e$ value to compare to the real site situation.

4.2. Effect of Formation Heterogeneity on $S_e$

4.2.1. The Fracture Model. In Case 2, a single horizontal factual of 525 m long and 1 m wide near the injection well was built (Figure 2); hydrogeological parameters of the fracture model are given in Tables 1 and 2. This section only considers the effect of formation heterogeneity on $S_e$ and does not consider the gravity effect. The simulation results are given below after a 1-year simulation.

In Figure 11(a), the fast flow of CO$_2$ due to the horizontal fracture is visible and the fracture is filled with CO$_2$ after a 1-year simulation ($S_e = 1.0$). The maximum migration line of CO$_2$ is about 2,800 m in the horizontal direction, which is larger than that in the homogeneous model in Figure 5(a). In Figure 11, the black circle areas show low $S_e$ zones. The low $S_e$ zones in Figure 11(a) indicate high liquid saturation ($S_l$) zones, and local high $S_e$ zones are formed in both the upper and lower parts of the fracture. In Figure 11(b), the local fast flow in the fracture makes the value of $S_e$ unusually high in the injection well. Except for injection wells, there is no salt precipitation in other areas (in Figure 11(b), the $S_e$ only appear in the injection well mesh). The $S_e$ value shows a linear rise to 0.746 in the injection well when the simulation ends (Figure 12(a)). However, the increase in salt precipitation did not reach a steady state. If the simulation time prolongs to $t_e$, the $S_e$ value could rise to 1.0 and lead to the complete blocking of the pore space at the time of 4.4384 $\times$ 10$^7$ s ($t_e$ in Figure 12(b); $t_e$ means the time that salt precipitation no longer increases; $t_e$ means 2-year simulation time). The $S_e$ difference compared to the homogeneous model in the 1-year simulation is $\Delta S_{eg} = +0.6400$ (Figure 12(a)). In Figure 12(b), the increment of $S_e$ caused by the fracture in this study can reach the maximum $\Delta S_{eg} = +0.8940$ if the simulation time has been extended. This complete blockage of the fracture structure is observed by several laboratory experiments, and solid precipitates mainly near the well where a high gas flow rate is maintained [30, 71, 72]. It is necessary to avoid fractures near the injection well when choosing the storage site although these fractures will not lead to CO$_2$ leakage.

4.2.2. Permeability Heterogeneous Models. Case 2-1, Case 2-2, and Case 2-3 were joined together to research the effect of heterogeneity with three permeability heterogeneous models. Different grid permeabilities were used to display the formation heterogeneity. Three different permeability distributions are given in Figure 3. The different permeability change intervals indicate different heterogeneities. The parameters used for the simulation are given in Tables 1 and 2. The simulation results are given below.

Compared to Figure 5(a), contour maps of $S_e$ in Figure 13 are all showing asymmetrical properties. Compared to simulation conditions, the difference in CO$_2$ distribution is mainly

![Figure 8: Idealized 2D schematic representation of the formation in this study for four different well locations.](image-url)

![Figure 9: $S_e$ value at the injection well for different $D$.](image-url)
attributed to the influence of heterogeneity. In Figure 13(a), $S_g$ in the lower part of the sand formation is greater than that in the upper part of the formation, because there are high-permeability channels in the lower part (Figure 3(a)). More low-permeability zones will be formed with increasing formation heterogeneity (Figures 3(b) and 3(c)). These low-permeability zones will be formed low $S_g$ areas, and more liquid is surrounded by gas, which indicates the preferential flow in the heterogeneous sand formation (Figure 13(b) and Figure 13(c)). Like the preferential flow caused by gravity, the preferential flow caused by the heterogeneity of the formation also increases the distance of $\text{CO}_2$ migration, from 2,200 m in the homogeneous model (Figure 5(a)) to 2,800 m in the heterogeneity model (Figure 13).

Figure 14 shows the time evolution of $S_s$ in the injection well for three different heterogeneity models and one homogeneous model. Compared with the $S_s$ value in the homogeneous model, the heterogeneous model causes a significant increase in $S_s$ at the injection well. As heterogeneity increases, the increase in $S_s$ increases from $\Delta S_{sH1} (+0.0045)$ to $\Delta S_{sH2} (+0.0077)$ and $\Delta S_{sH3} (+0.0080)$ (Figure 14). This means that the stronger the heterogeneity, the more salt precipitates at the injection well. This is consistent with previous research [73]. When the results of gravity effects are compared with the results of heterogeneity effects, the independent influence of formation heterogeneity on the $S_s$ value is much lower than that of gravity effect and fracture heterogeneity effect in this study.

4.3. Combining Gravity and Heterogeneity Effect. Gravity and heterogeneity exist at the same time in a real site project. Case 3, Case 3-1, Case 3-2, and Case 3-3 were joined to
investigate the collective effect of heterogeneity and gravity on the value of $S_h$. Schematic diagrams of heterogeneous models are shown in Figure 3. The simulation results are given below after a 1-year simulation.

In Figure 15, there are two significant preferential flows in the sand formation. The gathering of CO$_2$ at the bottom of shale formation means the preferential flow is caused by gravity; the local high $S_h$ flow passage in the horizontal direction means the preferential flow caused by fracture (Figure 15(a)), and the asymmetric sawtooth migration of CO$_2$ means the preferential flow caused by heterogeneity (Figures 15(b)–15(d)). The maximum CO$_2$ migration lines in these three different heterogeneity models are all more than 2,200 meters. However, this distance decreases with increasing heterogeneity, which shows the opposite result in Figure 13. Compared to Figure 6(a), the joining of gravity and heterogeneity decreases the CO$_2$ migration line in the horizontal direction; heterogeneity shows a resistance effect of the CO$_2$ migration line caused by the gravity effect.

The fracture is full of gas, and the upper and lower parts of the fracture are areas of high water saturation (Figure 15(a)). The black circle area in the figure is the area of high water saturation; the phenomenon of residual trapping of liquid is more obvious in the case of stronger heterogeneity (Figure 15(d)). These high water saturation zones could supply the additional mass of salt to the injection well in 2-year simulation.

Figure 12: Time evolution of $S_h$ and mass of salt at the injection well: (a) time evolution of $S_h$; (b) time evolution of $S_h$ at the injection well in 2-year simulation.

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Simulation results of case studies are given below. Figure 17 is the value at the injection well for different injection rates in three different models; the minimum heterogeneity model is used here (permeability change interval is -1.6~1.2). \(\Delta S_{sG}, \Delta S_{sG}^4, \Delta S_{sG}^5,\) and \(\Delta S_{sG}^6\) indicate the increment caused by gravity effect; \(\Delta S_{sH1}, \Delta S_{sH1}^4, \Delta S_{sH1}^5,\) and \(\Delta S_{sH1}^6\) mean the increment caused by the minimum heterogeneity effect. The value of \(\Delta S_s\) decreased as \(q\) increased in all three models; this is a common result of many scholars [19, 43, 44, 73, 76]. The gravity effect and the heterogeneity effect both can cause the \(S_s\) to increase at the injection well in all four \(q\) simulations. However, the increase of \(q\) would reduce the \(S_s\) value increment caused by the gravity effect (from \(\Delta S_{sG} = +0.0520\) to \(\Delta S_{sG}^6 = +0.0010\)) and heterogeneity effect (from \(\Delta S_{sH1} = +0.0045\) to \(\Delta S_{sH1}^6 = +0.0012\)). The increase in

Figure 13: Contour map of \(S_g\) of three different heterogeneity models: (a) low heterogeneity, permeability change interval is -1.6~1.2; (b) medium heterogeneity, permeability change interval is -3.5~2.5; (c) high heterogeneity, permeability change interval is -5~4.

Figure 14: Time evolution of \(S_s\) at the injection well for three different heterogeneity models.
S value caused by gravity is greater than that caused by heterogeneity in situations of 0.1585 kg/s, 0.22 kg/s, and 0.28 kg/s, which means that gravity has a dominant effect on solid aggravation. The difference in increment caused by gravity and heterogeneity in each q simulation is slowly shrieking. When it comes to the situation of 0.35 kg/s, the increase in the S value caused by gravity (ΔS_G = +0.0010) becomes smaller than that caused by heterogeneity (ΔS_H1 = +0.0012); the gravity no longer has a dominant effect on solid aggravation. This is mainly due to the high q that decrease gravity dominant, and the viscous force began to show a dominant force.

Figure 15: Contour map of S_g of four different heterogeneity models when considering gravity effect: (a) fracture heterogeneity; (b) low heterogeneity; (c) medium heterogeneity; (d) high heterogeneity.

Figure 16: Time evolution of S_s at the injection well for four different heterogeneous models: (a) time evolution of S_s for fracture heterogeneity; (b) time evolution of S_s at the injection well for three different heterogeneous models when considering the gravity effect.
In Figure 18, \( \Delta S_{\text{GH1}} \), \( \Delta S_{\text{GH2}} \), and \( \Delta S_{\text{GH3}} \) mean the \( S_s \) increment in three heterogeneous models compare to the homogeneous model when the gravity is considered. The \( S_s \) value is increased with the heterogeneity enhancement (from \( \Delta S_{\text{GH1}} = +0.0022 \) to \( \Delta S_{\text{GH2}} = +0.0037 \) and \( \Delta S_{\text{GH3}} = +0.0039 \)). This means that the stronger the heterogeneity, the more salt precipitates, which is similar to Figure 14 and opposite to Figure 16(b). The only difference between Figures 18 and 16(b) is the value of \( q \).

5. Conclusions

This paper researched the effect of gravity and heterogeneity on salt precipitation by using the numerical simulation method. The effect of gravity on salt precipitation was studied by changing the position of the injection well and determining whether to consider gravity. The effect of heterogeneity on \( S_s \) was studied by building four different heterogeneous models. The collective effect of gravity and heterogeneity on \( S_s \) was studied, which provides more information on the effect of formation heterogeneity. The main conclusions obtained from this study are as follows:

(i) Gravity has a great effect on preferential flow, which would influence the accumulation of salt precipitation near the injection well. The preferential flow caused by the gravity effect increased the \( S_s \) value in the injection well and changed the solid distribution in the sand layer compared to the simulation without the gravity effect. The influence of gravity could be reduced by changing the position of the injection well, that is, reducing the distance from the injection well to the caprock. Furthermore, in
the laboratory experiment, the limited size of the sample would underestimate the effect of gravity on $S_s$. This would underestimate the effect of salt precipitation compared to actual site conditions.

(ii) Formation heterogeneity has a significant effect on $S_s$. The fracture model is the most common heterogeneous model used in both laboratory experiments and site-scale simulations. The fracture near the injection well caused an abnormal increase in salt precipitation when not considering the gravity effect. If the injection time is long enough, the maximum $S_s$ value can increase to 1.0. Three different permeability heterogeneous models had been built according to the permeability range. When the gravity effect is not considered, the preferential flow of the formation increased with increasing heterogeneity; the stronger the heterogeneity, the greater the amount of precipitation near the well.

(iii) There is a competitive effect between gravity and heterogeneity on the value of $S_s$. The gravity effect decreases $S_s$ in the fracture model. When it comes to heterogeneous models with gravity, salt precipitation decreases with increasing heterogeneity. This conclusion is opposite to simulation results without gravity effect in heterogeneous models. Fracture heterogeneity would always keep a dominant effect on $S_s$ due to the high $S_s$ increase at the single effect simulation; gravity effect can limit preferential flow caused by the fracture. Formation heterogeneity has a low effect on $S_s$ compared to the gravity effect in a low $q$ situation. The heterogeneity effect can limit the preferential flow caused by gravity.

(iv) In addition to reducing the distance from the injection well to the caprock, the gravity effect can also be reduced by changing the dominant flow caused by gravity. At high $q$, viscous forces will control fluid distribution, and gravity forces will not dominate the flow. When heterogeneity becomes the dominant effect on $S_s$, the amount of salt precipitation and the intensity of heterogeneity are positively correlated, which means that the $S_s$ value will increase with the increases in heterogeneity.

(v) The results of this article can give some inspiration to the site project. Reducing the distance from the injection well to the caprock can effectively reduce salt precipitation at the injection well. Fractures near injection wells must be avoided, and they can lead to large accumulations of salt deposits. At low $q$, gravity forces will dominate CO$_2$ flow; heterogeneity, in turn, inhibits the growth of salt precipitation in injection wells. Regions with strong heterogeneity can be chosen to inject when the $q$ cannot be increased. At high $q$, viscous forces dominate the CO$_2$ flow, and selecting a relatively homogeneous formation injection helps reduce salt precipitation. If possible, increased $q$ can effectively reduce salt precipitation under certain formation conditions.

**Nomenclature**

- $D$: Distances between the injection well and caprock
- $g$: Gravity
- $k$: Permeability
- $k_0$: Initial permeability
- $k_r$: Absolute permeability
- $k_r'$: Relative permeability
- $k_{rg}$: Gas relative permeability
- $k_{rl}$: Liquid relative permeability
- $N_{gv}$: Gravity/viscous ratio
- $p$: Porosity
Data Availability

All data generated or analyzed during this study are included in this published article.

Conflicts of Interest

The authors declare that there is no conflict of interest regarding the publication of this paper.

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